



Market Performance Report April 2018

June 1, 2018

ISO Market Quality and Renewable Integration

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Executive Summary¹

The market performance in April 2018 is summarized below.

CAISO area performance,

- Peak loads for ISO continued to be low in April when temperatures stayed low.
- Across all market, such as the integrated forward market (IFM), the fifteen-minute market (FMM) and real-time market (RTD), SDG&E prices were elevated in a few days due to transmission congestion.
- Congestion rents for interties fell to \$5.13 million from \$6.76 million in March. Majority of the congestion rents in April accrued on MALIN (46 percent) intertie and NOB (49 percent) intertie.
- In the congestion revenue rights (CRR) market, revenue adequacy was 64.99 percent, worsening from the 79.67 percent in March. The line 22192_DOUBLTTP_138_22300_FRIARS contributed largely to the revenue shortfall.
- The monthly average ancillary service cost to load rose to \$1.16/MWh from \$0.88/MWh in March. There were 48 scarcity events this month.
- The cleared virtual supply and the cleared demand moved closer in the middle of April. The profits from convergence bidding rose to \$2.50 million from \$0.57 million in March.
- The bid cost recovery inched up to \$6.41 million from \$5.85 million in March.
- The real-time energy offset increased to \$5.07 million from \$1.81 million in March. The real-time congestion offset cost dropped to \$1.32 million from \$3.55 million in March.
- The volume of exceptional dispatch rose to 47,380 MWh from 44,485 MWh in March. The main contributor to this volume was planned transmission outage. The monthly average of total exceptional dispatch volume as a percentage of load percentage was 0.28 percent in April, unchanged from March.

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, the prices for AZPS and NEVP were elevated on April 9-11 due to upward load adjustment, net import reduction, generation outage, and renewable deviation. In the RTD, the price for AZPS was elevated on April 5 due to tight supply and the price for NEVP was elevated on April 27 due to net import reduction and generation outage.
- The monthly average prices in FMM for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were \$30.67, \$20.68, \$21.63, \$30.45, \$22.64, \$17.51, \$17.18 and \$17.74 respectively.
- The monthly average prices in RTD for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were \$26.50, \$18.69, \$20.24, \$26.42, \$22.16, \$19.38, \$18.20 and \$18.93 respectively.
- Bid cost recovery, real-time imbalance energy offset, and real-time congestion offset costs for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were \$1.33 million, \$7.41 million and -\$2.21 million respectively.

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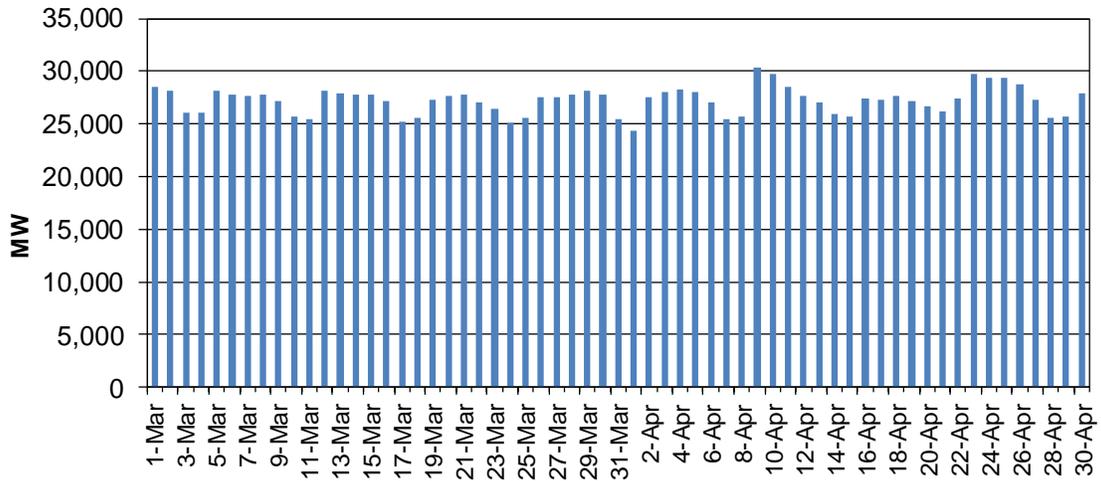
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Market Characteristics

Loads

As the transition towards the summer takes place, peak loads for ISO continued to be low in April, below 30,000 MW for all but one day of April.

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-availability 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	26.30%	\$49,188,214	-\$5,670
Feb-17	92.31%	\$3,157,590	-\$1,867,721
Mar-17	91.92%	\$2,975,585	-\$1,550,365
Apr-17	89.46%	\$3,641,392	-\$1,483,548
May-17	96.44%	\$1,017,191	-\$1,017,191
Jun-17	94.24%	\$4,058,330	-\$1,502,850
Jul-17	95.20%	\$3,277,858	-\$1,940,268
Aug-17	64.11%	\$29,701,024	-\$19,051
Sep-17	96.52%	\$1,055,396	-\$1,055,396
Oct-17	97.42%	\$690,037	-\$690,037
Nov-17	96.15%	\$1,483,755	-\$1,483,755
Dec-17	96.87%	\$1,517,252	-\$1,517,252
Jan-18	97.59%	\$1,169,857	-\$893,352
Feb-18	95.46%	\$2,480,894	-\$1,759,093
Mar-18	93.60%	\$2,749,829	-\$1,537,297
Apr-18	92.40%	\$4,069,059	-\$1,546,330

² On June 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.

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

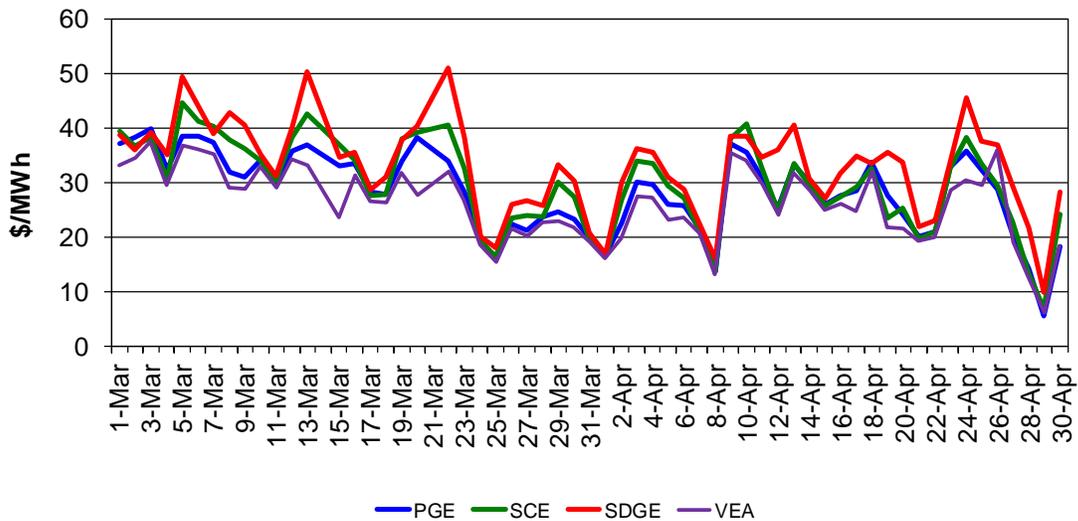


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	April 12-13, 24	DOUBLTTP-FRIARS -138kV 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 occurrence dates when the binding constraints resulted in relatively high or low DLAP prices. On April 9-11, all four DLAP LMPs were elevated due to upward load adjustment, net import reduction, generation outage, and renewable deviation.

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

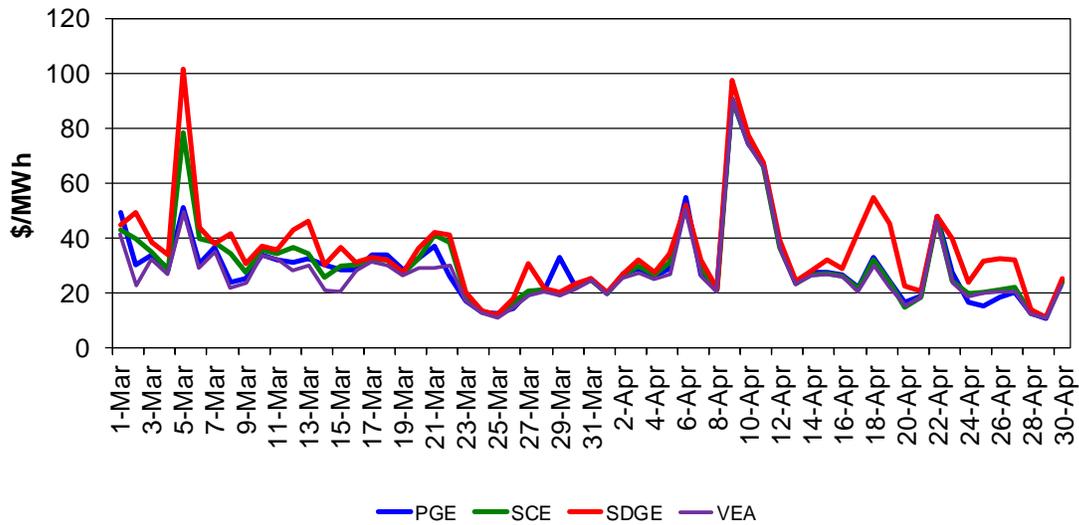
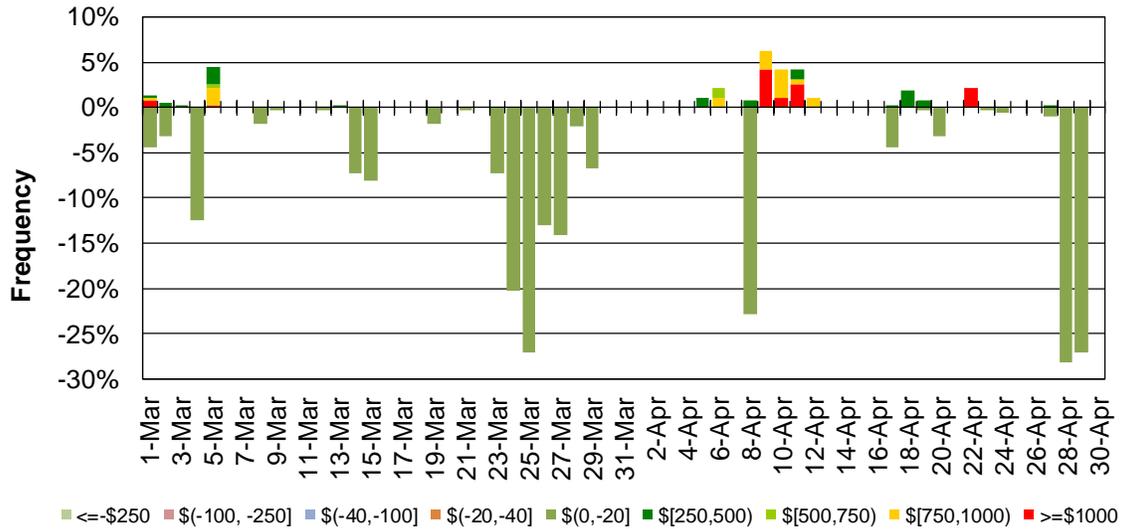


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	April 17-19	OMS 5730606 TL50003_NG, MIGUEL_BKs_MXFLW_NG
SDG&E	April 24-26	DOUBLTTP-FRIARS -138kV line

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 0.82 percent in April from 0.22 percent in March. The cumulative frequency of negative prices decreased to 2.93 percent in April from 4.21 percent in March.

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.

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

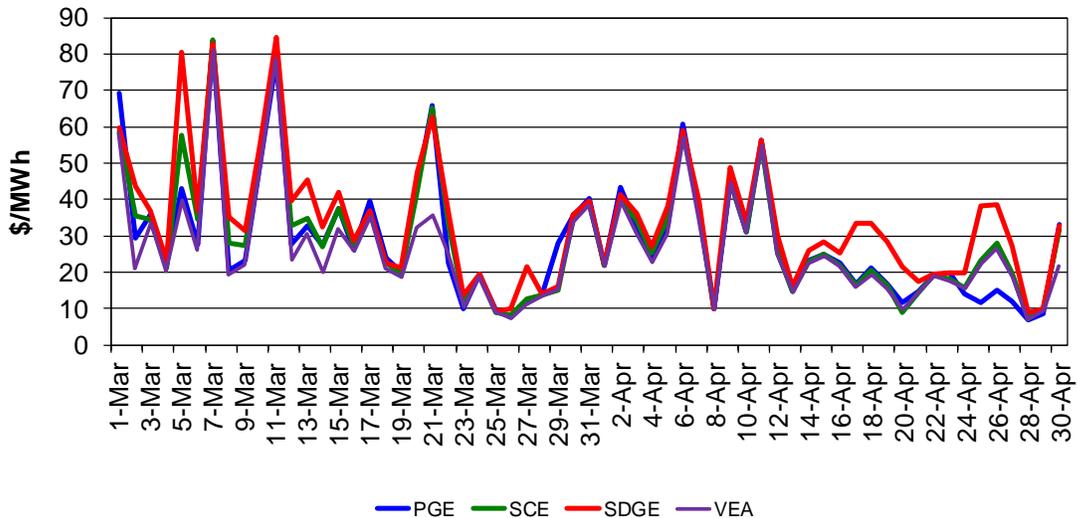
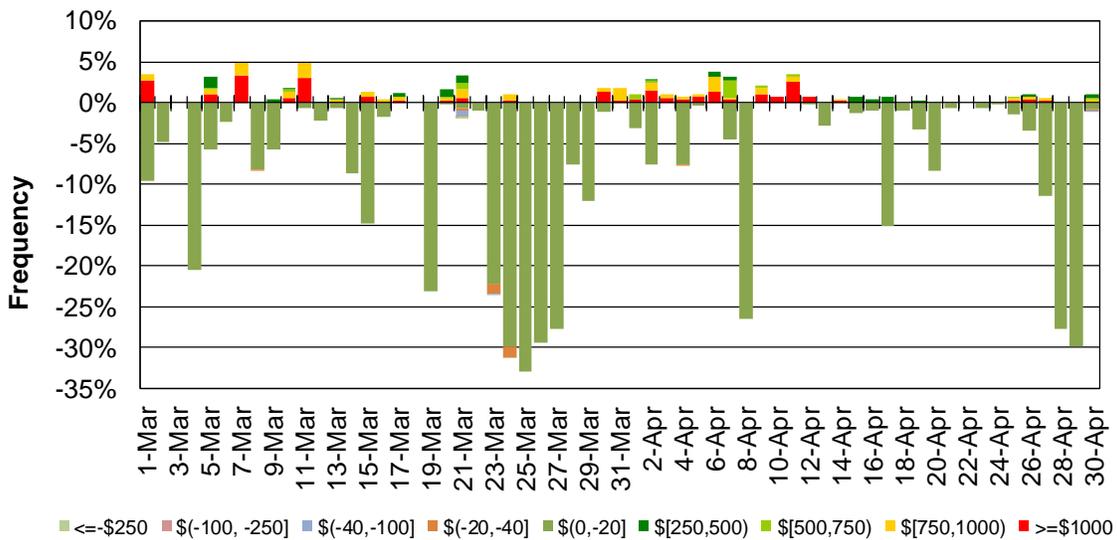


Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E	April 17-19	OMS 5730606 TL50003_NG, MIGUEL_BKs_MXFLW_NG
SDG&E	April 20, 24-26	DOUBLTTP-FRIARS -138kV line

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 0.08 percent in April from 1.02 percent in March. The cumulative frequency of negative prices fell to 5.32 percent in April from 8.97 percent in March.

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



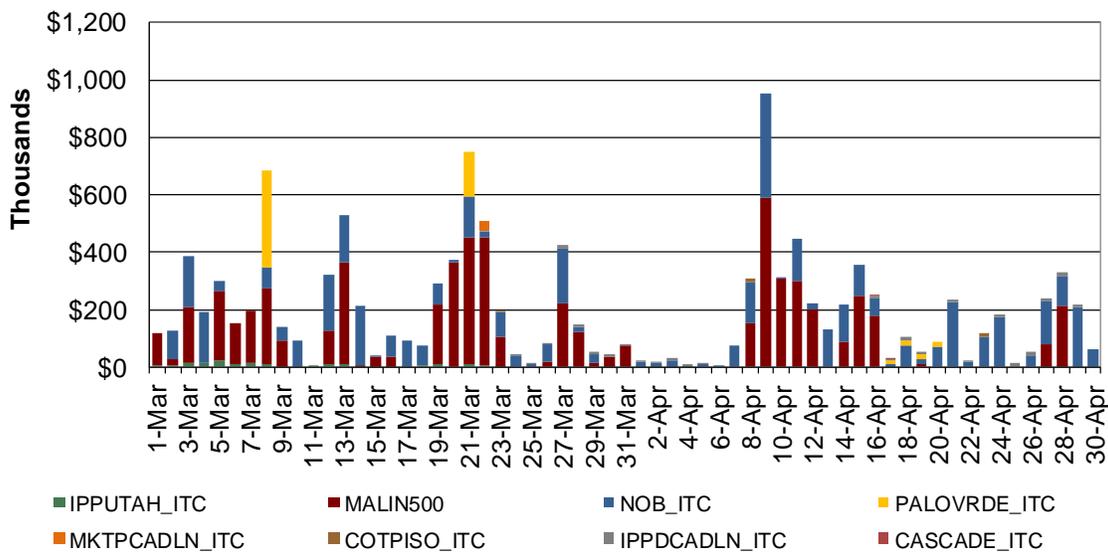
Congestion

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 April fell to \$5.13 million from \$6.76 million in March. Majority of the congestion rents in April accrued on MALIN (46 percent) intertie and NOB (49 percent) intertie.

The congestion rent on NOB inched up to \$2.50 million in April from \$2.18 million in March. The congestion rent on MALIN dropped to \$2.36 million in April from \$3.85 million in March.

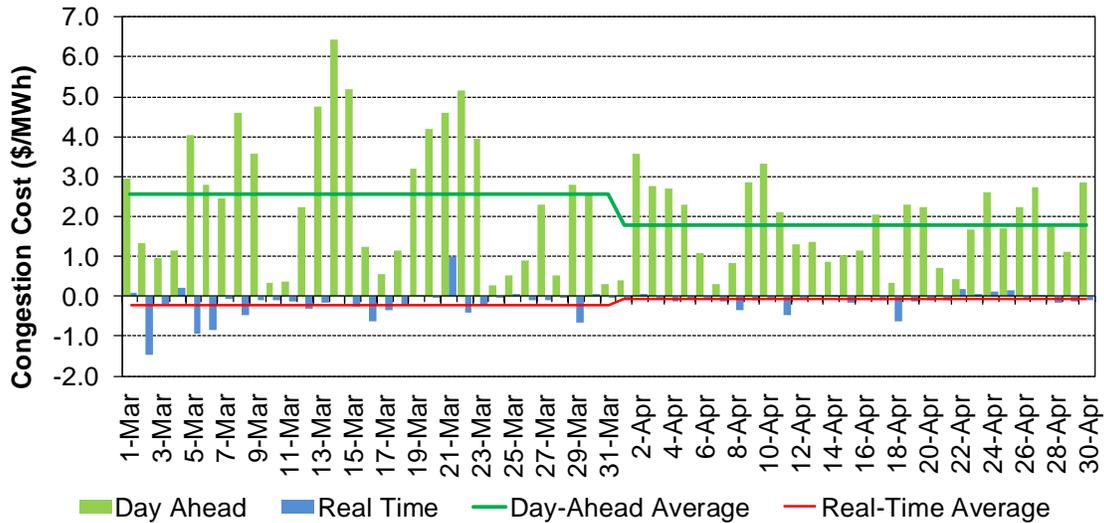
Figure 7: IFM Congestion Rents by Interties (Import)



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

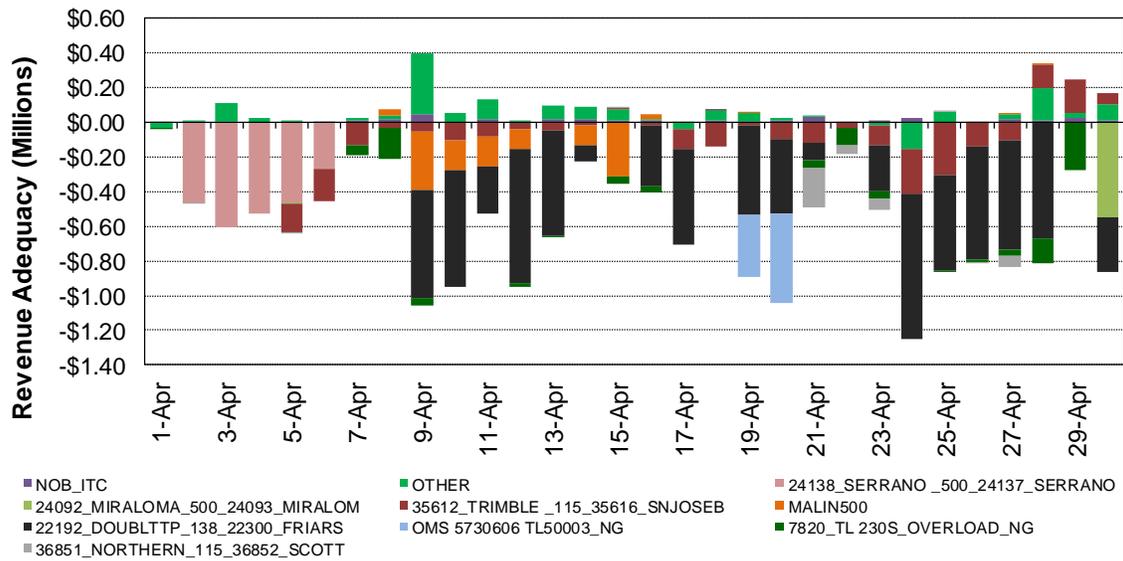


The average congestion cost per MWh of load served in the integrated forward market decreased to \$1.80/MWh in April from \$2.56/MWh in March. The average congestion cost per load served in the real-time market rose to -\$0.08/MWh in April from -\$0.21/MWh in March.

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 April increased to \$520,470 from the average revenue deficit of \$355,489 in March.

Figure 9: Daily Revenue Adequacy of Congestion Revenue Rights

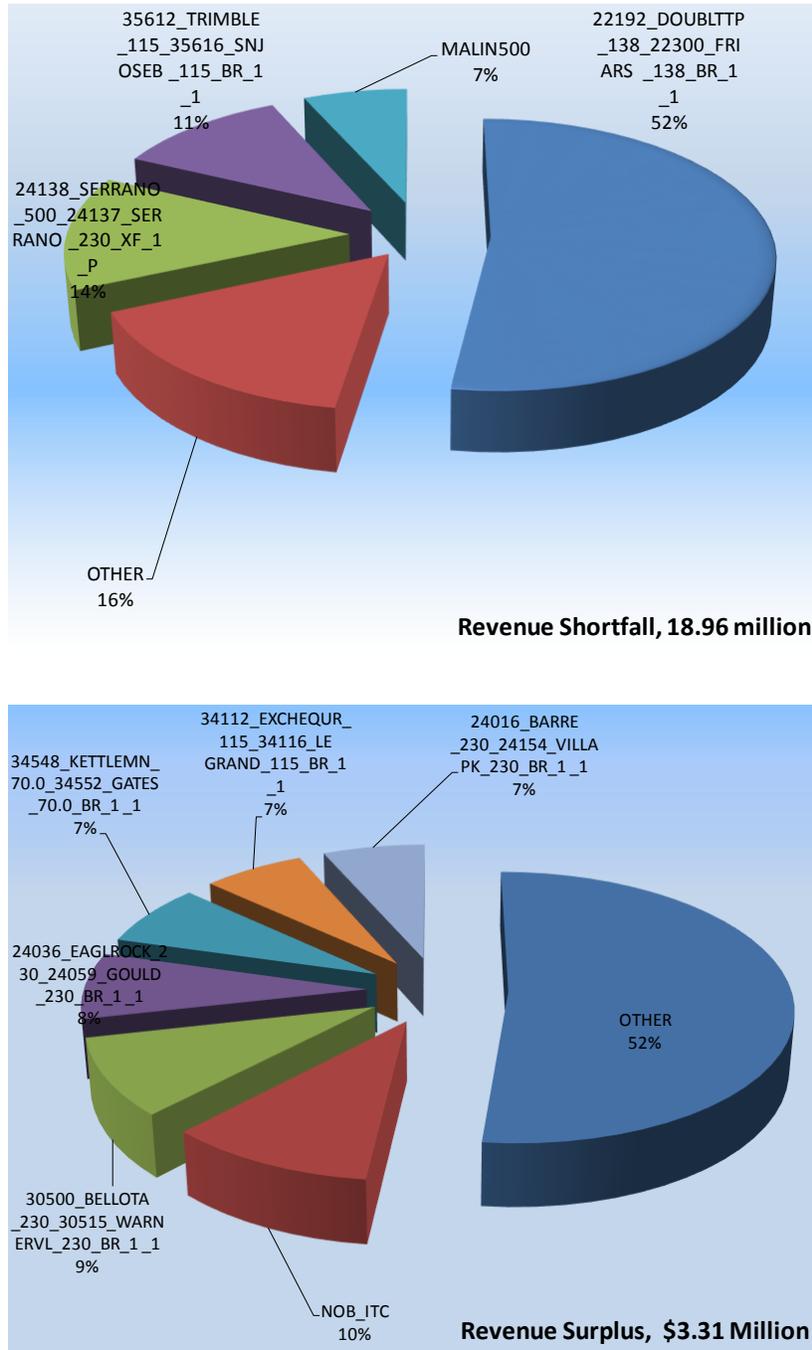


Overall, April experienced a CRR revenue deficit. Revenue shortfalls were observed in more than twenty days of April. The main reasons are

- The line 22192_DOUBLTTP_138_22300_FRIARS was binding in 19 days of this month, resulting in revenue shortfall of \$8.93 million.
- The transformer 24138_SERRANO_500_24137_SERRANO was binding in five days of this month, resulting in revenue shortfall of \$2.32 million. The congestion was driven by the Serrano bank outage.

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 64.99 percent in April. Out of the total congestion rents, 2.60 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in April were in deficit by \$15.61 million, compared to the deficit of \$11.02 million in March. The auction revenues credited to the balancing account for April were \$6.20 million. As a result, the balancing account for April had a deficit of approximately \$9.39 million, which will be allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	\$29,762,840.43
Existing Right Exemptions	-\$773,764.54
Available Congestion Revenues	\$28,989,075.89
CRR Payments	\$44,603,165.84
CRR Revenue Adequacy	-\$15,614,089.95
Revenue Adequacy Ratio	64.99%
Annual Auction Revenues	\$3,045,544.70
Monthly Auction Revenues	\$3,150,716.00
CRR Settlement Rule	\$31,410.96
Allocation to Measured Demand	-\$9,386,418.28

Ancillary Services

IFM (Day-Ahead) Average Price

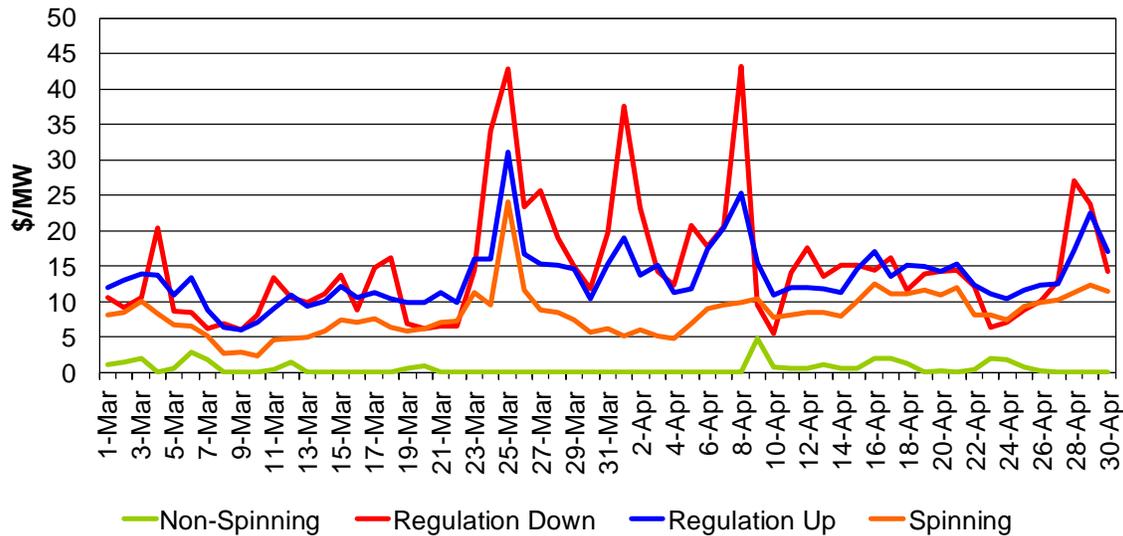
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In April the monthly average procurement increased for regulation up and regulation down and decreased for spinning and non-spinning reserves.

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

	Average Procured				Average Price			
	Reg Up	Reg Dn	Spinning	Non-Spinning	Reg Up	Reg Dn	Spinning	Non-Spinning
Apr-18	329	441	933	936	\$14.68	\$16.26	\$9.18	\$0.71
Mar-18	324	417	992	992	\$12.31	\$13.75	\$7.41	\$0.50
Percent Change	1.57%	5.83%	-5.90%	-5.62%	19.26%	18.22%	23.91%	41.81%

The monthly average prices increased for all four types of ancillary services in April. Figure 11 shows the daily IFM average ancillary service prices. The average price for regulation down was elevated on April 1 and 8 due to high opportunity cost of energy.

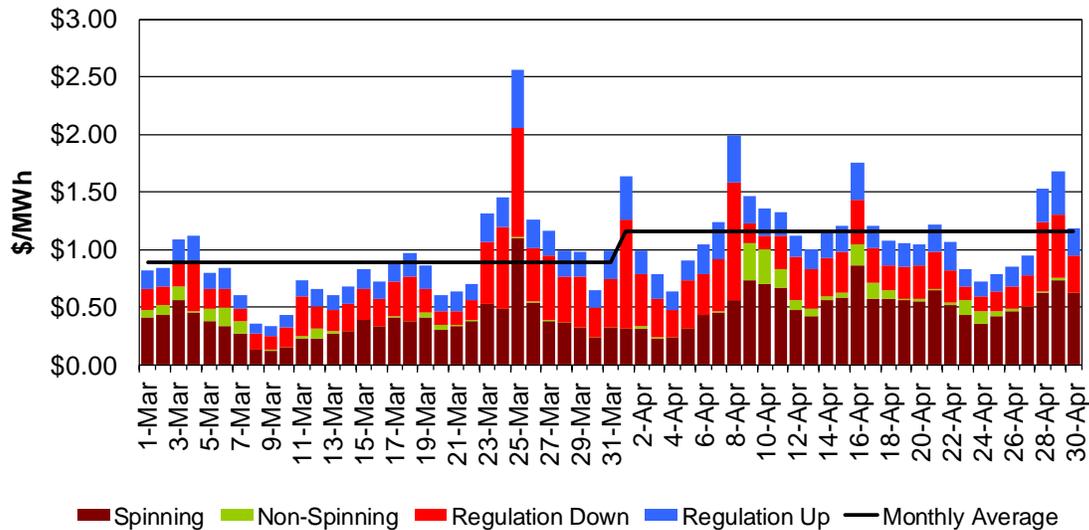
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load rose to \$1.16/MWh in April from \$0.88/MWh in March.

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. The scarcity events in April are shown in the table below.

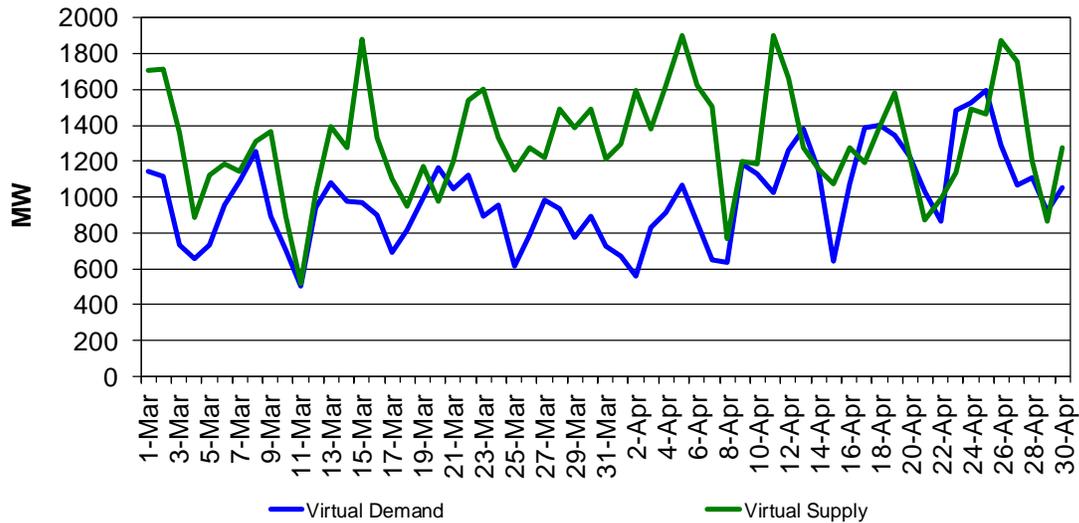
Date	Hour Ending	Interval	Ancillary Service	Region	Shortfall (MW)	Percentage of Requirement
Apr 2	5	2	Regulation Down	NP26_EXP	0.05	0.05%
Apr 2	6	2	Regulation Up	NP26_EXP	1.66	1.2%
Apr 3	17	4	Regulation Down	CAISO_EXP	0.16	0.04%
Apr 6	11	2	Regulation Down	CAISO_EXP	0.15	0.03%
Apr 7	10	1	Regulation Down	NP26_EXP	4	3.9%
Apr 7	17	4	Regulation Down	NP26_EXP	3.8	3.6%
Apr 8	10	4	Regulation Down	CAISO_EXP	3.9	0.8%
Apr 8	21	1	Regulation Down	NP26_EXP	31	29.5%
Apr 9	19	4	Spin	CAISO_EXP	10.4	1%
Apr 9	20	3	Non-Spin	CAISO_EXP	111.2	10.4%
Apr 9	20	4	Non-Spin	CAISO_EXP	111.2	10.4%
Apr 9	21	2	Regulation Down	NP26_EXP	5.96	5.7%
Apr 11	6	4	Regulation Up	NP26_EXP	3.3	2.4%
Apr 11	20	3	Non-Spin	CAISO_EXP	44.6	3.4%
Apr 11	20	4	Non-Spin	CAISO_EXP	22.1	1.7%
Apr 11	22	1	Regulation Down	NP26_EXP	0.8	0.8%

Apr 12	8	4	Regulation Down	NP26_EXP	1.6	1.5%
Apr 12	8	4	Regulation Up	NP26_EXP	2.6	2.6%
Apr 12	14	2	Regulation Down	NP26_EXP	1.2	1.1%
Apr 12	14	3	Regulation Down	NP26_EXP	1.2	1.1%
Apr 12	14	4	Regulation Down	NP26_EXP	1.2	1.1%
Apr 12	24	1	Regulation Down	CAISO_EXP	33	7.9%
Apr 12	24	2	Regulation Down	NP26_EXP	0.4	0.4%
Apr 14	14	2	Regulation Down	NP26_EXP	2.1	2.1%
Apr 14	14	3	Regulation Down	NP26_EXP	2.1	2.1%
Apr 14	14	4	Regulation Down	NP26_EXP	2.1	2.1%
Apr 14	21	1	Regulation Up	NP26_EXP	24.7	30.7%
Apr 14	23	2	Regulation Down	NP26_EXP	0.7	0.7%
Apr 15	20	2	Regulation Up	NP26_EXP	4.6	4.6%
Apr 15	22	2	Regulation Up	NP26_EXP	0.4	0.4%
Apr 15	22	4	Regulation Up	NP26_EXP	0.4	0.4%
Apr 15	24	4	Regulation Up	NP26_EXP	0.2	0.2%
Apr 18	1	1	Regulation Up	SP26_EXP	1.4	1.3%
Apr 18	1	3	Regulation Up	SP26_EXP	1.7	1.6%
Apr 19	2	2	Regulation Up	SP26_EXP	8.2	7.8%
Apr 19	11	1	Regulation Up	SP26_EXP	12.4	11.8%
Apr 19	11	2	Regulation Up	SP26_EXP	12.7	12%
Apr 19	11	3	Regulation Up	SP26_EXP	12.7	12%
Apr 28	4	2	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	4	3	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	4	4	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	5	2	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	5	3	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	5	4	Regulation Down	NP26_EXP	0.08	0.08%
Apr 28	7	2	Regulation Down	NP26_EXP	5.2	5%
Apr 30	6	1	Regulation Down	CAISO_EXP	12	2.7%
Apr 30	20	1	Regulation Down	NP26_EXP	7.6	7.2%
Apr 30	20	2	Regulation Down	NP26_EXP	16.2	15.4%

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 and the cleared demand moved closer in the middle of April.

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

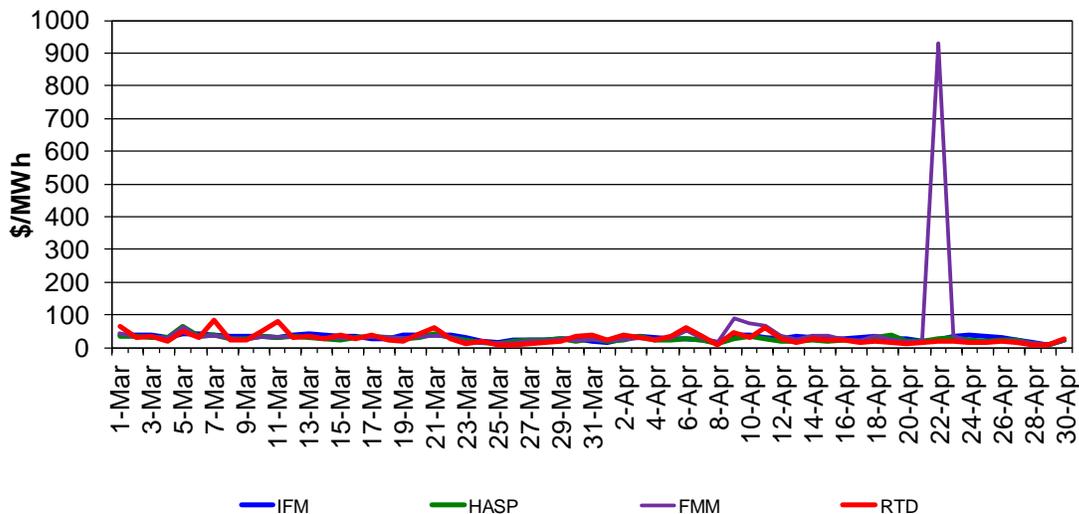
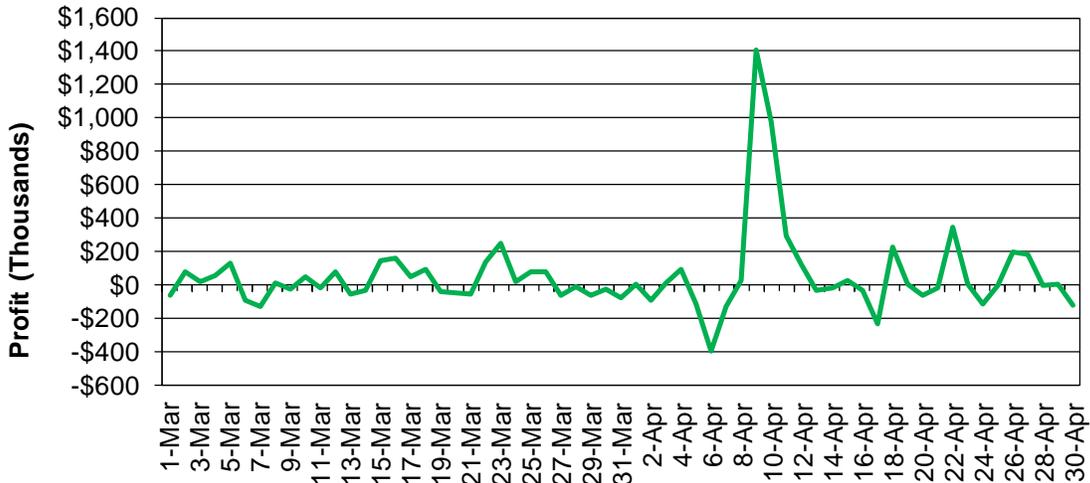


Figure 15 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding rose to \$2.50 million in April from \$0.57 million in March.

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 trended upward since January. The majority of the curtailments was economic.

Figure 16: Renewable Curtailment by Reason

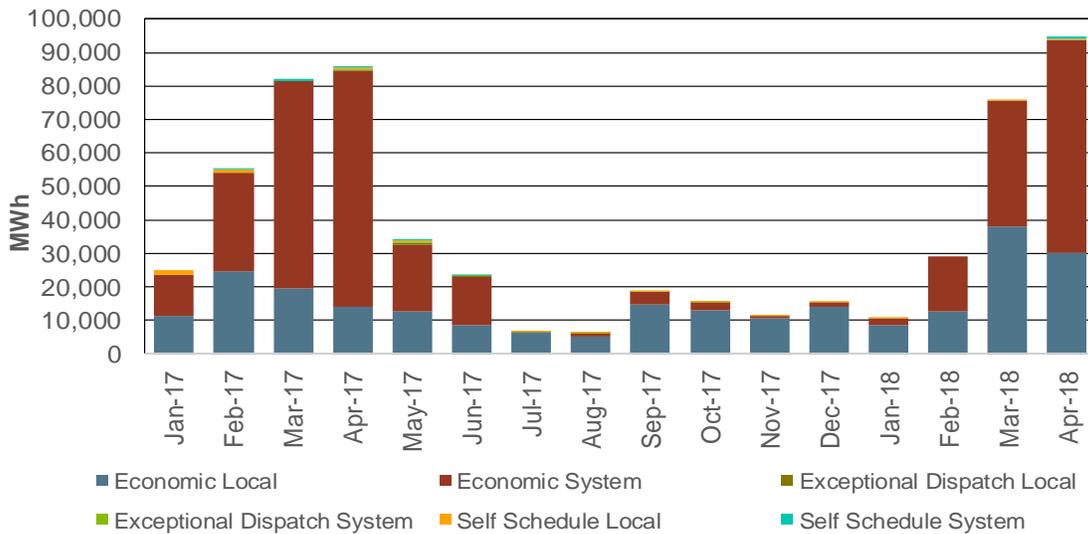
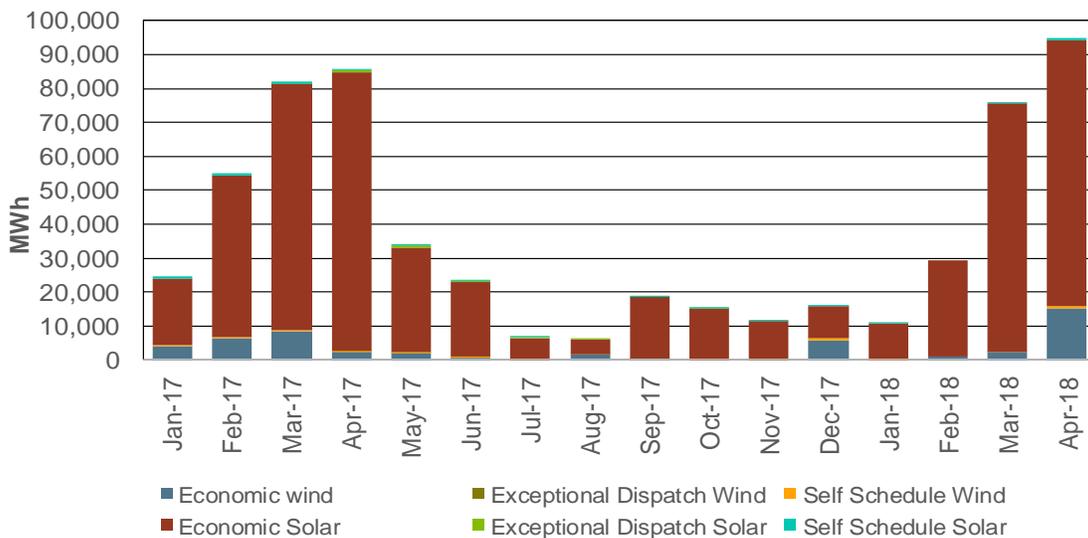


Figure 17: Renewable Curtailment by Resource Type



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 increased to \$0.58 million in April from \$0.34 million in March. Flexible ramping down uncertainty payment rose to \$83,192 in April from \$61,040 in March.

Figure 18: Flexible Ramping Up/down Uncertainty Payment

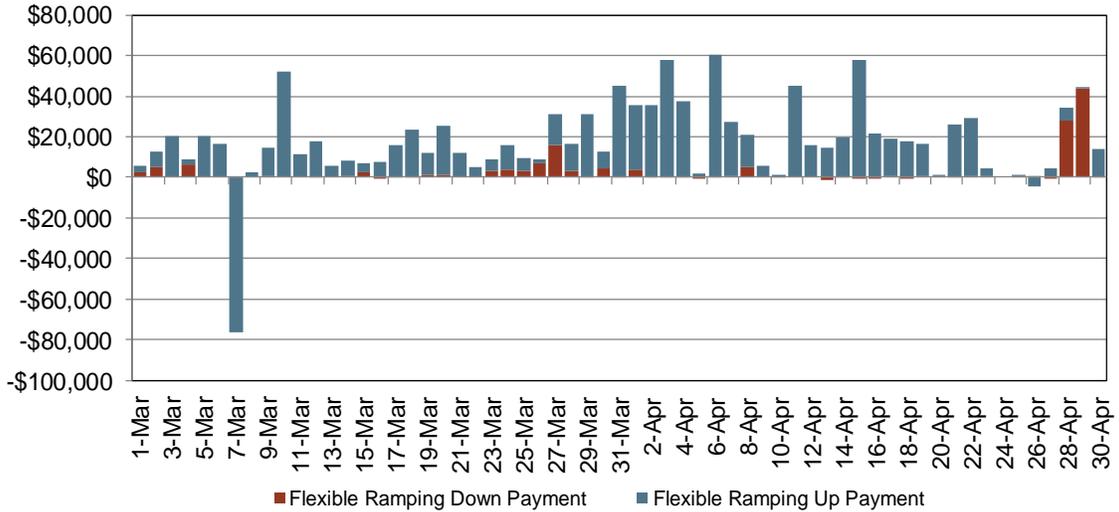
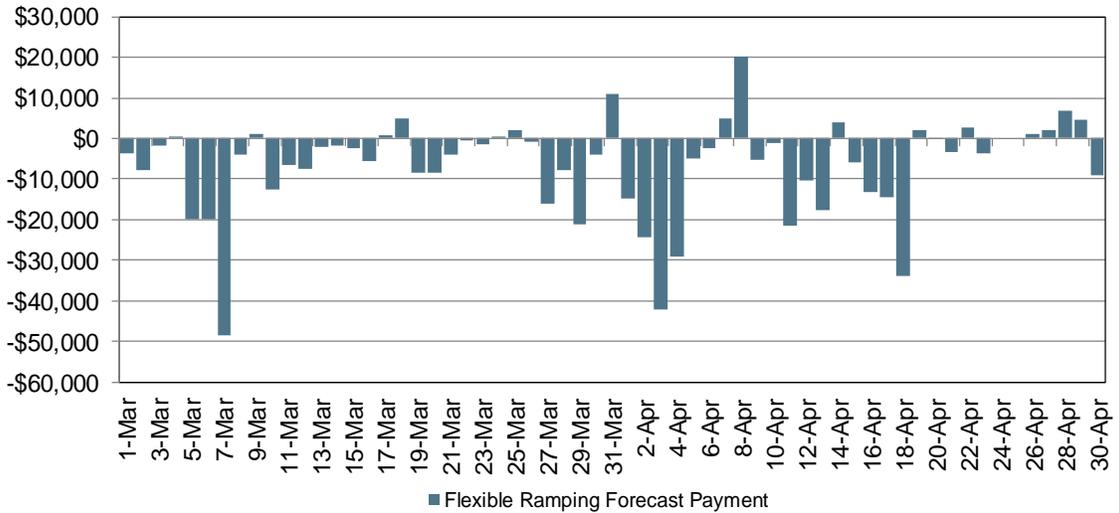


Figure 19 shows the flexible ramping forecast payment. Flexible ramping forecast payment edged down to -\$208,066 this month from -\$195,956 observed in March.

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 April decreased to \$0.31 million from \$0.40 million in March.

Figure 20: Exceptional Dispatch Uplift Costs

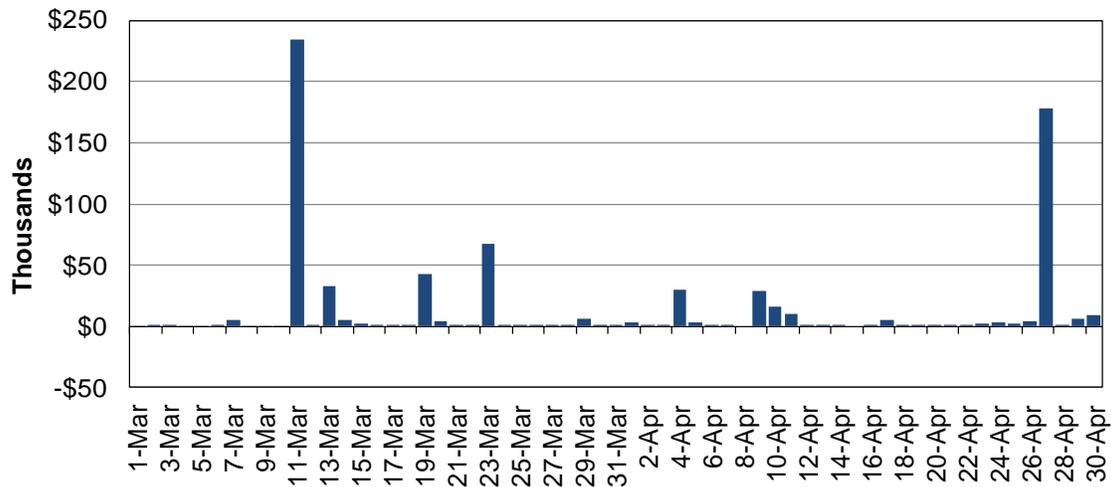


Figure 21 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for April inched up to \$6.41 million from \$5.85 million in March. Out of the total monthly bid cost recovery payment for the three markets in April, the IFM market contributed 14 percent, RTM contributed 64 percent, and RUC contributed 22 percent of the total bid cost recovery payment.

Figure 21: Bid Cost Recovery Allocation

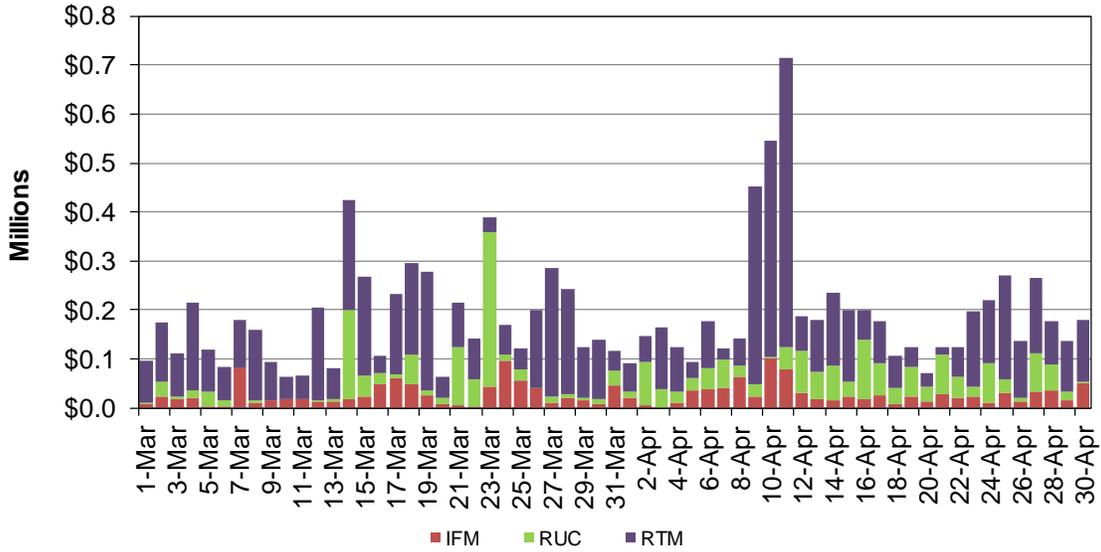


Figure 22 and Figure 23 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 22: Bid Cost Recovery Allocation by LCR

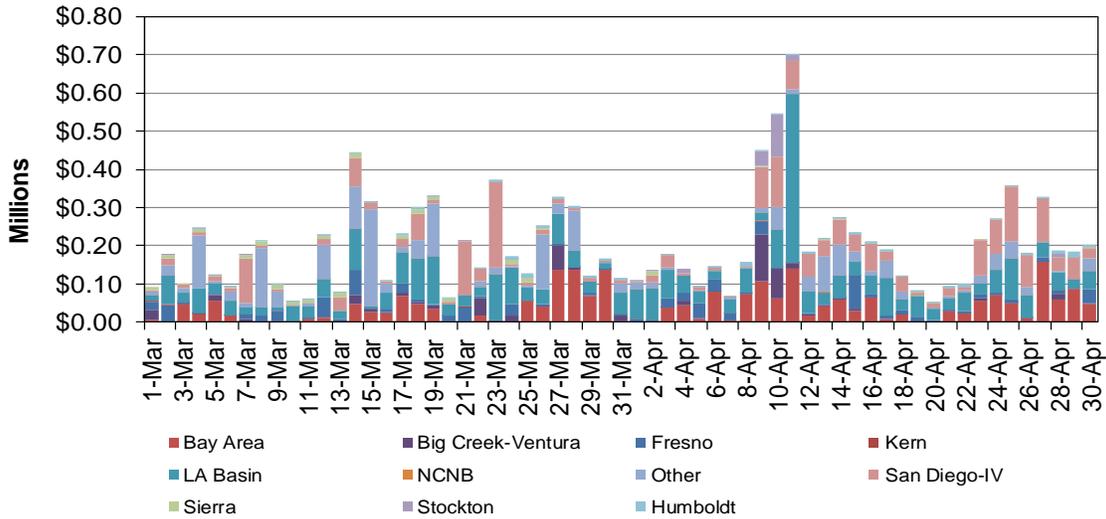


Figure 23: Monthly Bid Cost Recovery Allocation by LCR

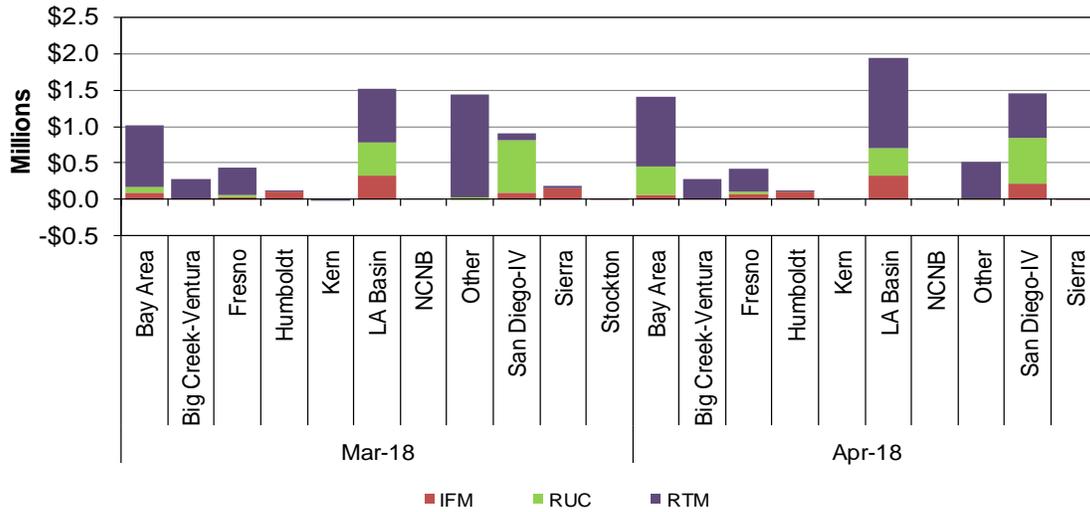


Figure 24 and Figure 25 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 24: Bid Cost Recovery Allocation by UDC

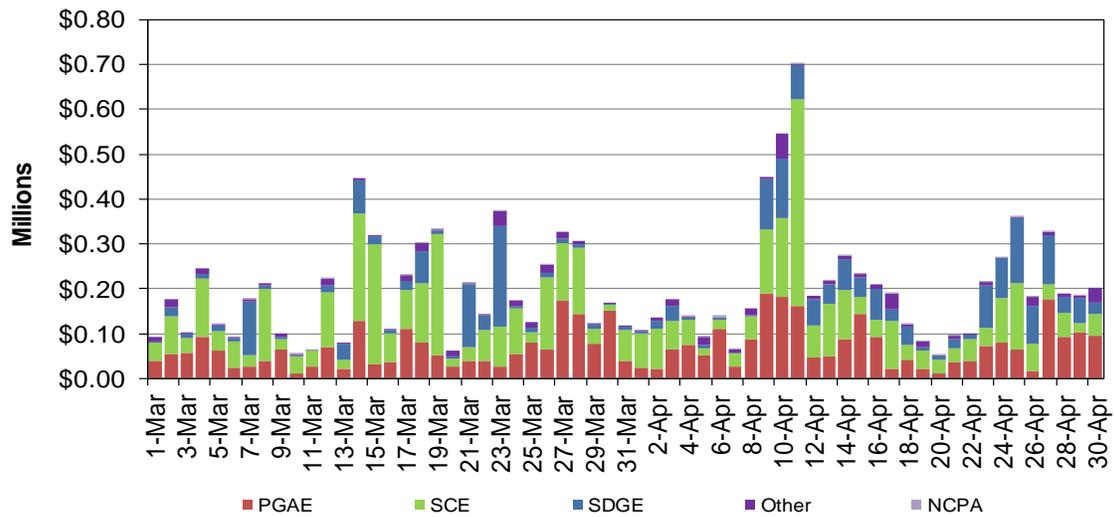


Figure 25: Monthly Bid Cost Recovery Allocation by UDC

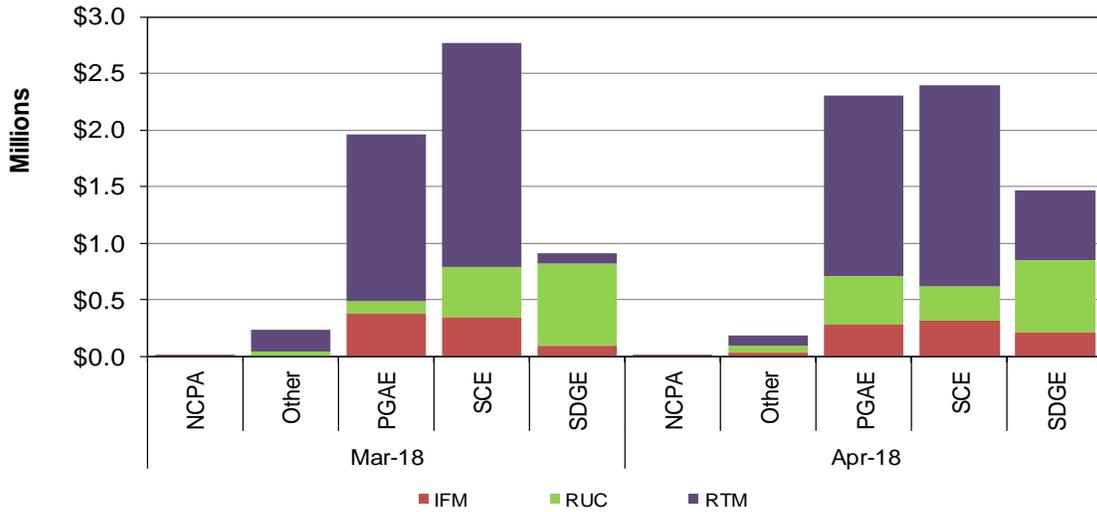


Figure 26 shows the cost related to BCR by cost type in RUC.

Figure 26: Cost in RUC

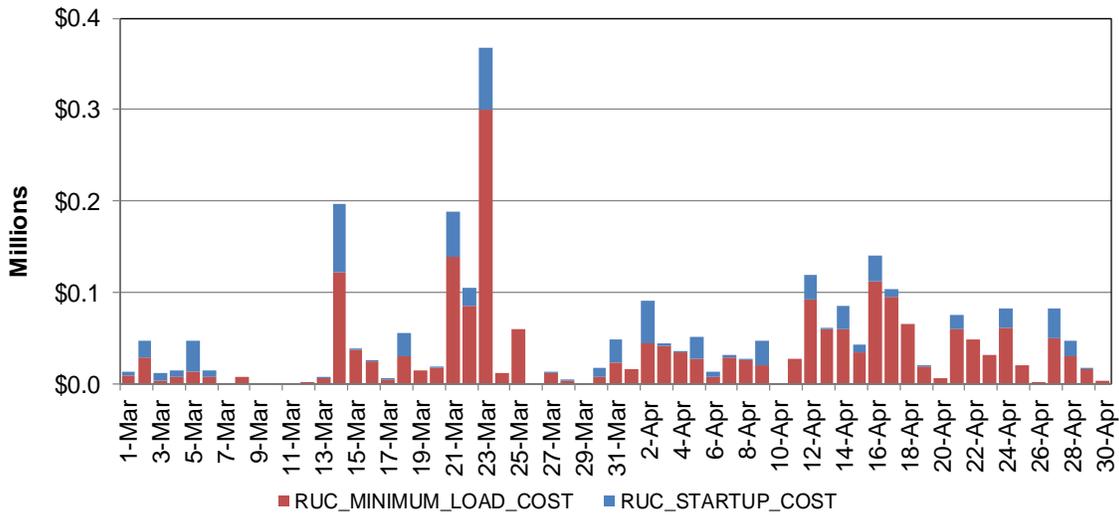


Figure 27 and Figure 28 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 27: Cost in RUC by LCR

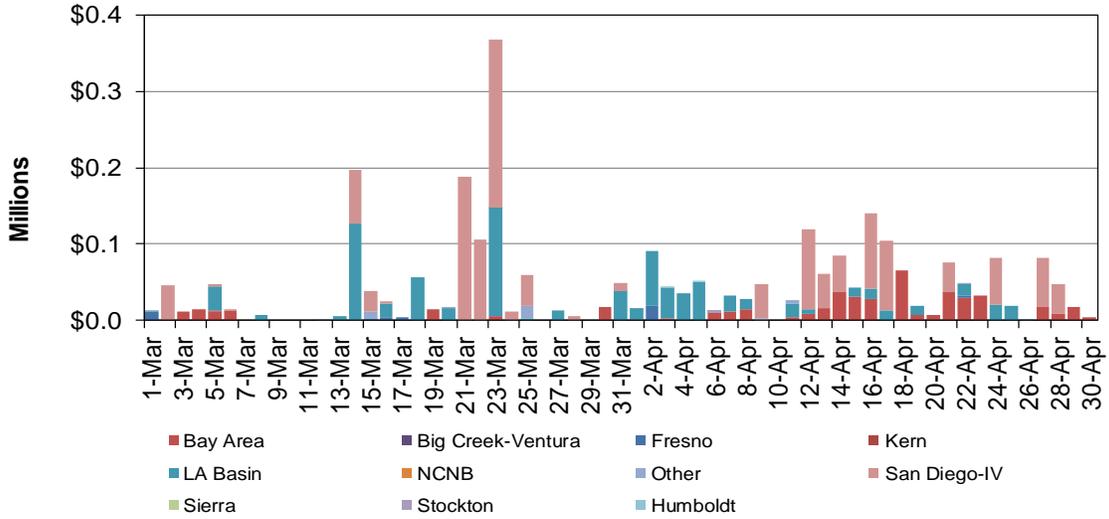


Figure 28: Monthly Cost in RUC by LCR

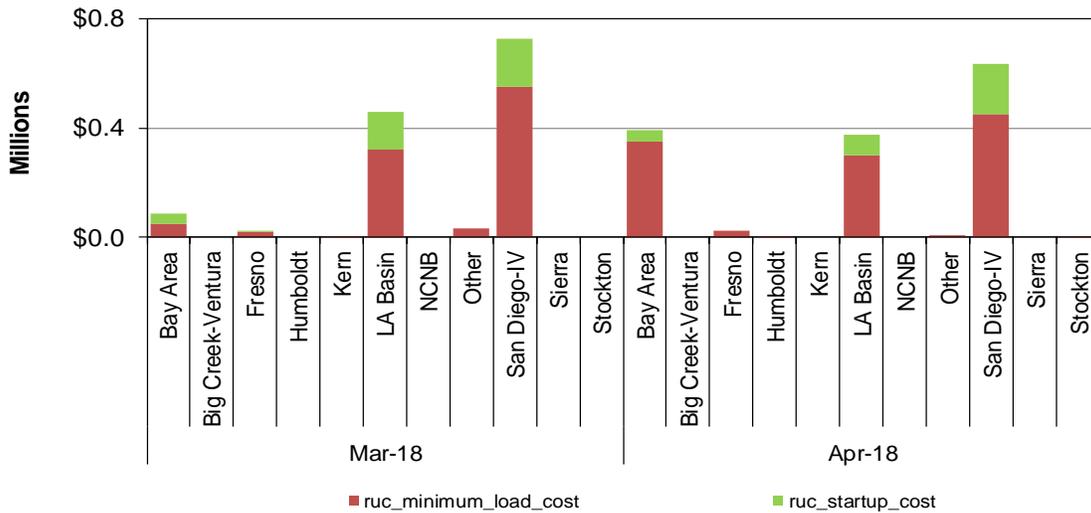


Figure 29 and Figure 30 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 29: Cost in RUC by UDC

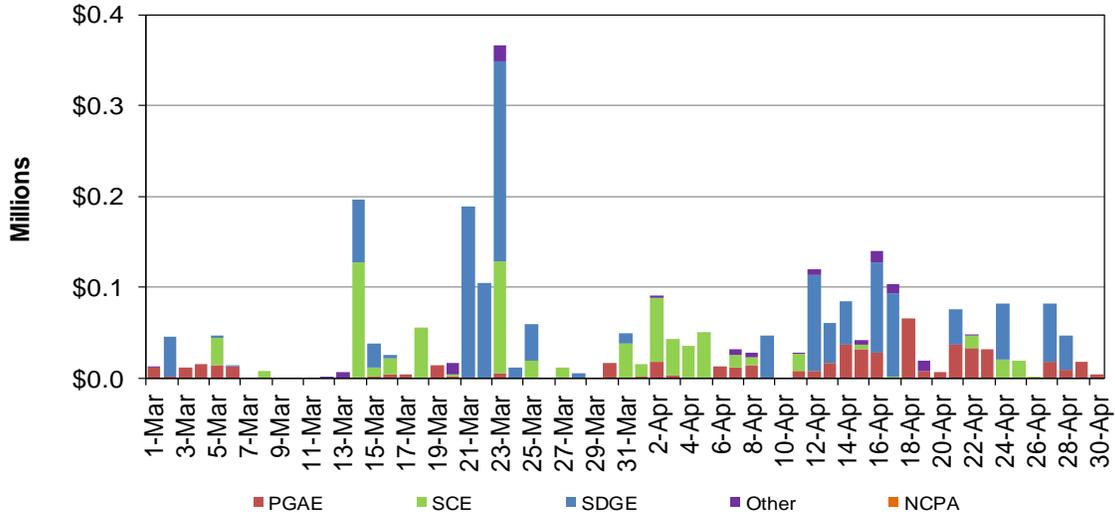


Figure 30: Monthly Cost in RUC by UDC

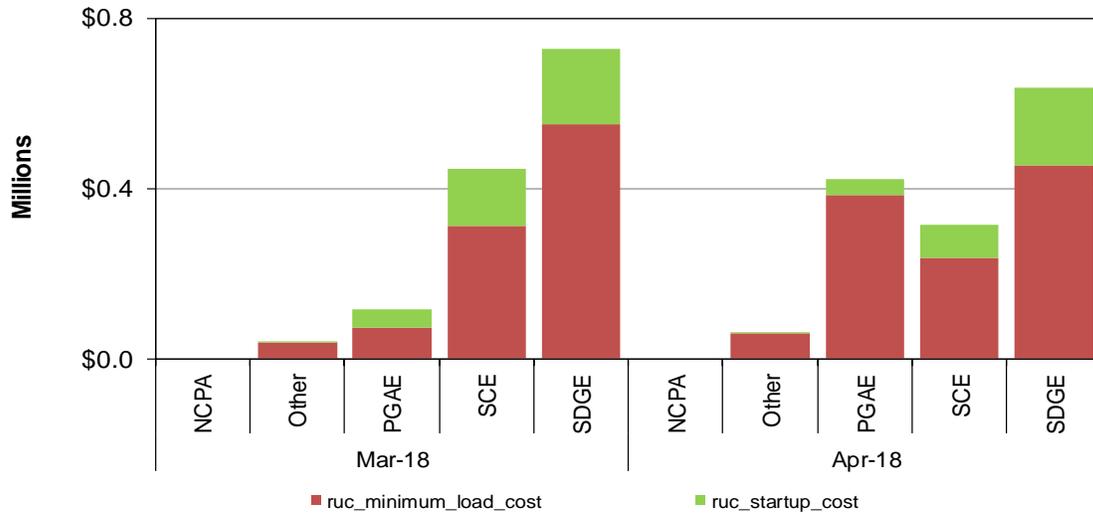


Figure 31 shows the cost related to BCR in real time by cost type. Minimum load cost contributed largely to the real time cost this month.

Figure 31: Cost in Real Time

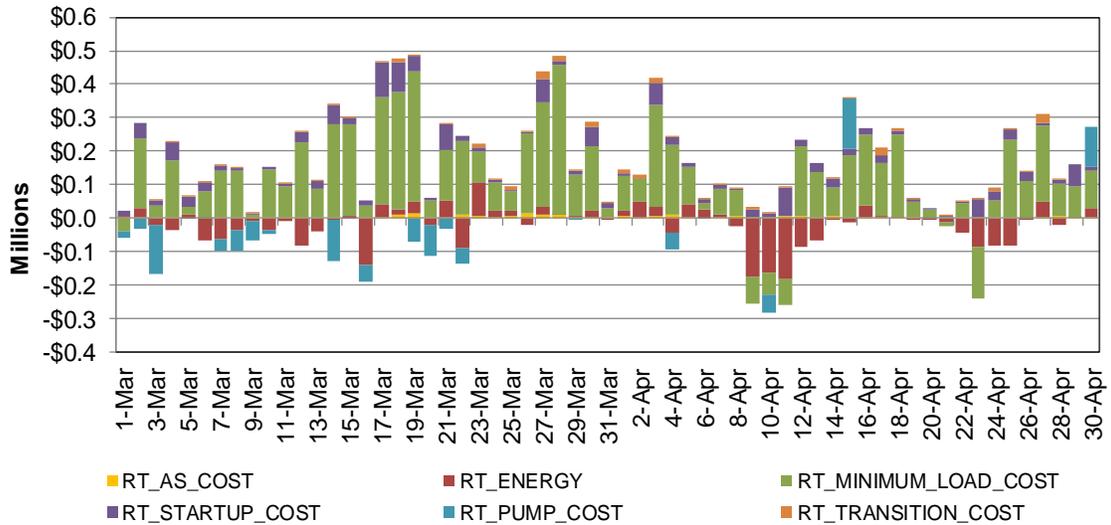


Figure 32 and Figure 33 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 32: Cost in Real Time by LCR

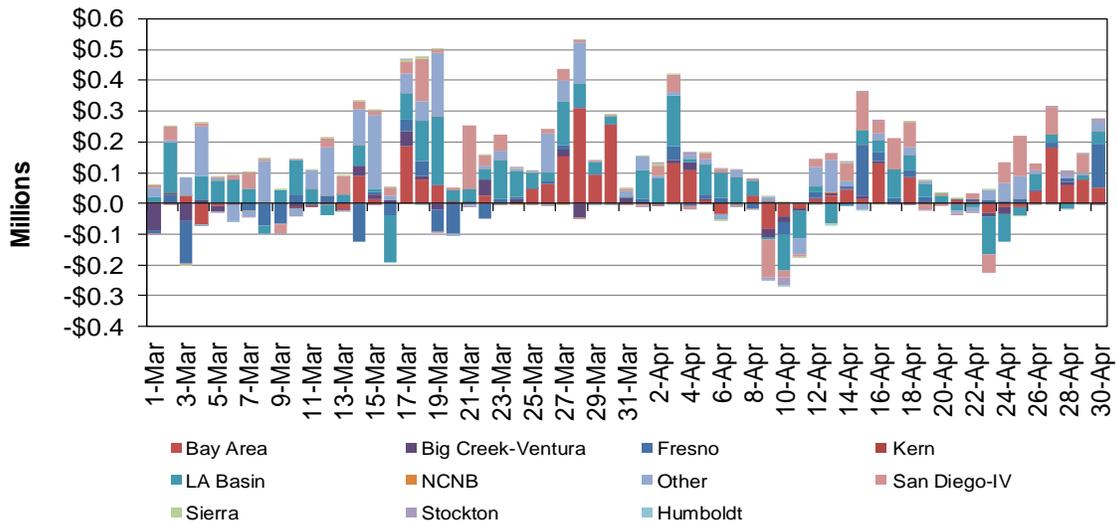


Figure 33: Monthly Cost in Real Time by LCR

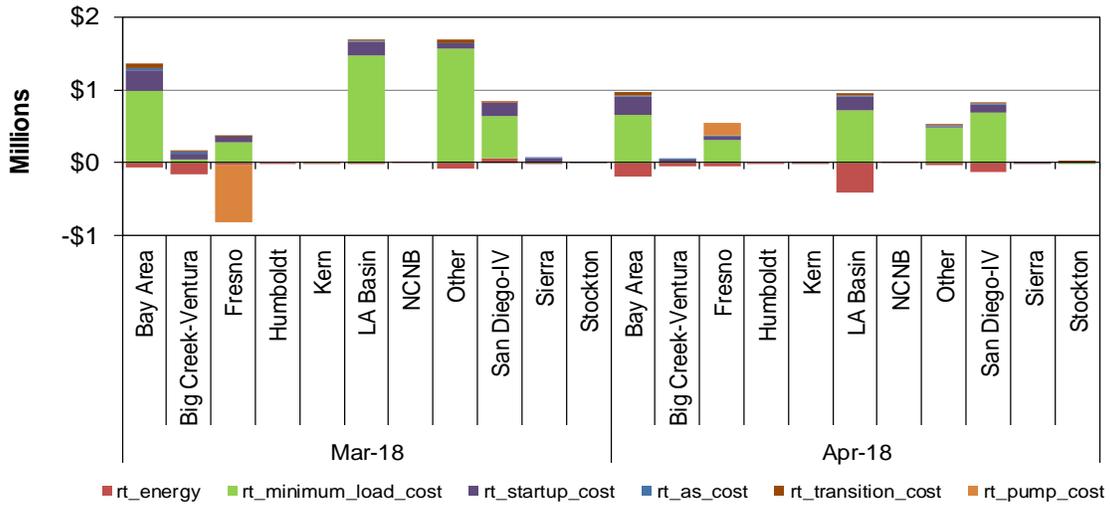


Figure 34 and Figure 35 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 34: Cost in Real Time by UDC

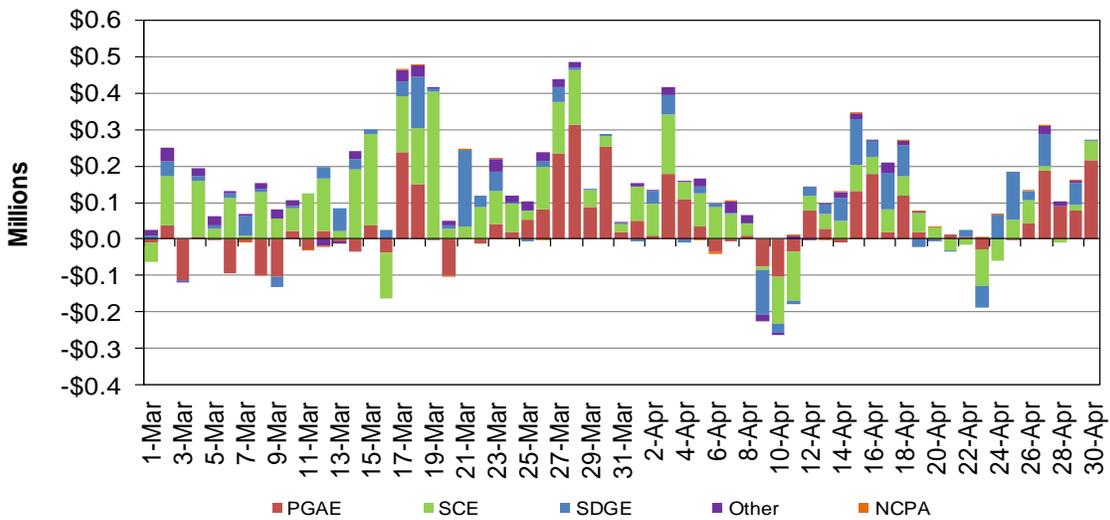


Figure 35: Monthly Cost in Real Time by UDC

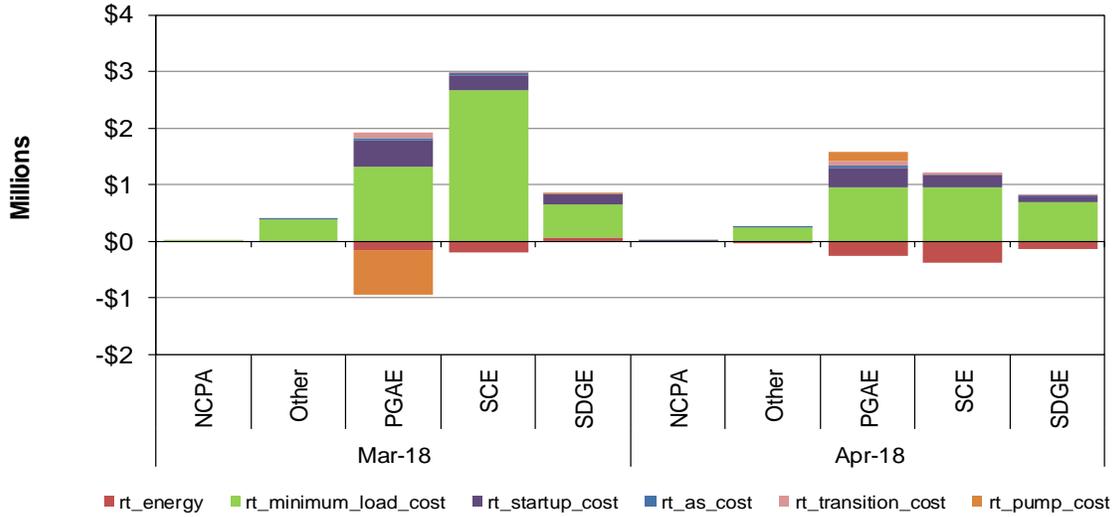


Figure 36 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM this month.

Figure 36: Cost in IFM

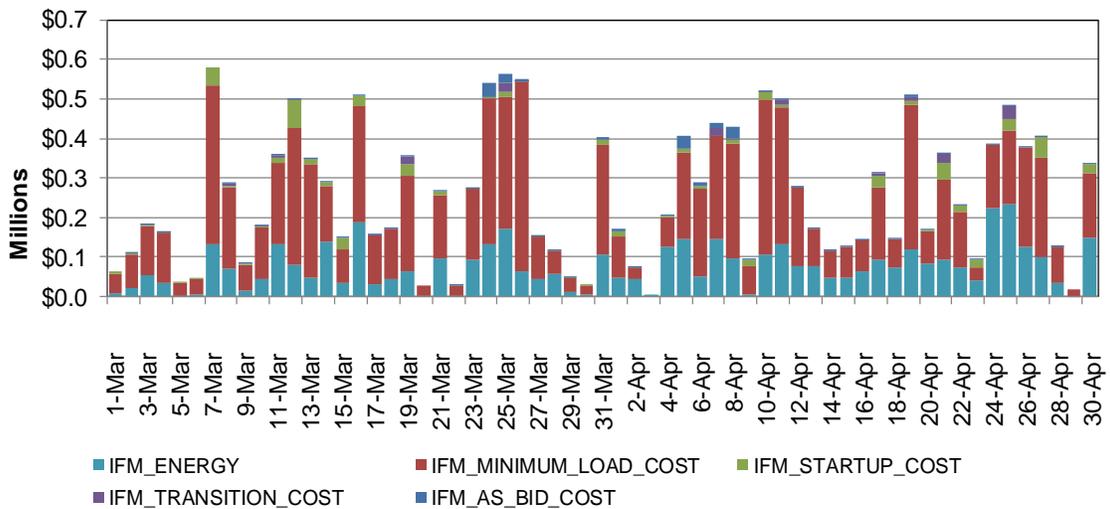


Figure 37 and Figure 38 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 37: Cost in IFM by LCR

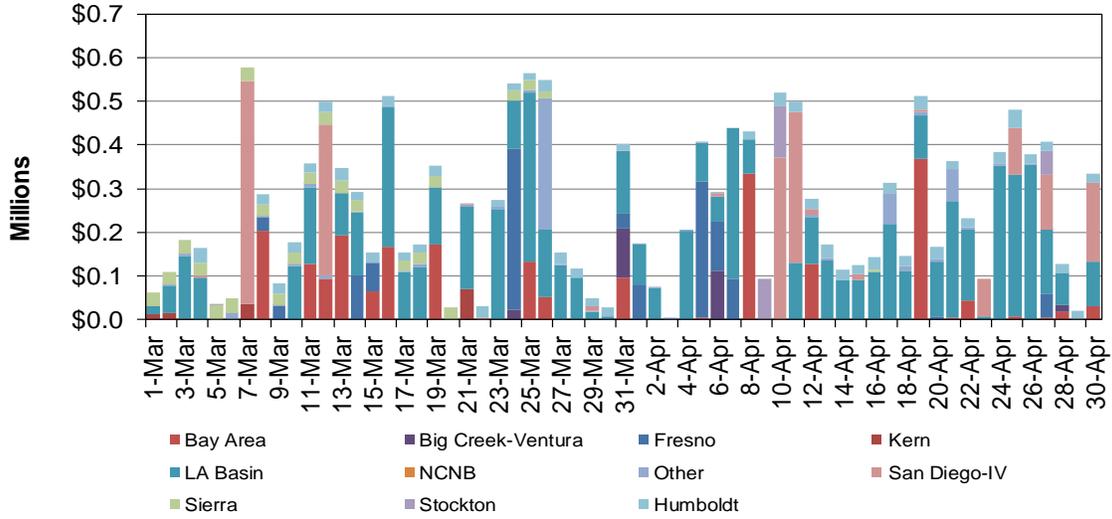


Figure 38: Monthly Cost in IFM by LCR

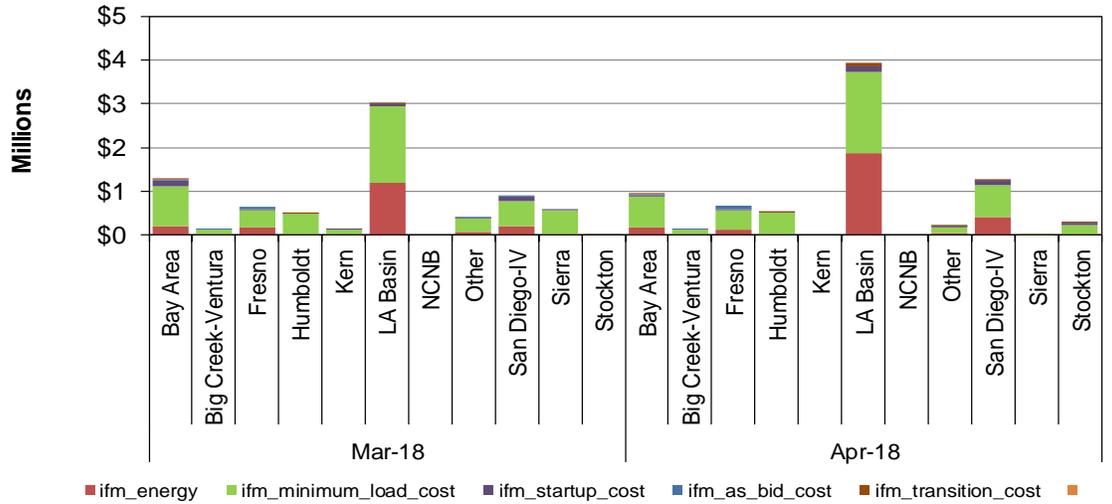


Figure 39 and Figure 40 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 39: Cost in IFM by UDC

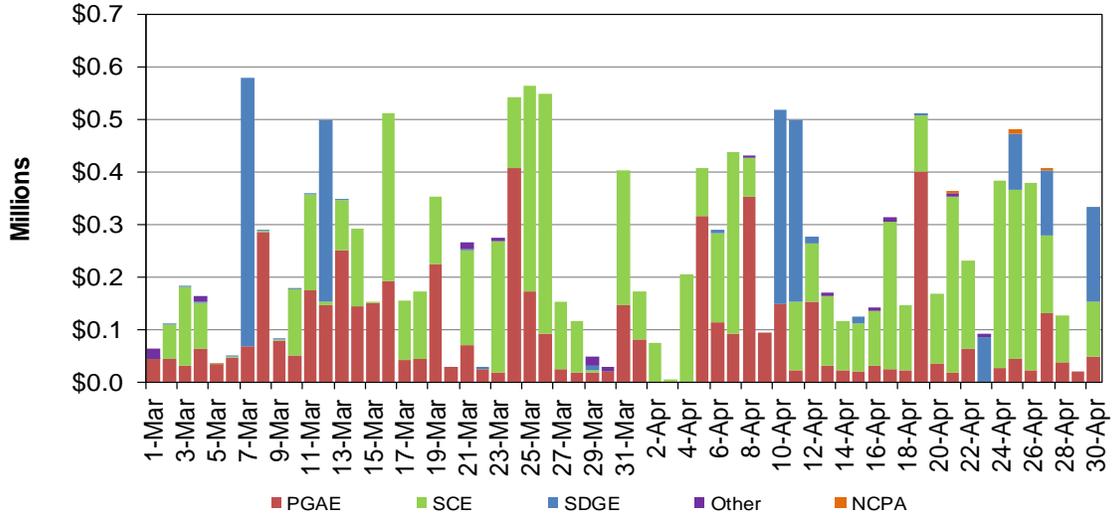
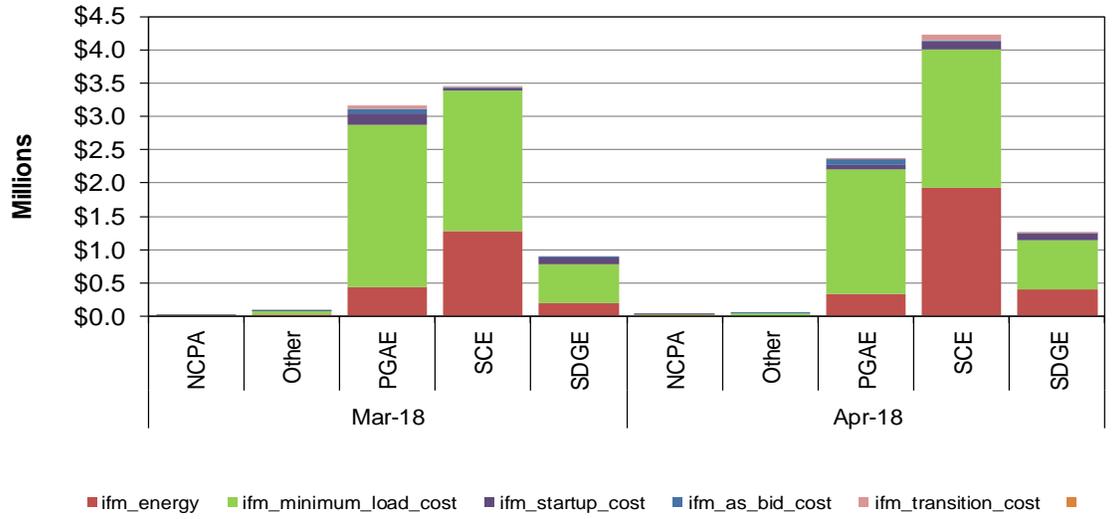


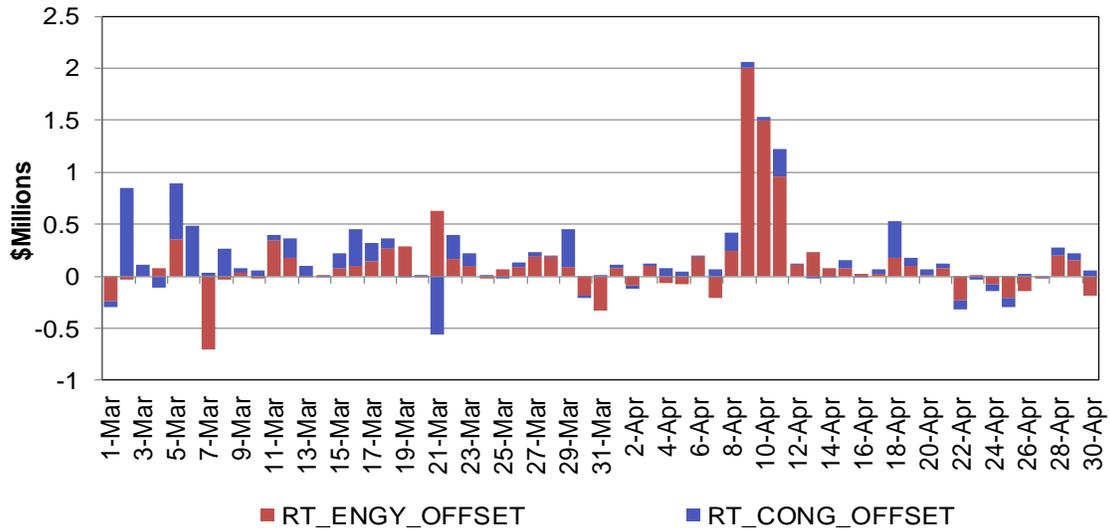
Figure 40: Monthly Cost in IFM by UDC



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 \$5.07 million in April from \$1.81 million in March. Real-time congestion offset cost dropped to \$1.32 million in April from \$3.55 million in March.

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 70 market disruptions this month. 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.

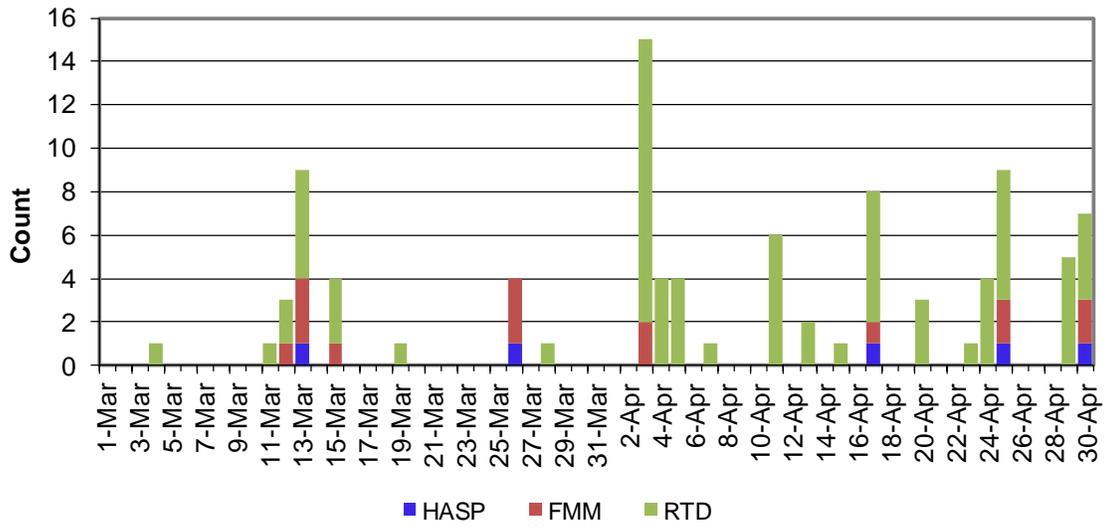
Table 7: Summary of Market Disruption

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	3	0
FMM Interval 3	0	0
FMM Interval 4	3	0
Real-Time Dispatch	60	0

Figure 42 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On April 3, two FMM and 13 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: 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 April rose to 47,380 MWh from 44,485 MWh in March.

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

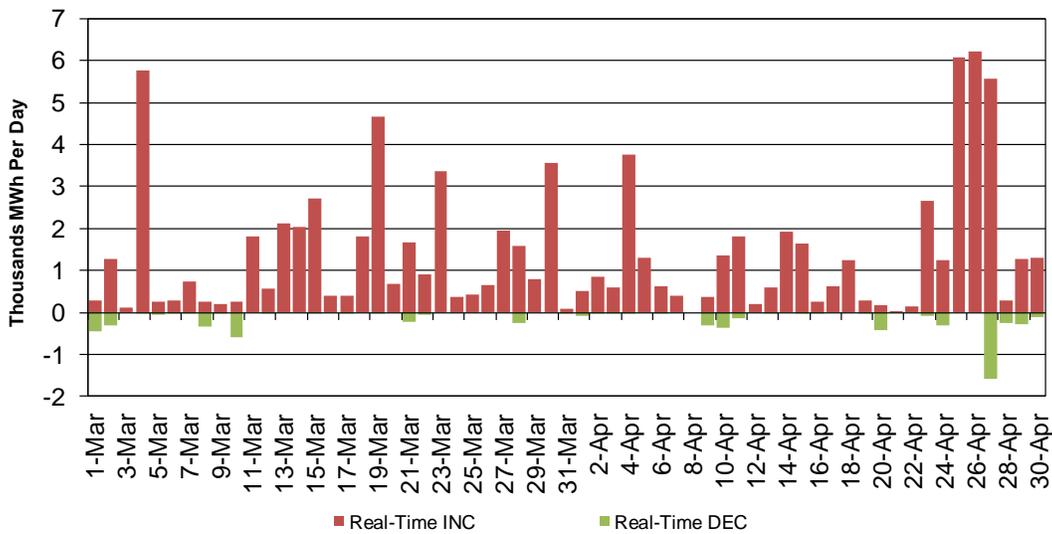


Figure 44 shows the volume of the exceptional dispatch broken out by reason.⁴ The majority of the exceptional dispatch volumes in April were driven by planned transmission outage (41 percent), other reliability requirement (19 percent), and operating procedure number and constraint (12 percent).

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

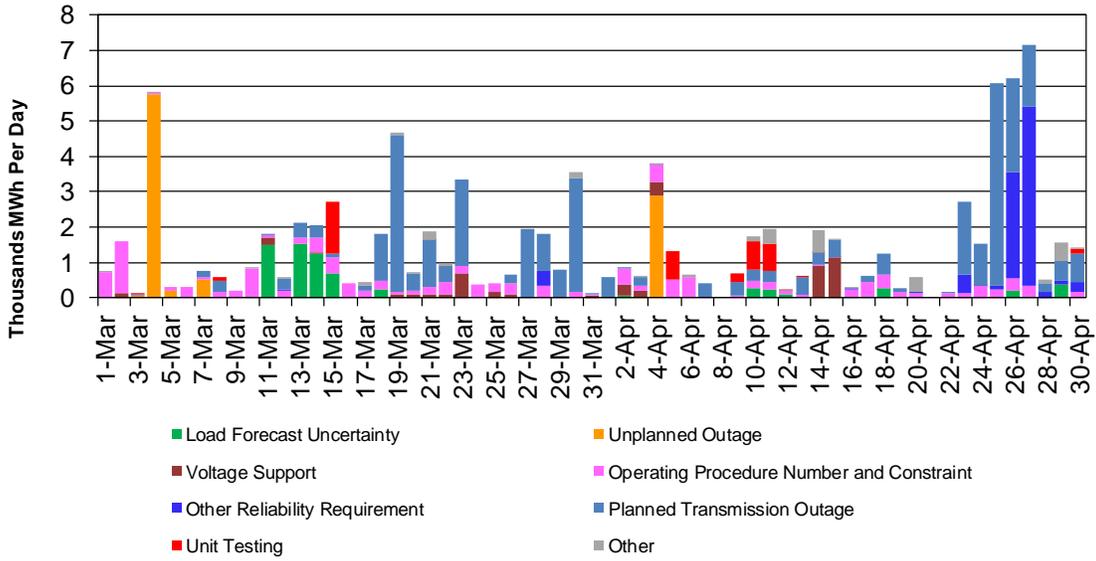
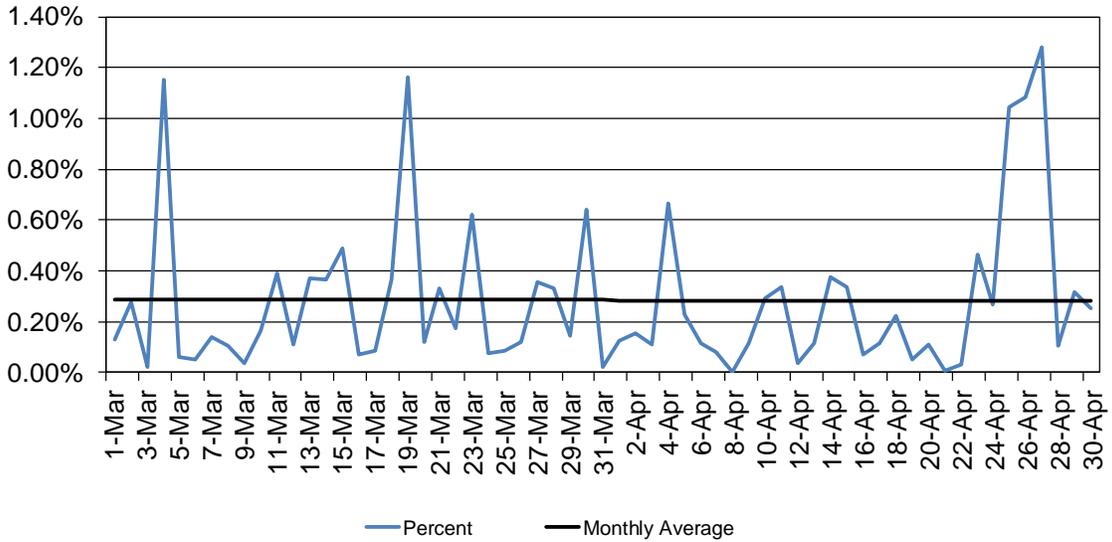


Figure 45 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage was 0.28 percent in April, unchanged from March.

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). 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.

Figure 46 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), and Powerex (BCHA) for all hours in FMM. The prices for AZPS and NEVP were elevated on April 9-11 due to upward load adjustment, net import reduction, generation outage, and renewable deviation.

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

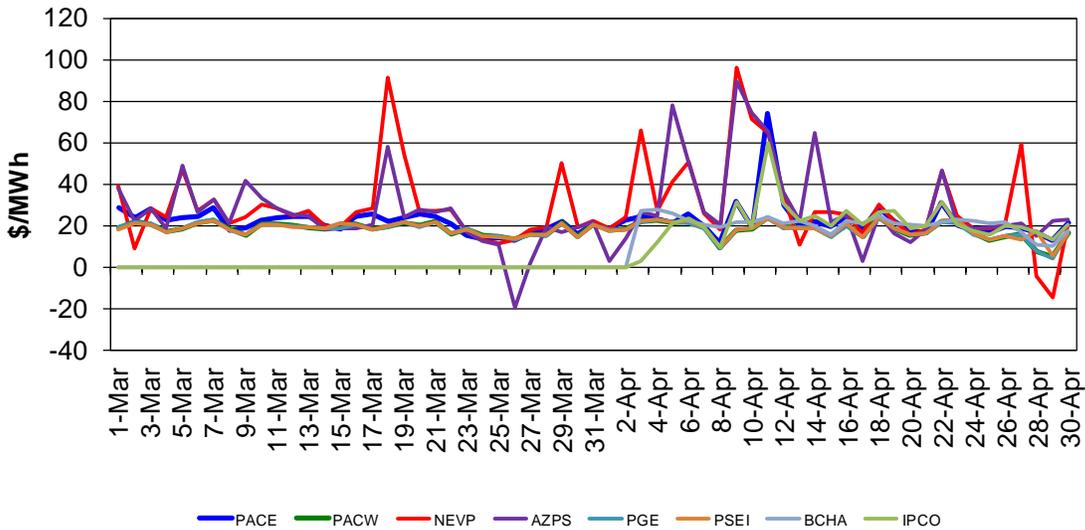


Figure 47 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA for all hours in RTD. The price for AZPS was elevated on April 5 due to tight supply. The price for NEVP was elevated on April 27 due to net import reduction and generation outage.

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

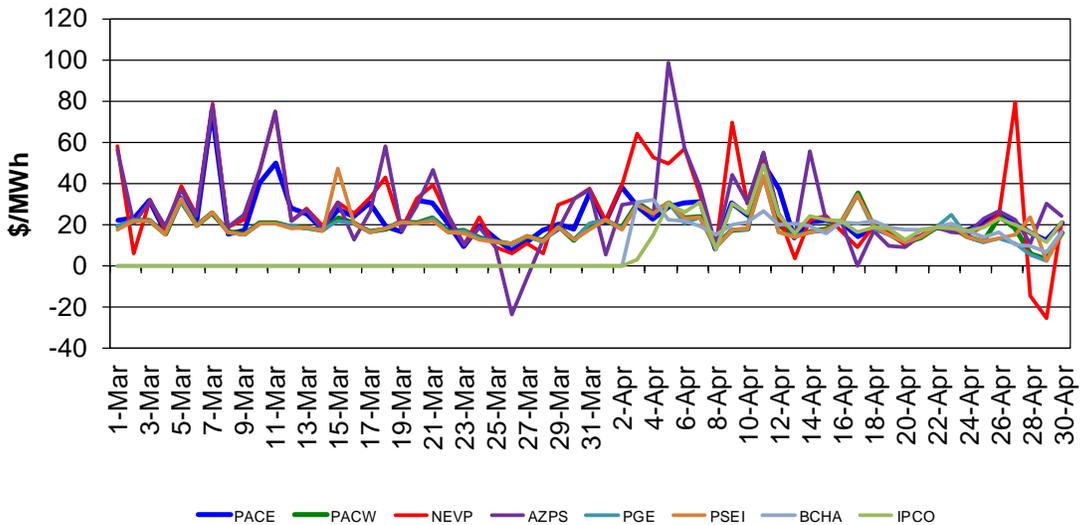


Figure 48 shows the daily price frequency for prices above \$250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above \$250/MWh increased to 0.38 percent in April from 0.16 percent in March. The cumulative frequency of negative prices rose to 2.87 percent in April from 2.46 percent in March.

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

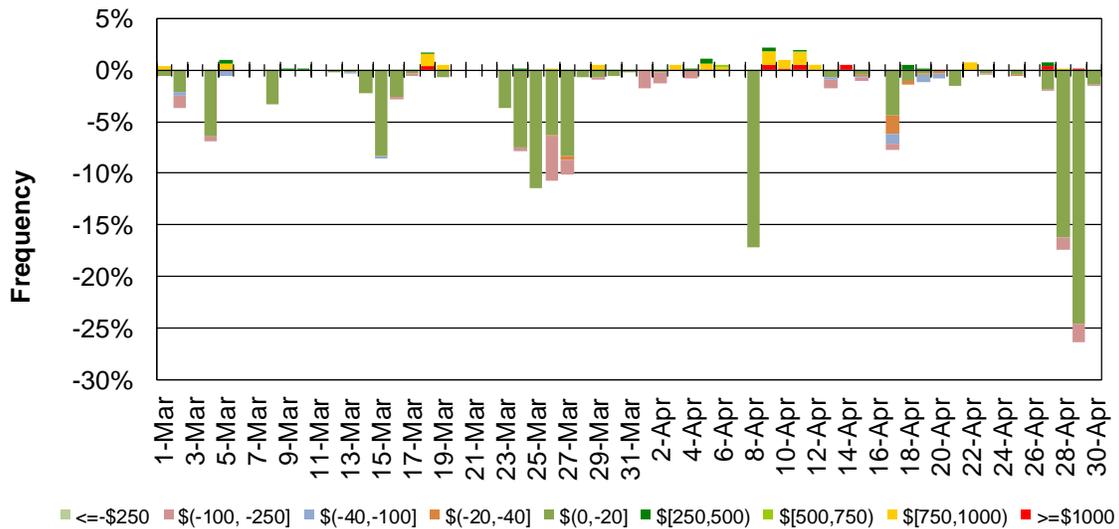


Figure 49 shows the daily price frequency for prices above \$250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above \$250/MWh increased to 0.70 percent in April from 0.52 percent in March. The cumulative frequency of negative prices fell to 4.20 percent in April from 5.94 percent in March.

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

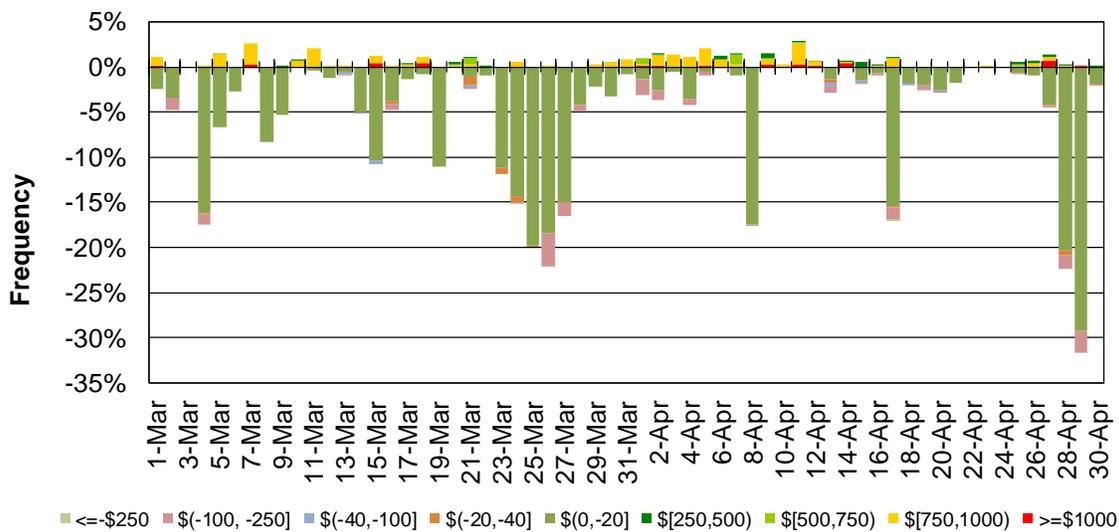


Figure 50 shows the daily volume of EIM transfer for CAISO in FMM. “Import” represents the total EIM transfer from other balancing areas (BAs) into CAISO. “Export” represents the total EIM transfer out of CAISO to other BAs in FMM.

Figure 50: EIM Transfer for CAISO in FMM

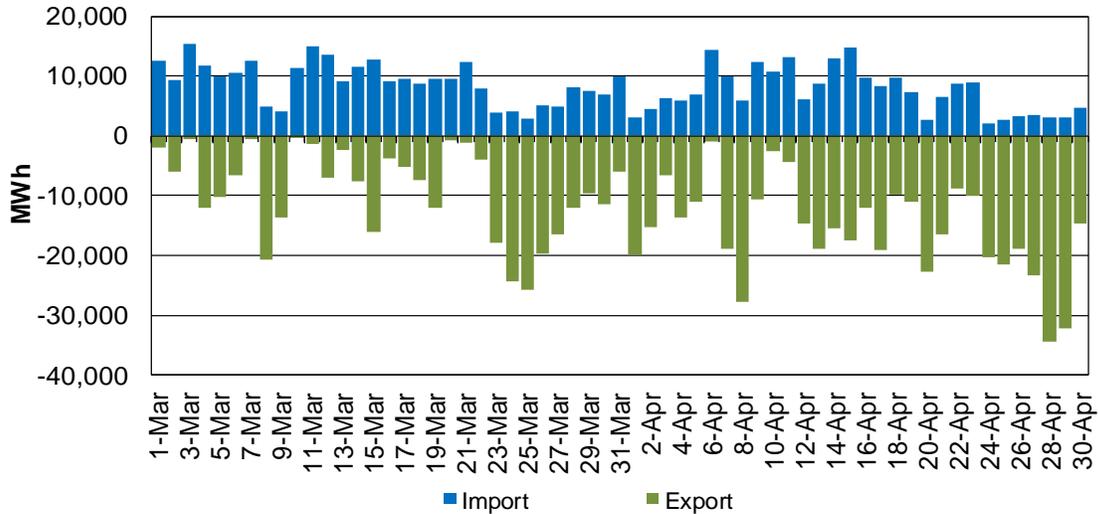


Figure 51 shows the daily volume of EIM transfer for PACE in FMM. Figure 52 shows the daily volume of EIM transfer for PACW in FMM.

Figure 51: EIM Transfer for PACE in FMM

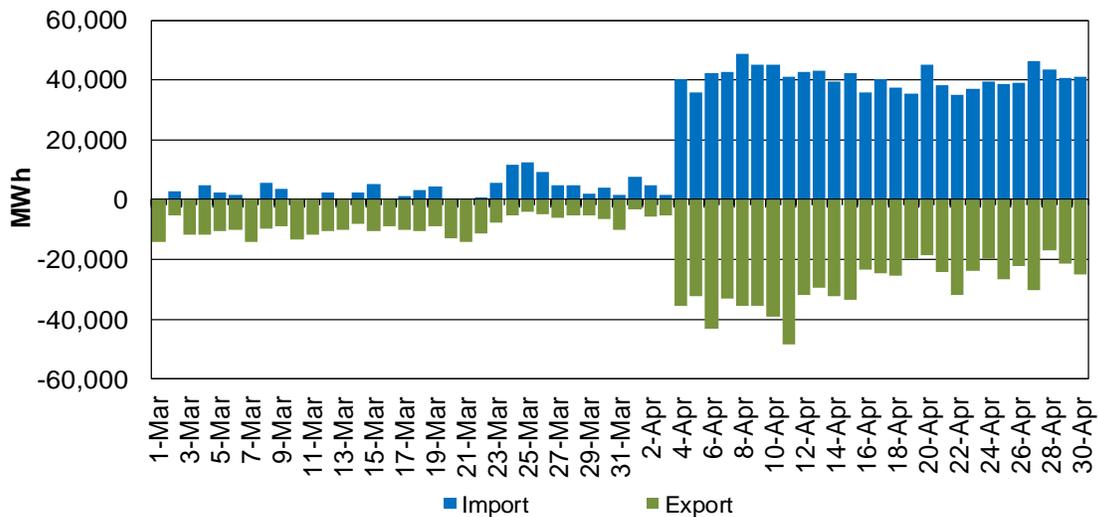


Figure 52: EIM Transfer for PACW in FMM

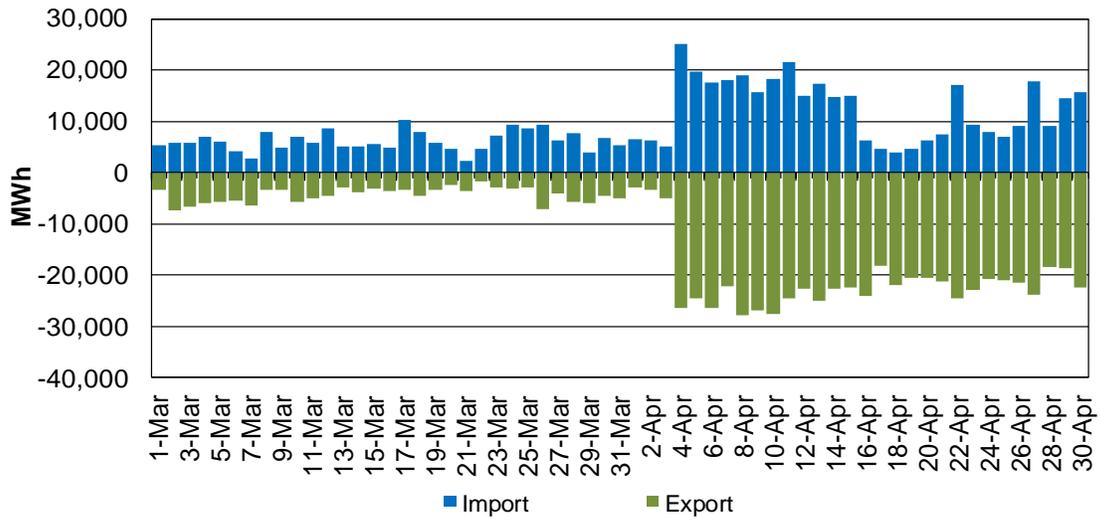


Figure 53 shows the daily volume of EIM transfer for NEVP in FMM.

Figure 53: EIM Transfer for NEVP in FMM

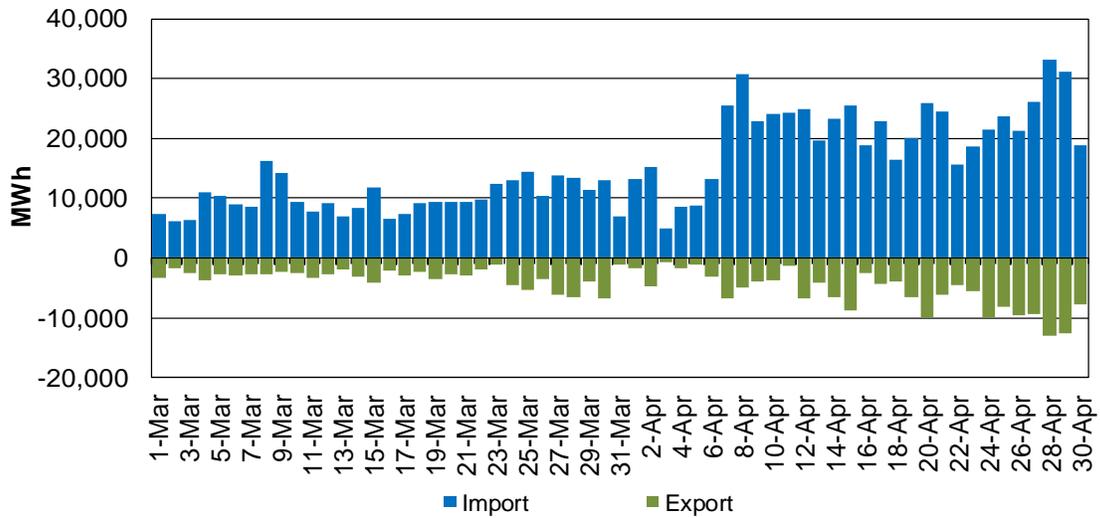


Figure 54 shows the daily volume of EIM transfer for AZPS in FMM.

Figure 54: EIM Transfer for AZPS in FMM

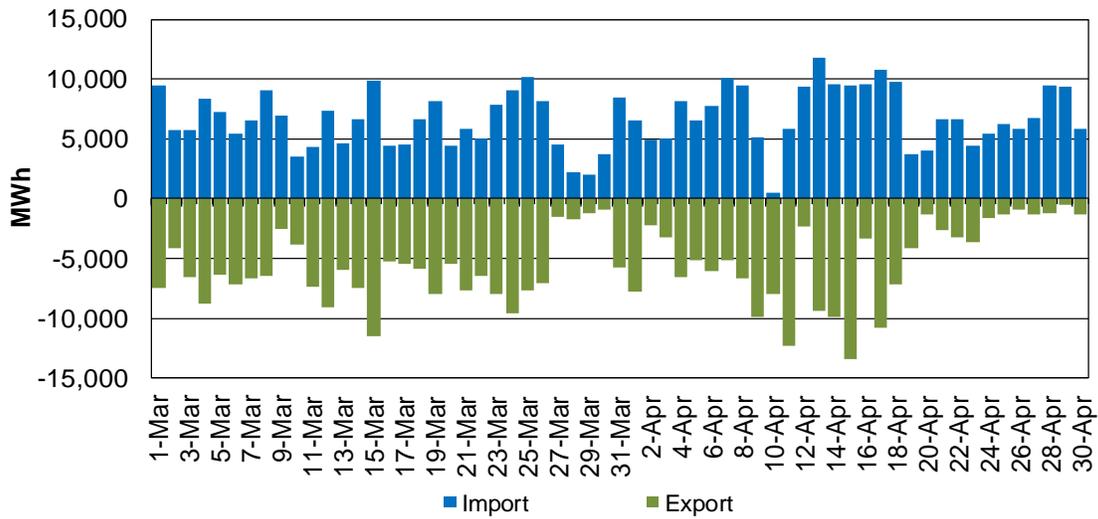


Figure 55 shows the daily volume of EIM transfer for PSEI in FMM.

Figure 55: EIM Transfer for PSEI in FMM

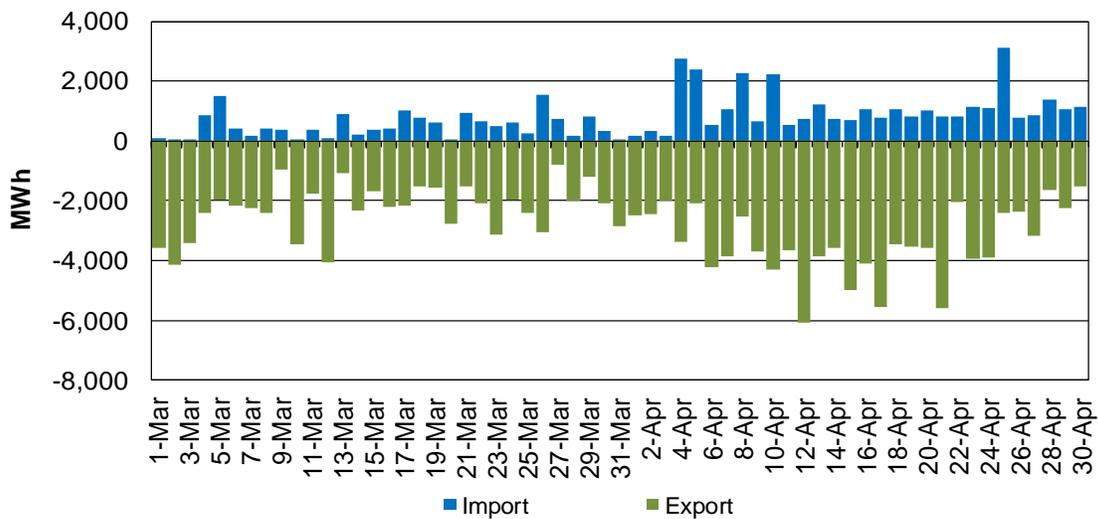


Figure 56 shows the daily volume of EIM transfer for PGE in FMM.

Figure 56: EIM Transfer for PGE in FMM

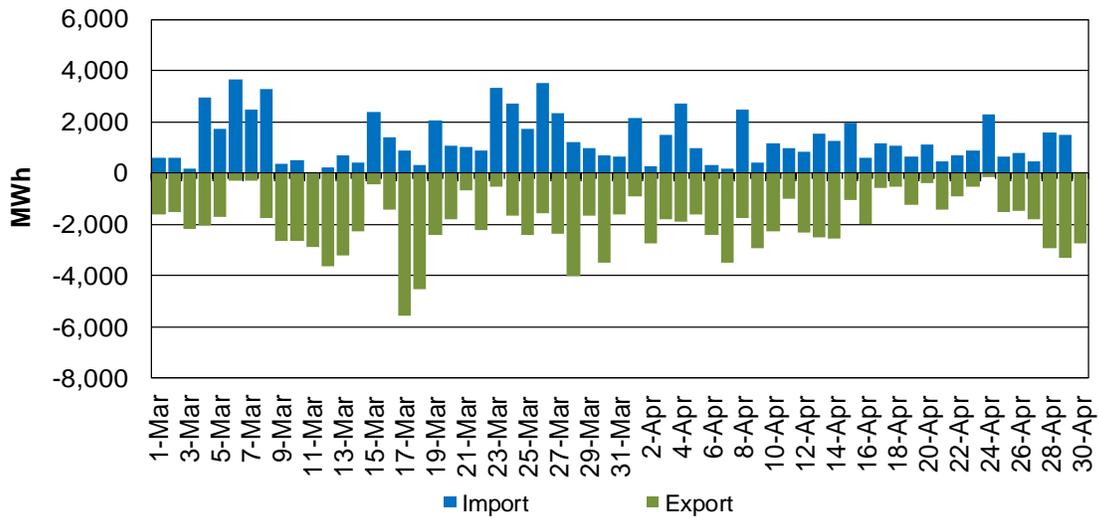


Figure 57 shows the daily volume of EIM transfer for BCHA in FMM.

Figure 57: EIM Transfer for BCHA in FMM

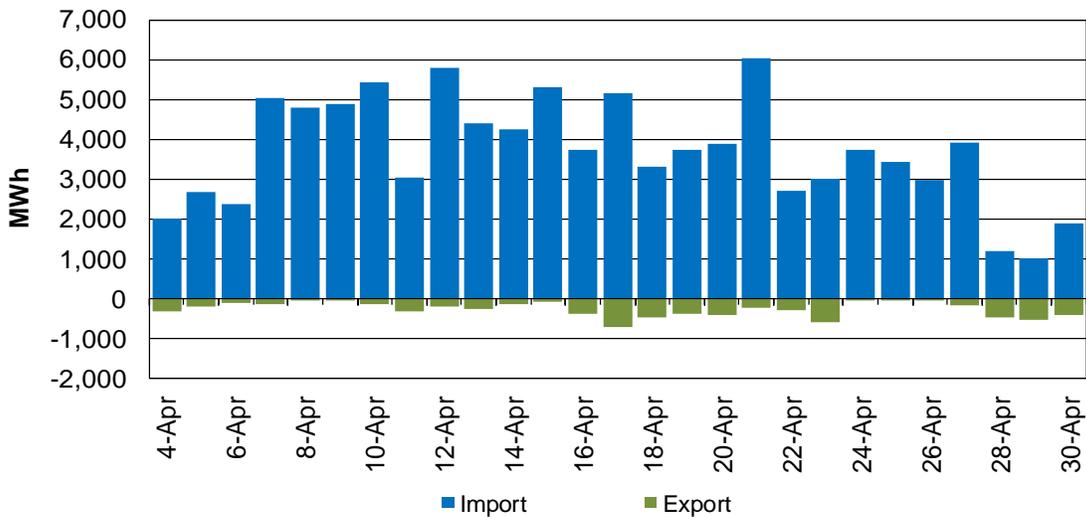


Figure 58 shows the daily volume of EIM transfer for IPCO in FMM.

Figure 58: EIM Transfer for IPCO in FMM

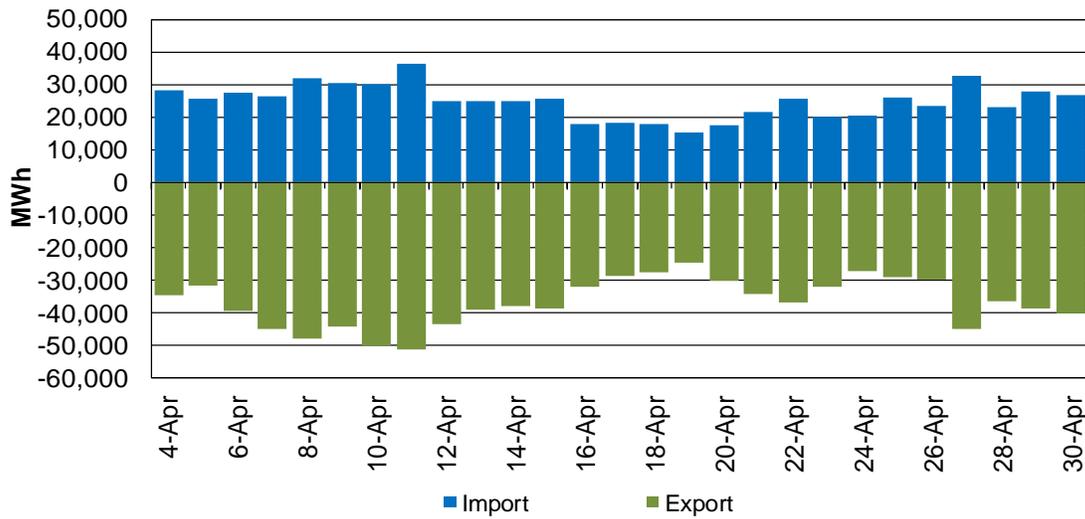


Figure 59 shows the daily volume of EIM for ISO in RTD.

Figure 59: EIM Transfer for CAISO in RTD

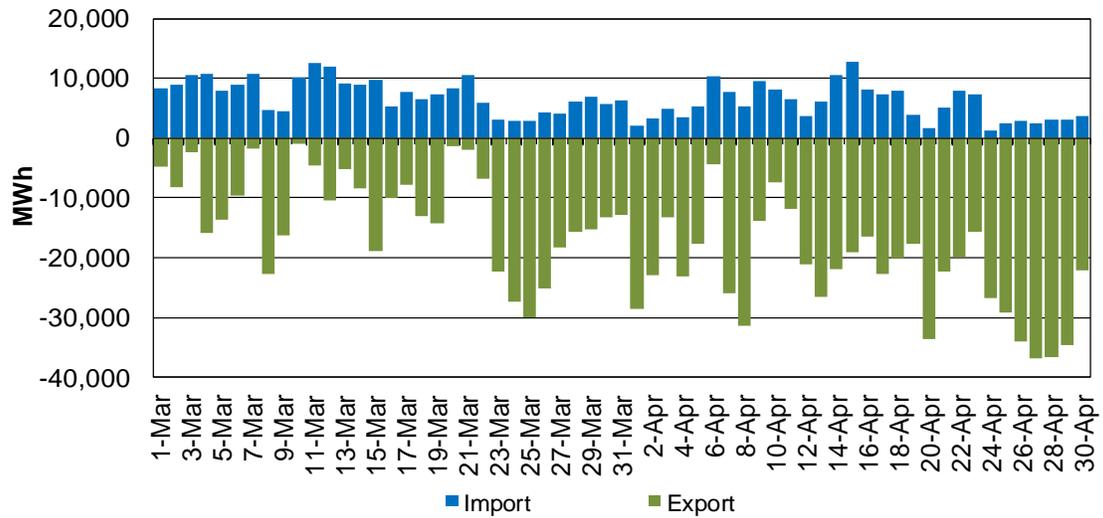


Figure 60 shows the daily volume of EIM transfer for PACE in RTD. Figure 61 shows the daily EIM transfer volume for PACW in RTD.

Figure 60: EIM Transfer for PACE in RTD

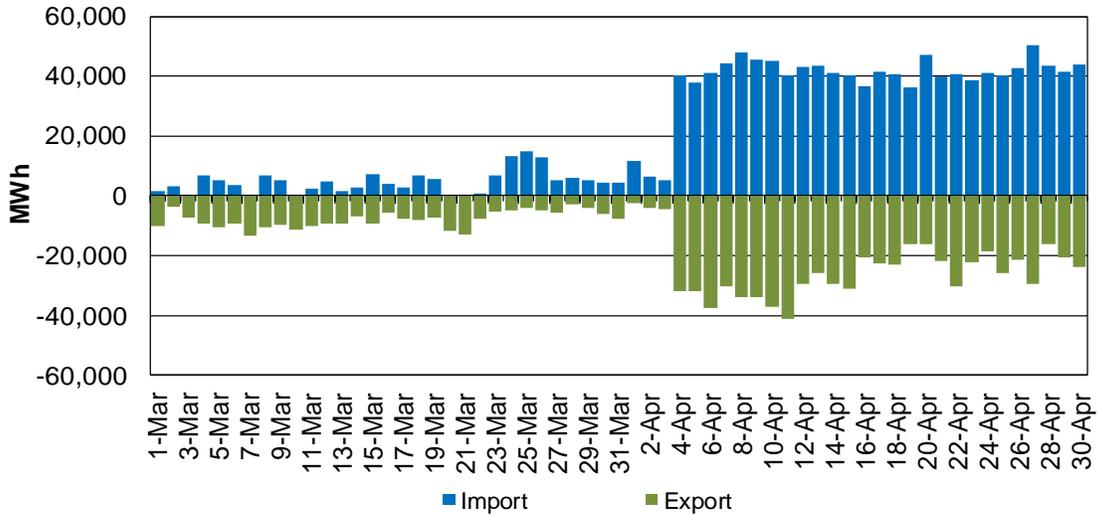


Figure 61: EIM Transfer for PACW in RTD

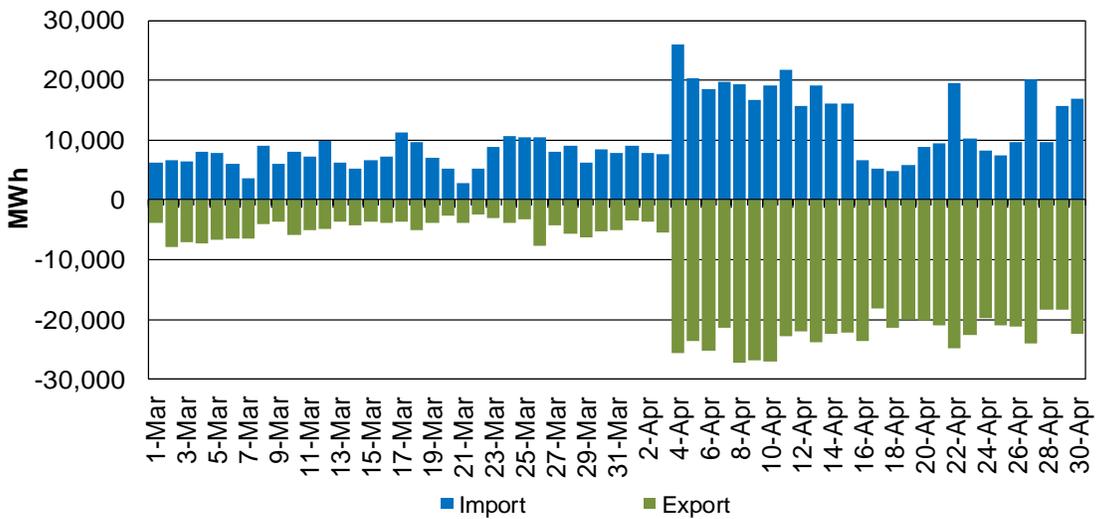


Figure 62 shows the daily EIM transfer volume for NEVP in RTD.

Figure 62: EIM Transfer for NEVP in RTD

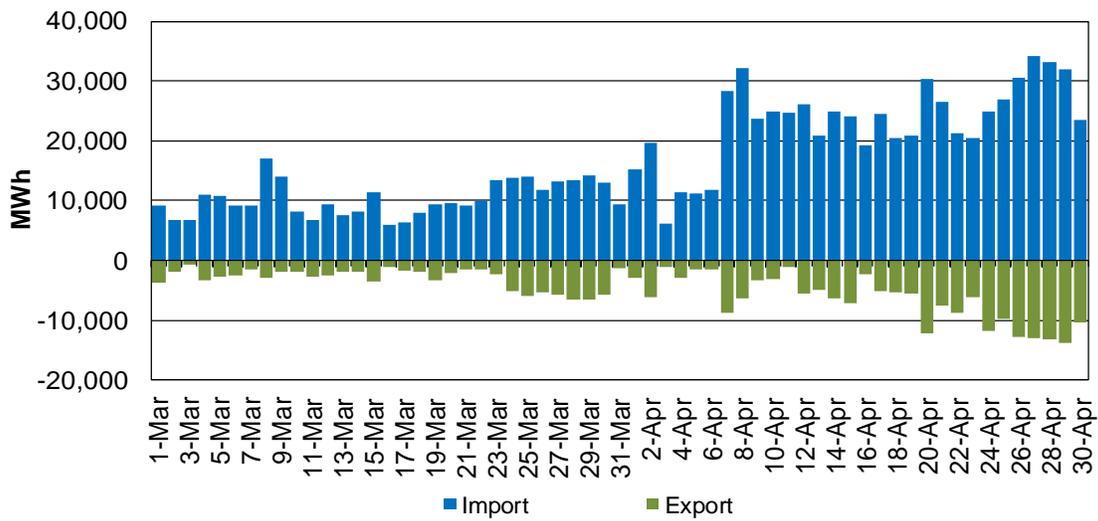


Figure 63 shows the daily volume EIM transfer for AZPS in RTD.

Figure 63: EIM Transfer for AZPS in RTD

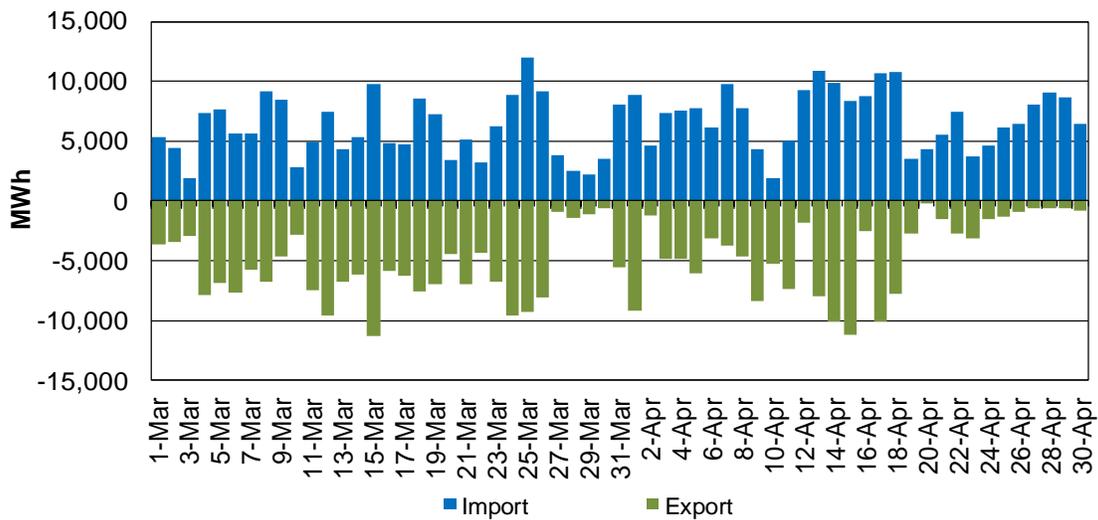


Figure 64 shows the daily volume EIM transfer for PSEI in RTD.

Figure 64: EIM Transfer for PSEI in RTD

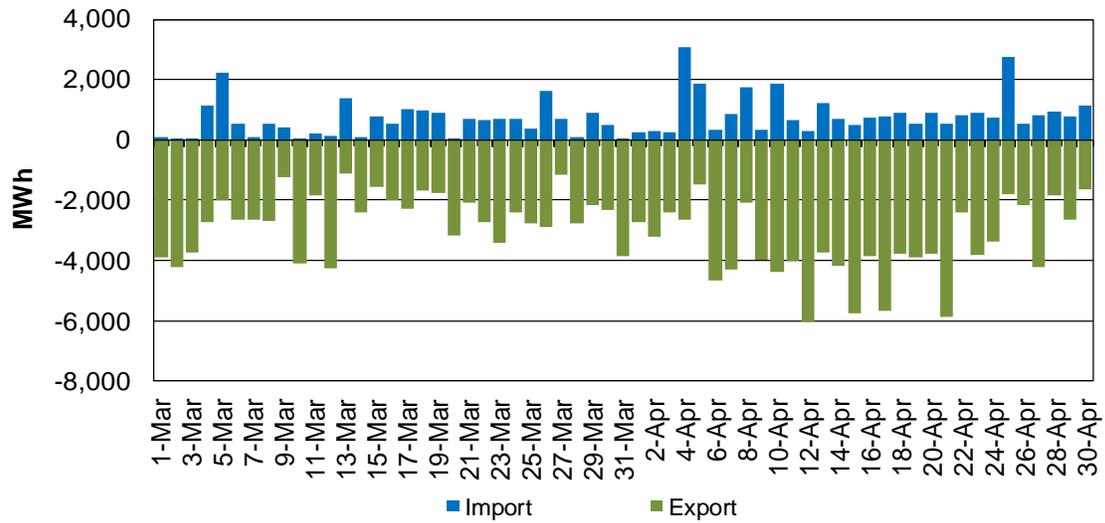


Figure 65 shows the daily volume EIM transfer for PGE in RTD.

Figure 65: EIM Transfer for PGE in RTD

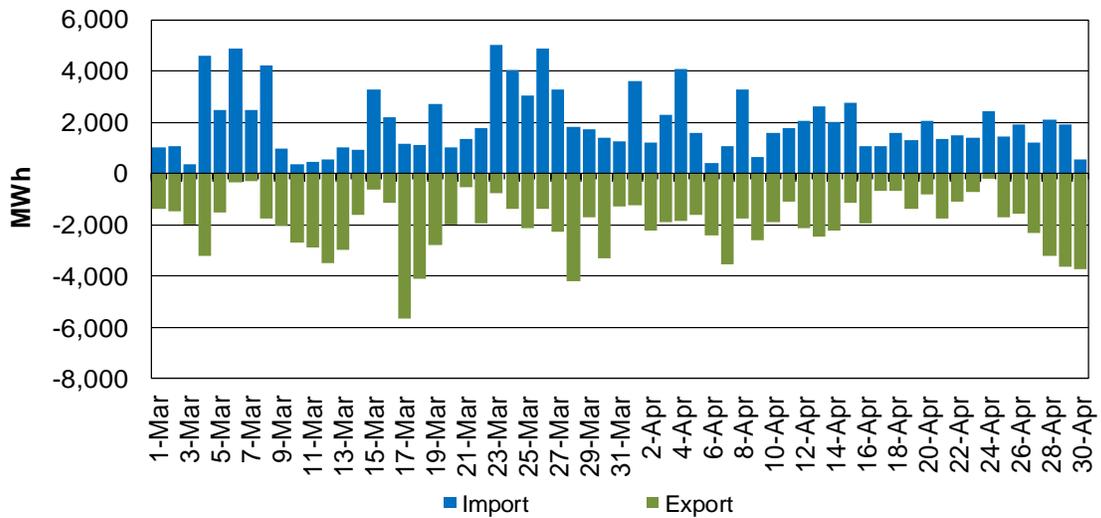


Figure 66 shows the daily volume EIM transfer for BCHA in RTD.

Figure 66: EIM Transfer for BCHA in RTD

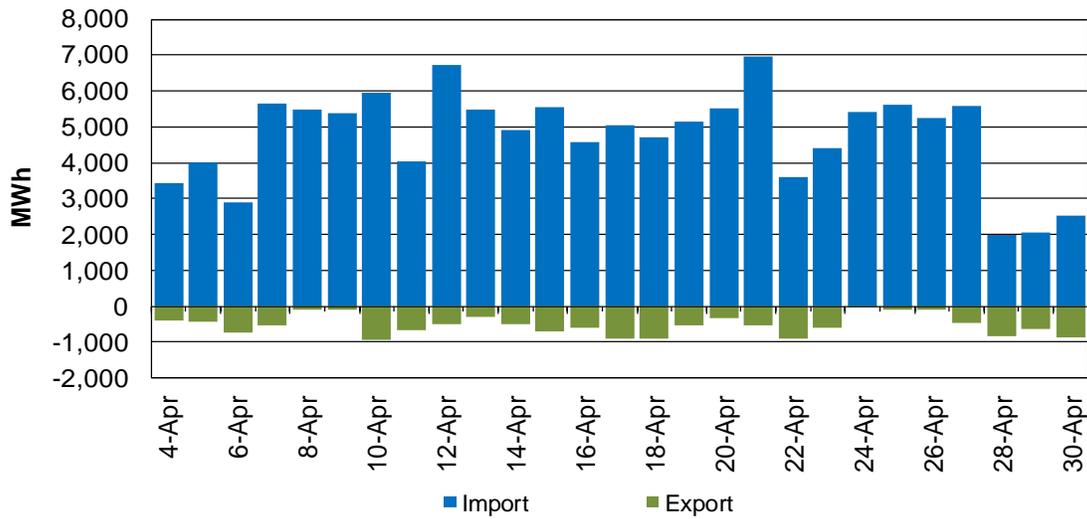


Figure 67 shows the daily volume EIM transfer for IPCO in RTD.

Figure 67: EIM Transfer for IPCO in RTD

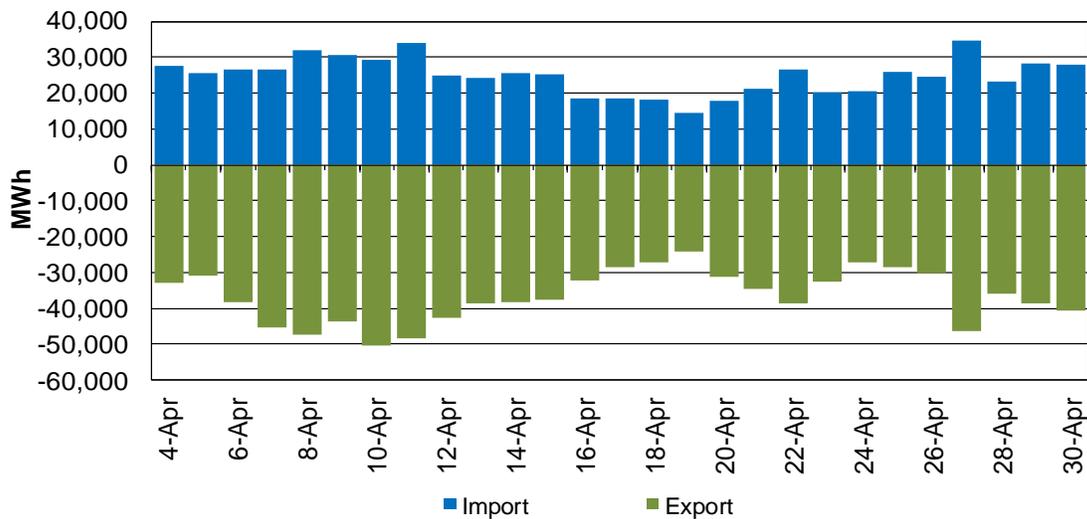


Figure 68 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTIEO was \$7.41 million in April, increasing from -\$0.34 million in March.

Figure 68: EIM Real-Time Imbalance Energy Offset by Area

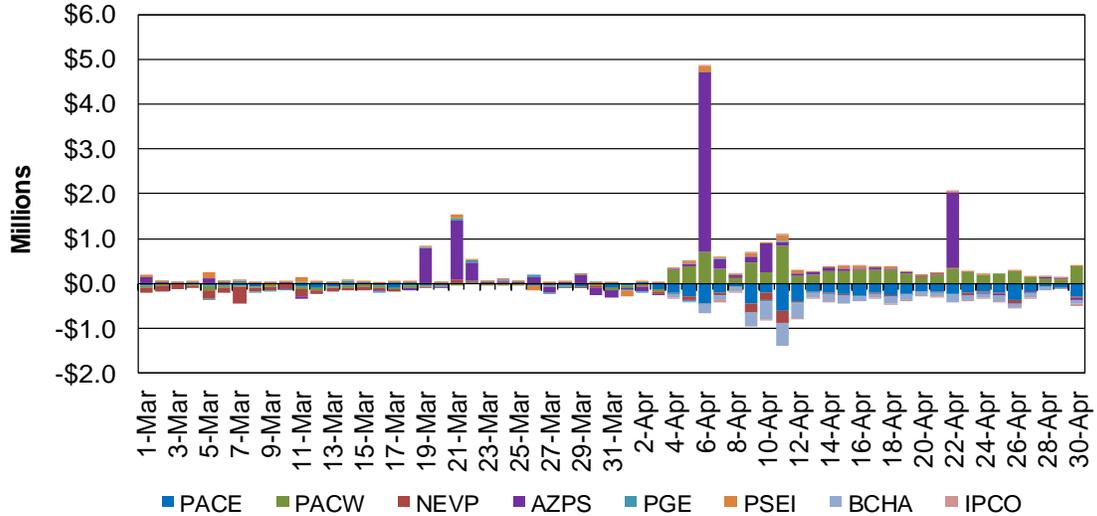


Figure 69 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTCO edged down to -\$2.21 million in April from -\$2.15 million in March.

Figure 69: EIM Real-Time Congestion Imbalance Offset by Area

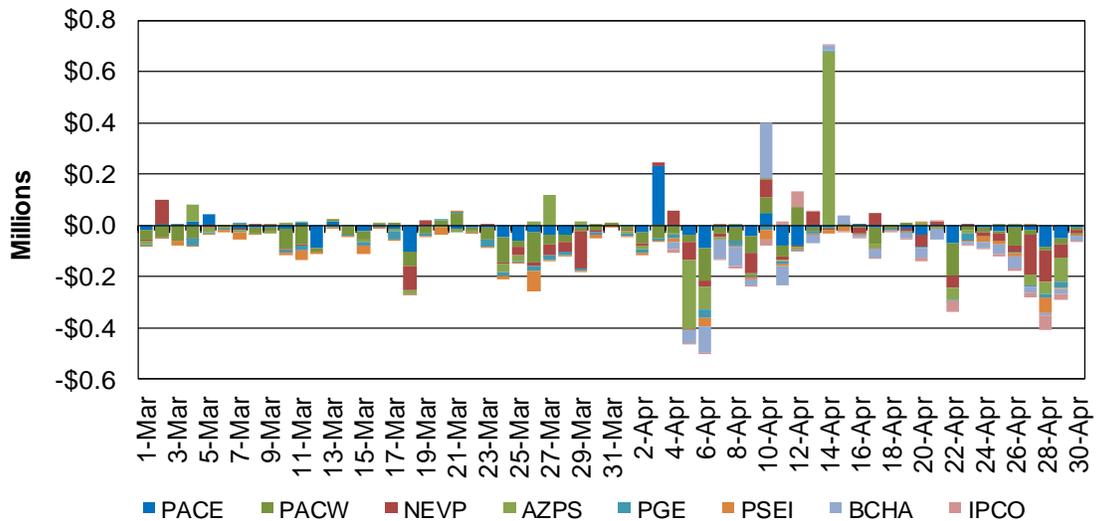


Figure 70 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total BCR increased to \$1.33 million in April from \$1.12 million in March.

Figure 70: EIM Bid Cost Recovery by Area

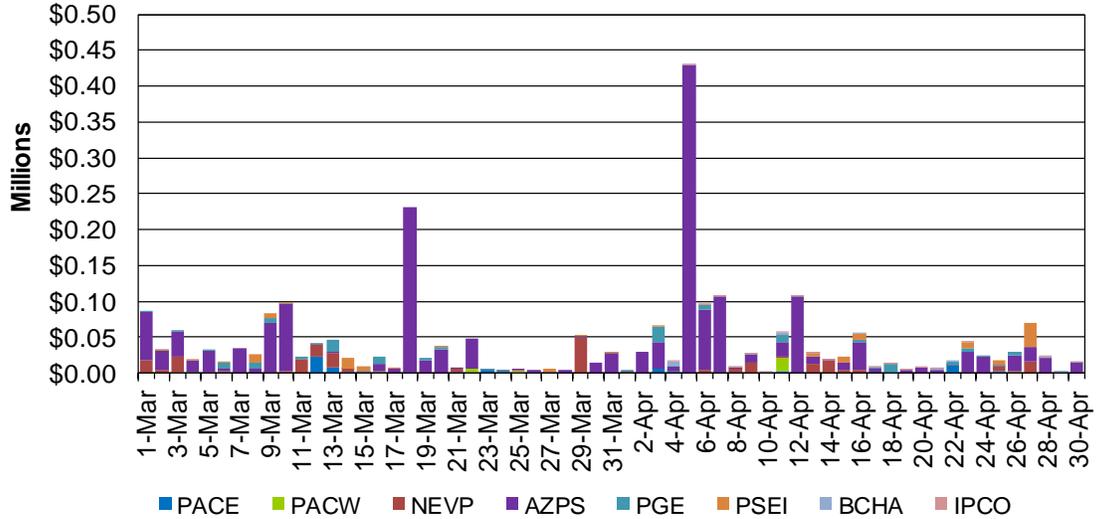


Figure 71 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping up uncertainty payment in April increased to \$0.70 million from \$0.44 million in March.

Figure 71: Flexible Ramping Up Uncertainty Payment

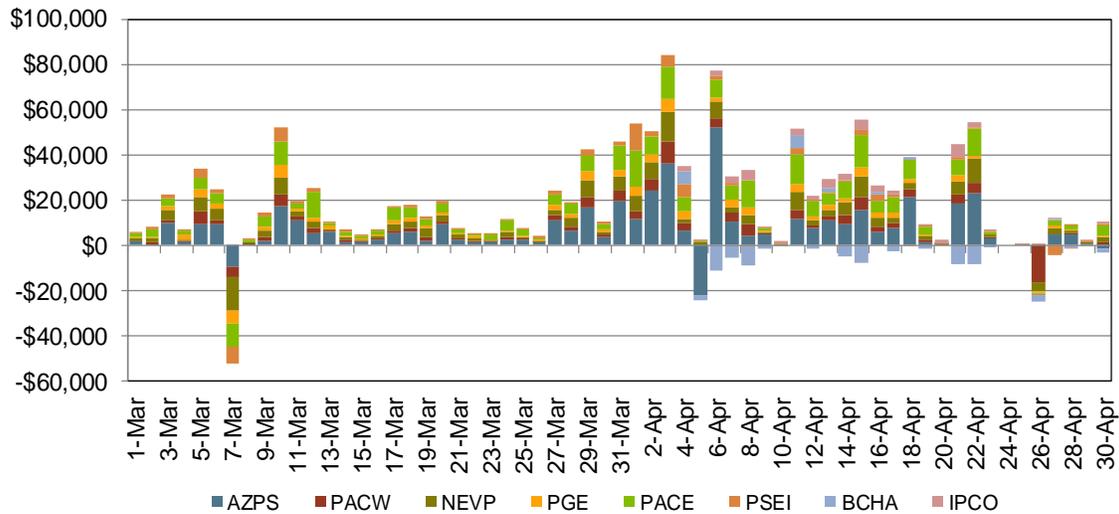


Figure 72 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping down uncertainty payment in April decreased to \$76,723 from \$97,714 million in March.

Figure 72: Flexible Ramping Down Uncertainty Payment

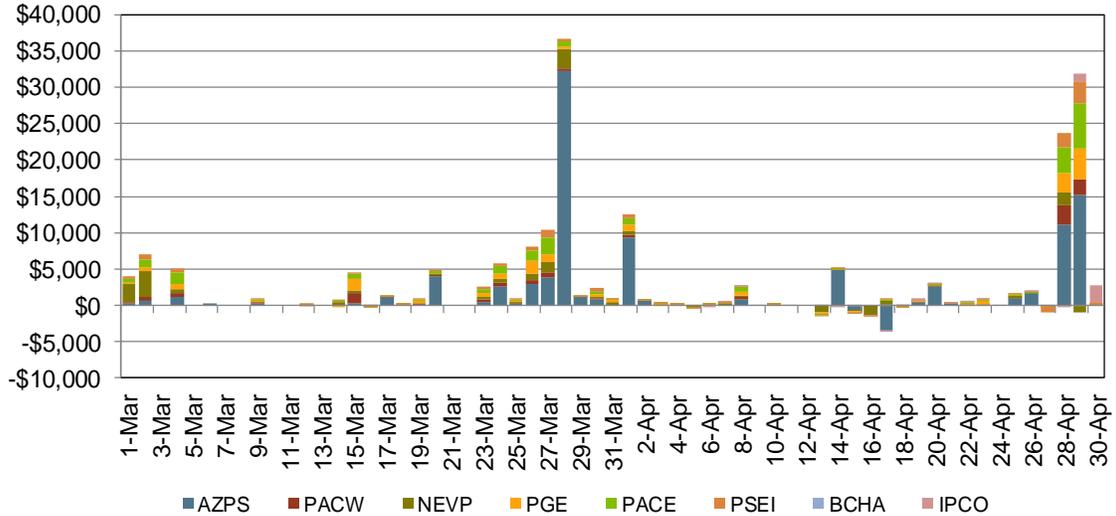
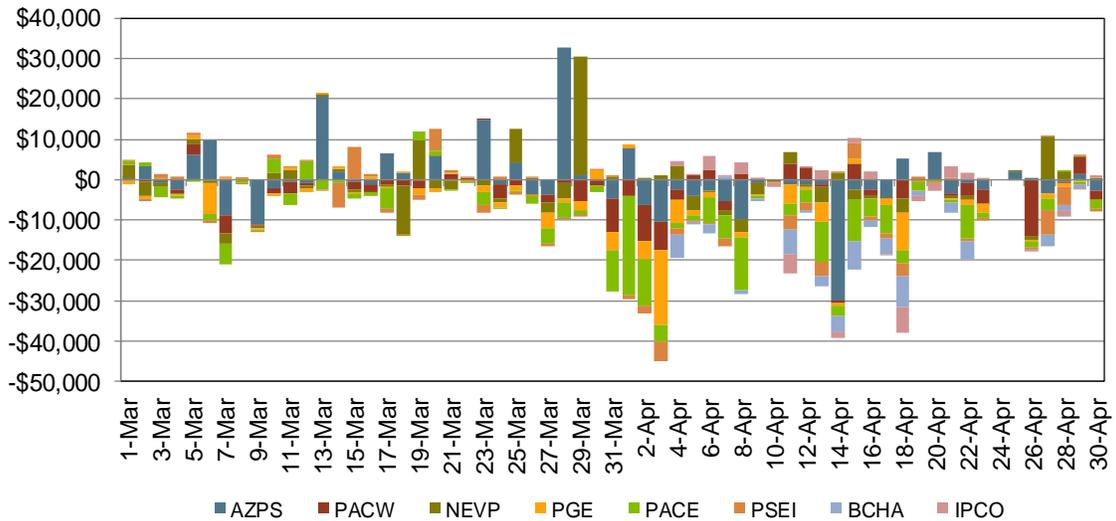


Figure 73 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total forecast payment in April dropped to -\$0.34 million from -\$5,593 in March.

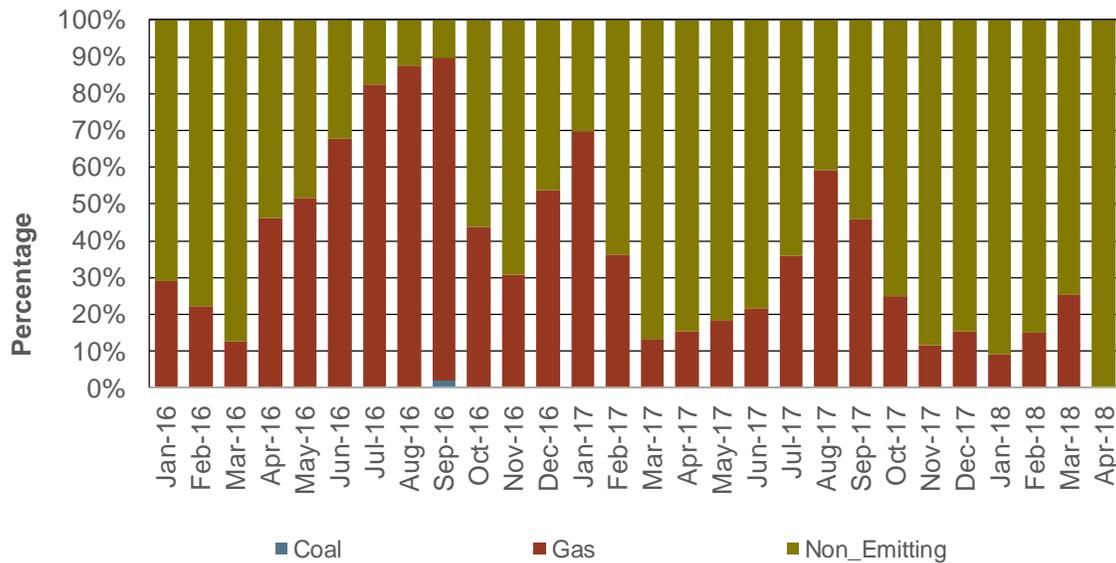
Figure 73: Flexible Ramping Forecast Payment



The ISO’s Energy Imbalance Market Business Practice Manual⁵ 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 bids⁶.

The EIM dispatches to support transfers into the ISO were documented in Figure 74 and Table 8 below.

Figure 74: 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](http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Energy%20Imbalance%20Market).

⁶ 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-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%	21.42%	78.58%	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%
Oct-17	0.00%	24.85%	75.15%	100%
Nov-17	0.00%	11.57%	88.43%	100%
Dec-17	0.00%	15.36%	84.64%	100%
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%