Market Performance Report July 2020

September 14, 2020

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The main highlights of market performance for July 2020 are summarized below.

CAISO area performance:

- Peak loads for ISO area exceeded 40,000 MW for five days in July driven by hot weather.
- Across the integrated forward market (IFM), fifteen-minute market (FMM) and real-time market (RTD), PGAE prices were depressed for a few days due to transmission congestion.
- Congestion rents for interties fell to $17.40 million from $26.54 million in June. Majority of the congestion rents accrued on NOB (49 percent) and Malin500 (50 percent) intertie.
- In the congestion revenue rights (CRR) market, the balancing account for July had a surplus of approximately $10.64 million, which was allocated to measured demand.
- The monthly average ancillary service cost to load rose to $0.52/ MWh from 0.45/MWh in June. There were no scarcity events this month.
- The cleared virtual supply moved close to cleared demand in early July. The profits from convergence bidding escalated to $9.40 million from $2.25 million in June.
- The bid cost recovery increased to $11.64 million from $4.93 million in June.
- The real-time energy offset cost increased to $3.53 million in July from -$2.52 million in June. The real-time congestion cost rose to $11.54 million from $8.85 million in June.
- The volume of exceptional dispatch increased to 93,009 MWh from 74,905 MWh in June. The main reasons to the monthly volume were planned transmission outage and reliability assessment. The monthly average of total exceptional dispatch volume as a percentage of load percentage was 0.43 percent in July, inching up from 0.39 percent in June.

[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 NEVP prices spiked on July 30 due to renewable deviation and upward load forecast adjustment.
- The monthly average prices in FMM for EIM entities (AZPS, BANCSMUD, BCHA, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP) were $29.09, $25.74, $11.16, $22.32, $46.62, $24.38, $16.79, $16.16, $16.53, $15.78, and $29.27 respectively.
- The monthly average prices in RTD for EIM entities (AZPS, BANCSMUD, BCHA, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP) were $30.76, $25.32, $10.89, $23.76, $51.6, $25.53, $17.64, $16.42, $17.37, $16.09, and $29.21 respectively.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (AZPS, BANCSMUD, BCHA, IPCO, NEVP, PACE, PACW, PGE, PSEI, SCL and SRP) were $0.71 million, -$4.00 million and -$1.58 million respectively.

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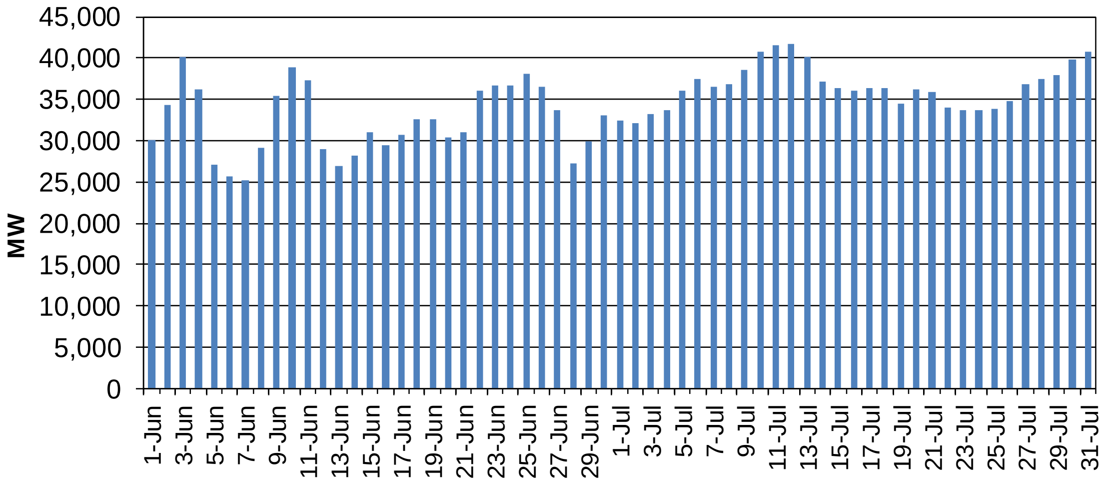
Market Characteristics

Loads

Peak loads for ISO area exceeded 40,000 MW for five days in July due to hot weather.

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 total non-availability charge, total availability incentive payment, system RA average actual availability, and flexible RA average actual availability separately.

Table 1: Resource Adequacy Availability and Payment

	Total Non-availability Charge	Total Availability Incentive Payment	Flexible Average Actual Availability	System Average Actual Availability
Jan19	$1,381,334	-$1,381,334	98.25%	96.69%
Feb19	$1,858,922	-$1,837,042	95.73%	97.27%
Apr19	$3,792,889	-$2,039,727	93.83%	93.72%
May19	$2,809,132	-$2,753,623	93.31%	97.51%
Jun19	$3,331,178	-$1,992,534	92.66%	96.62%
Jul19	$1,648,195	-$2,042,559	97.03%	97.01%
Aug19	$2,214,156	-$2,728,227	97.45%	95.96%
Sep19	$3,162,035	-$2,988,545	96.77%	94.98%
Oct19	$1,094,547	-$2,247,052	97.51%	97.52%
Nov19	$1,818,975	-$2,127,382	96.60%	95.59%
Dec19	$3,040,198	-$2,441,759	94.59%	95.48%
Jan20	$1,510,951	-$1,510,951	96.91%	97.32%
Feb20	$2,560,794	-$1,957,751	97.37%	94.29%
Mar20	$2,020,680	-$2,200,356	96.30%	96.43%
Apr20	$1,615,066	-$2,038,434	96.84%	97.14%
May20	$1,692,803	-$1,692,803	96.57%	97.00%
Jun20	$1,633,691	-$1,633,691	97.48%	96.41%
Jul20	$3,491,083	-$2,618,070	97.19%	94.48%

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 dates when the binding constraints resulted in relatively high or low DLAP prices.

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

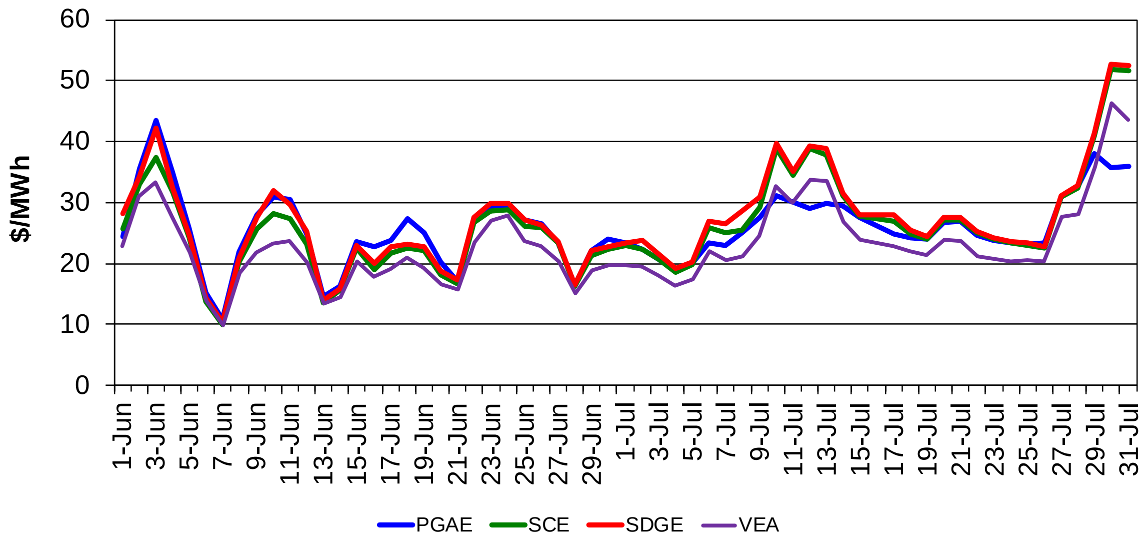


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDGE	July 10-13	MIDWAY-VINCENT-500 kV line
PGAE	July 29-31	MIDWAY-VINCENT-500 kV line

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 dates when the binding constraints resulted in relatively high or low DLAP prices. July 11 saw elevated prices for all four DLAPs due to upward load forecast adjustment.

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

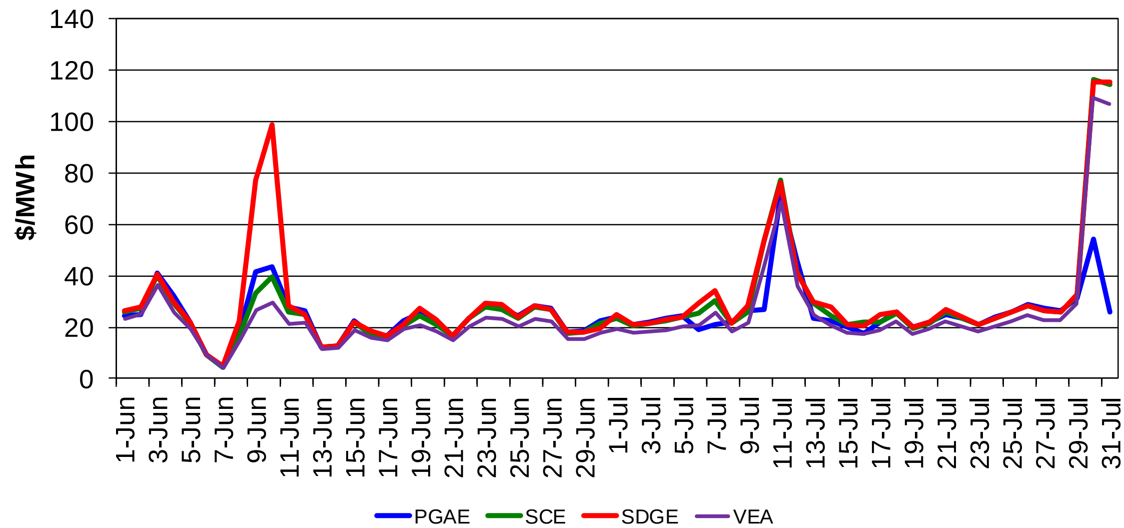
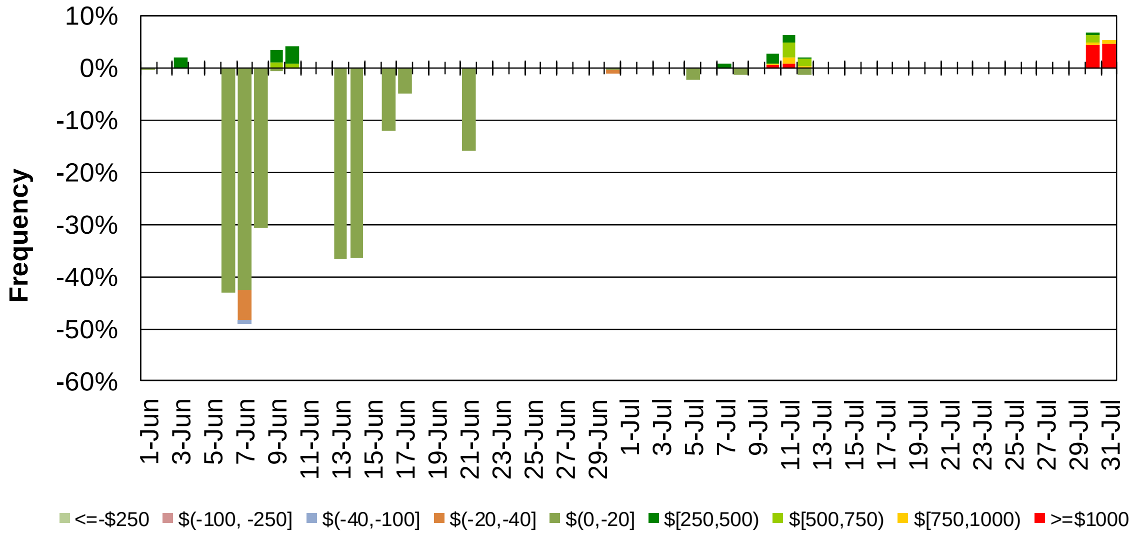


Table 3: FMM Transmission Constraints

DLAP	**Date**	**Transmission Constraint**
PGAE	July 10	MIDWAY-WIRLWIND-500 kV line, 6410_CP1_NG
PGAE	July 30	MIDWAY-VINCENT-500 kV line, MIDWAY-WIRLWIND-500 kV line
PGAE	July 31	MIDWAY-VINCENT-500 kV line, 6410_CP1_NG

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 0.78 percent in July from 0.32 percent in June. The cumulative frequency of negative prices dropped to 0.16 percent in July from 7.68 percent in June.

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 dates when the binding constraints resulted in relatively high or low DLAP prices. On July 11 all four DLAPs were elevated due to upward load forecast adjustment.

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

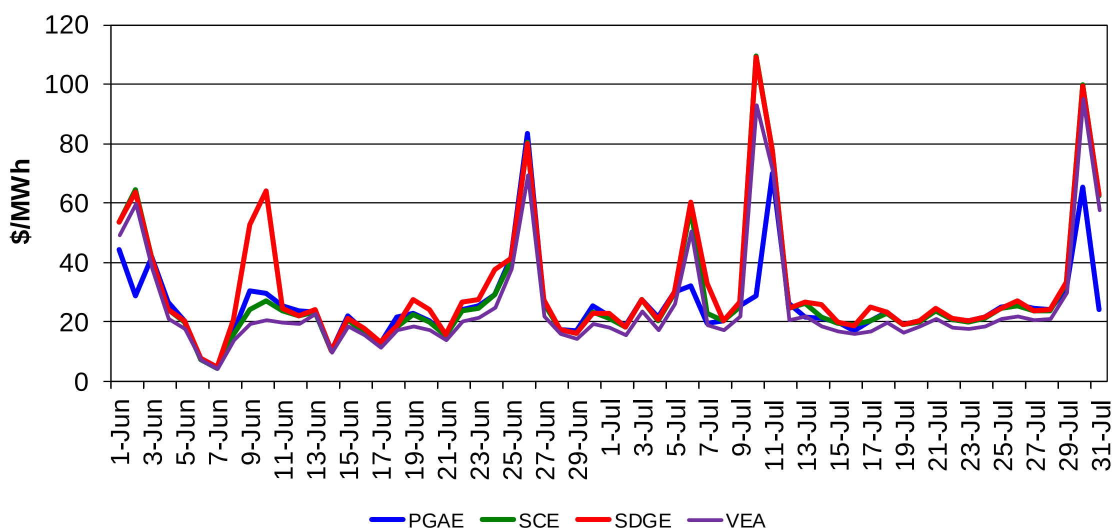


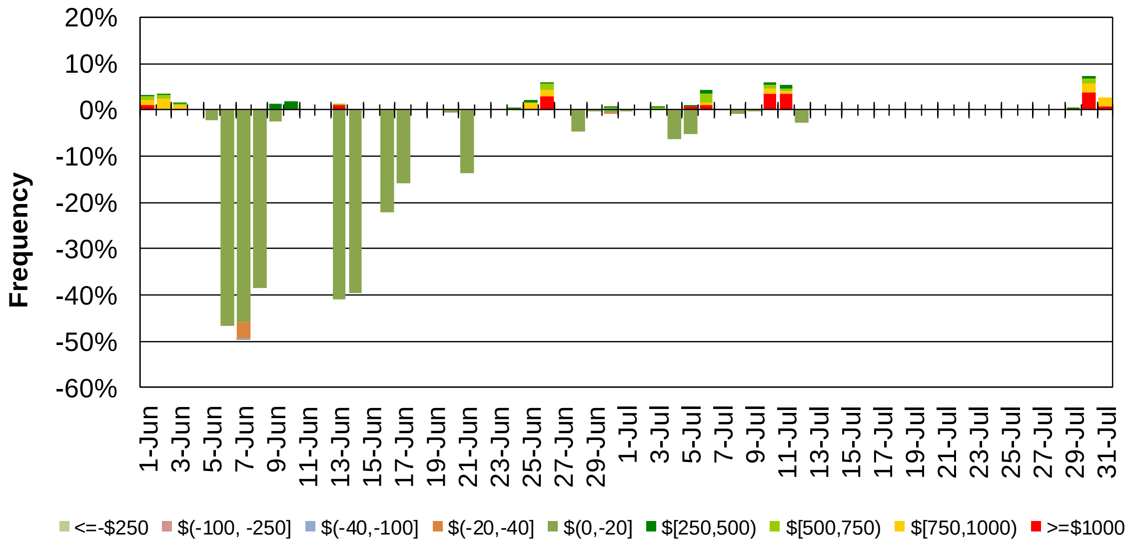
Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
PGAE	July 6	MIDWAY-VINCENT-500 kV line, MIDWAY-WIRLWIND-500 kV line
PGAE	July 10	6410_CP1_NG
PGAE	July 30	MIDWAY-VINCENT-500 kV line,

		MIDWAY-WIRLWIND-500 kV line
PGAE	July 31	MIDWAY-VINCENT-500 kV line, 6410_CP1_NG

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 increased to 0.92 percent in July from 0.74 percent in June. The cumulative frequency of negative prices skidded to 0.51 percent in July from 9.25 percent in June.

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



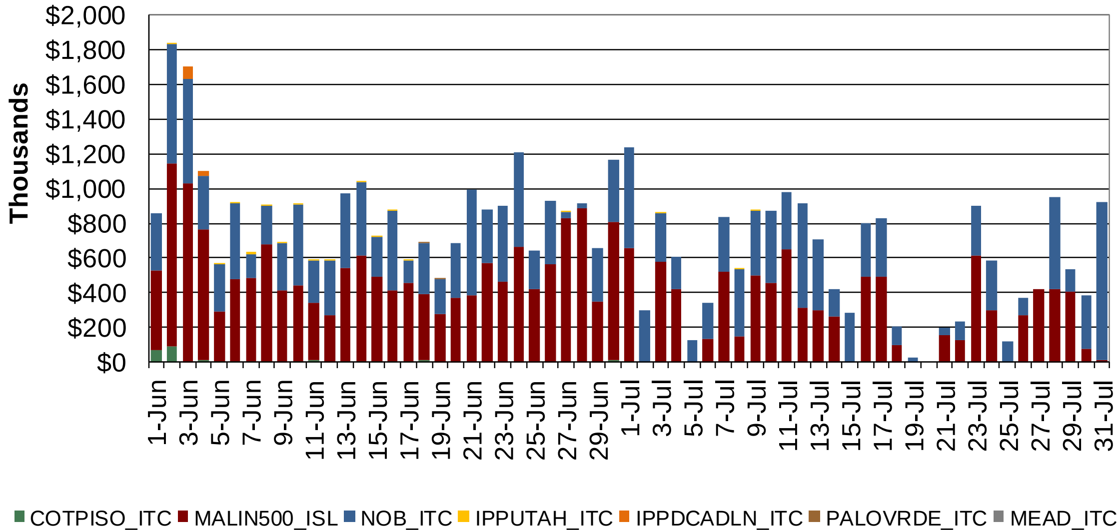
Congestion

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 July fell to $17.40 million from $26.54 million in June. Majority of the congestion rents in July accrued on NOB (49 percent) and Malin500 (50 percent) intertie.

The congestion rent on Malin500 fell to $8.82 million in July from $16.11 million in June. The congestion rent on NOB slid to $8.58 million in July from $10.01 million in June.

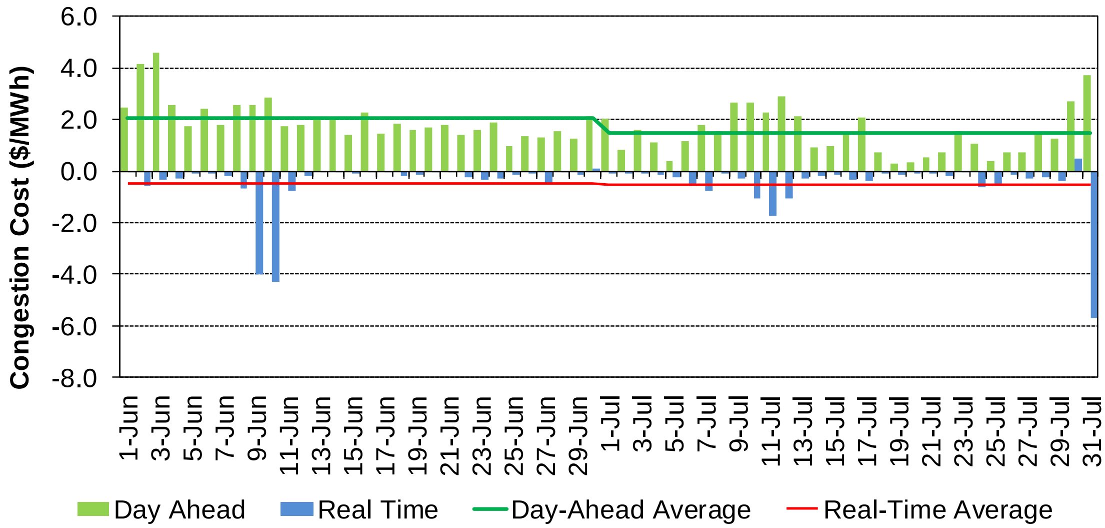
Figure 7: IFM Congestion Rents by Interties (Import)



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 decreased to $1.48/MWh in July from $2.05/MWh in June. The average congestion cost per load served in the real-time market inched down to -$0.54/MWh in July from -$0.49/MWh in June.

Congestion Revenue Rights

Congestion revenue rights auction efficiency 1B became in effect on January 1, 2019. It includes key changes related to the congestion revenue rights settlements process:

- Targeted reduction of congestion revenue rights payouts on a constraint by constraint basis.
- Distribute congestion revenues to the extent that CAISO collected the requisite revenue on the constraint over the month. That is, implement a pro-rata funding for CRRs.
- Allow surpluses on one constraint in one hour to offset deficits on the same constraint in another hour over the course of the month.
- Only distribute surpluses to congestion revenue rights if the surplus is collected on a constraint that the congestion revenue right accrued a deficit, and only up to the full target payment value of the congestion revenue right.
- Distribute remaining surplus revenue at the end of the month, which are associated with constraints that collect more surplus over the month than deficits, to measured demand.

Figure 9 illustrates the CRR notional value in the corresponding month for the various transmission elements that experienced congestion during the month. CRR notional value is calculated as the product of CRR implied flow and constraint shadow price in each hour per constraint and CRR.

Figure 9: Daily CRR Notional Value by Transmission Element

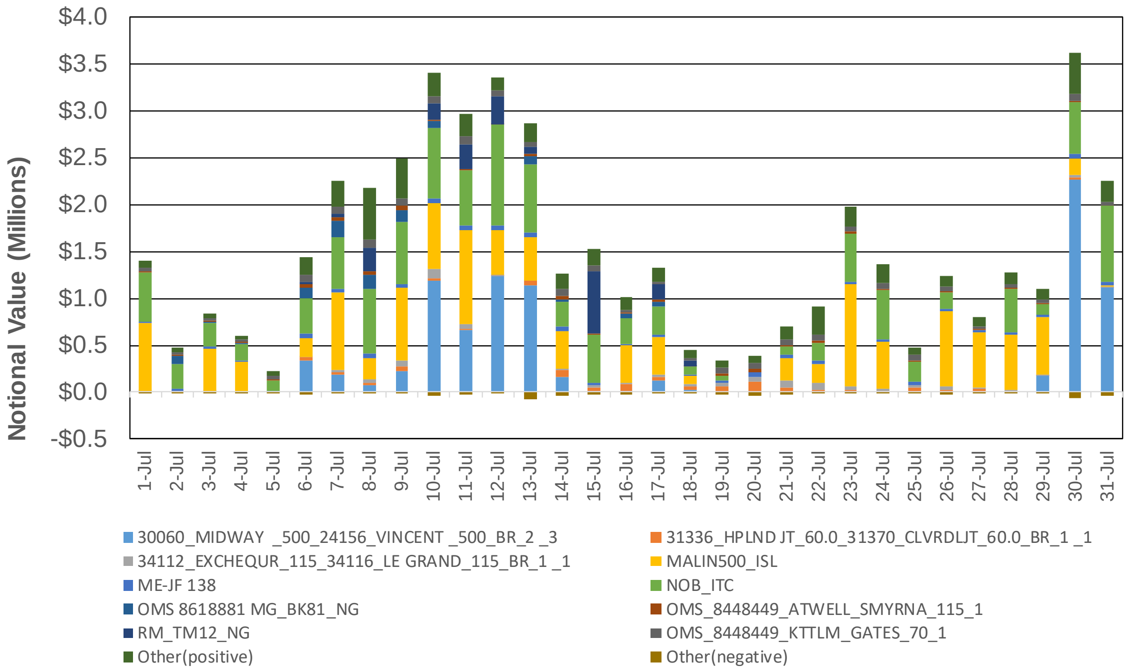
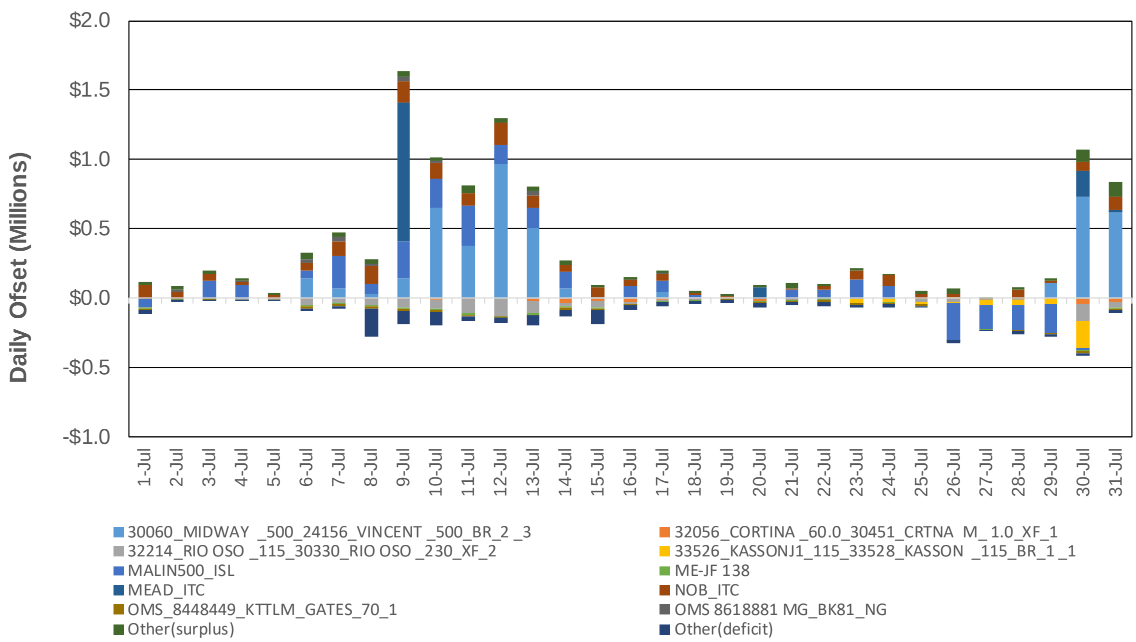


Figure 10 illustrates the daily CRR offset value in the corresponding month for the transmission elements that experienced congestion during the month.

Figure 10: Daily CRR Offset Value by Transmission Element



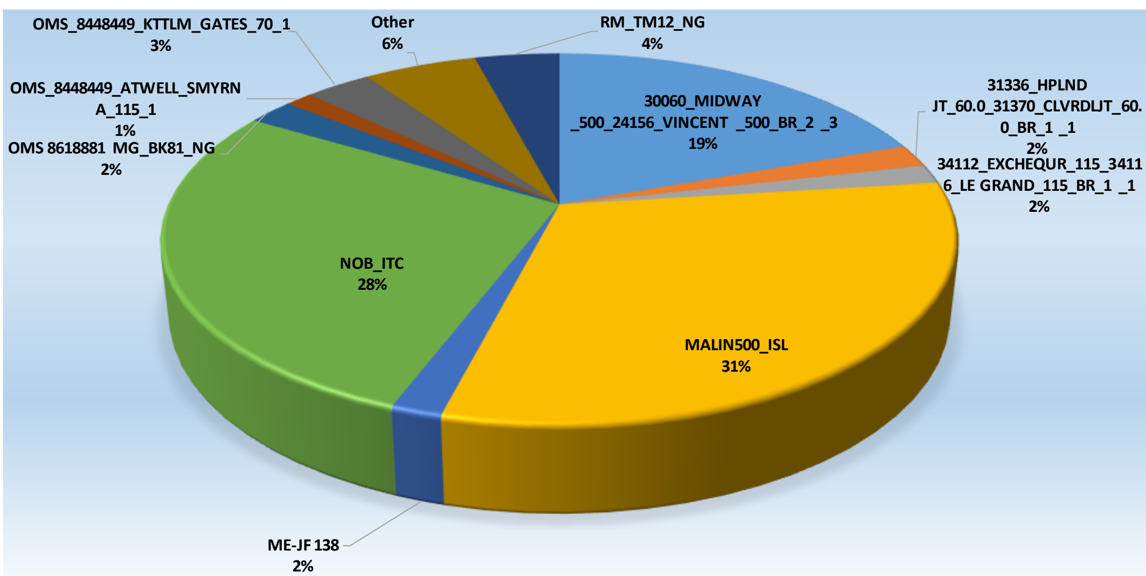
CRR offset value is the difference between the revenue collected from the day-ahead congestion and CRR notional value. It is also calculated in each hour per constraint and CRR. A positive CRR offset value represents surplus and a negative CRR offset value represents shortfall.

CRR offset surplus were observed in 23 days this month. The main reasons are

- The line 30060_MIDWAY _500_24156_VINCENT _500_BR_2 _3 was binding in 17 days of this month, resulting in offset surplus of $4.48 million. This line was binding in July mainly due to contingency enforced for local area protection and high demand in Southern California.
- The intertie NOB_ITC was binding in most days of this month, resulting in offset surplus of $1.85 million.
- The intertie MALIN500 was binding in 25 days of this month, resulting in offset surplus of $1.38 million. MALIN500 was binding in July mainly driven by high power flow on it and de-rates.

The shares of the CRR payment on various congested transmission elements for the reporting period are shown in Figure 11 and the monthly summary for CRR revenue adequacy is provided in Table 5.

Figure 11: CRR Payment by Transmission Element



Net monthly balancing surplus in July was $4.86 million. The auction revenues credited to the balancing account for July was $5.78 million. As a result, the balancing account for July had a surplus of approximately $10.64 million, which was allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

Row	Description	Formula	Amount
1	CRR Notional Value		$28,807,627
2	CRR Deficit		-$1,879,995
3	CRR Settlement Rule		-$296,422
4	CRR Adjusted Payment		$26,631,211
5	CRR Surplus		$5,763,264
6	Monthly Auction Revenue		$3,431,041
7	Annual Auction Revenue		$2,347,777
8	CRR Daily Balancing Account		$4,872,662
9	Net Monthly Balancing Surplus	row 5 + row 8 - (row 6 + row 7)	$4,857,109
10	Allocation to Measured Demand	row 6 + row 7 + row9	$10,635,927

Ancillary Services

IFM (Day-Ahead) Average Price

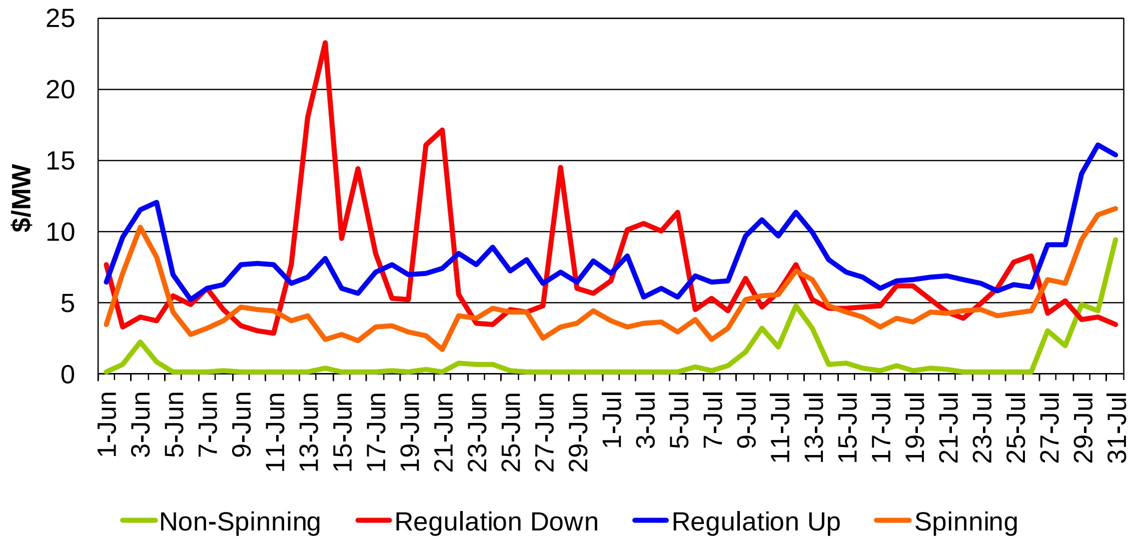
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In July the monthly average procurement rose for all types of ancillary services. .

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
Jul-20	346	474	1104	1101	$8.16	$5.98	$5.04	$1.43
Jun-20	336	381	1052	1053	$7.48	$7.55	$4.03	$0.31
Percent Change	2.97%	24.30%	4.91%	4.56%	9.10%	-20.79%	25.02%	366.11%

The monthly average prices increased for regulation up, spinning and non-spinning reserves in July. Figure 12 shows the daily IFM average ancillary service prices. The average prices for regulation up, spinning and non-spinning reserves increased on July 29-31 due to high opportunity cost of energy.

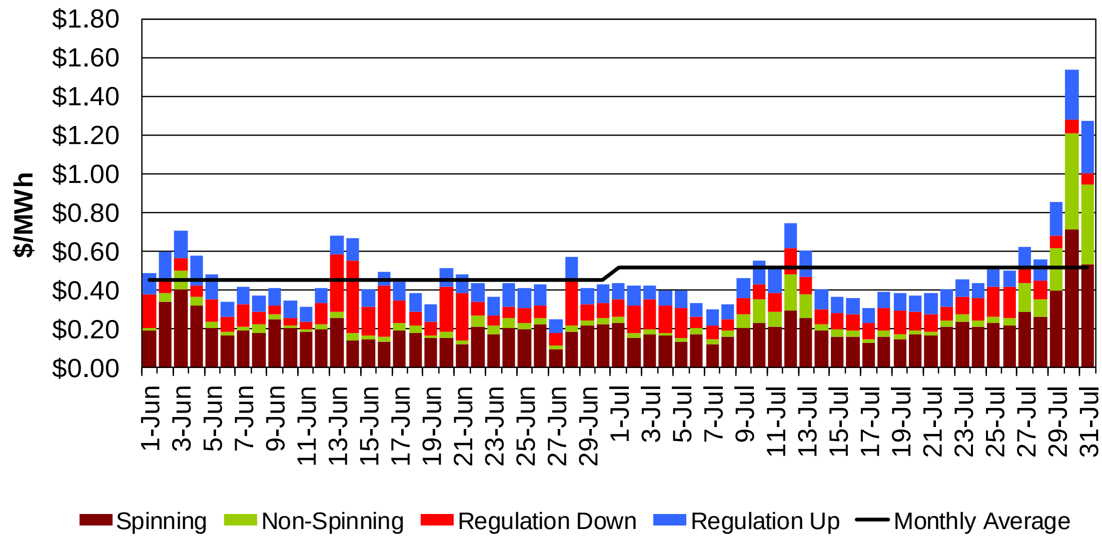
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load rose to $0.52/MWh in July from 0.45/MWh in June. July 29-31 saw relatively high average costs driven by high prices for regulation up, spinning and non-spinning reserves in day-ahead market.

Figure 13: System (Day-Ahead and Real-Time) Average Cost to Load



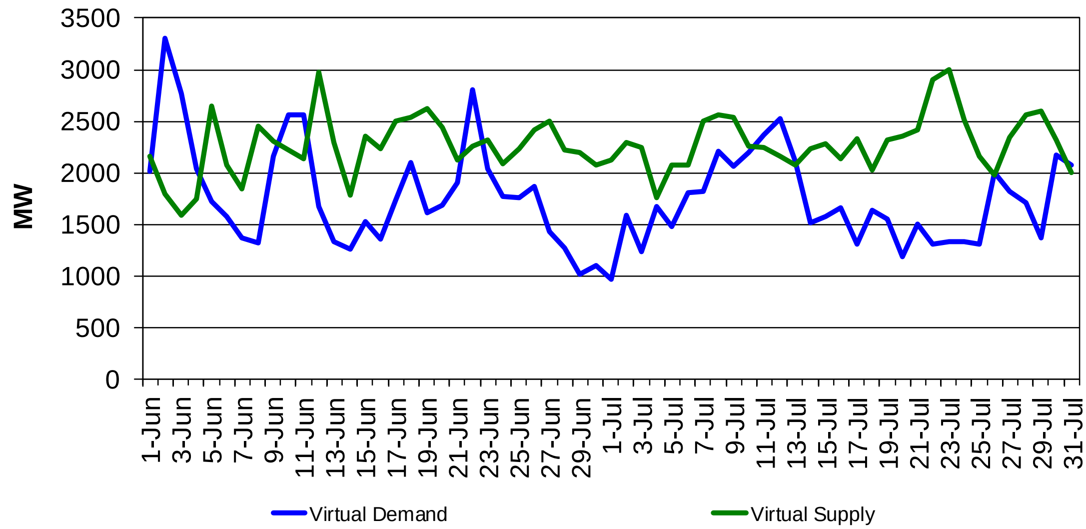
Scarcity Events

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. There were no scarcity events this month.

Convergence Bidding

Figure 14 below shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. The cleared virtual supply moved close to cleared demand in early July.

Figure 14: Cleared Virtual Bids



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or "converge". Figure 15 shows the energy prices (namely the energy component of the LMP) in IFM, hour ahead scheduling process (HASP), FMM, and RTD.

Figure 15: IFM, HASP, FMM, and RTD Prices

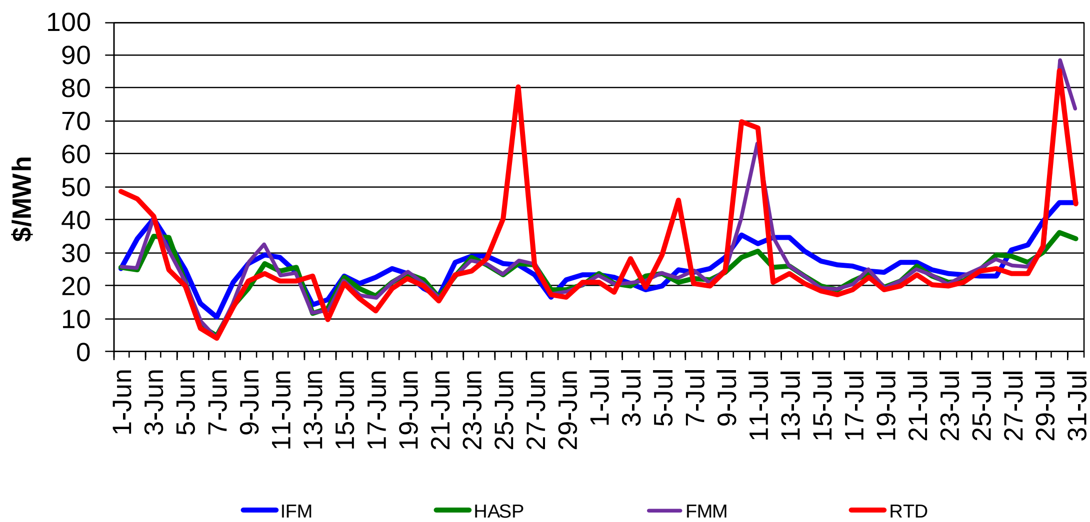
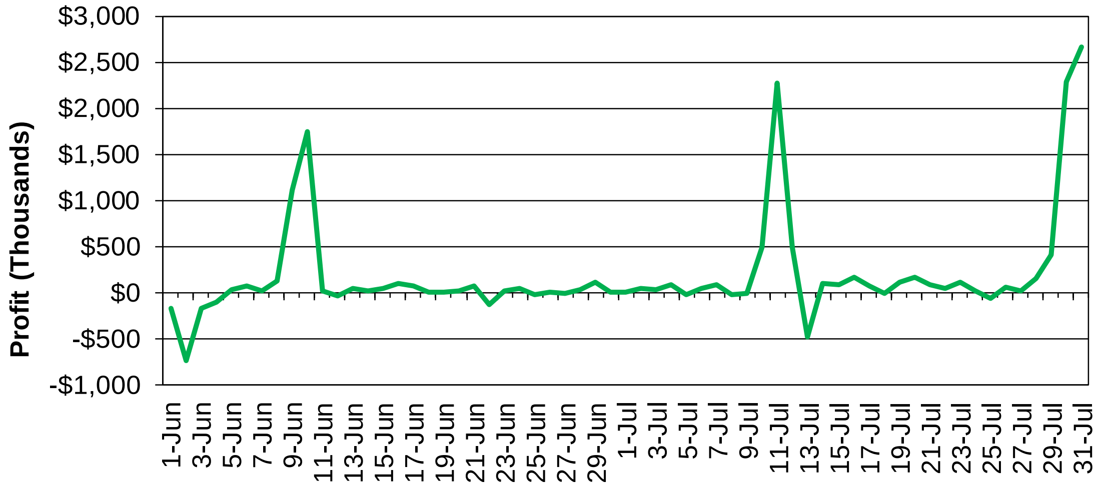


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding in July escalated to $9.40 million from $2.25 million in June. The majority of profits in July can be attributed to high profits on July 11 and 30-31 when FMM prices were much higher than DA prices.

Figure 16: Convergence Bidding Profits



Renewable Generation Curtailment

Figure 17 below shows the monthly wind and solar VERs (variable energy resource) curtailment due to system wide condition or local congestion in RTD. Figure 18 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 17 and Figure 18 below show, the renewable curtailment skidded in July. The majority of the curtailment was economic and solar.

Figure 17: Renewable Curtailment by Reason

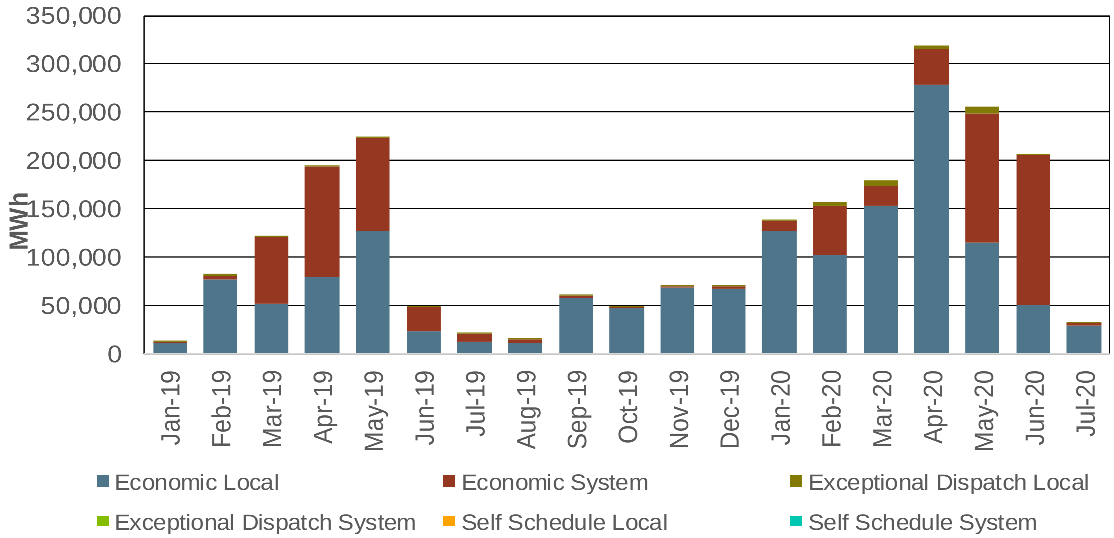
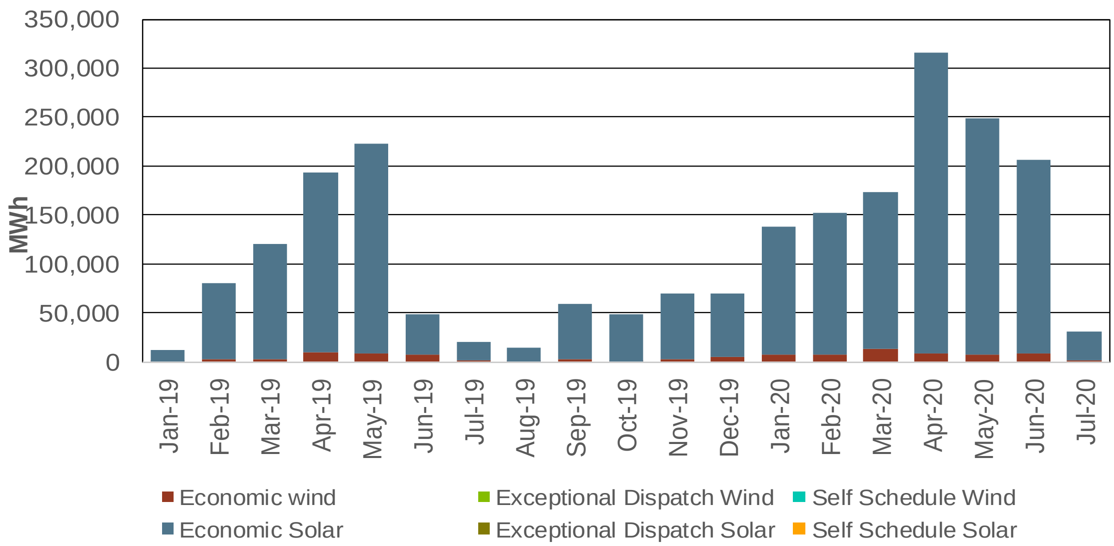


Figure 18: Renewable Curtailment by Resource Type



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 19 shows the flexible ramping up and down uncertainty payments. Flexible ramping up uncertainty payment increased to $94,236 in July from $20,953 in June. Flexible ramping down uncertainty payment decreased to $3,998 in July from $40,982 in June.

Figure 19: Flexible Ramping Up/down Uncertainty Payment

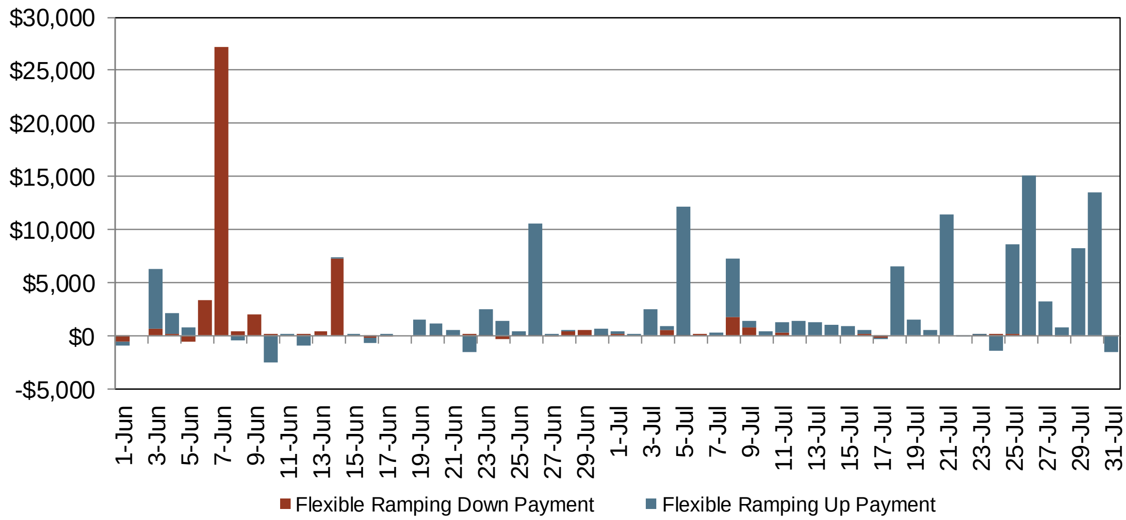
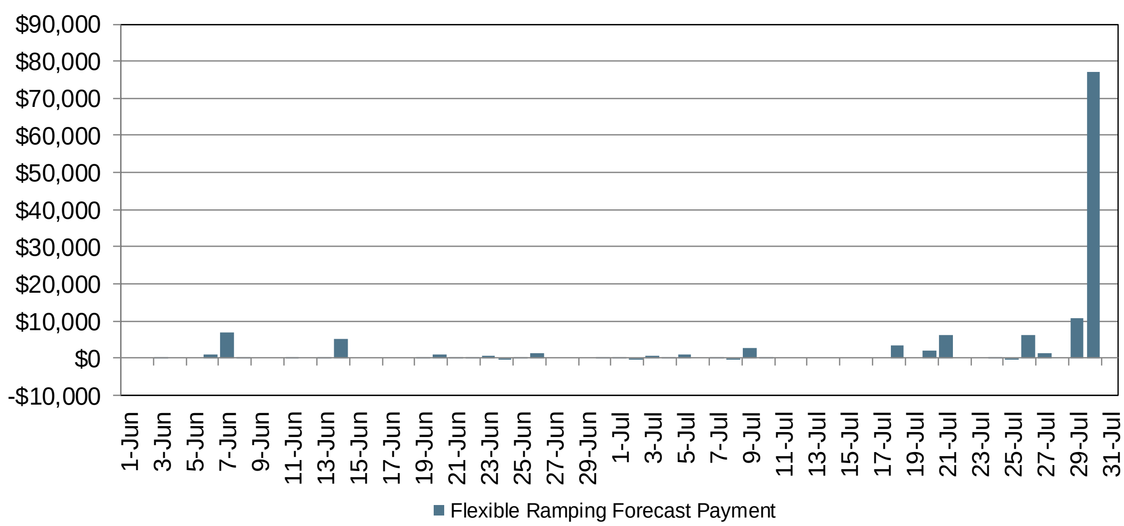


Figure 20 shows the flexible ramping forecast payment. Flexible ramping forecast payment rose to $111,865 this month from $17,227 in June.

Figure 20: Flexible Ramping Forecast Payment



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 21 shows the daily uplift costs due to exceptional dispatch payments. The monthly uplift costs in July increased to $443,043 from $32,621 in June. The uplift costs were high on July 30 and 31 due to the exceptional dispatches issued for unplanned outages and load forecast uncertainty.

Figure 21: Exceptional Dispatch Uplift Costs

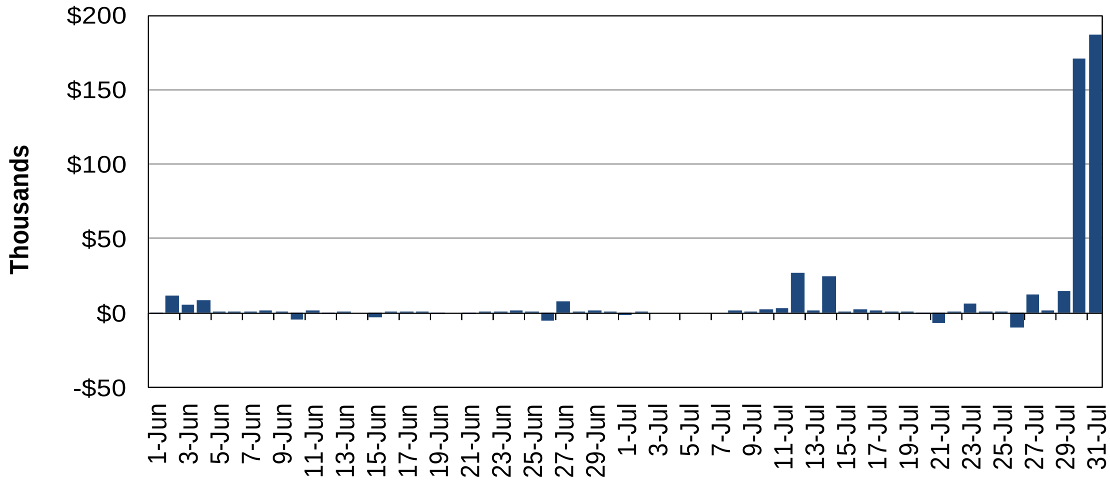


Figure 22 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for July increased to $11.64 million from $4.93 million in June. Out of the total monthly bid cost recovery payment for the three markets in July, the IFM market contributed 18 percent, RTM contributed 45 percent, and RUC contributed 37 percent of the total bid cost recovery payment.

Figure 22: Bid Cost Recovery Allocation

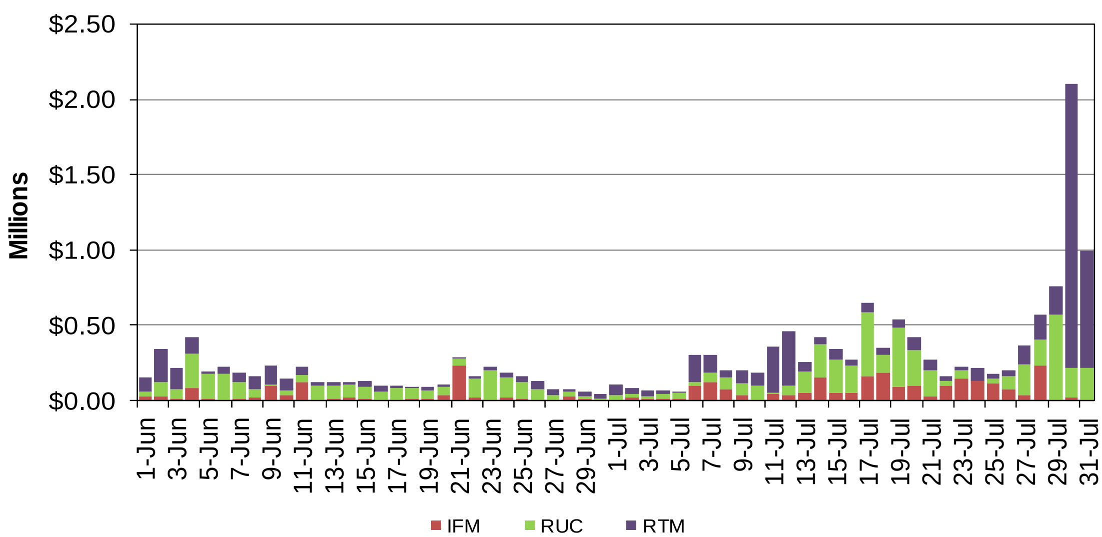


Figure 23 and Figure 24 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 23: Bid Cost Recovery Allocation by LCR

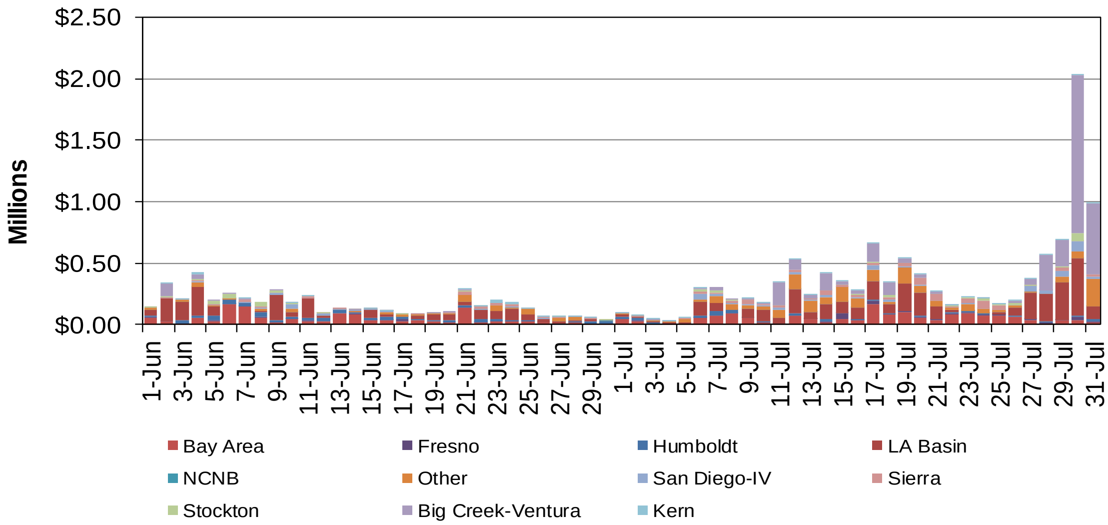


Figure 24: Monthly Bid Cost Recovery Allocation by LCR

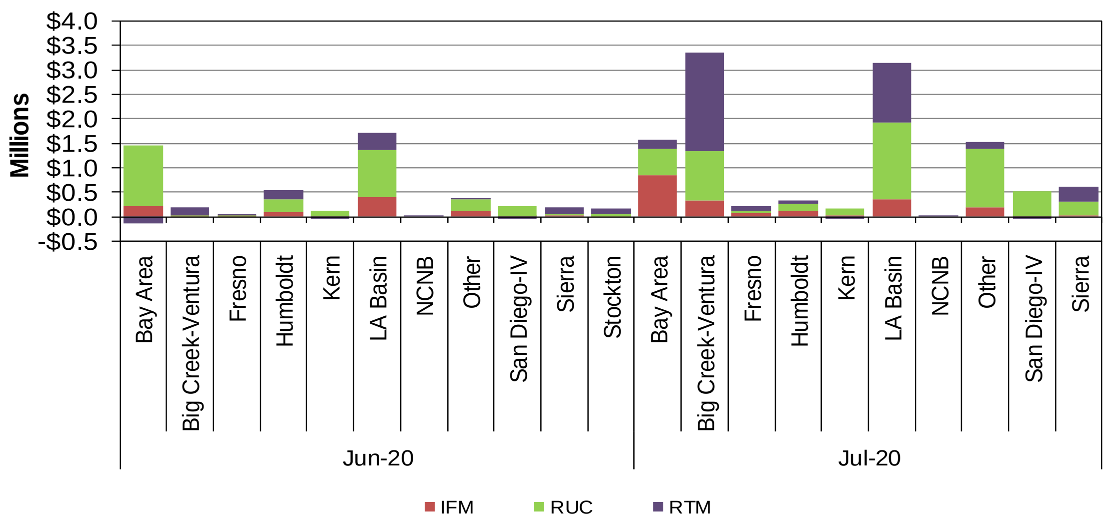


Figure 25 and Figure 26 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 25: Bid Cost Recovery Allocation by UDC

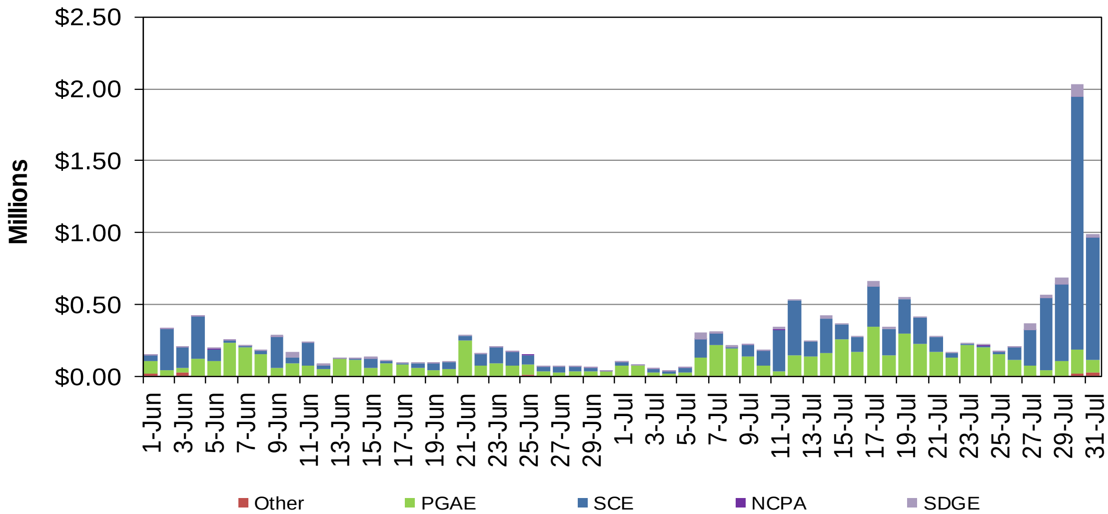


Figure 26: Monthly Bid Cost Recovery Allocation by UDC

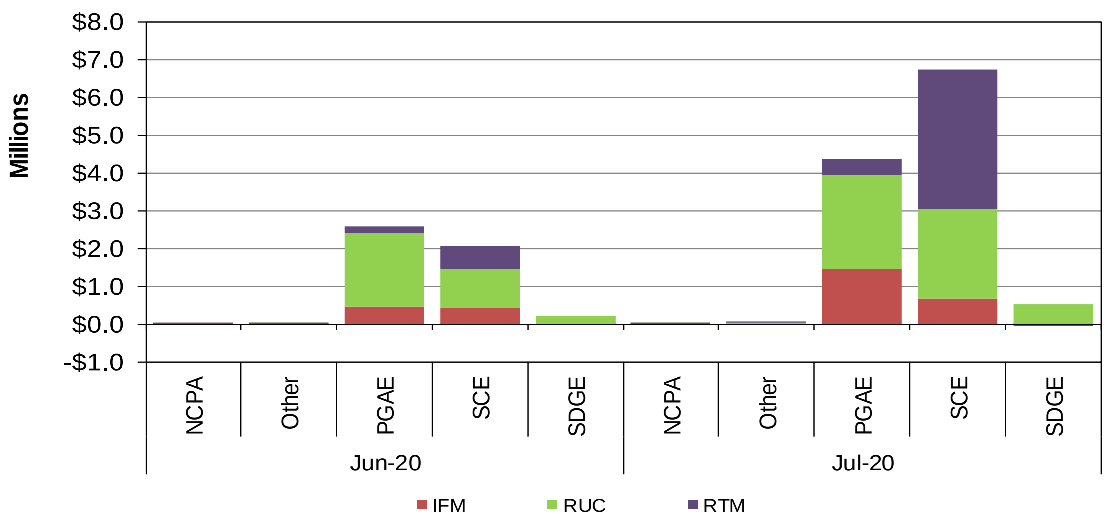


Figure 27 shows the cost related to BCR by cost type in RUC.

Figure 27: Cost in RUC

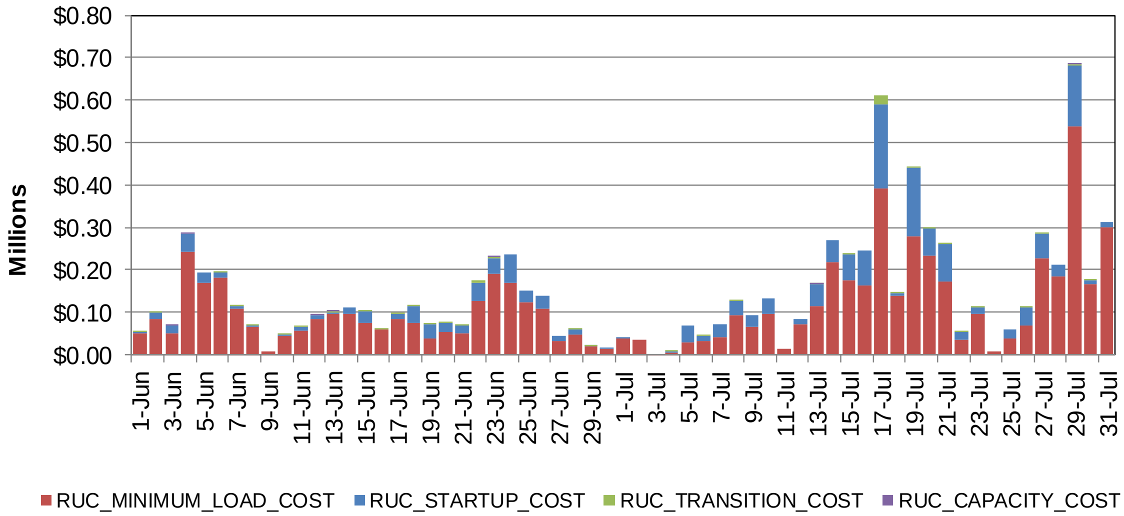


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 28: Cost in RUC by LCR

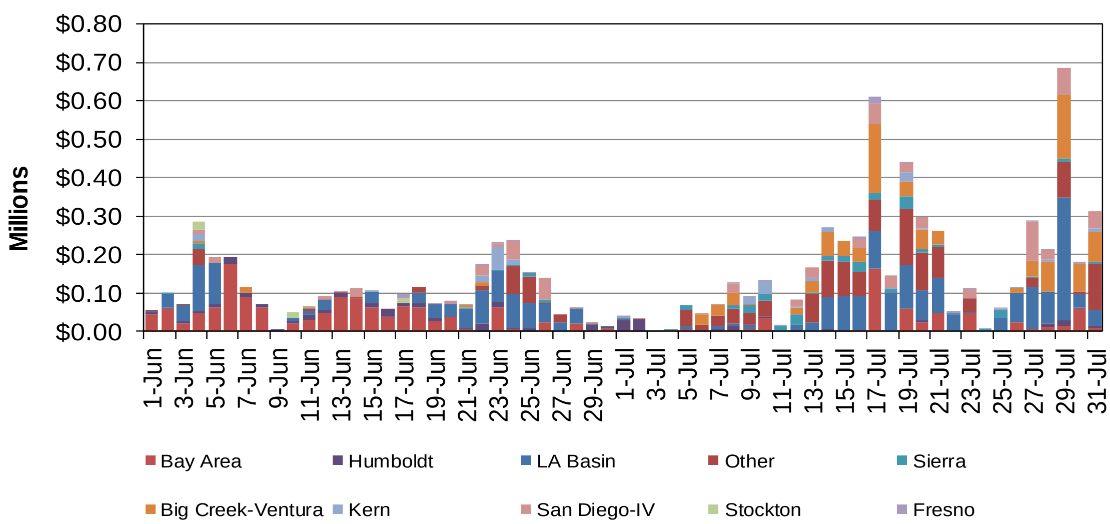


Figure 29: Monthly Cost in RUC by LCR

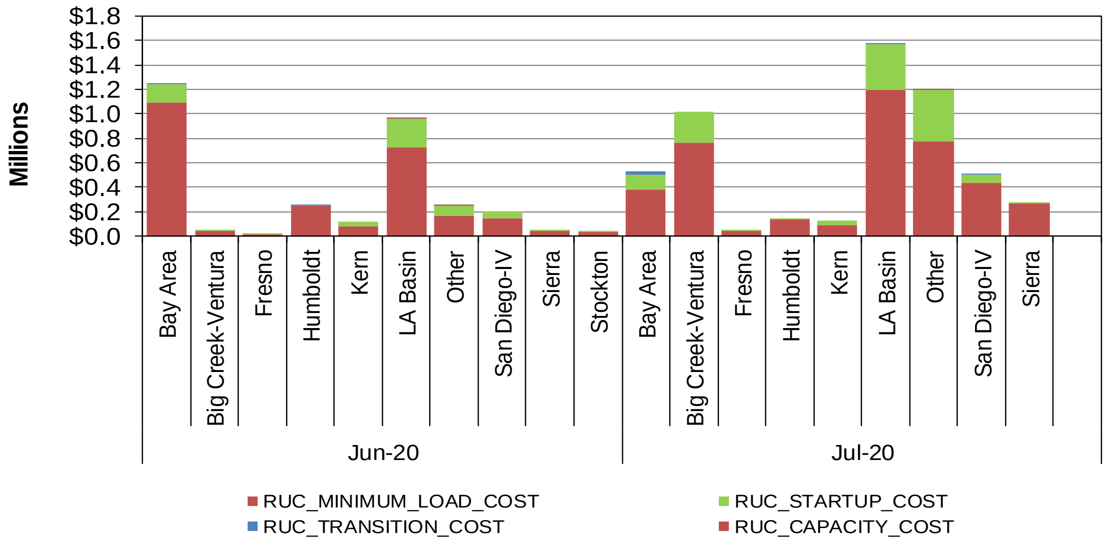


Figure 30 and Figure 31 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 30: Cost in RUC by UDC

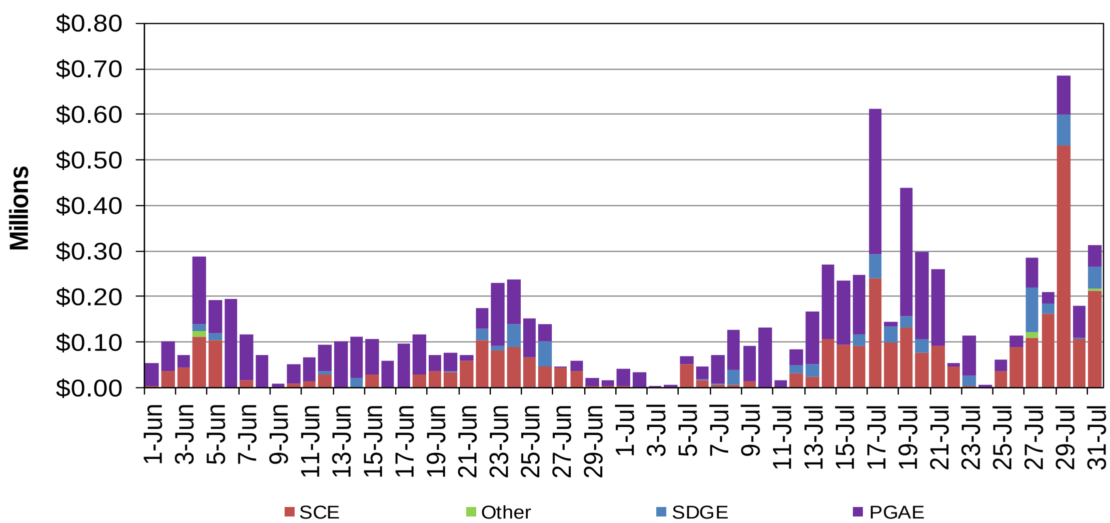


Figure 31: Monthly Cost in RUC by UDC

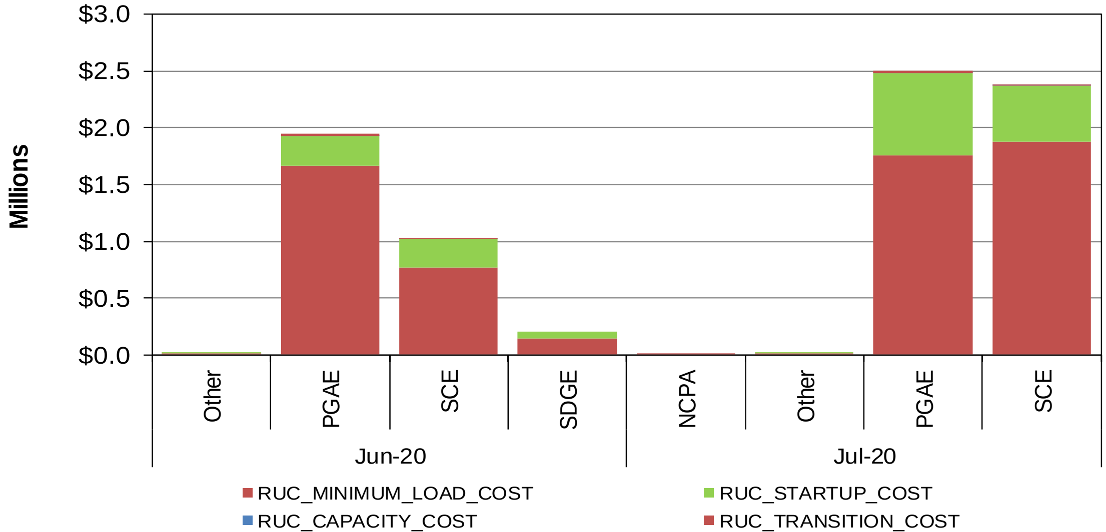


Figure 32 shows the cost related to BCR in real time by cost type. Minimum load cost contributed largely to the real time cost this month.

Figure 32: Cost in Real Time

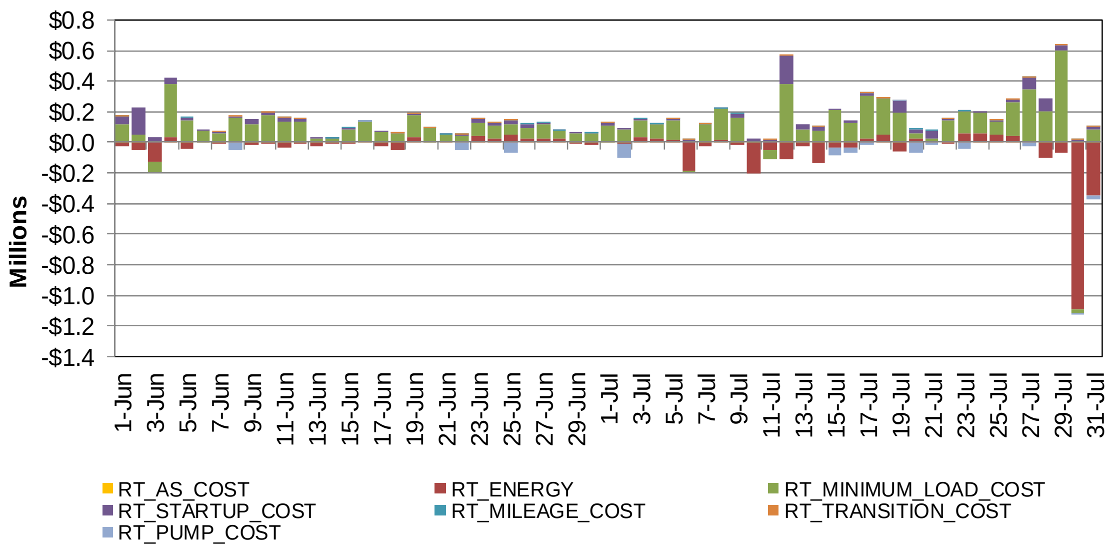


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 33: Cost in Real Time by LCR

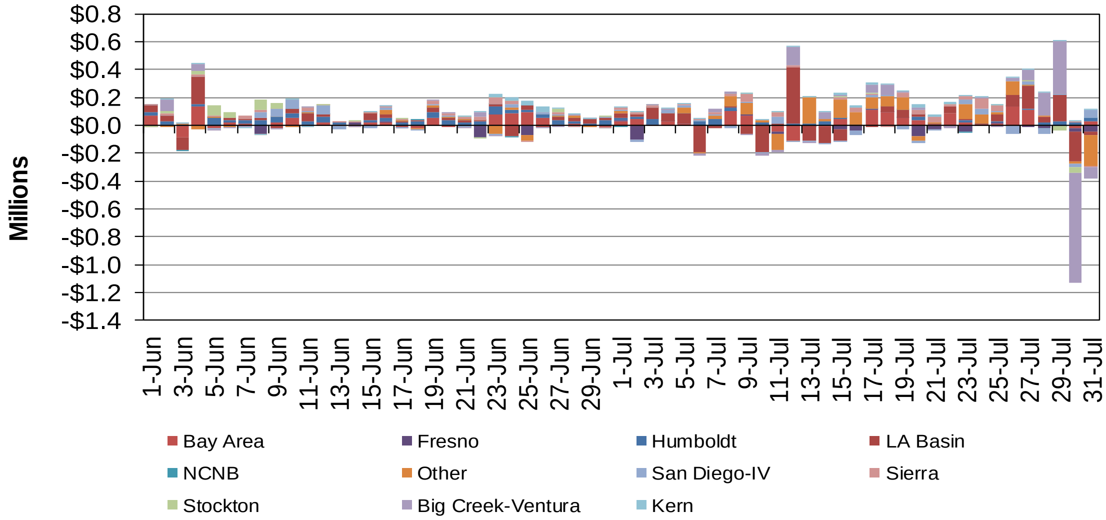


Figure 34: Monthly Cost in Real Time by LCR

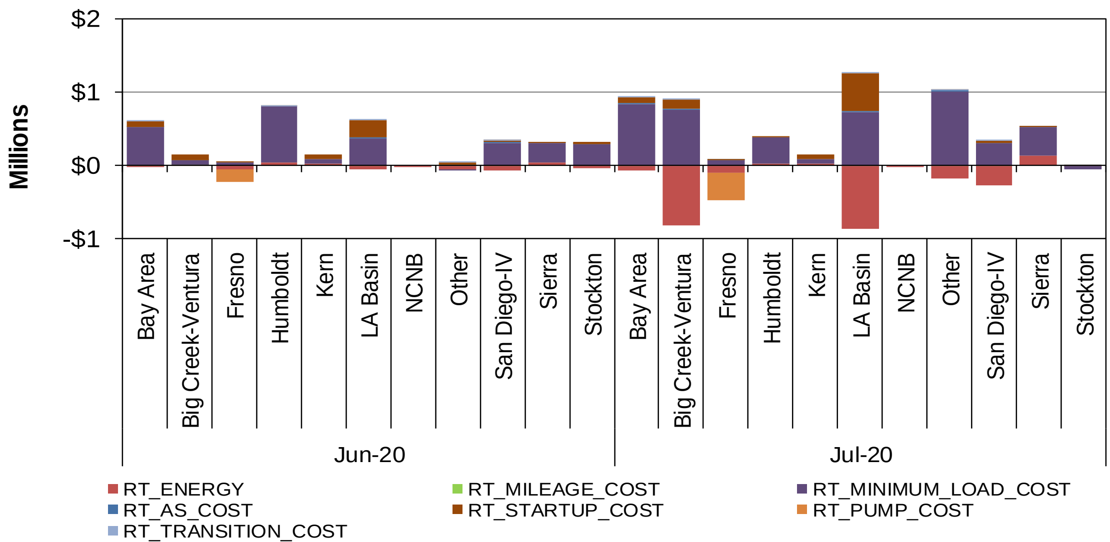


Figure 35 and Figure 36 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 35: Cost in Real Time by UDC

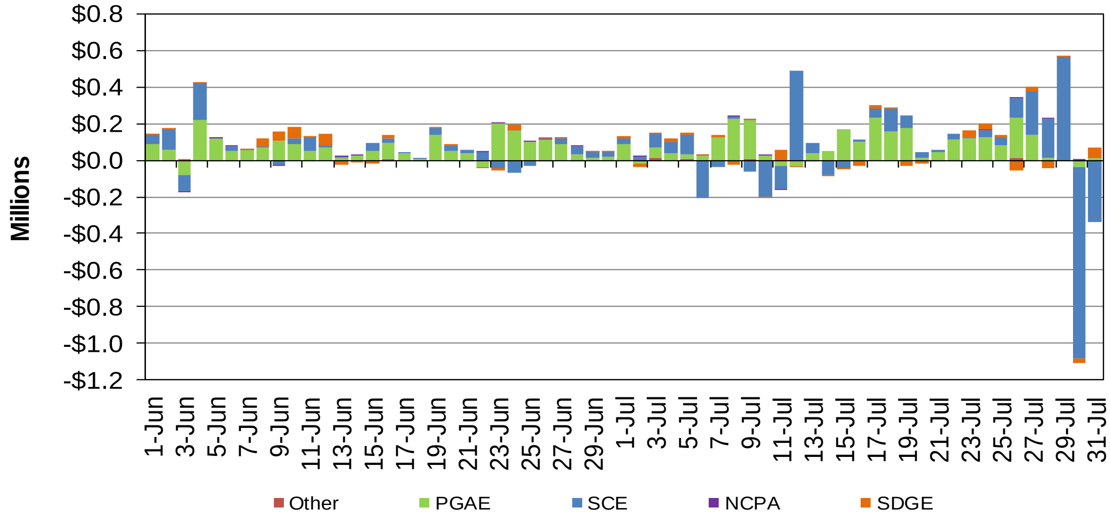


Figure 36: Monthly Cost in Real Time by UDC

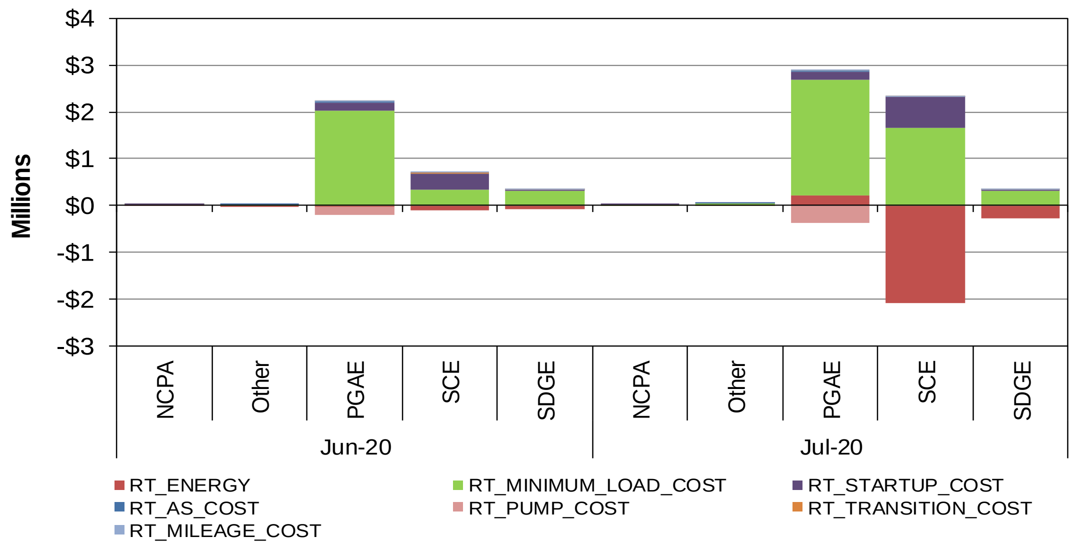


Figure 37 shows the cost related to BCR in IFM by cost type.

Figure 37: Cost in IFM

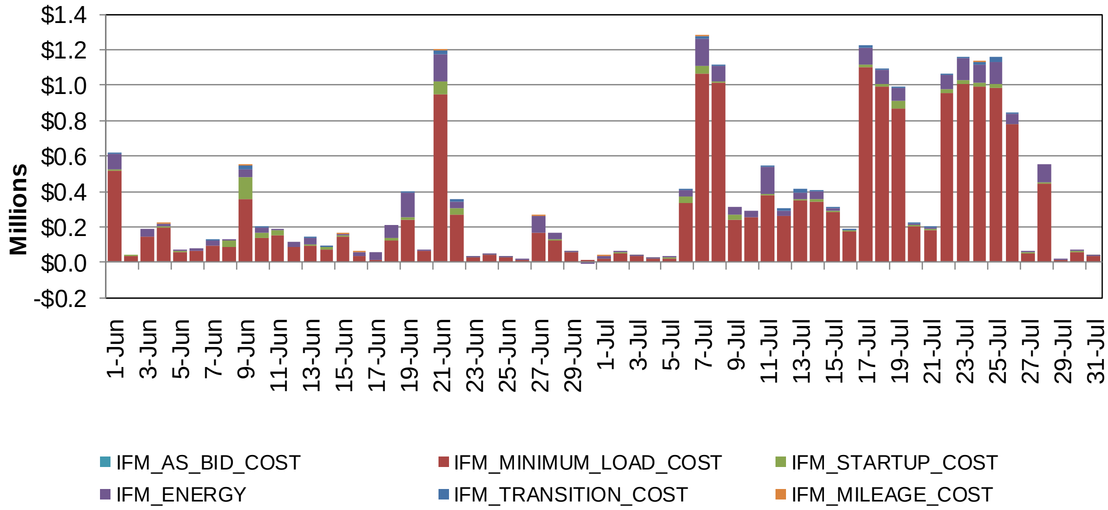


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 38: Cost in IFM by LCR

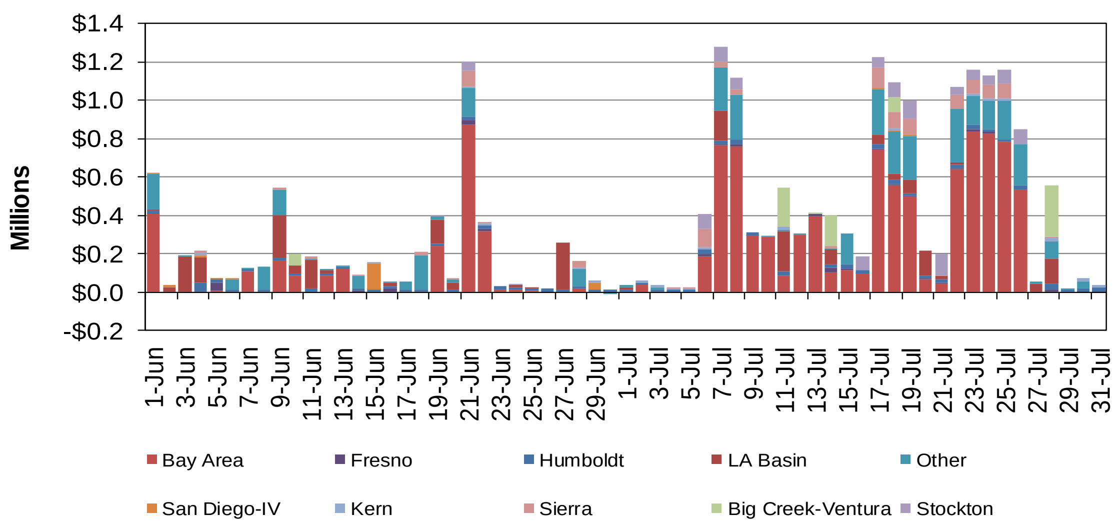


Figure 39: Monthly Cost in IFM by LCR

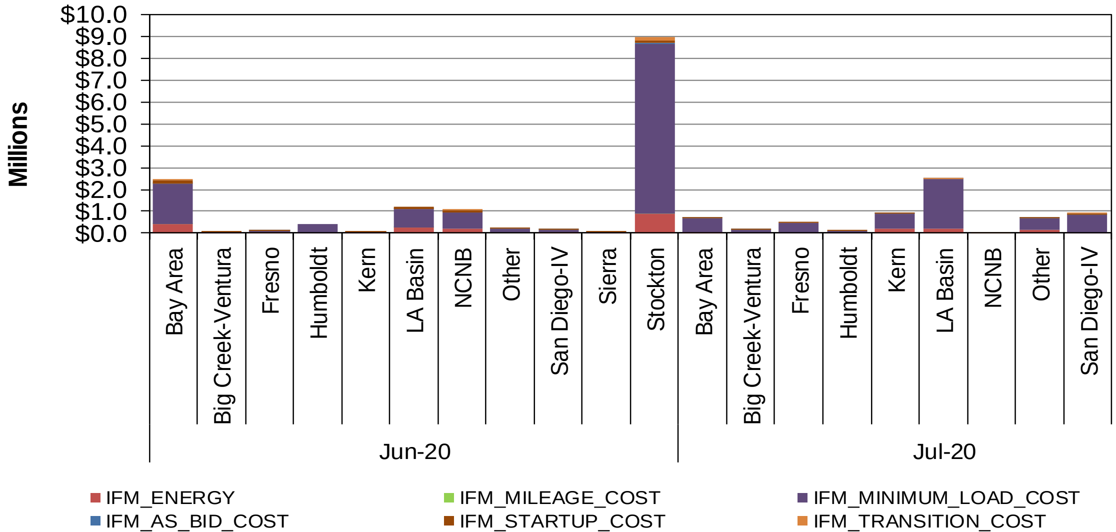


Figure 40 and Figure 41 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 40: Cost in IFM by UDC

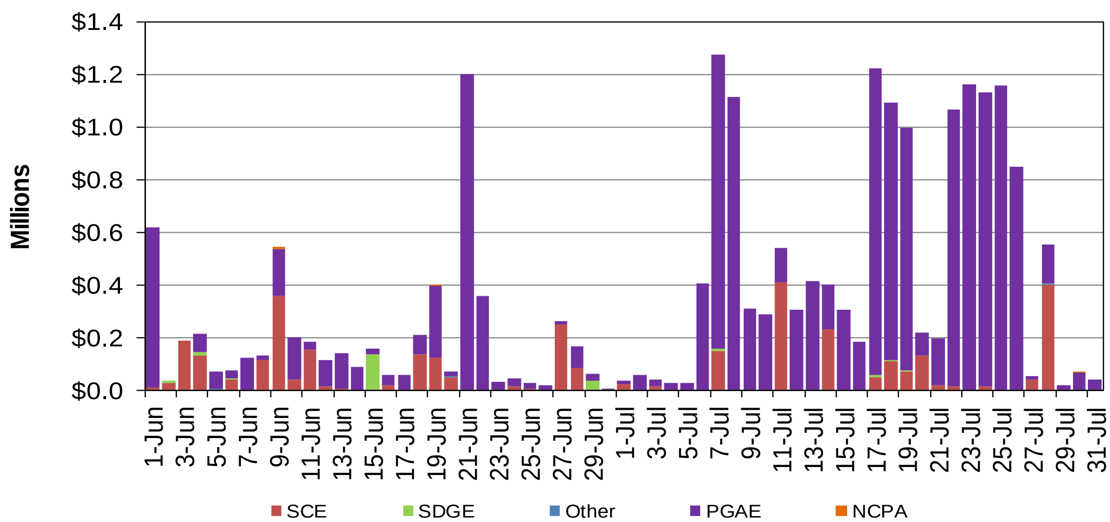
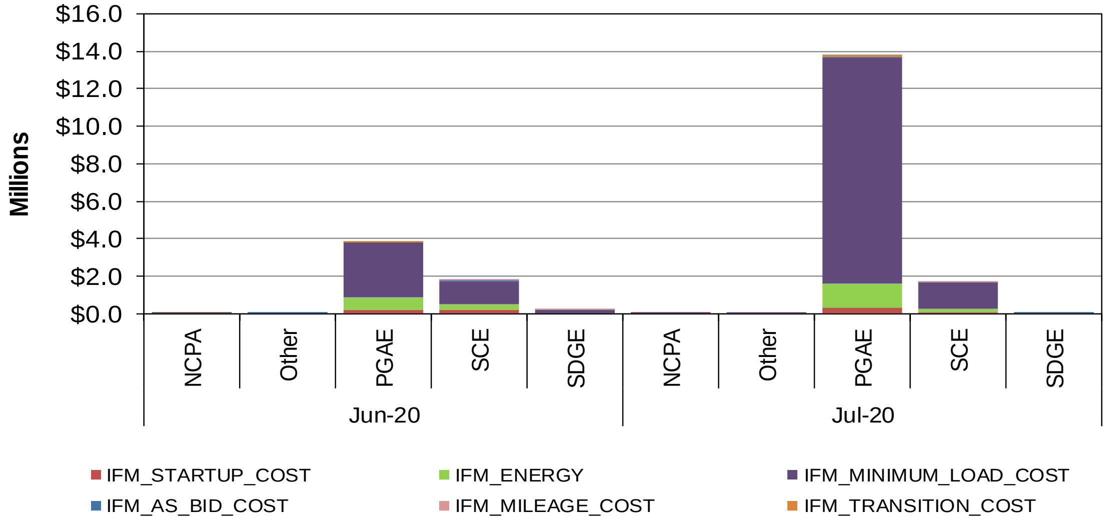


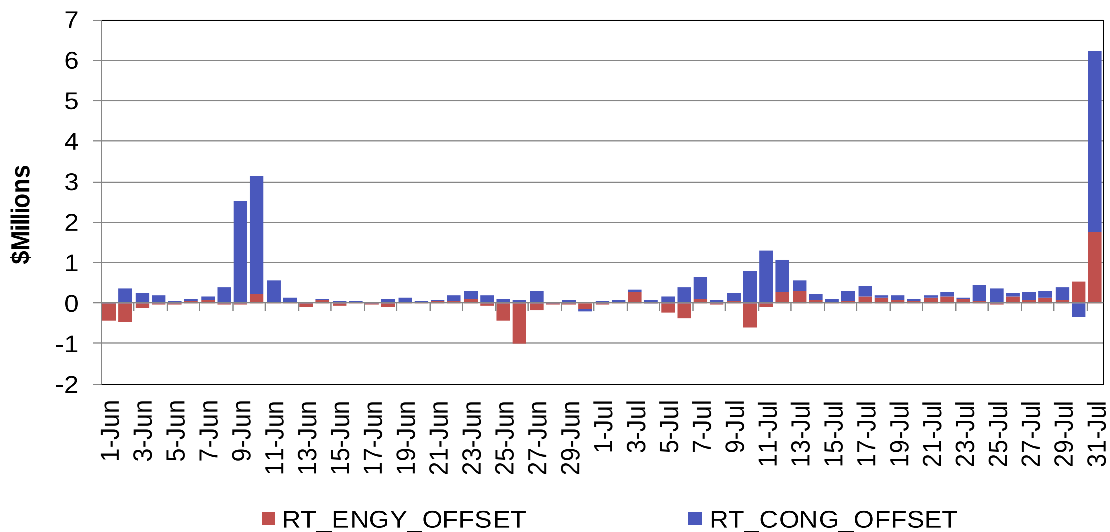
Figure 41: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 42 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost increased to $3.53 million in July from -$2.52 million in June. Real-time congestion offset cost in July rose to $11.54 million from $8.85 million in June.

Figure 42: 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.[2] 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.

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

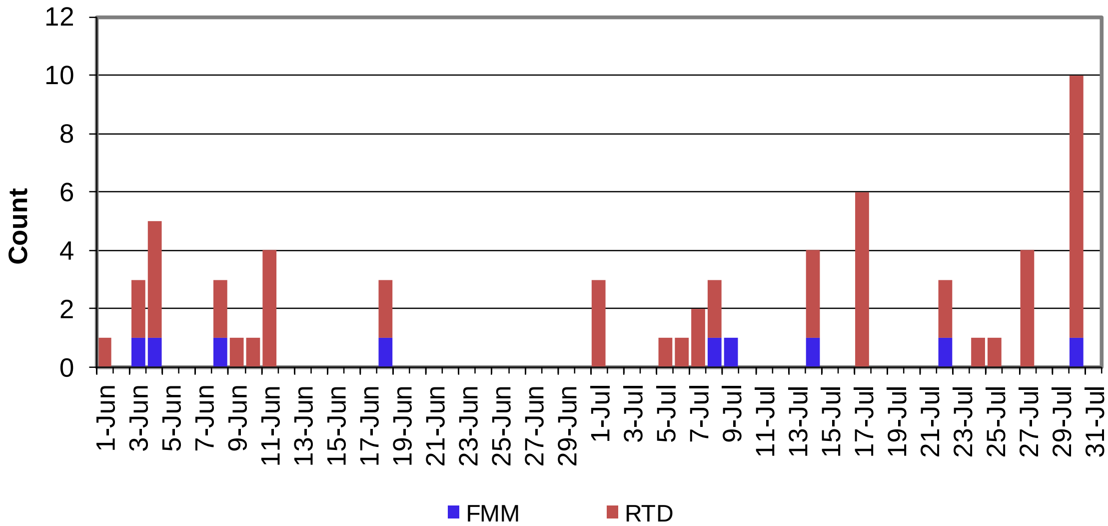
Table 7: Summary of Market Disruption

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	4	0
FMM Interval 2	0	0
FMM Interval 3	0	0
FMM Interval 4	1	0
Real-Time Dispatch	35	0

There were a total of 40 market disruptions this month. Figure 43 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On July 30, there were one FMM and nine RTD market disruptions due to application issue.

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

Figure 43: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 44 shows the daily volume of exceptional dispatches, broken out by market type: real-time incremental dispatch and real-time decremental dispatch. 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 July increased to 93,009 MWh from 74,905 MWh in June.

Figure 44: Total Exceptional Dispatch Volume (MWh) by Market Type

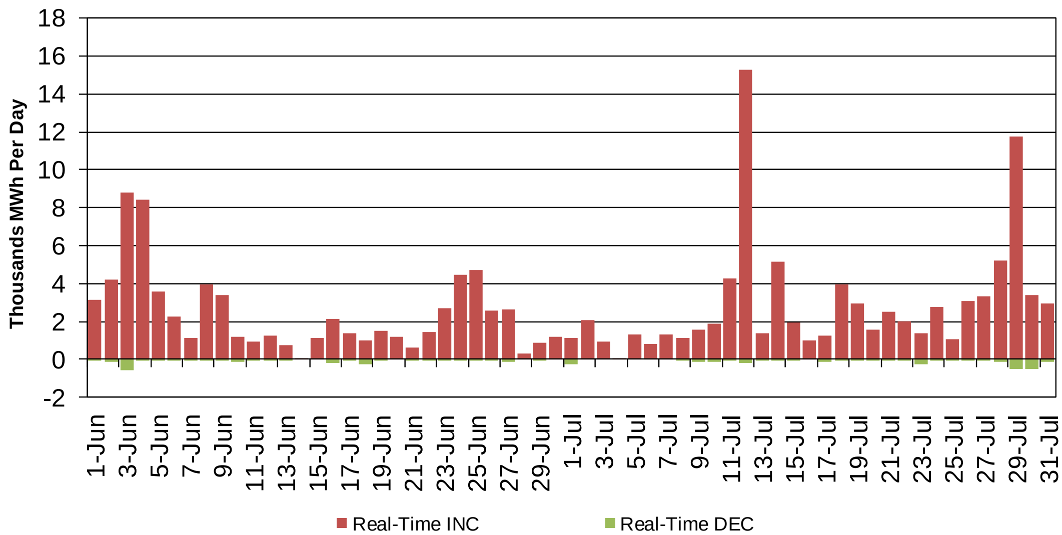


Figure 45 shows the volume of the exceptional dispatch broken out by reason.[3] The majority of the exceptional dispatch volumes in July were driven by planned transmission outage (25 percent), reliability assessment (30 percent), ramping capacity 19 percent), and load forecast uncertainty (16 percent).

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

Figure 45: Total Exceptional Dispatch Volume (MWh) by Reason

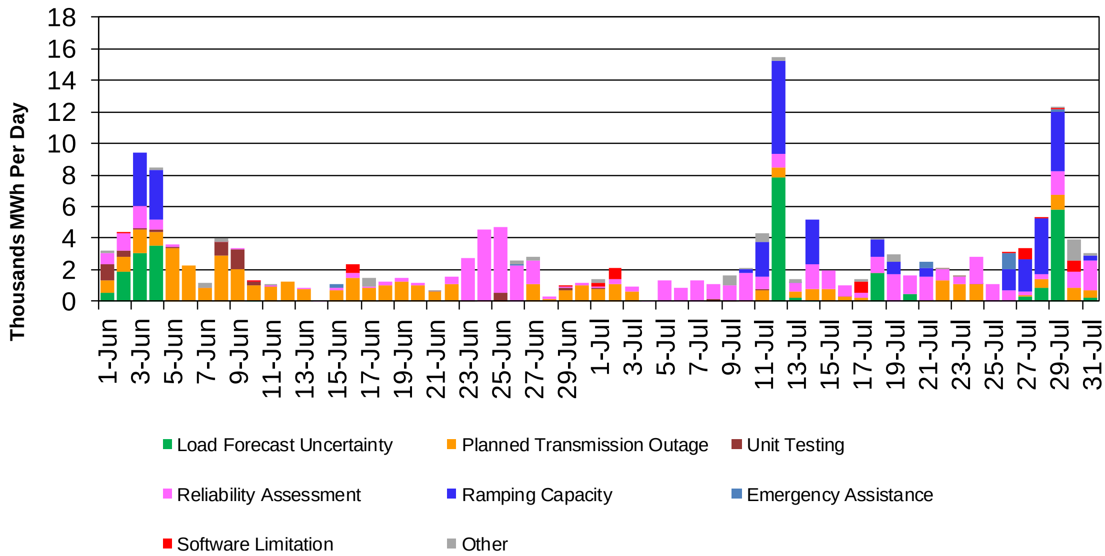
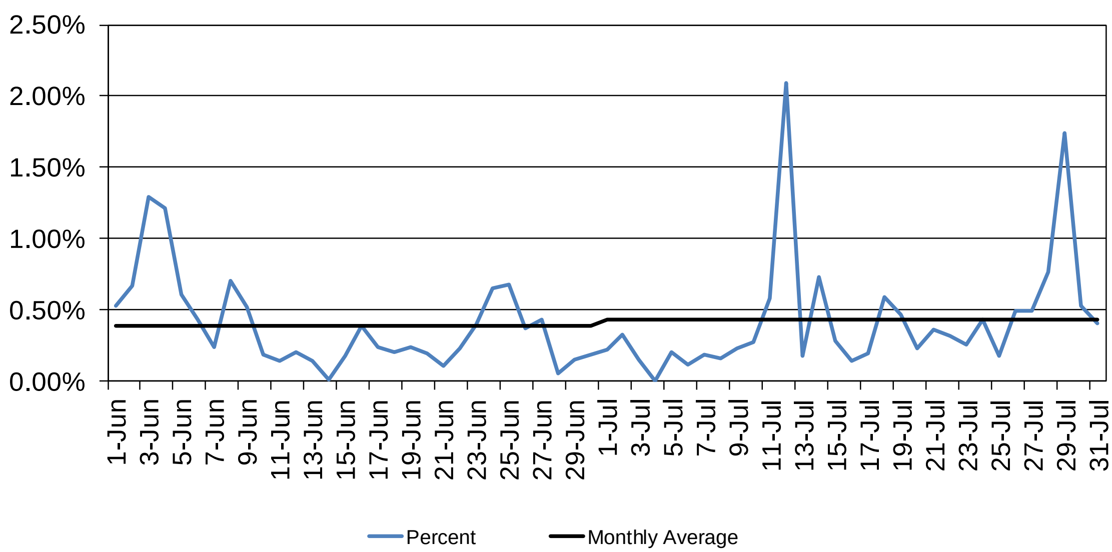


Figure 46 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage was 0.43 percent in July, inching up from 0.39 percent in June.

Figure 46: 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). 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.

On October 1, 2017, Portland General Electric Company (PGE) became the fifth western utility to successfully begin full participation in the western Energy Imbalance Market (EIM). PGE joins Arizona Public Service, Puget Sound Energy, NV Energy, PacifiCorp and the ISO, together serving over 38 million consumers in eight states: California, Arizona, Oregon, Washington, Utah, Idaho, Wyoming and Nevada.

On April 4, 2018, Boise-based Idaho Power and Powerex of Vancouver, British Columbia successfully entered the western Energy Imbalance Market (EIM) today, allowing the ISO's real-time power market to serve energy imbalances occurring within about 55 percent of the electric load in the Western Interconnection. The eight western EIM participants serve more than 42 million consumers in the power grid stretching from the border with Canada south to Arizona, and eastward to Wyoming.

On April 3, 2019, Sacramento Municipal Utility District (SMUD), part of the Balancing Authority of Northern California (BANC), successfully began full participation in the Western EIM, becoming the first publicly owned agency to be an EIM entity in the Western EIM.

On April 1, 2020, Seattle City Light (SCL) and Salt River Project (SRP) successfully joined the Western EIM. The two utilities serve about 1.5 million customers in the West's first real-time energy market. Together with Salt River Project and Seattle City Light, the current EIM participants represent 61 percent of the load in the Western Electric Coordinating Council (WECC).

Figure 47 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS), Puget Sound Energy (PSEI), Portland General Electric Company (PGE), Idaho Power (IPCO), Powerex (BCHA), Sacramento Municipal Utility District (BANCSMUD), Seattle City Light (SCL) and Salt River Project (SRP) for all hours in FMM. On July 30, NEVP price spiked due to renewable deviation and upward load forecast adjustment.

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

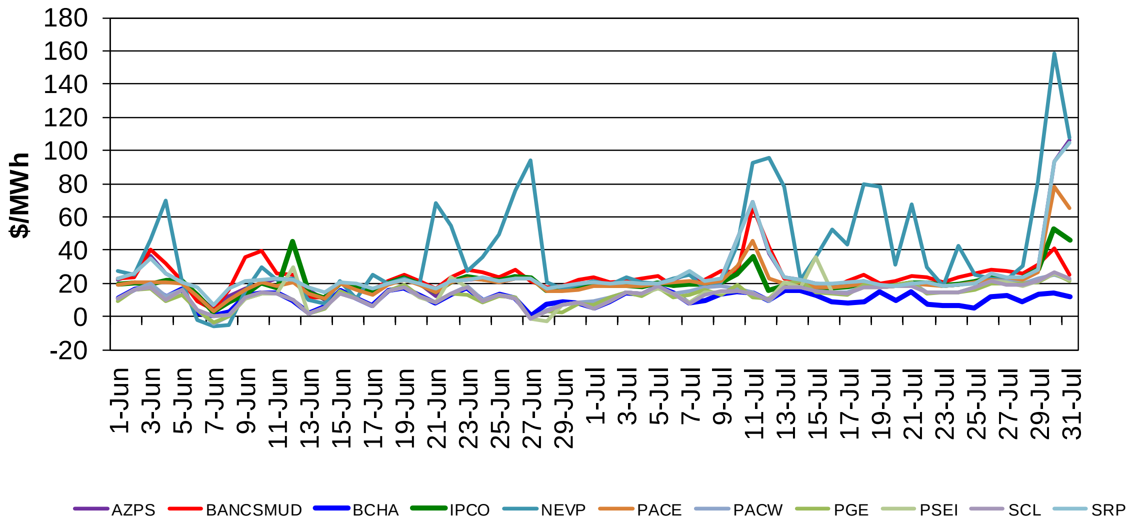


Figure 48 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP for all hours in RTD. The price for NEVP was elevated on July 30 due to renewable deviation and upward load forecast adjustment.

Figure 48: EIM Simple Average LAP Prices (All Hours) in RTD

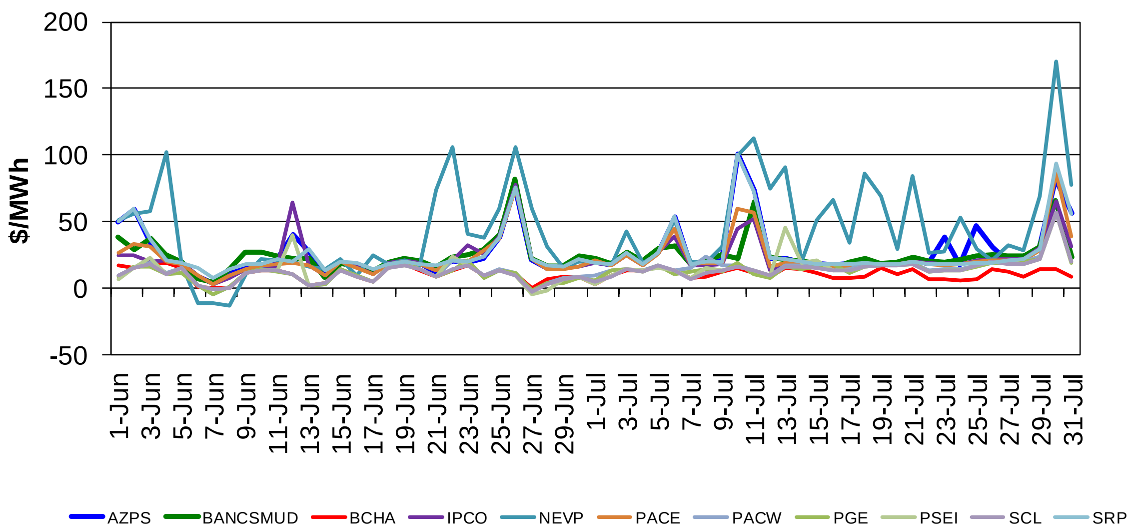


Figure 49 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP. The cumulative frequency of prices above $250/MWh increased to 0.65 percent in July from 0.17 percent in June. The cumulative frequency of negative prices dropped to 1.19 percent in July from 10.50 percent in June.

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

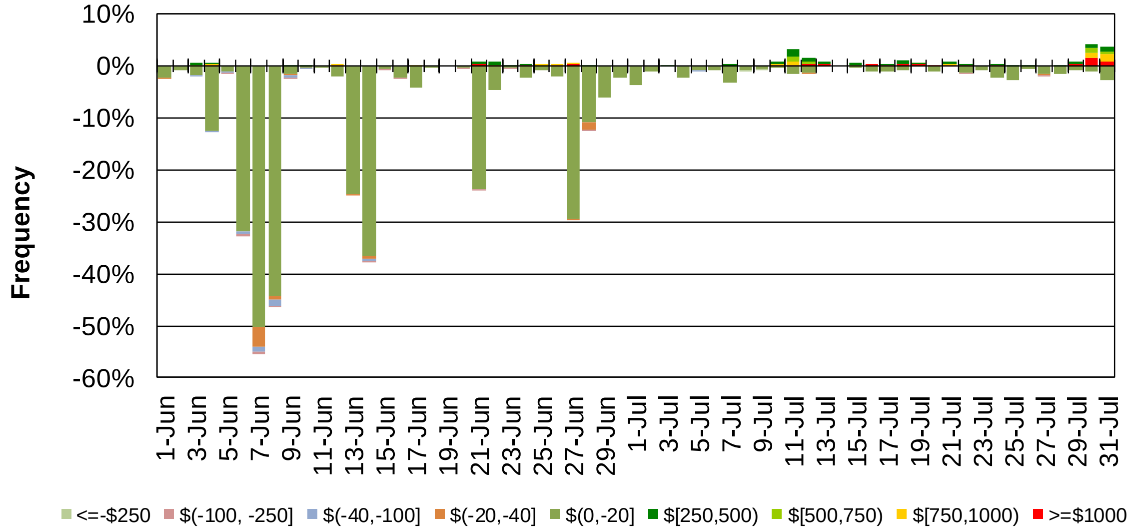


Figure 50 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP. The cumulative frequency of prices above $250/MWh increased to 0.81 percent in July from 0.49 from in June. The cumulative frequency of negative prices fell to 2.07 percent in July from 12.29 percent in June.

Figure 50: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in RTD

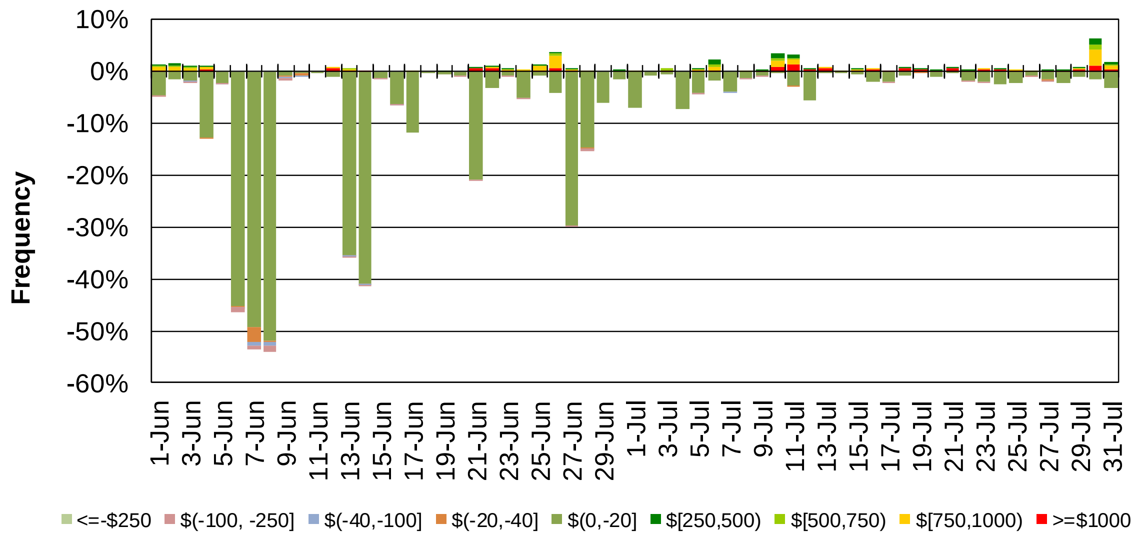


Figure 51 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP respectively. Total RTIEO in July rose to -$4.00 million from -$6.30 million in June.

Figure 51: EIM Real-Time Imbalance Energy Offset by Area

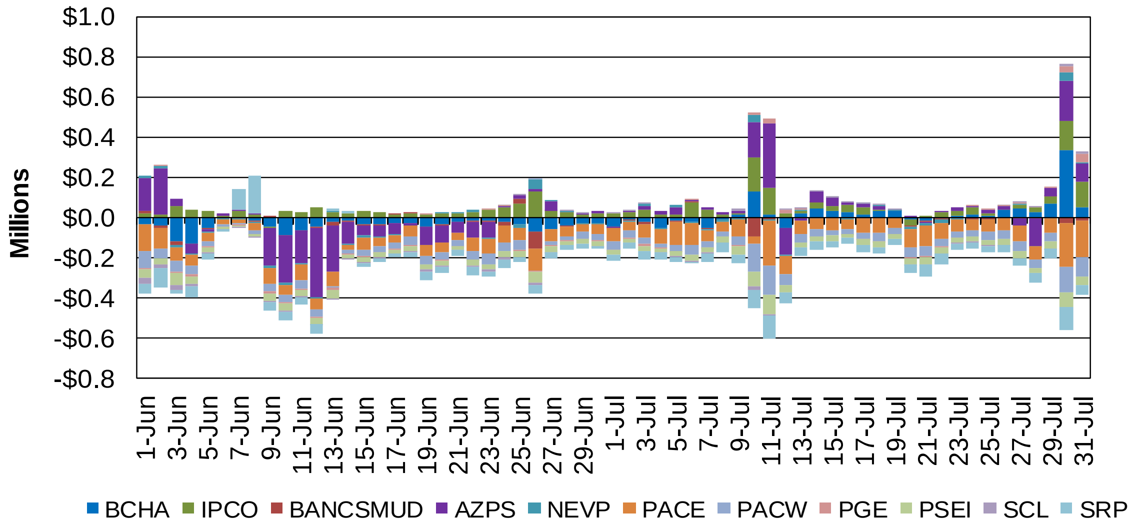


Figure 52 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP respectively. Total RTCO increased to -$1.58 million in July from -$2.26 million in June.

Figure 52: EIM Real-Time Congestion Imbalance Offset by Area

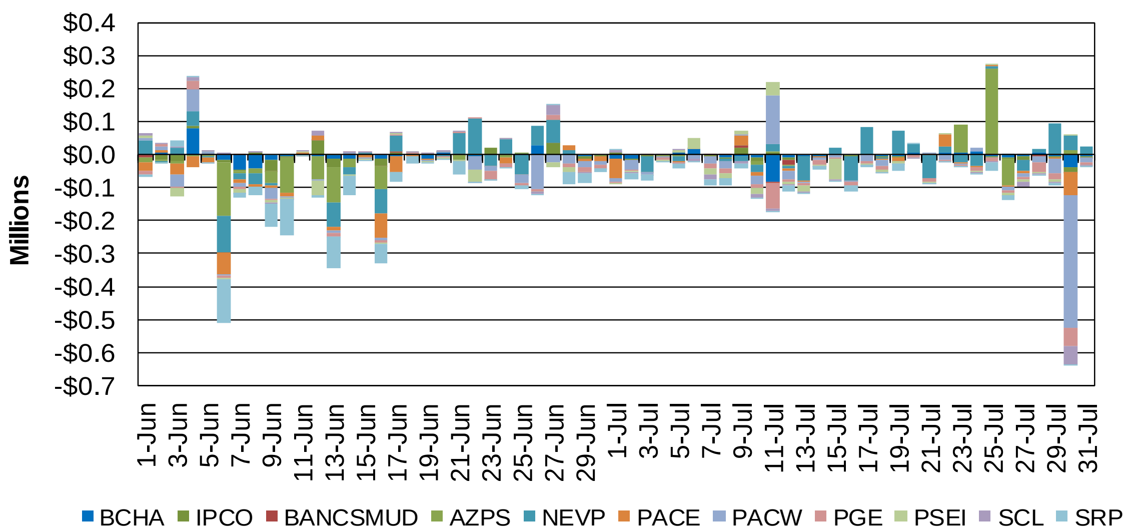


Figure 53 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP respectively. Total BCR inched up to $0.71 million in July from $0.65 million in June.

Figure 53: EIM Bid Cost Recovery by Area

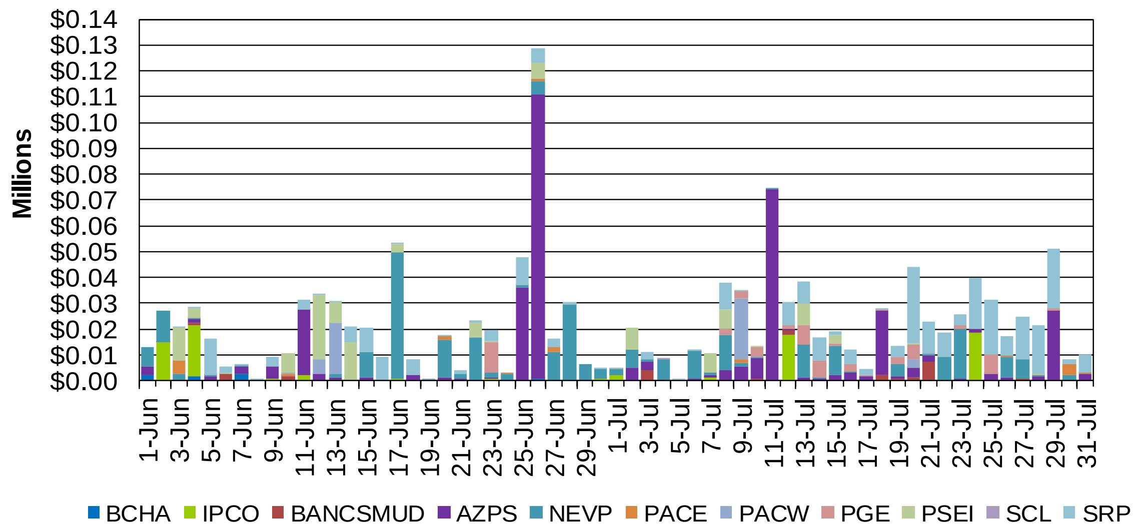


Figure 54 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP respectively. Total flexible ramping up uncertainty payment in July increased to $154,067 from -$17,971 in June.

Figure 54: Flexible Ramping Up Uncertainty Payment

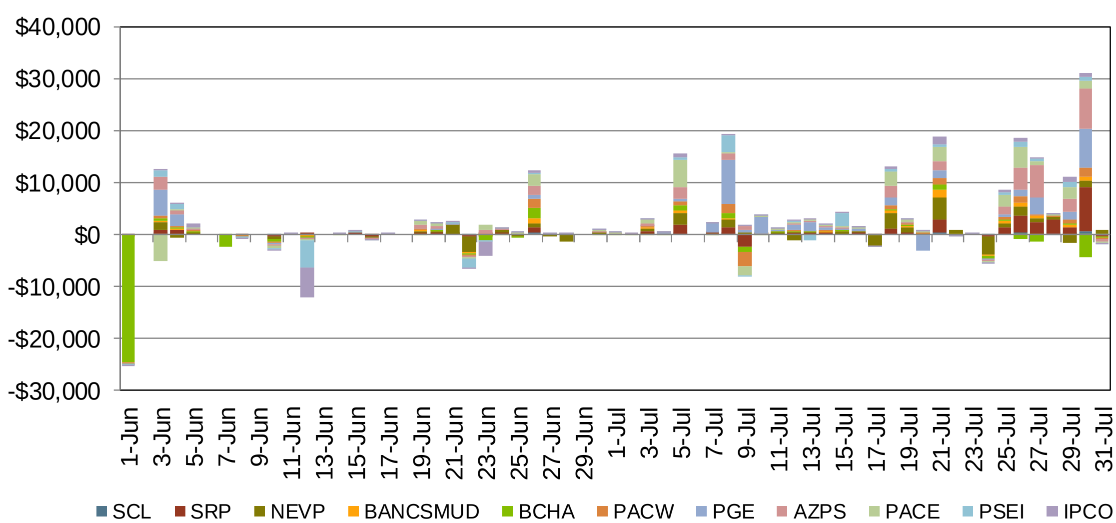


Figure 55 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMUD, SCL and SRP respectively. Total flexible ramping down uncertainty payment in July slipped to $14,302 from $36,986 in June.

Figure 55: Flexible Ramping Down Uncertainty Payment

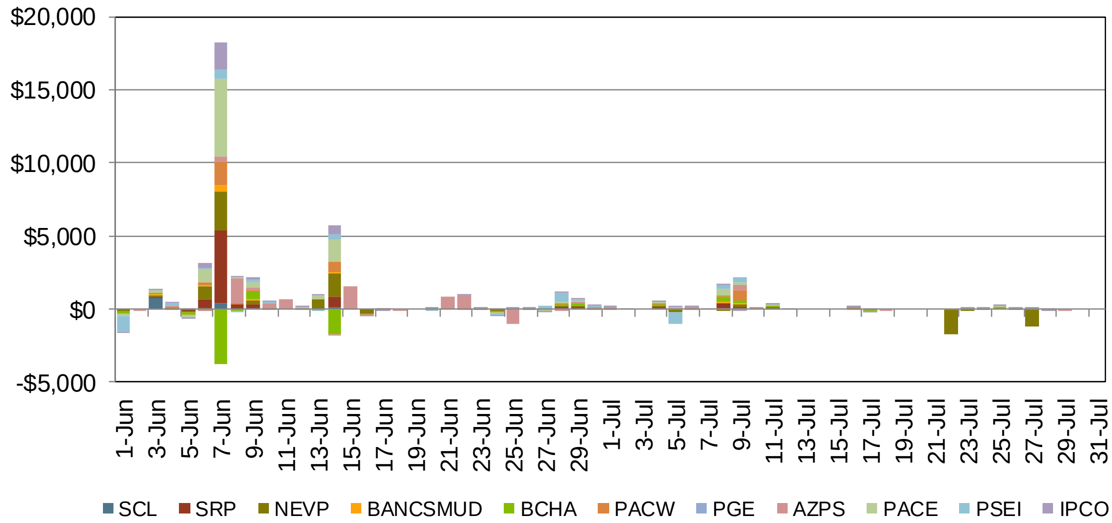
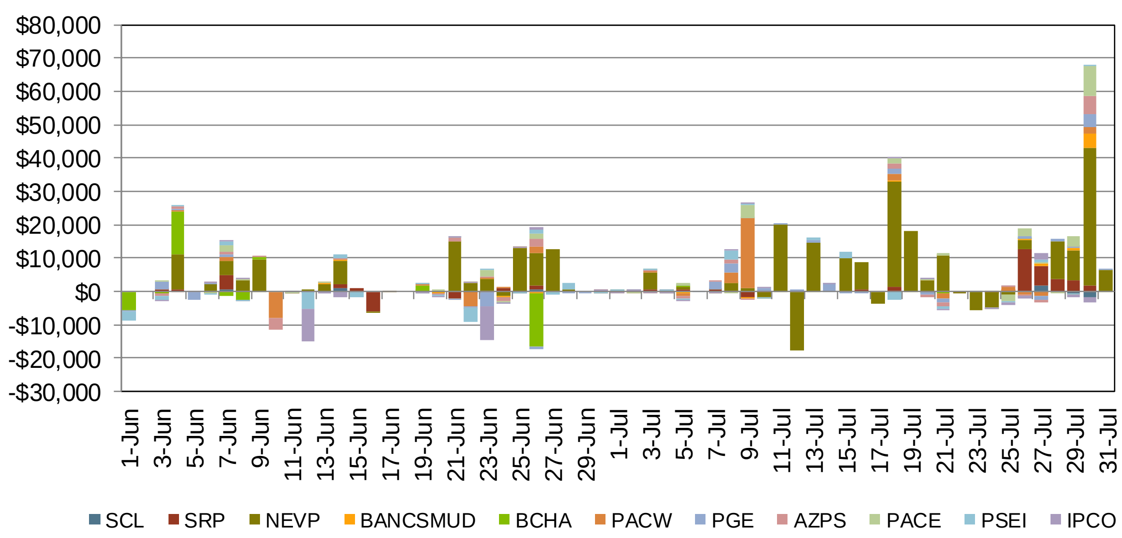


Figure 56 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, BCHA, BANCSMU, SCL and SRP respectively. Total forecast payment in July rose to $261,893 from $47,855 in June.

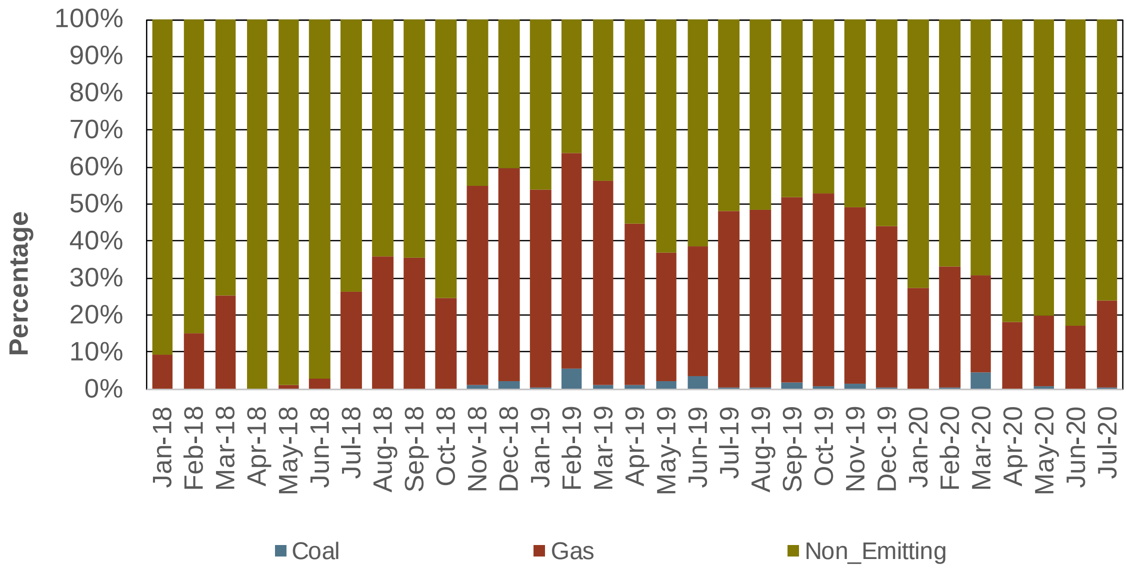
Figure 56: Flexible Ramping Forecast Payment



The ISO's Energy Imbalance Market Business Practice Manual[4] 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[5].

The EIM dispatches to support transfers into the ISO were documented in Figure 57 and Table 8 below.

Figure 57: Percentage of EIM Transfer into ISO by Fuel Type



[4] 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.
[5] A submitted bid may 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
Jan-18	0.00%	9.12%	90.88%	100%
Feb-18	0.00%	15.20%	84.80%	100%
Mar-18	0.16%	25.00%	74.84%	100%
Apr-18	0.00%	0.14%	99.86%	100%
May-18	0.00%	1.09%	98.91%	100%
Jun-18	0.00%	2.89%	97.11%	100%
Jul-18	0.00%	26.21%	73.79%	100%
Aug-18	0.00%	35.87%	64.13%	100%
Sep-18	0.00%	35.50%	64.50%	100%
Oct-18	0.00%	24.51%	75.49%	100%
Nov-18	1.16%	53.81%	45.03%	100%
Dec-18	2.00%	57.77%	40.23%	100%
Jan-19	0.46%	53.65%	45.89%	100%
Feb-19	5.64%	58.06%	36.30%	100%
Mar-19	1.07%	55.40%	43.52%	100%
Apr-19	1.13%	43.63%	55.25%	100%
May-19	2.22%	34.75%	63.03%	100%
Jun-19	3.47%	35.32%	61.21%	100%
Jul-19	0.49%	47.74%	51.77%	100%
Aug-19	0.51%	48.02%	51.48%	100%
Sep-19	1.77%	50.01%	48.22%	100%
Oct-19	0.68%	52.10%	47.22%	100%
Nov-19	1.39%	47.69%	50.92%	100%
Dec-19	0.54%	43.68%	55.78%	100%
Jan-20	0.17%	27.05%	72.79%	100%
Feb-20	0.36%	32.81%	66.83%	100%
Mar-20	4.42%	26.49%	69.09%	100%
Apr-20	0.20%	17.84%	81.95%	100%
May-20	0.71%	19.10%	80.19%	100%
Jun-20	0.04%	17.08%	82.88%	100%
Jul-20	0.44%	23.62%	75.93%	100%