Market Performance Report February 2017

April 7, 2017

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in February 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO were below 30,000 MW in most days of February.
- In the integrated forward market (IFM), PG&E DLAP prices were elevated in a couple of days due to transmission congestion. In the fifteen-minute market (FMM) and real-time market (RTD), SCE, SDG&E and VEA DLAP prices were depressed in a few days due to transmission congestion.
- Congestion rents for interties rose to $5.83 million from $2.70 million in January. Majority of the congestion rents in February accrued on MALIN500 (70 percent) intertie and NOB (26 percent) intertie.
- In the congestion revenue rights market, revenue adequacy increased to 69.87 percent from 52.21 percent in January. The nomogram 7820_TL23040_IV_SPS_NG contributed largely to the revenue shortfall. This nomogram was enforced to avoid overload in the underlying parallel 230 kV lines and cross tripping.
- The monthly average ancillary service cost to load rose to $0.75/MWh from $0.51/MWh in January. There were two ancillary service scarcity events this month.
- The cleared virtual supply was well above cleared demand throughout February. The profits from convergence bidding increased to $2.21 million from $1.54 million in January.
- The bid cost recovery inched up to $6.08 million from $5.67 million in January.
- The real-time energy offset cost fell to $2.58 million from $5.76 million in January. The real-time congestion offset cost skidded to $0.78 million from $2.23 million in January.
- The volume of exceptional declined to 50,738 MWh from 58,838 MWh in January, largely driven by planned transmission outage and constraint, and voltage support. The monthly average of total exceptional dispatch volume as a percentage of load satyed at 0.32 percent in February, relatively unchanged from January.

[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, prices in the AZPS area were depressed on February 23 and 28 due to low loads and reduced export. In the RTD market, the prices for AZPS were also depressed on February 23 and 28, driven by reduced export and transmission congestion.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $0.68 million, $0.27 million and -$1.28 million respectively.

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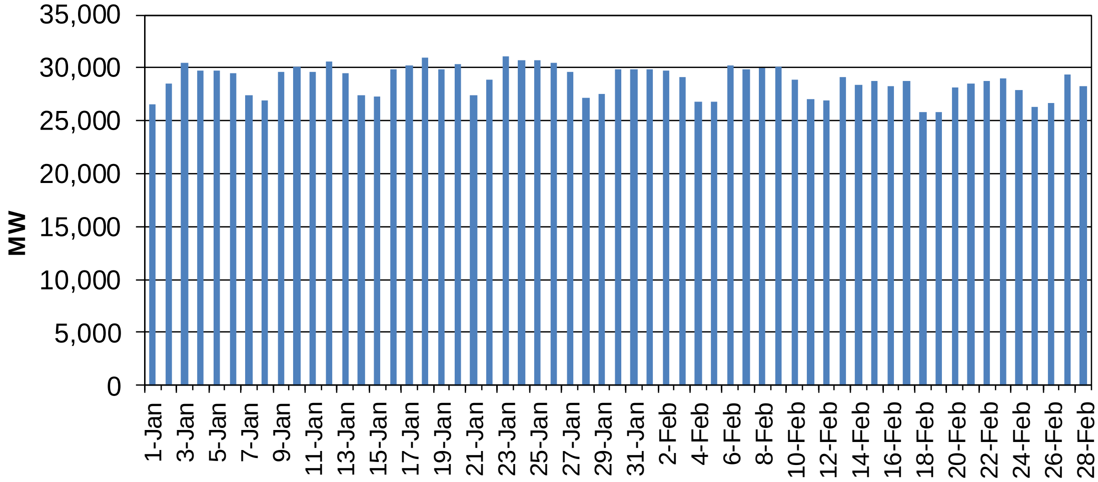
Market Characteristics

Loads

Peak loads for ISO were below 30,000 MW in most days of February.

Figure 1: System Peak Load



Direct Market Performance Metrics

Energy

Day-Ahead Prices

Figure 2 shows daily prices of four default load aggregate points (DLAPs). Table 1 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)

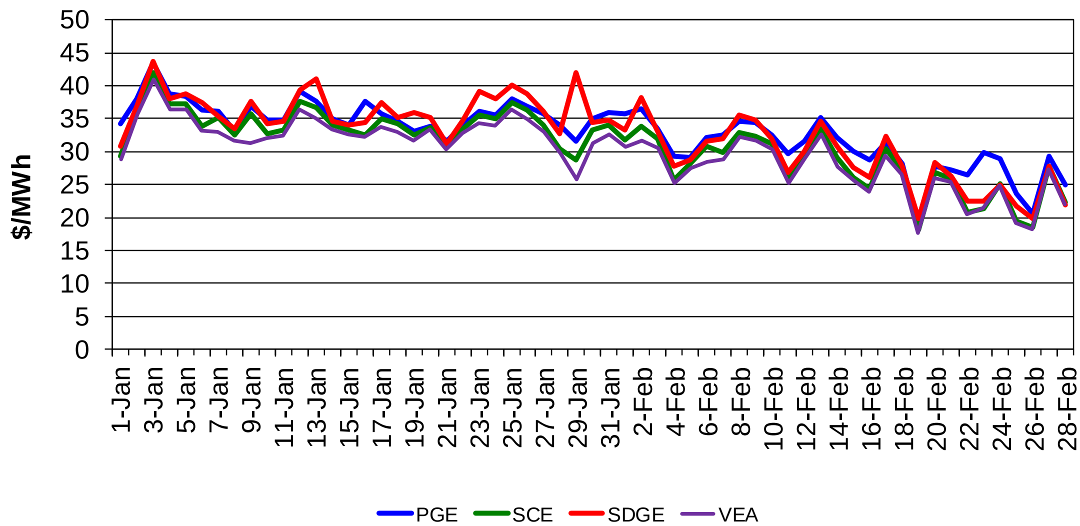


Table 1: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
PG&E	February 22, 24, 25	PATH15_S-N
PG&E	February 23	OMS 4621181 LBN_S-N

Real-Time Prices

FMM daily prices of the four DLAPs are shown in Figure 3. Table 2 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 February 19, all four DLAP Prices were relatively low, driven by downward load adjustment and renewable deviation.

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

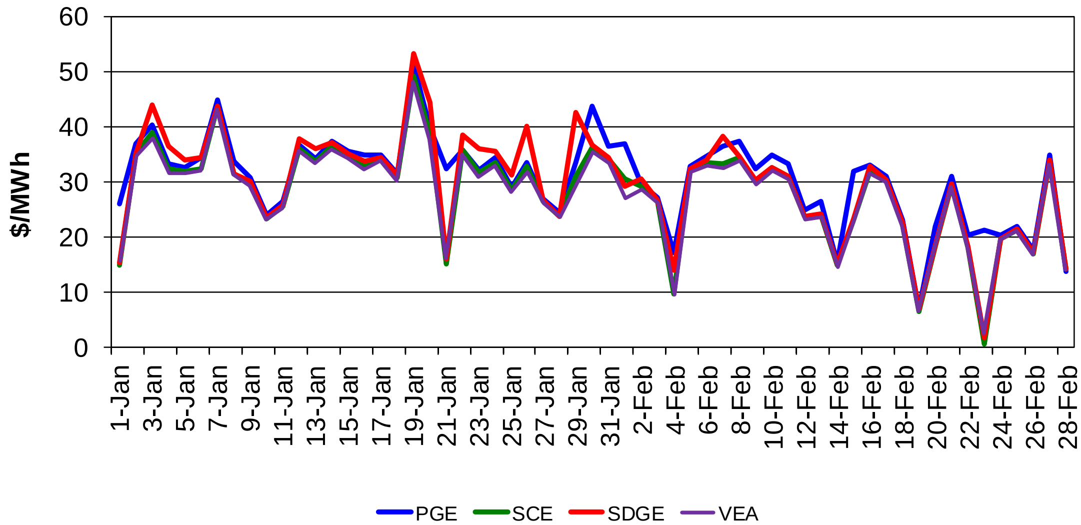
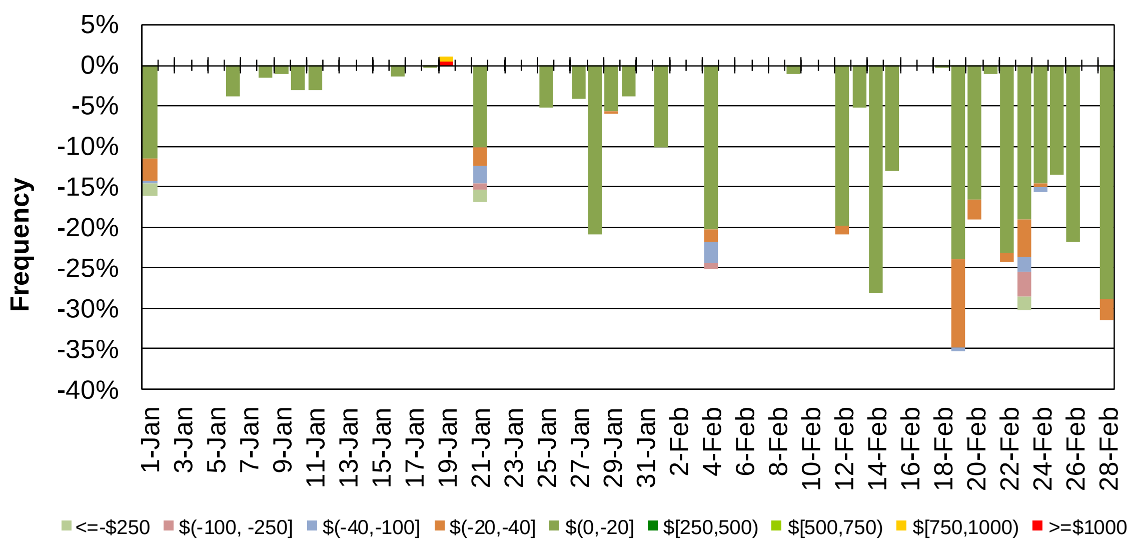


Table 2: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E, VEA	February 4	PATH15_S-N
SCE, SDG&E, VEA	February 23	OMS 4621181 LBN_S-N

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 edged down to 0 percent in February from 0.03 percent in January. The cumulative frequency of negative prices increased to 10.58 percent in February from 2.82 percent in January.

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 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.

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

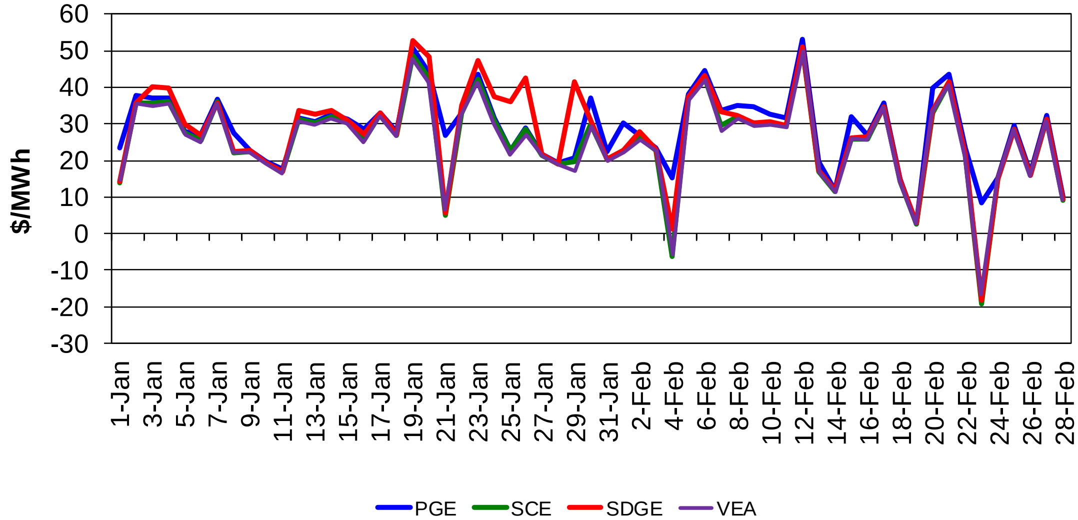
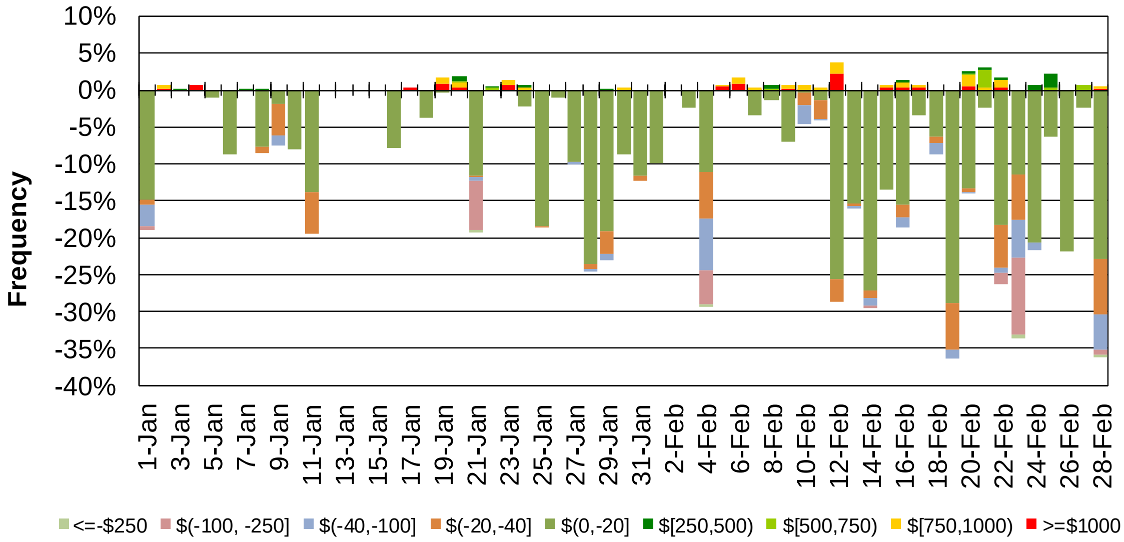


Table 3: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E, VEA	February 4	PATH15_S-N
SCE, SDG&E, VEA	February 23	OMS 4621181 LBN_S-N

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 edged up to 0.84 percent in February from 0.28 percent in January. The cumulative frequency of negative prices increased to 13.67 percent in February from 6.58 percent in January.

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



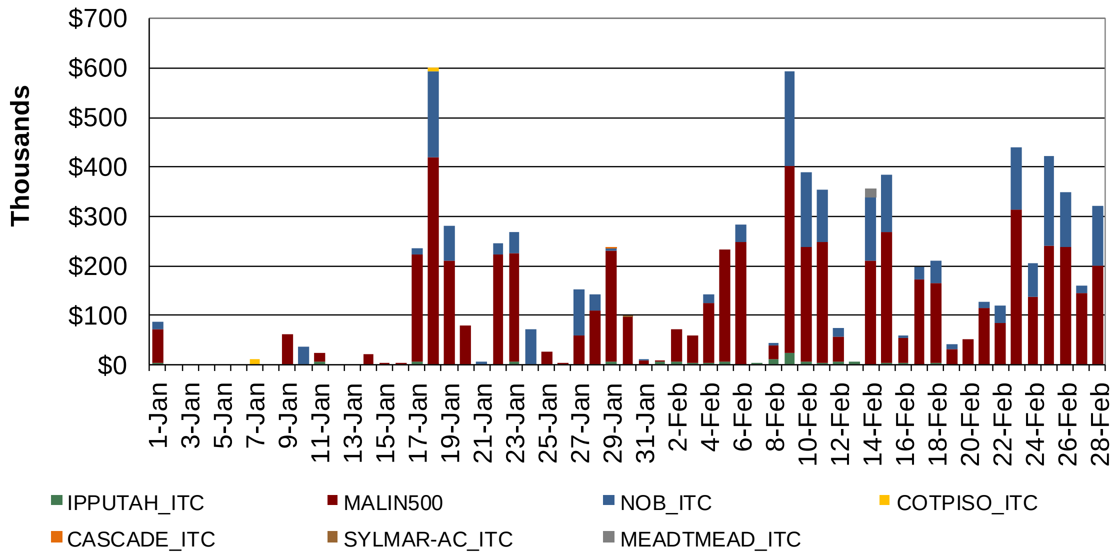
Congestion

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 February rose to $5.83 million from $2.70 million in January. Majority of the congestion rents in February accrued on MALIN500 (70 percent) intertie and NOB (26 percent) intertie.

The congestion rent on MALIN500 increased to $4.07 million in February from $2.07 million in January. MALIN500 was derated this month due to various outages including the outage of Malin-Round Mountain #1 500 kV line and Maxwell 500 kV series capacitors. The congestion rent on NOB increased to $1.53 million in February from $0.58 million in January.

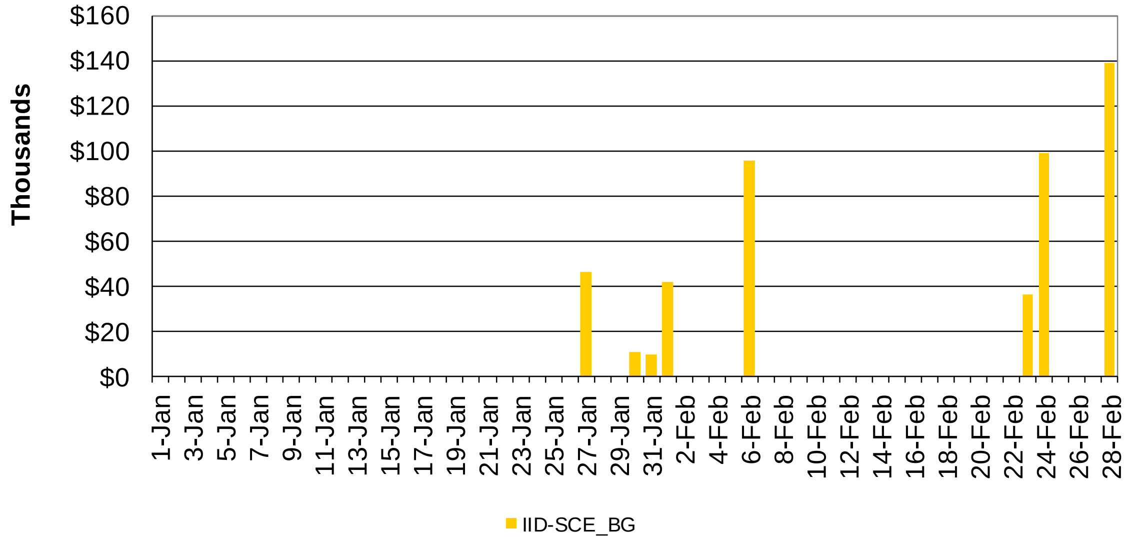
Figure 7: IFM Congestion Rents by Interties (Import)



Congestion Rents on Branch Groups

Figure 8 illustrates the IFM congestion rents on selected branch groups. Total congestion rents for branch groups rose to $0.41 million in February from $0.07 million in January.

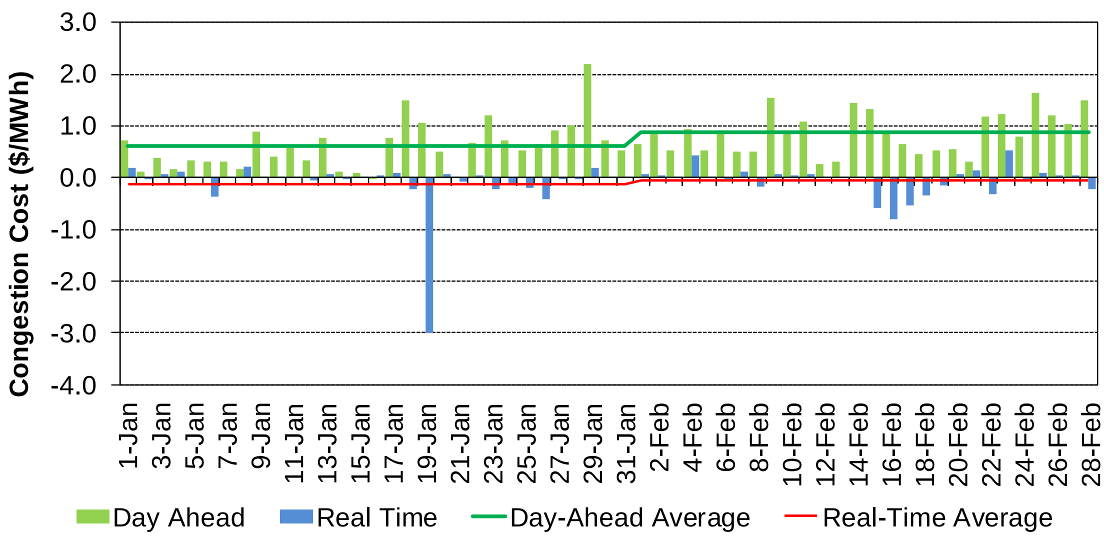
Figure 8: IFM Congestion Rents by Branch Group



Average Congestion Cost per Load Served

This metric quantifies the average congestion cost for serving one megawatt of load in the ISO system. Figure 9 shows the daily and monthly averages for the day-ahead and real-time markets respectively.

Figure 9: Average Congestion Cost per Megawatt of Served Load

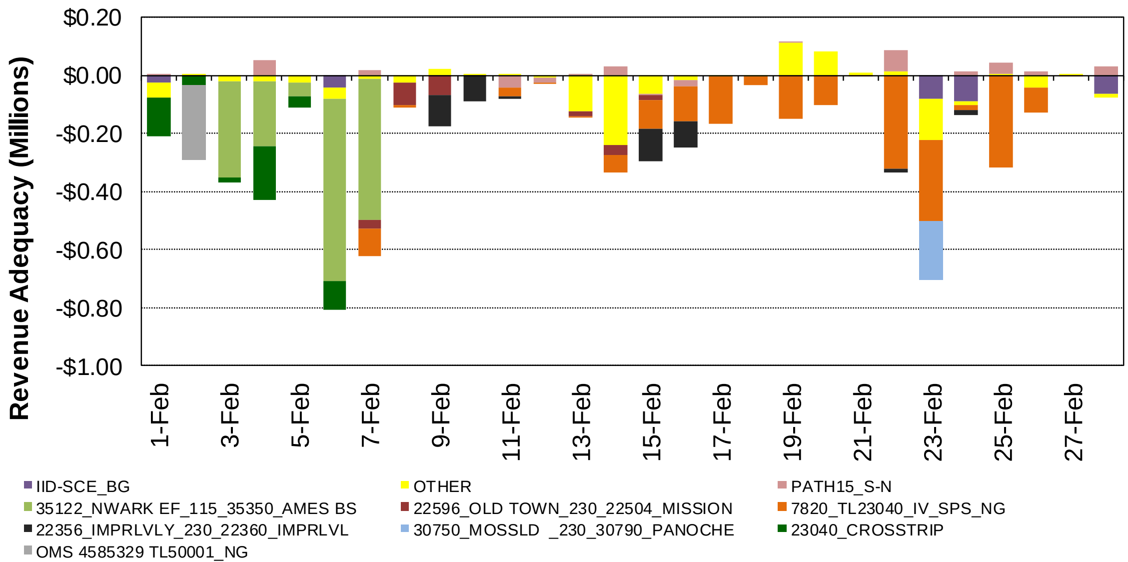


The average congestion cost per MWh of load served in the integrated forward market increased to $0.87/MWh in February from $0.60/MWh in January. The average congestion cost per load served in the real-time market went to -$0.05/MWh in February from $0.12/MWh in January.

Congestion Revenue Rights

Figure 10 illustrates the daily revenue adequacy for congestion revenue rights (CRRs) broken out by transmission element. The average CRR revenue deficit in February dropped to $214,188 from the average revenue deficit of $325,911 in January.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights

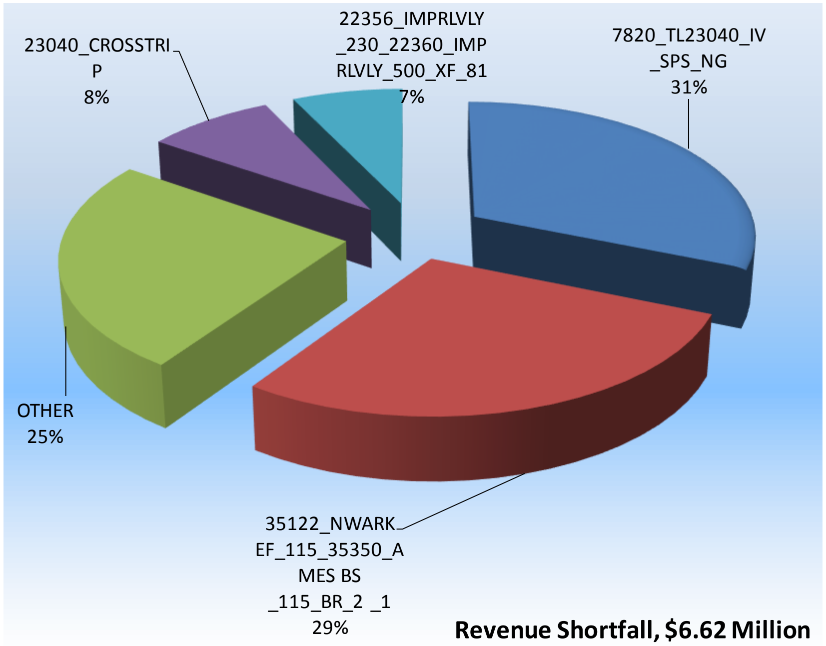


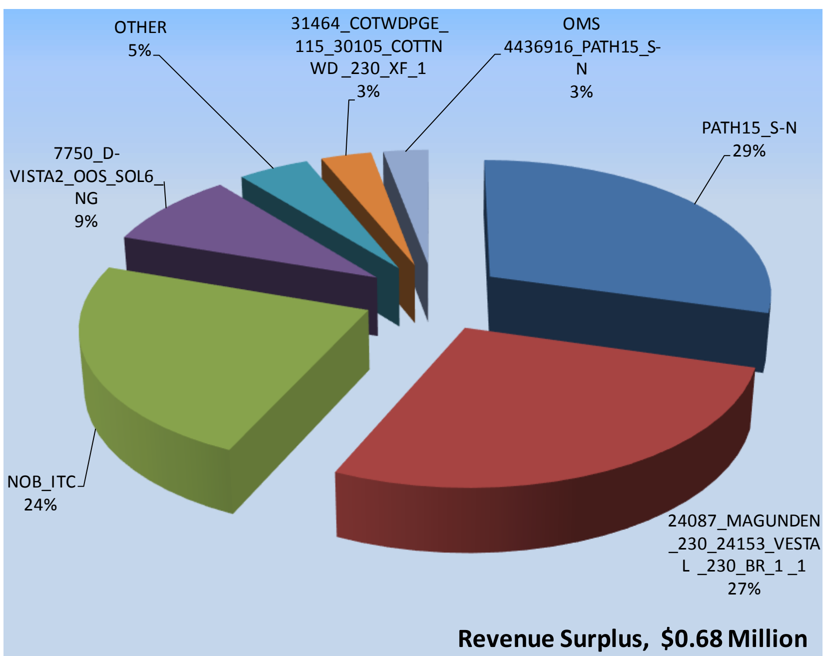
Overall, February experienced a CRR revenue deficit. Revenue shortfalls were observed in most days of this month. The main reasons are shown below.

- The nomogram 7820_TL23040_IV_SPS_NG was binding in 19 days of this month, resulting in revenue shortfall of $1.89 million. This nomogram was enforced to avoid overload in the underlying parallel 230 kV lines and cross tripping.
- The line 35122_NWARK EF_115_35350_AMES BS was binding in five days, resulting in revenue shortfall of $1.72 million. This line was congested in those days driven by the outage of Newark-Ravenswood 230 kV line.

The shares of the revenue surplus and deficit accruing 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 4.

Figure 11: 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 69.87 percent in February. Out of the total congestion rents, 3.87 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in February were in deficit by $5.99 million, compared to the deficit of $10.10 million in January. The auction revenues credited to the balancing account for February were $5.61 million. As a result, the balancing account for February had a deficit of approximately $0.38 million, which will be allocated to measured demand.

Table 4: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$14,470,320.29
Existing Right Exemptions	-$560,580.21
Available Congestion Revenues	$13,909,740.07
CRR Payments	$19,907,009.73
CRR Revenue Adequacy	-$5,997,269.66
Revenue Adequacy Ratio	69.87%
Annual Auction Revenues	$3,264,363.22
Monthly Auction Revenues	$2,348,849.16
CRR Settlement Rule	$8,300.82
Allocation to Measured Demand	-$375,756.46

Ancillary Services

IFM (Day-Ahead) Average Price

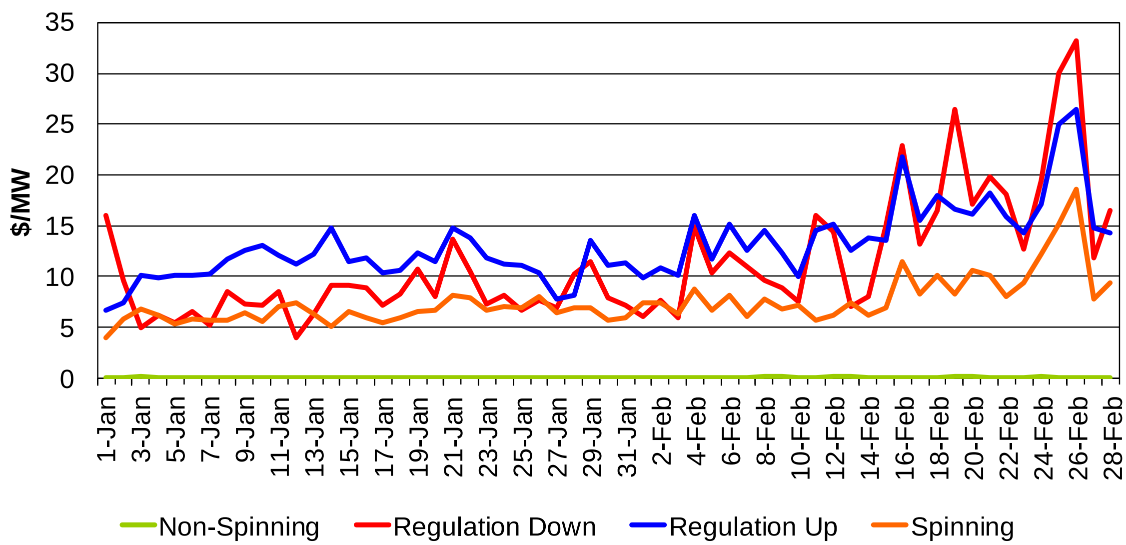
Table 5 shows the monthly IFM average ancillary service procurements and the monthly average prices. In February the monthly average procurement decreased for all four types of ancillary services.

Table 5: 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
Feb-17	322	380	715	708	$15.25	$14.75	$8.74	$0.11
Jan-17	337	403	717	736	$11.14	$8.23	$6.35	$0.09
Percent Change	-4.53%	-5.67%	-0.24%	-3.83%	36.84%	79.28%	37.49%	19.50%

The monthly average prices increased for all four types of ancillary services in February. Figure 12 shows the daily IFM average ancillary service prices. Regulation up, regulation down and spinning reserve prices trended upward in February. Regulation up and regulation down prices were relatively high on February 16, 19 and 25-26 due to high opportunity cost of energy.

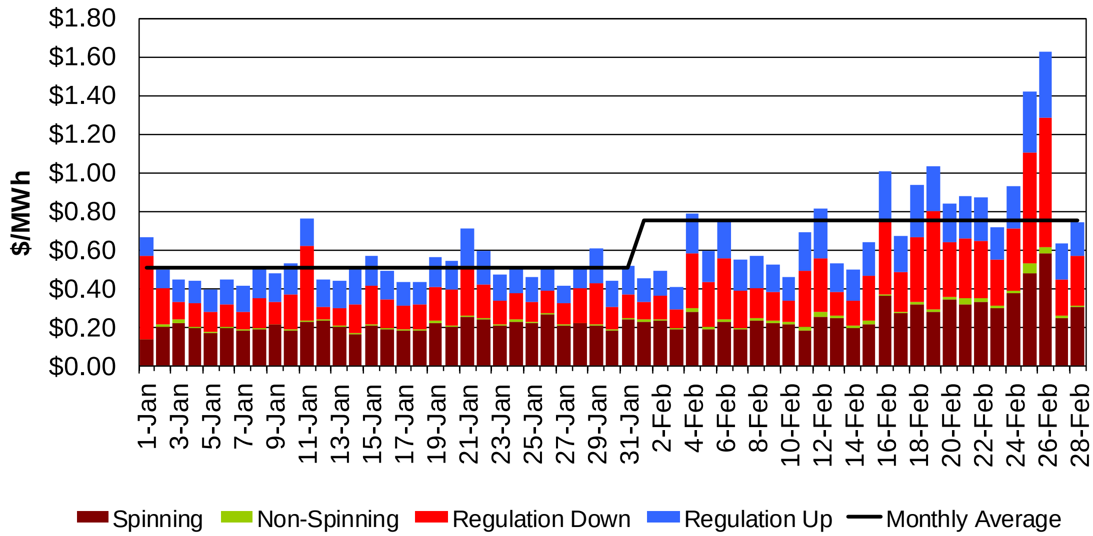
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load rose to $0.75/MWh in February from $0.51/MWh in January. The average costs were high on February 25 and 26, driven by high regulation up and regulation down prices in day-ahead market.

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



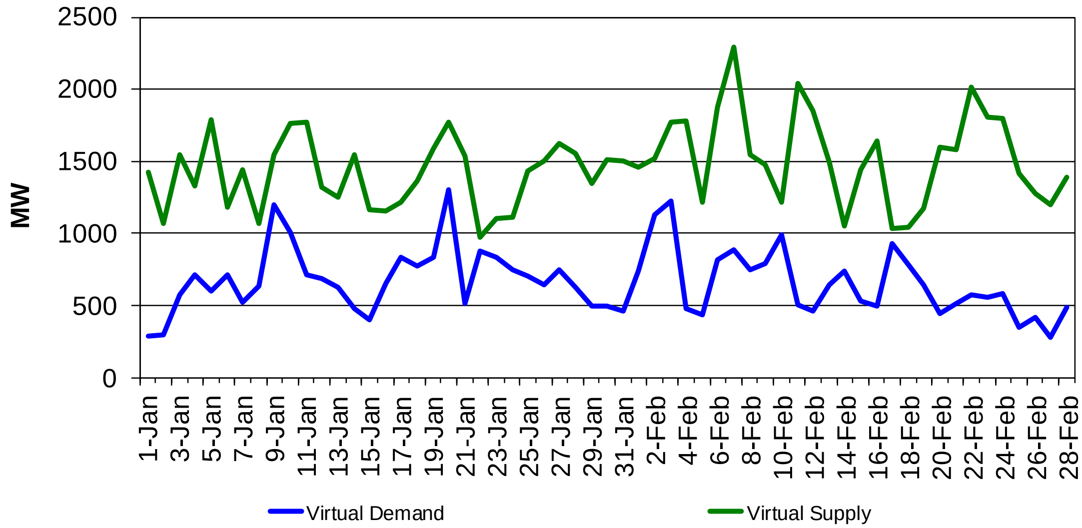
Scarcity Events

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. On February 12, 2017, a regulation scarcity occurred in the 15-minute market run for hour ending 10, interval 1 in the CAISO expanded system region. The procurement shortfall was 0.65 MW or 0.2% of the target procurement quantity. On February 25, 2017, another regulation scarcity occurred in the 15-minute market run for hour ending 14, intervals 1 and 3 in the California ISO expanded system region. The procurement shortfall was 3.07 MW or 1% of the target procurement quantity in each interval.

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 was well above cleared demand throughout this month.

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

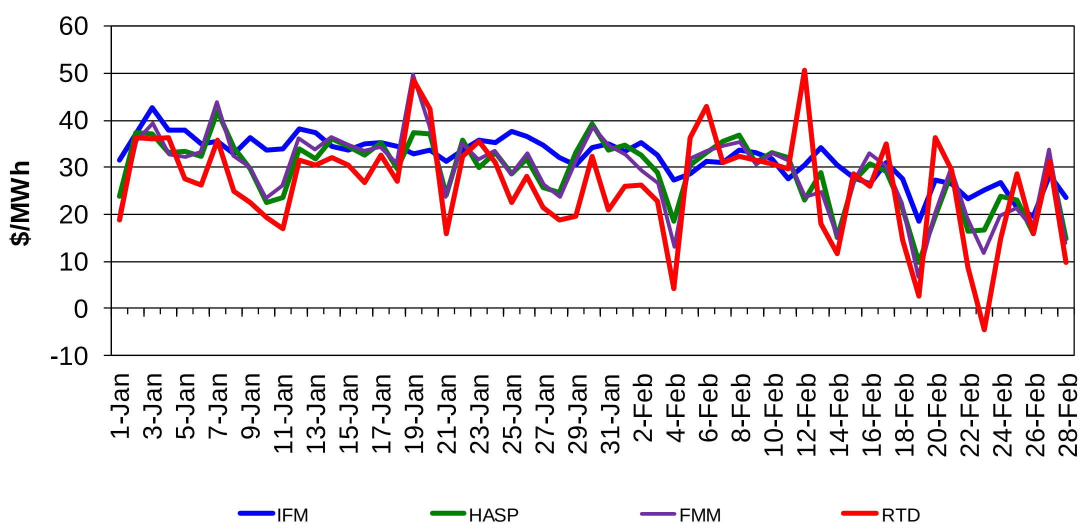
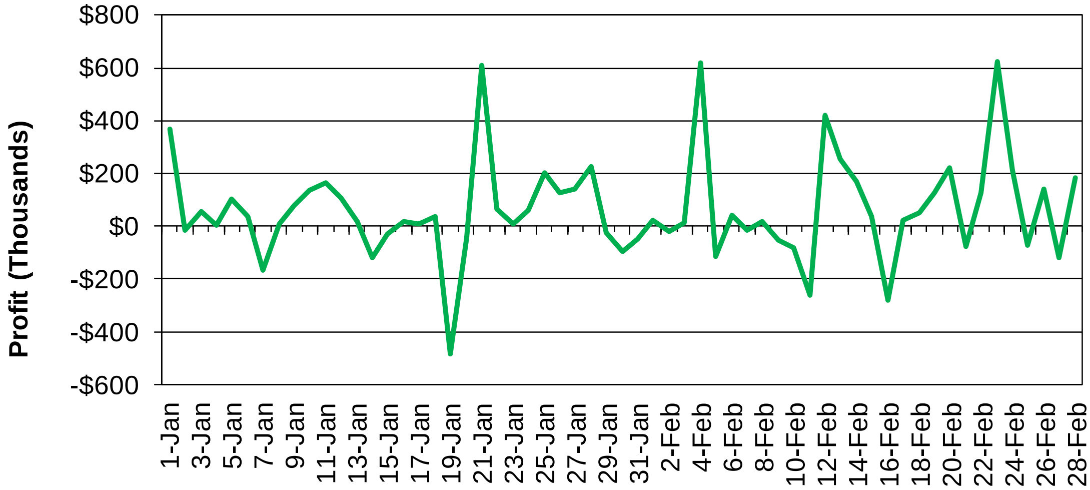


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding increased to $2.21 million in February from $1.54 million in January.

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 indicate, the renewable curtailment increased in February. The majority of the curtailments was economic.

Figure 17: Renewable Curtailment by Reason

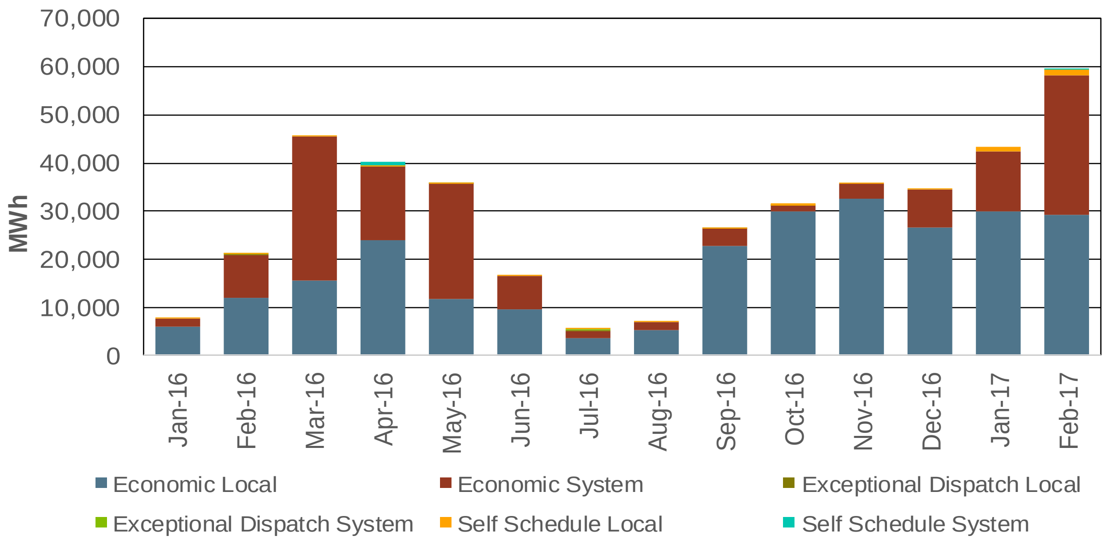
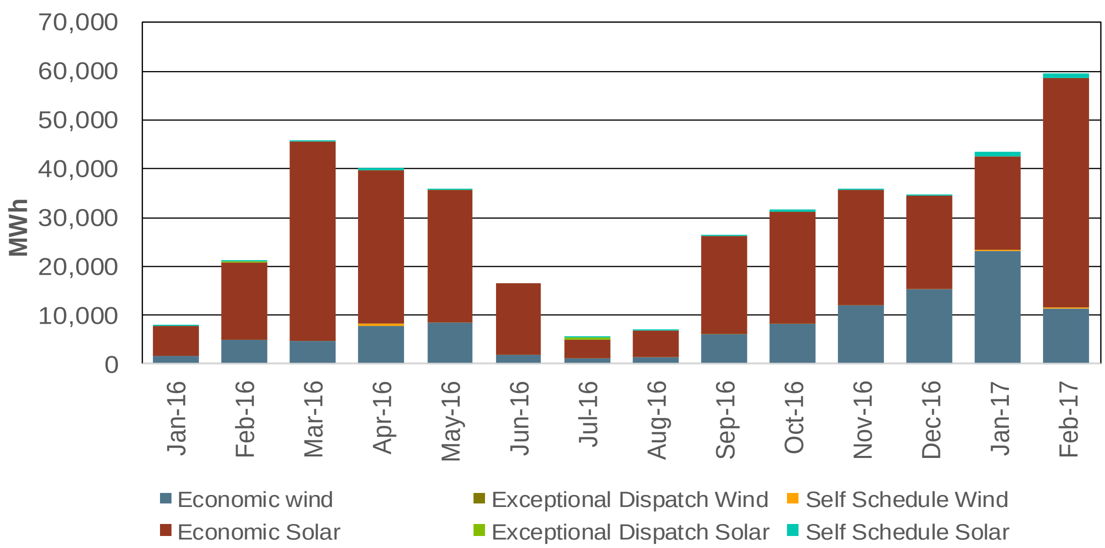


Figure 18: Renewable Curtailment by Resource Type



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 decreased to $1.13 million in February from $1.27 Million in January. Flexible ramping down uncertainty payment increased to $0.21 million in February from $0.10 Million in January.

Figure 19: Flexible Ramping Up/down Uncertainty Payment

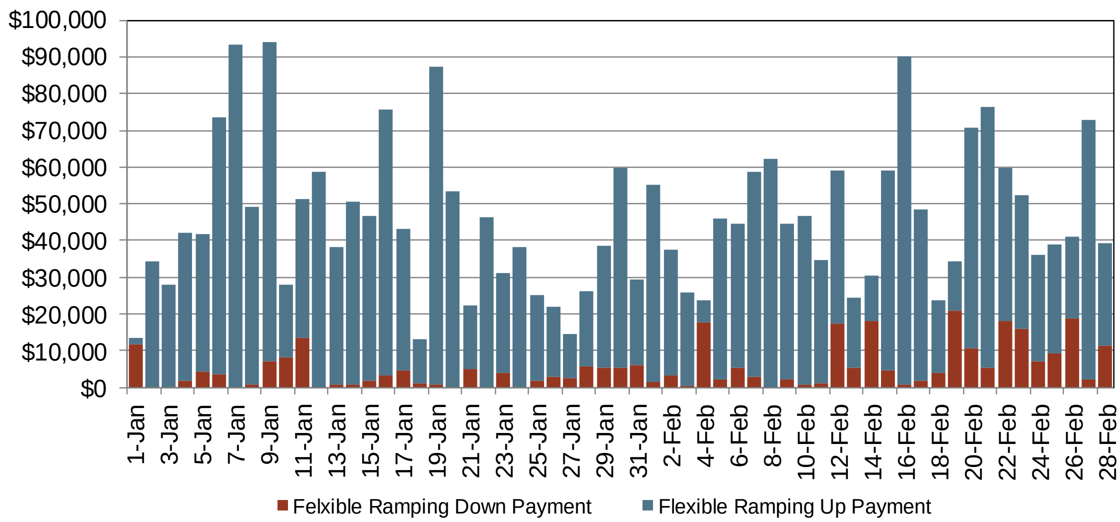
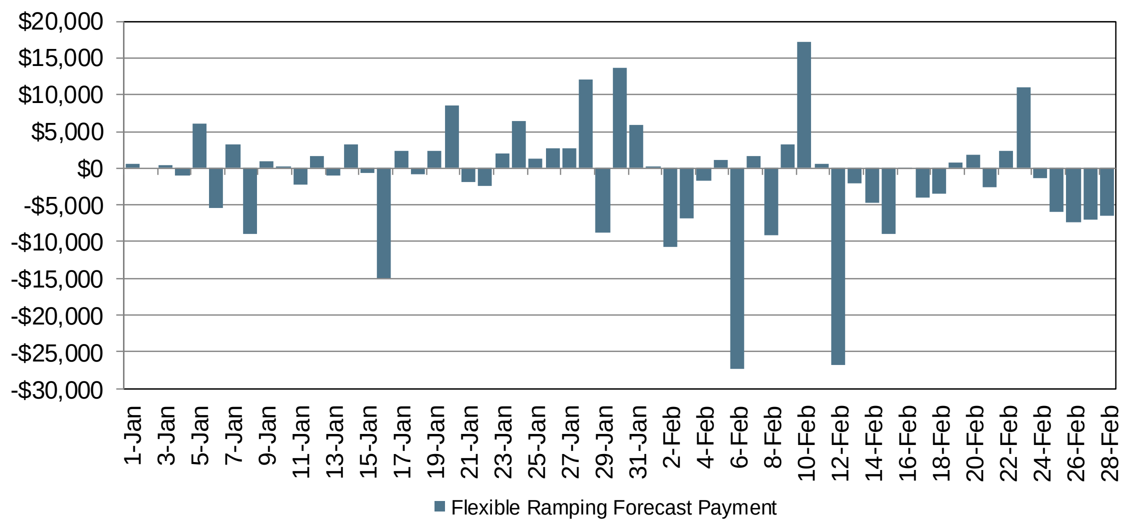


Figure 20 shows the flexible ramping forecast payment. Flexible ramping forecast payment fell to -$96,351 this month from $28,190 in January.

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 February dropped to $72,862 from $164,983 in January.

Figure 21: Exceptional Dispatch Uplift Costs

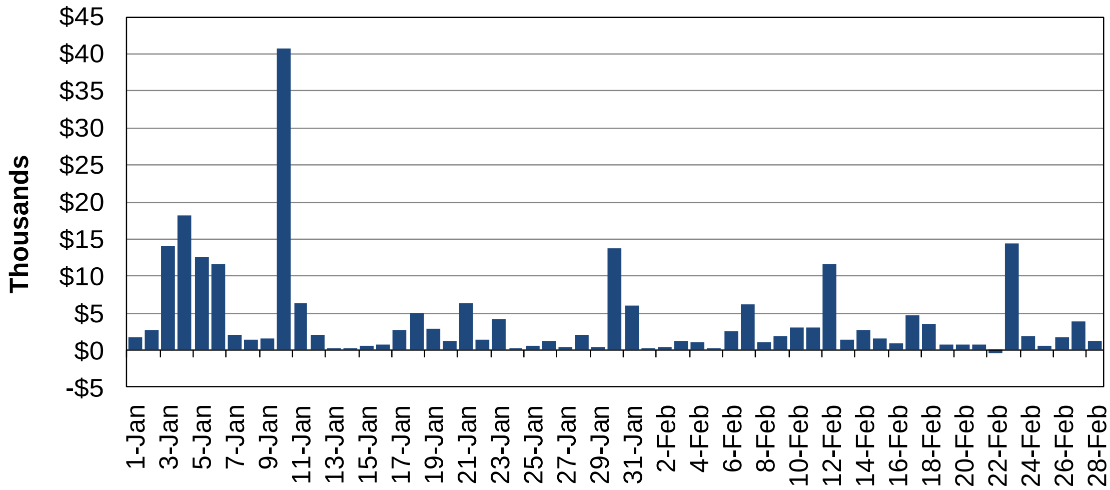


Figure 22 shows the allocation of bid cost recovery payment in the IFM, real-time unit commitment (RUC) and RTM markets. The total bid cost recovery for February increased to $6.08 million from $5.67 million in January. Out of the total monthly bid cost recovery payment for the three markets in February, the IFM market contributed 18 percent, RTM contributed 40 percent, and RUC contributed 42 percent of the total bid cost recovery payment.

Figure 22: Bid Cost Recovery Allocation

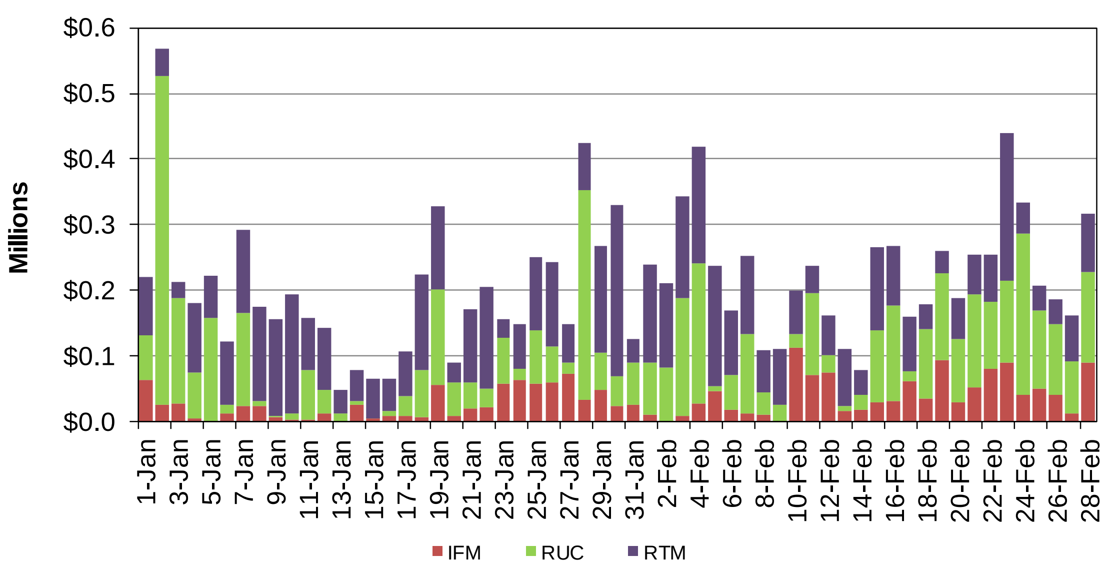


Figure 23 and Figure 24 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 23: Bid Cost Recovery Allocation by LCR

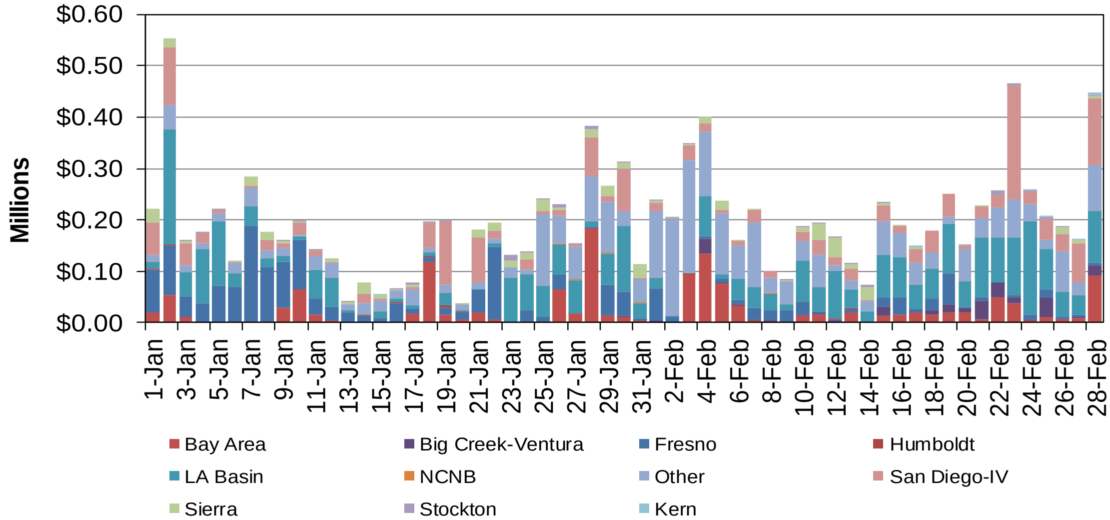


Figure 24: Monthly Bid Cost Recovery Allocation by LCR

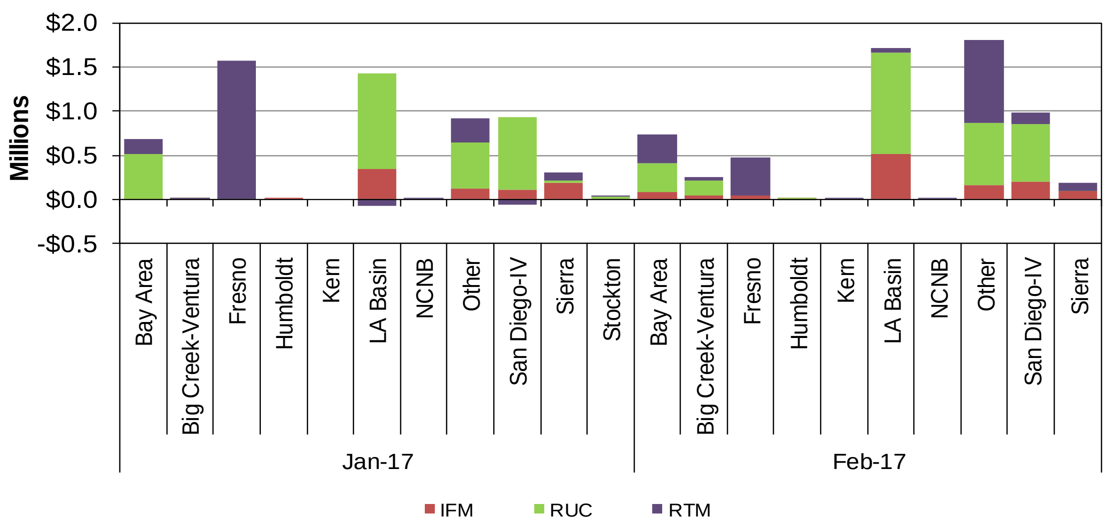


Figure 25 and Figure 26 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 25: Bid Cost Recovery Allocation by UDC

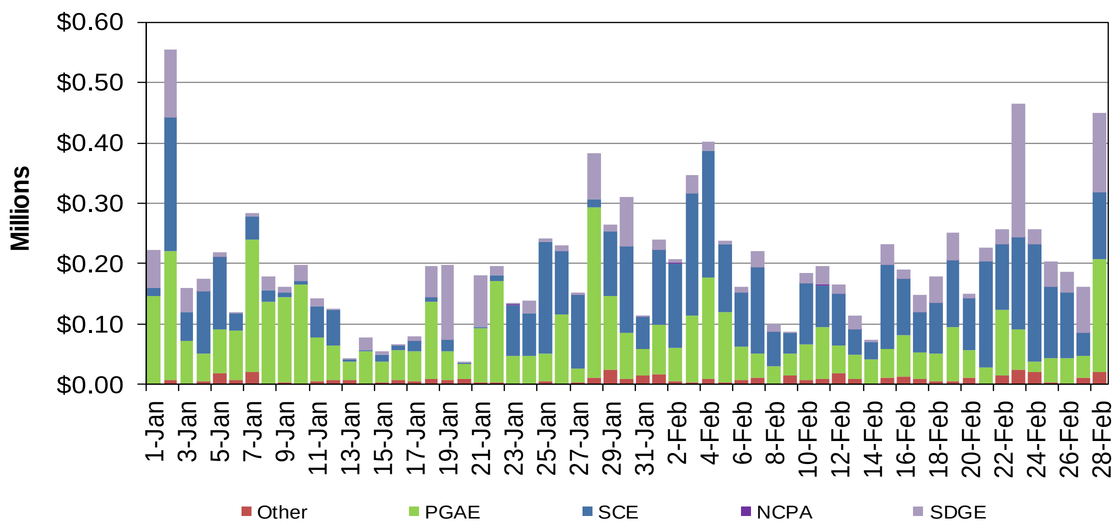


Figure 26: Monthly Bid Cost Recovery Allocation by UDC

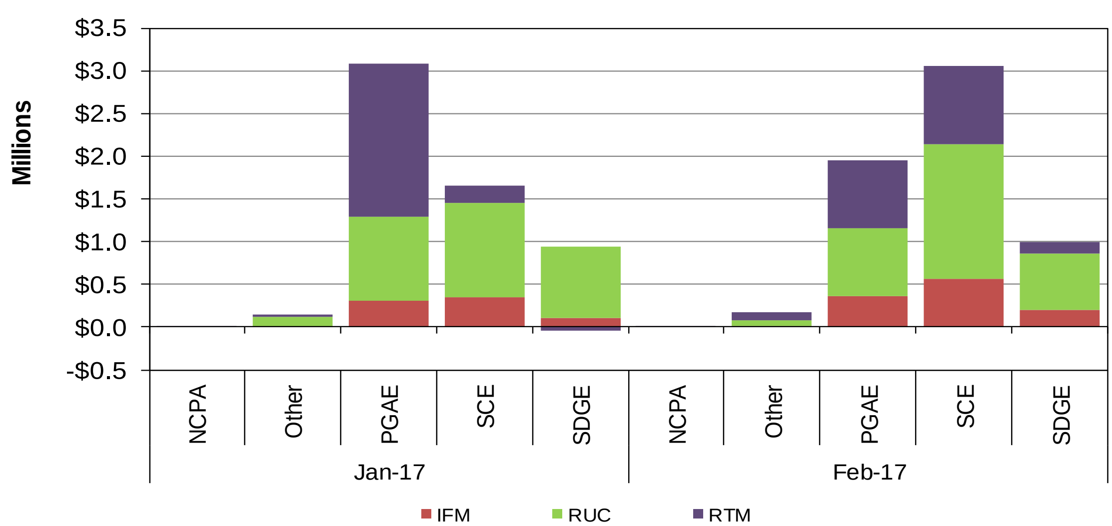


Figure 27 shows the cost related to BCR by cost type in RUC, which in February was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 27: Cost in RUC

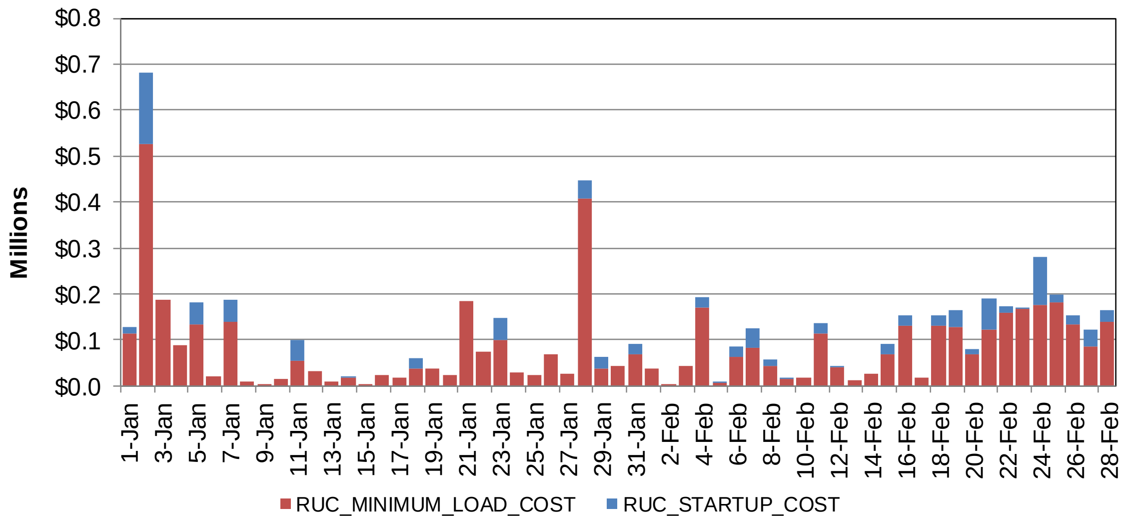


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 28: Cost in RUC by LCR

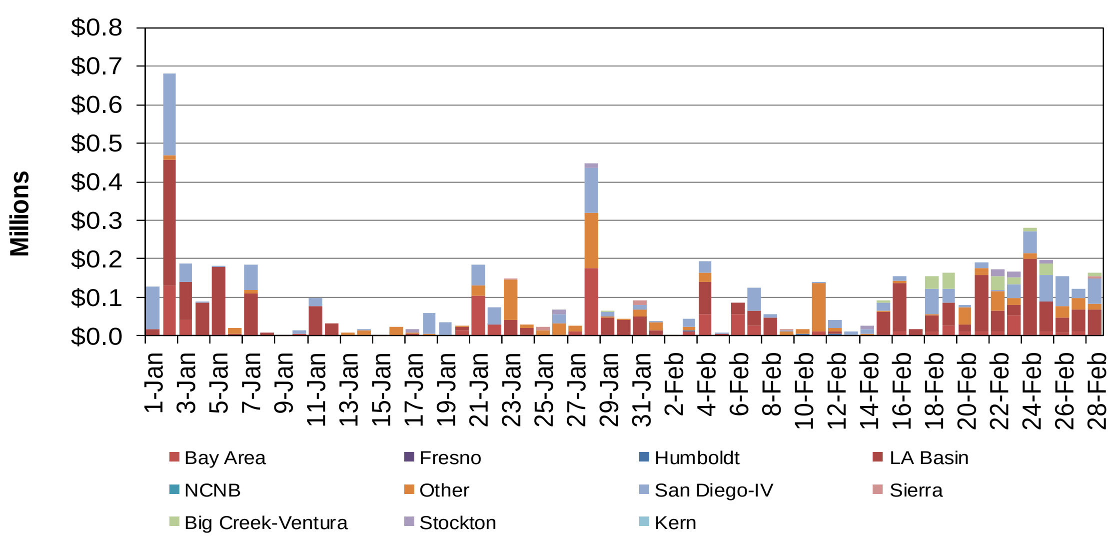


Figure 29: Monthly Cost in RUC by LCR

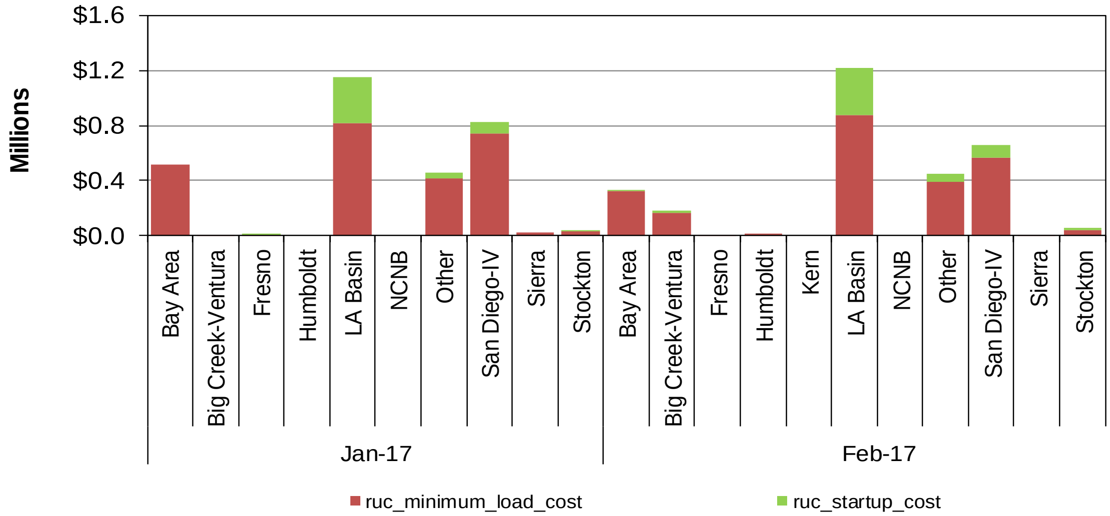


Figure 30 and Figure 31 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 30: Cost in RUC by UDC

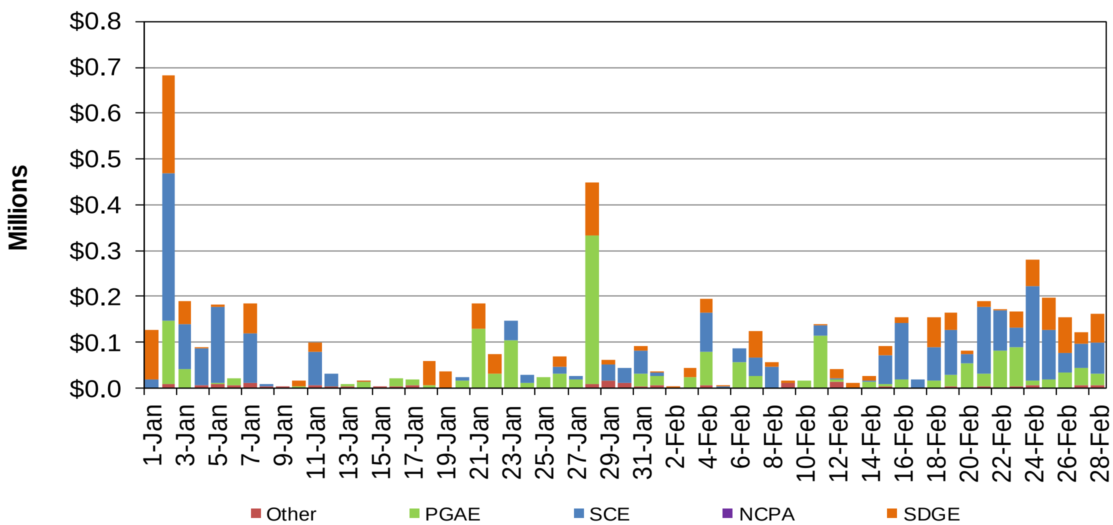


Figure 31: Monthly Cost in RUC by UDC

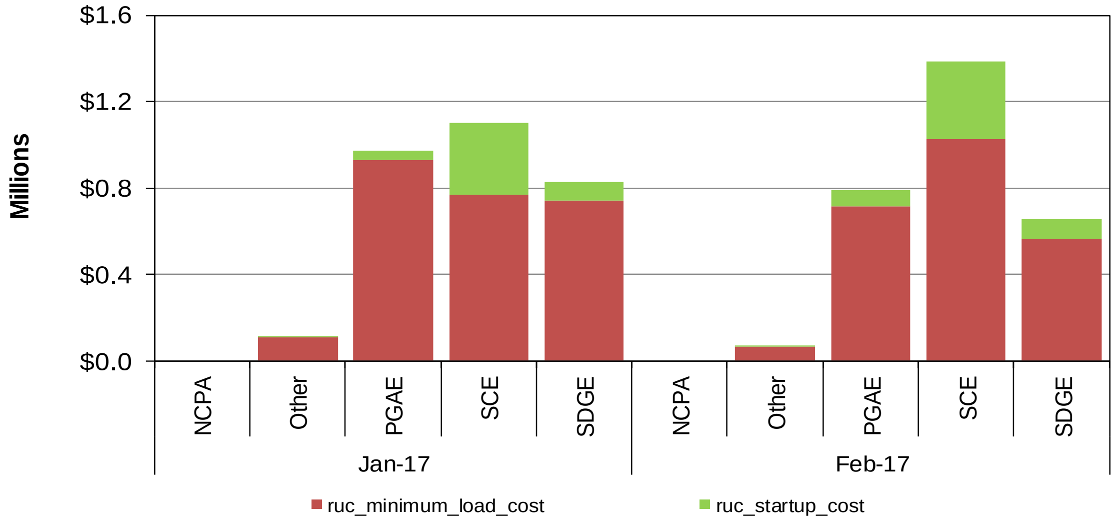


Figure 32 shows the cost related to BCR in real time by cost type. Minimum load cost contributed mostly to the real time cost in February.

Figure 32: Cost in Real Time

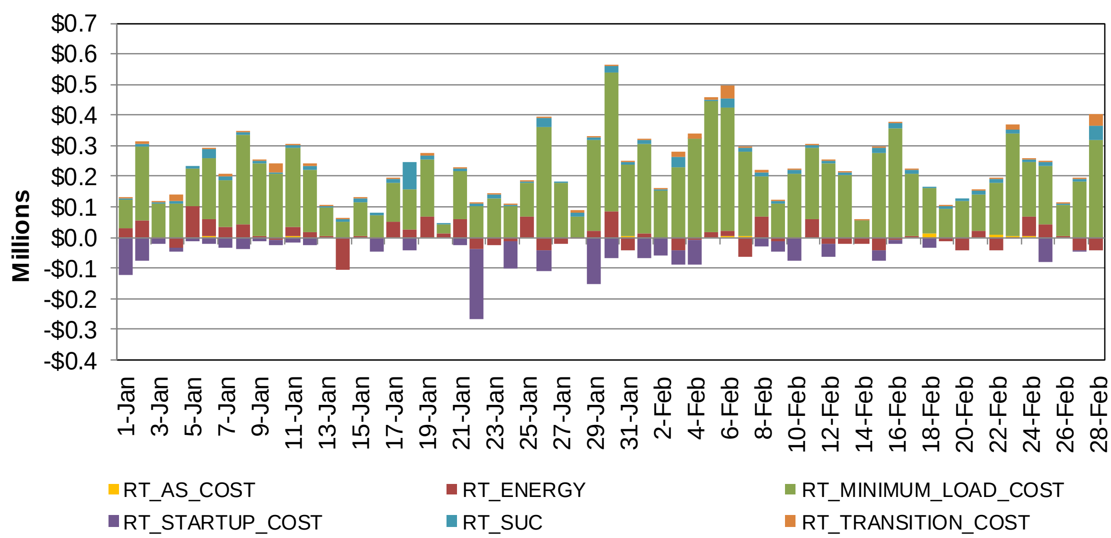


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 33: Cost in Real Time by LCR

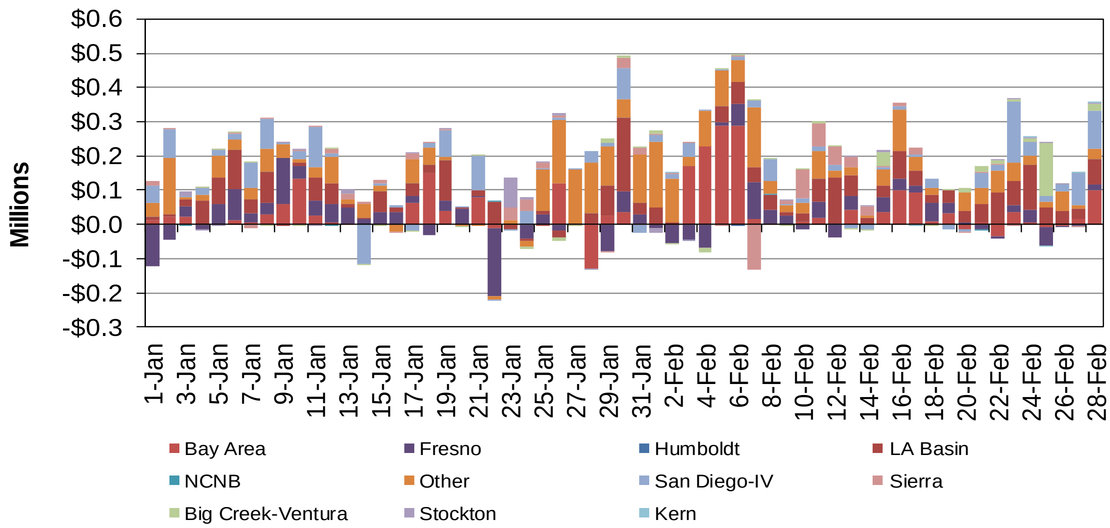


Figure 34: Monthly Cost in Real Time by LCR

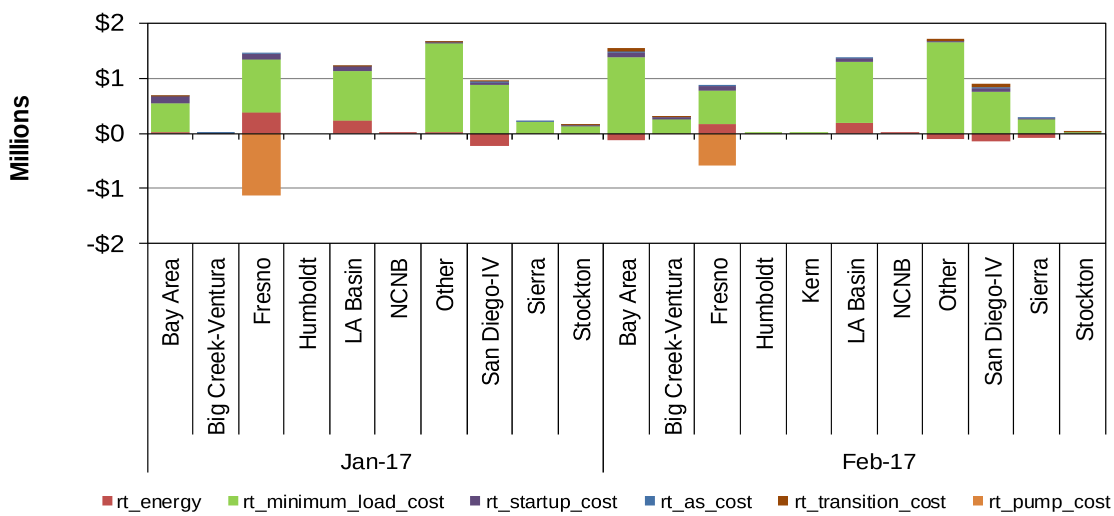


Figure 35 and Figure 36 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 35: Cost in Real Time by UDC

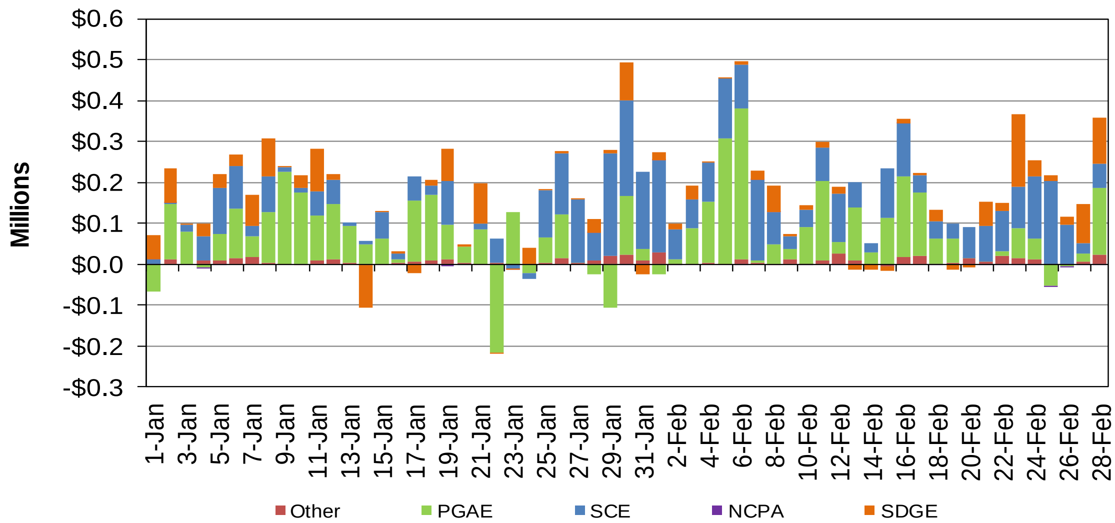


Figure 36: Monthly Cost in Real Time by UDC

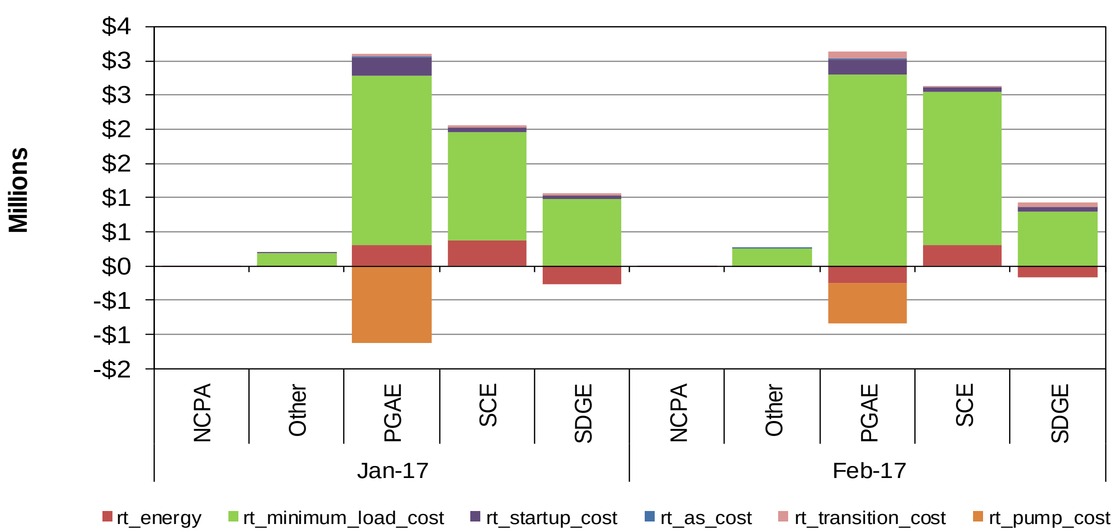


Figure 37 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in February.

Figure 37: Cost in IFM

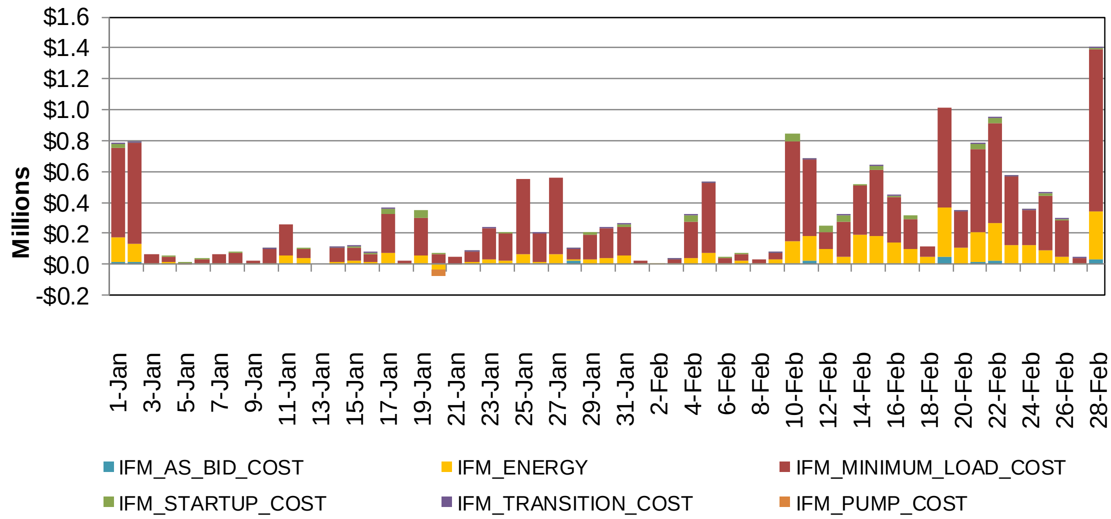


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 38: Cost in IFM by LCR

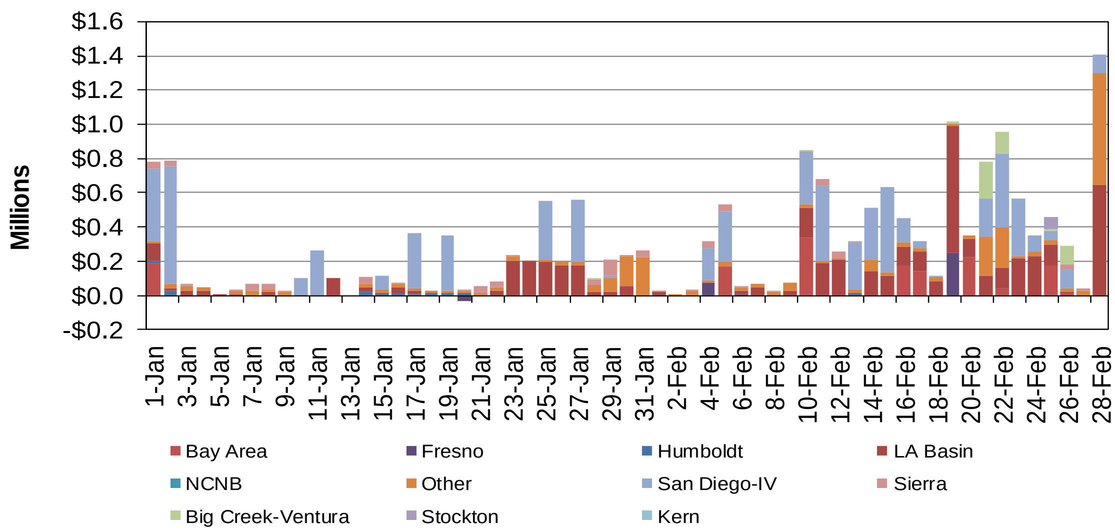


Figure 39: Monthly Cost in IFM by LCR

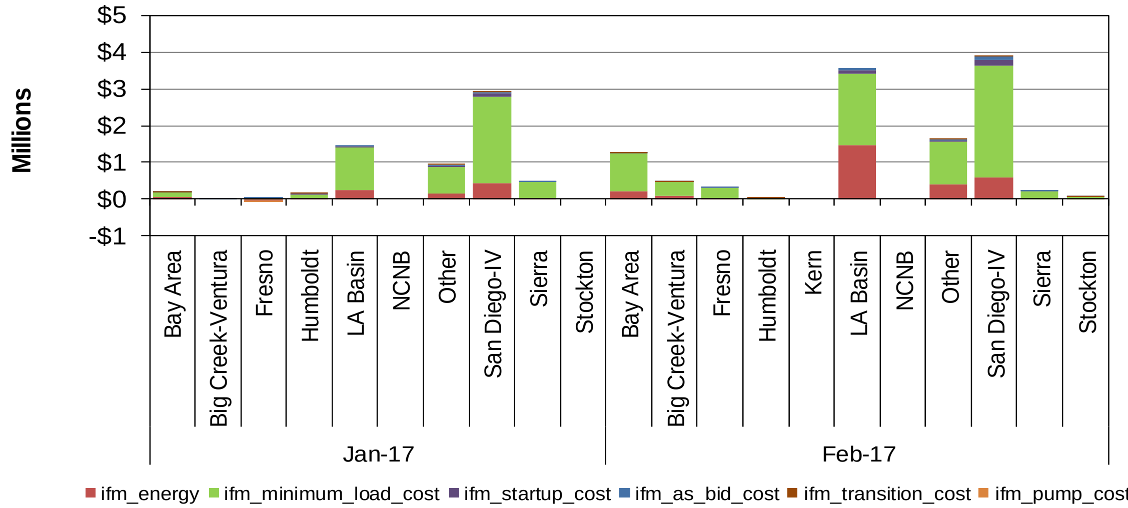


Figure 40 and Figure 41 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 40: Cost in IFM by UDC

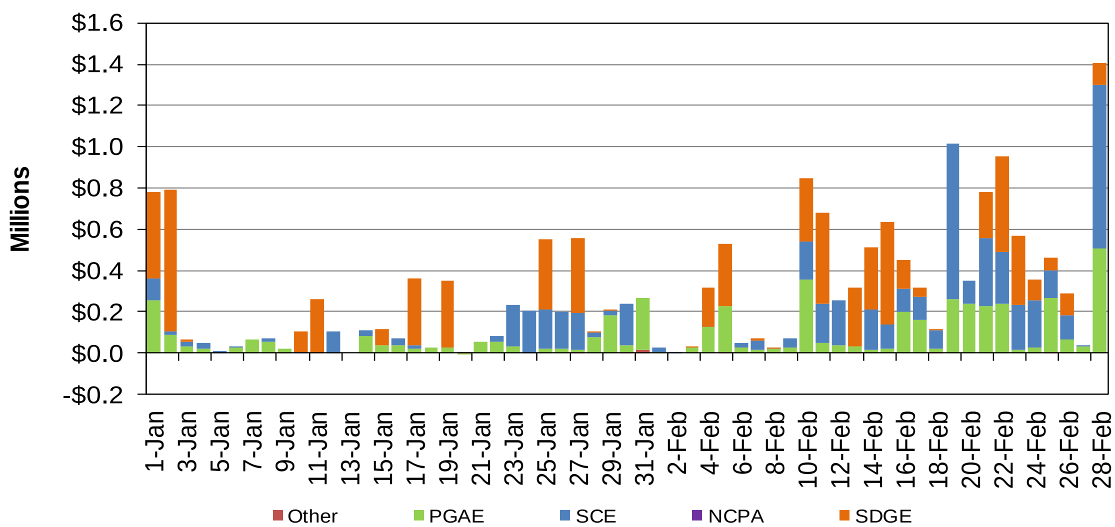
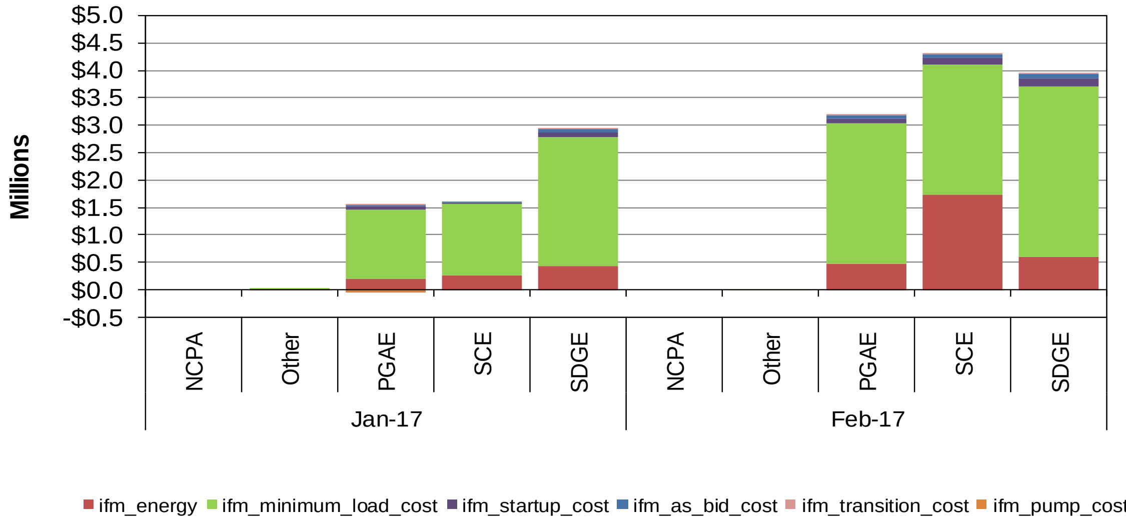


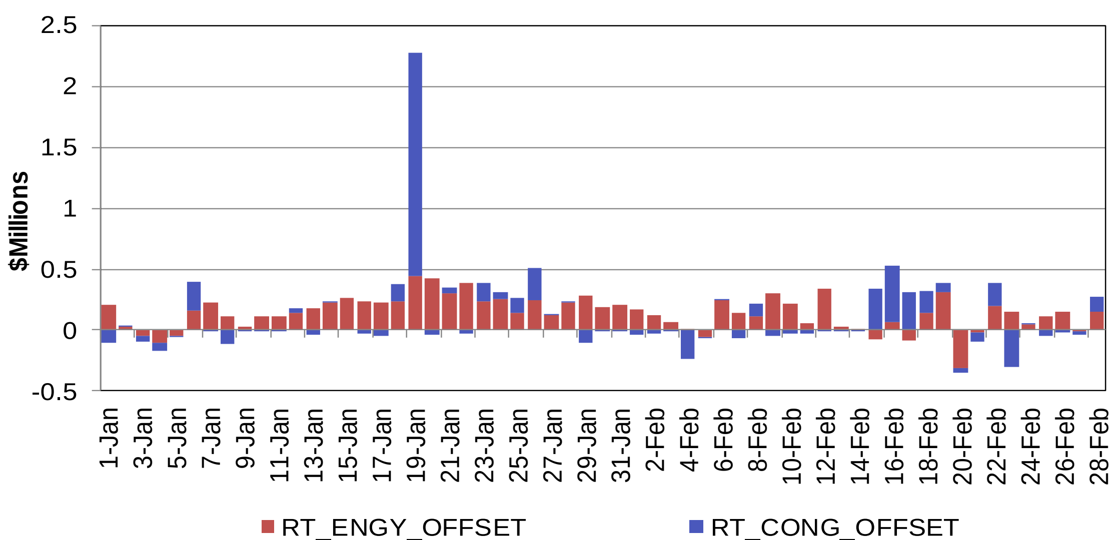
Figure 41: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 42 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost fell to $2.58 million in February from $5.76 million in January. Real-time congestion offset cost skidded to $0.78 million in February from $2.23 million in January.

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.

There were a total of 34 market disruptions in February. Table 6 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.

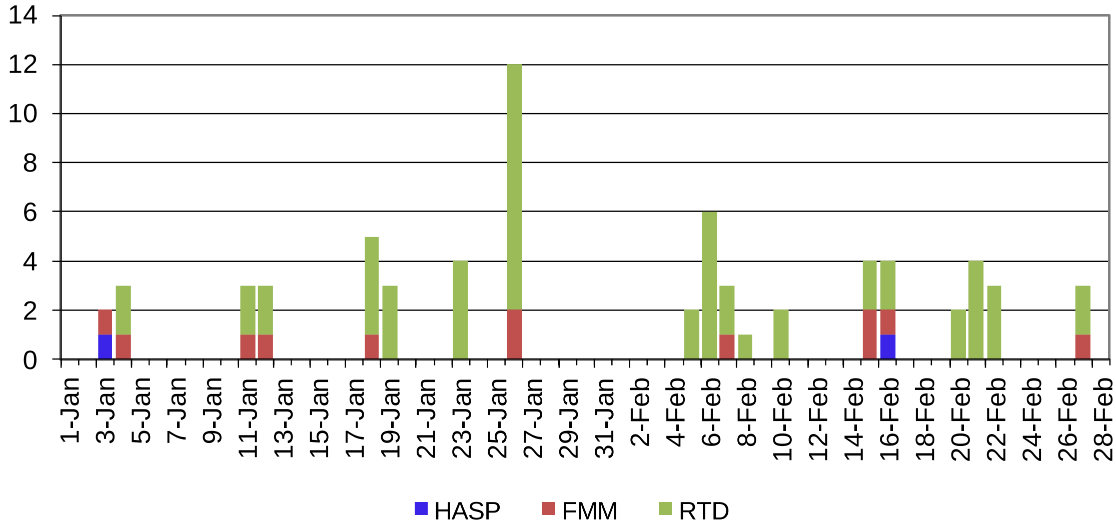
Table 6: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
FMM Interval 1	1	0
FMM Interval 2	1	0
FMM Interval 3	1	0
FMM Interval 4	3	0
Real-Time Dispatch	28	0

Figure 43 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On February 6, four RTD disruptions occurred due to application problem and two other RTD disruptions occurred due to broadcast not being successful.

[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: day-ahead, real-time incremental dispatch and real-time decremental dispatch. Generally, all day-ahead exceptional dispatches are unit commitments at the resource physical minimum. The real-time exceptional dispatches are among one of the following types: a unit commitment at physical minimum; an incremental dispatch above the day-ahead schedule and a decremental dispatch below the day-ahead schedule.

The total volume of exceptional dispatch in February declined to 50,738 MWh from 58,838 MWh in January.

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

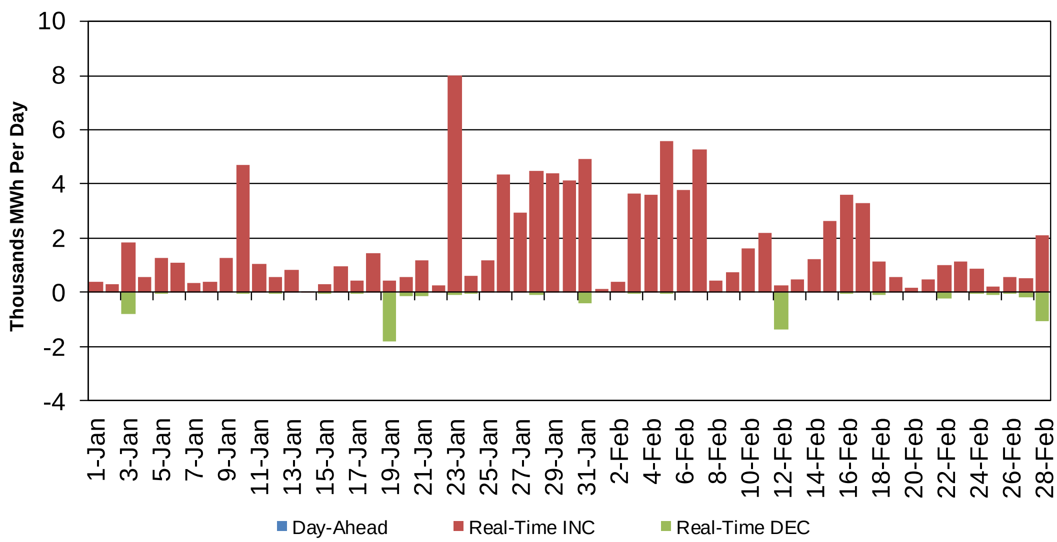


Figure 45 shows the volume of the exceptional dispatch broken out by reason.[3] The majority of the exceptional dispatch volumes in February were driven by planned transmission outage and constraint (48 percent), voltage support (21 percent), and operating procedure number and constraint (16 percent).

[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

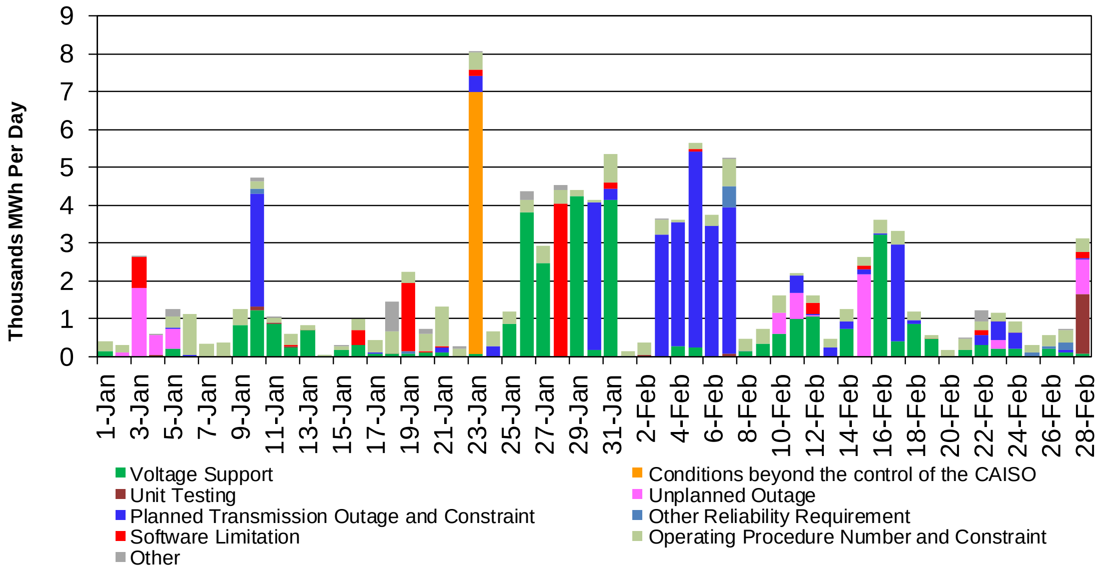
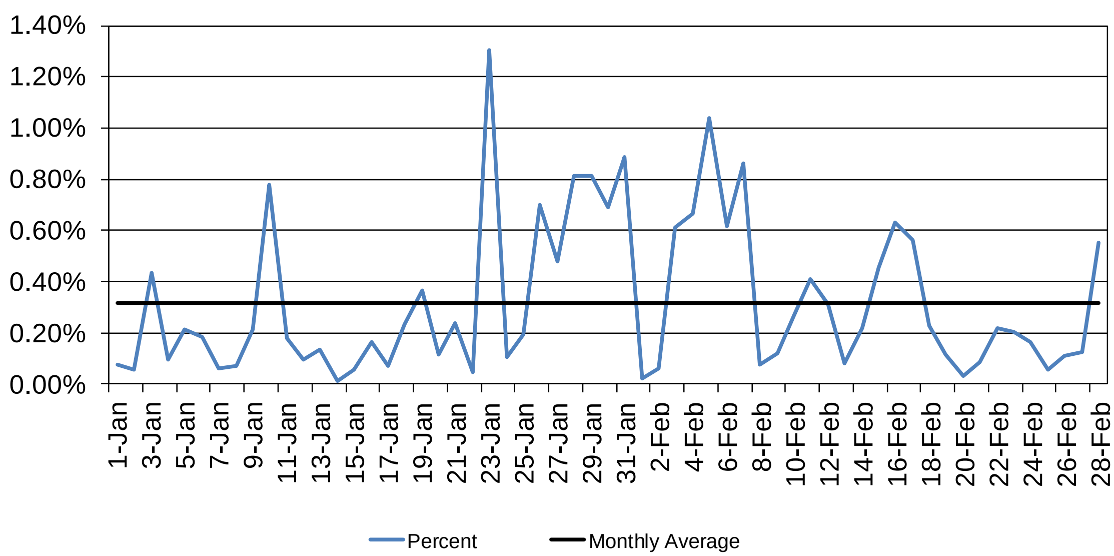


Figure 46 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage satyed at 0.32 percent in February, relatively unchanged from January.

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

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

Figure 47 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) for all hours in FMM. On February 23 and 28, the prices for AZPS were depressed due to low load forecast and reduced export.

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

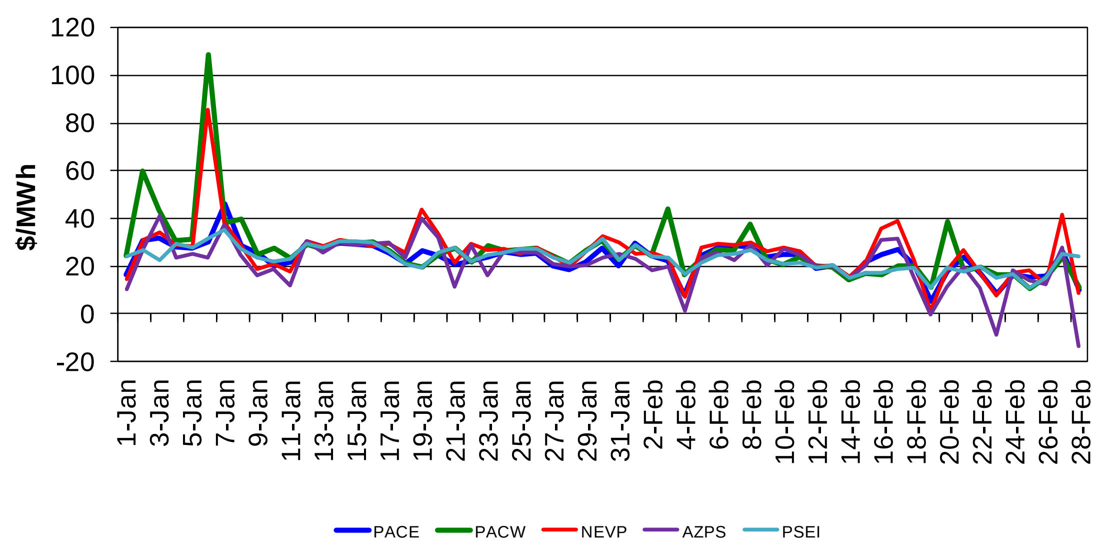


Figure 48 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. On February 17, the price for NEVP was elevated by higher load forecast. On February 20, the price for PACW was elevated due to reduced import. On February 23, the prices for AZPS, NEVP and PACE were depressed due to downward load adjustment and transmission congestion. On February 28, the price for AZPS was depressed due to reduced export and transmission congestion.

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

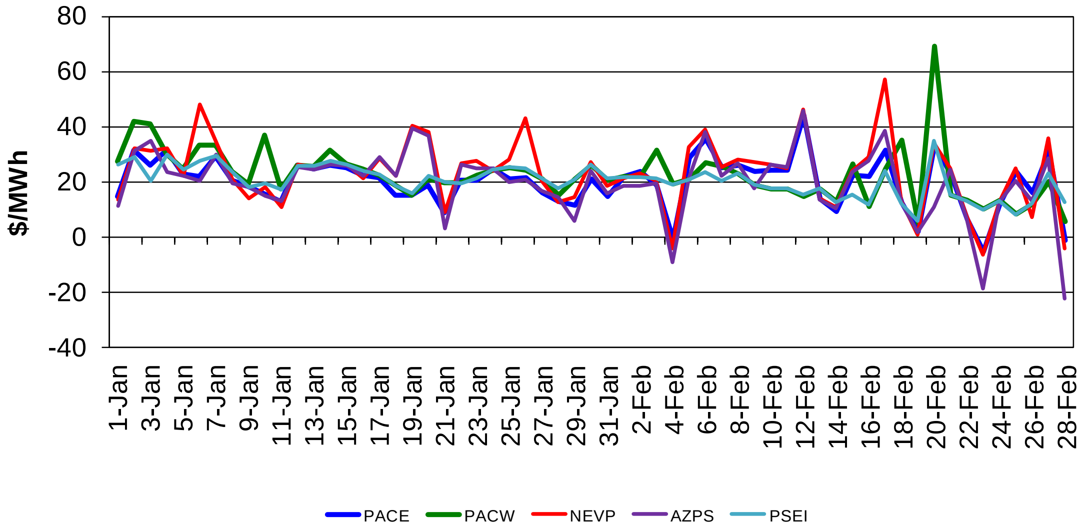


Figure 49 shows the daily price frequency for prices above \$250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above \$250/MWh decreased to 0.07 percent in February from 0.23 percent in January. The cumulative frequency of negative prices rose to 9.05 percent in February from 2.53 percent in January.

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

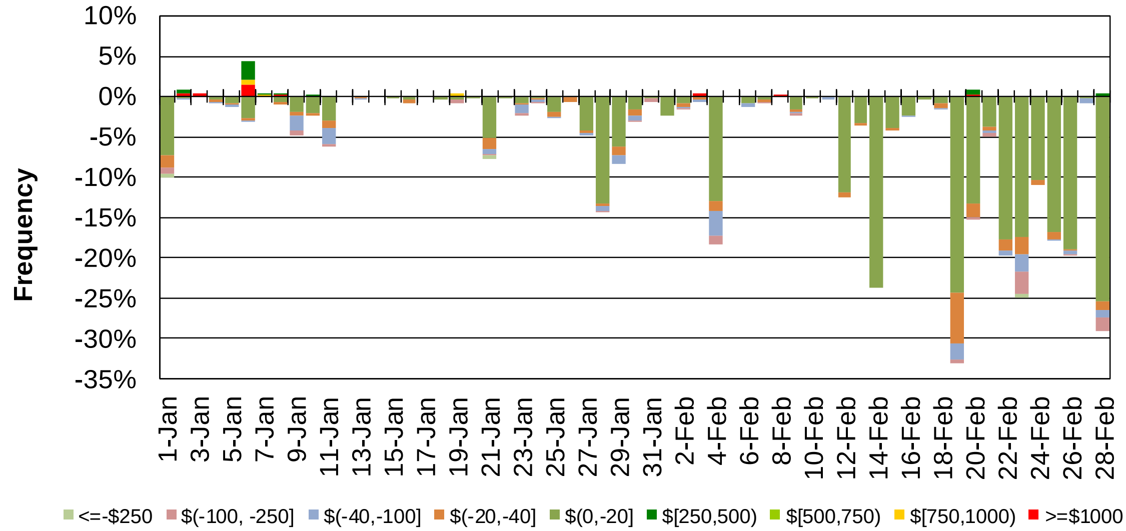


Figure 50 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh increased to 0.51 percent in February from 0.19 percent in January. The cumulative frequency of negative prices rose to 11.57 percent in February from 5.69 percent in January.

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

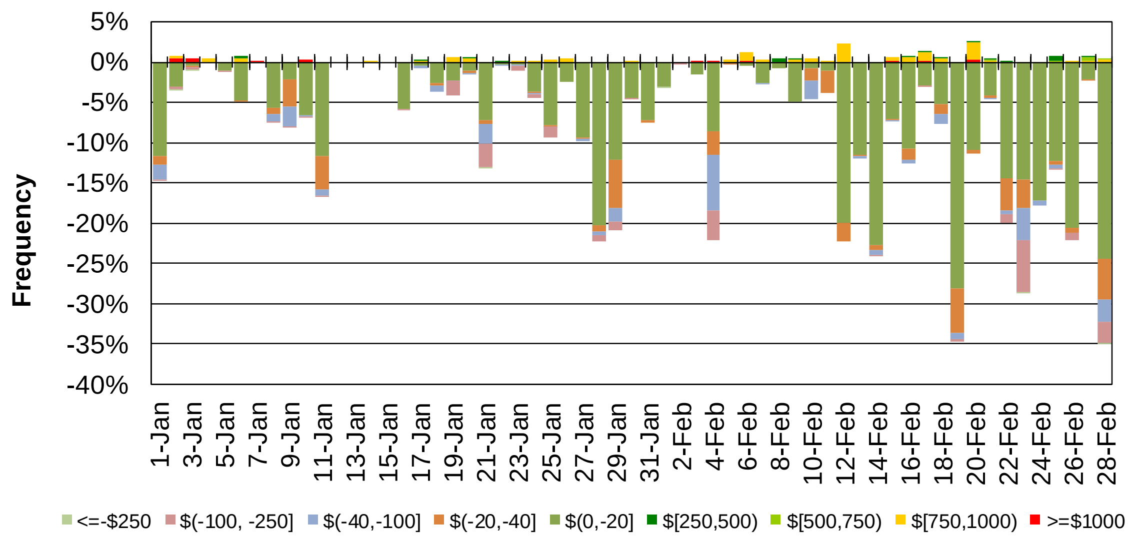


Figure 51 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. Figure 52 shows the daily volume of EIM transfer between PACE and PACW in FMM. The EIM transfer from PACE to PACW trended downward in February

Figure 51: EIM Transfer between CAISO and PAC in FMM

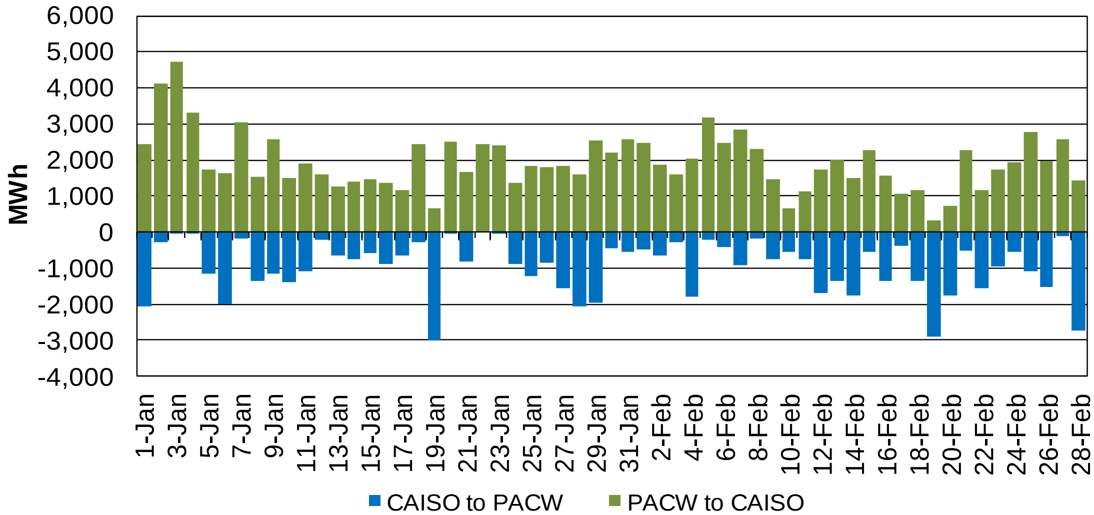


Figure 52: EIM Transfer between PACE and PACW in FMM

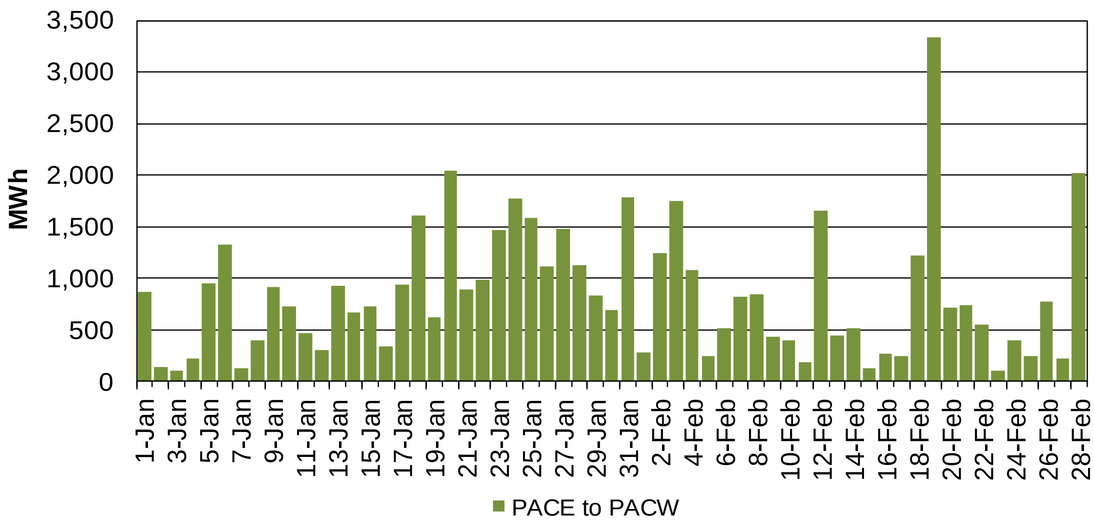


Figure 53 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. The EIM transfer from NEVP to ISO decreased in February compared with January. Figure 54 shows the daily volume of EIM transfer between PACE and NEVP in FMM. The EIM transfer from PACE to NEVP decreased this month.

Figure 53: EIM Transfer between CAISO and NEVP in FMM

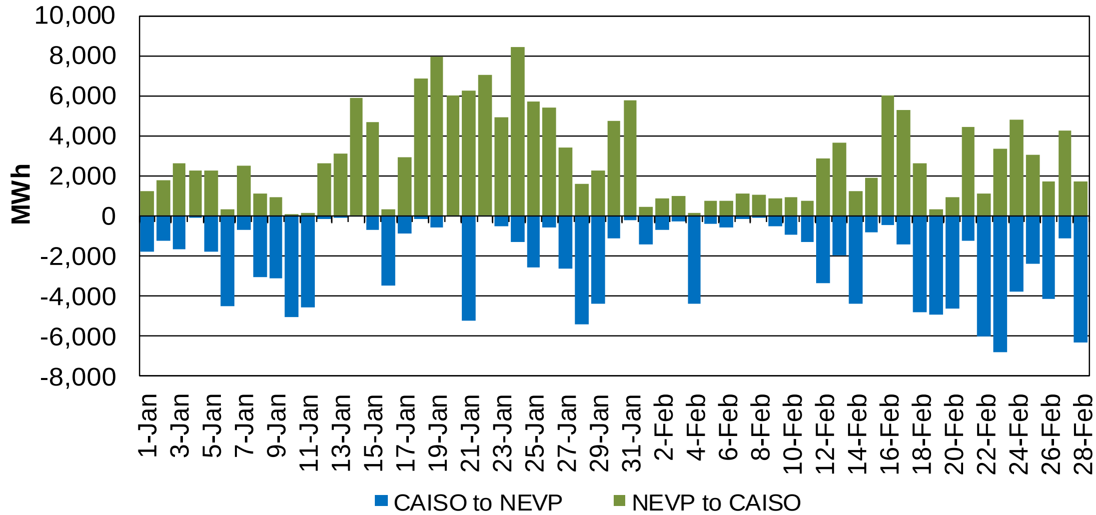


Figure 54: EIM Transfer between PACE and NEVP in FMM

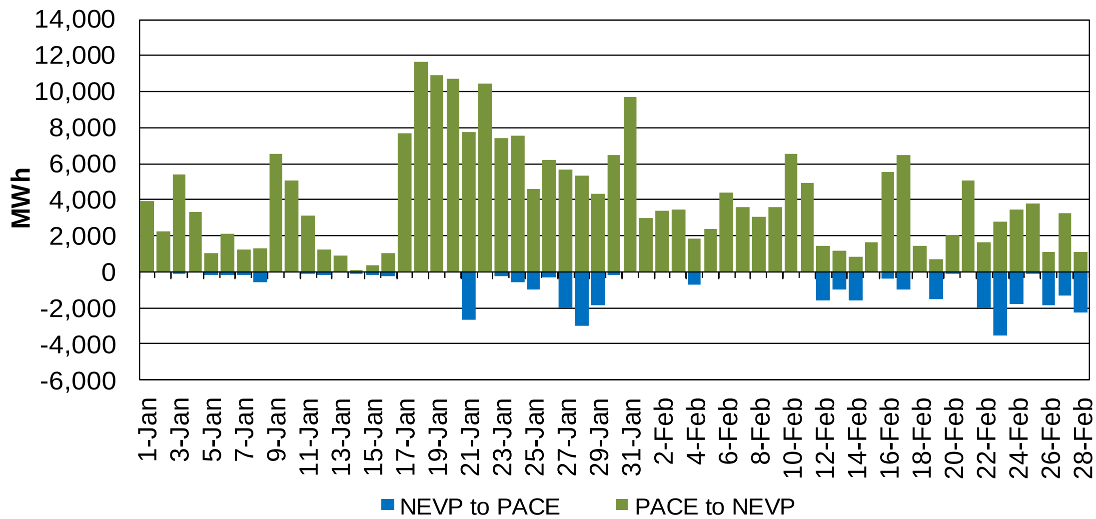


Figure 55 shows the daily volume of EIM transfer between ISO and AZPS in FMM. The EIM transfer from AZPS to ISO dropped in the second half of February. Figure 56 shows the daily volume of EIM transfer between PACE and AZPS in FMM.

Figure 55: EIM Transfer between CAISO and AZPS in FMM

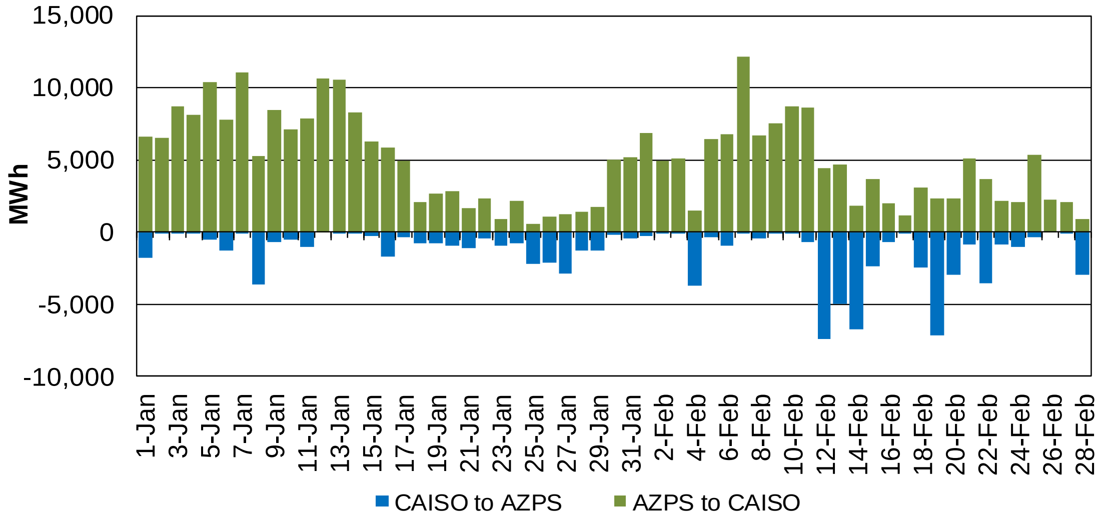


Figure 56: EIM Transfer between PACE and AZPS in FMM

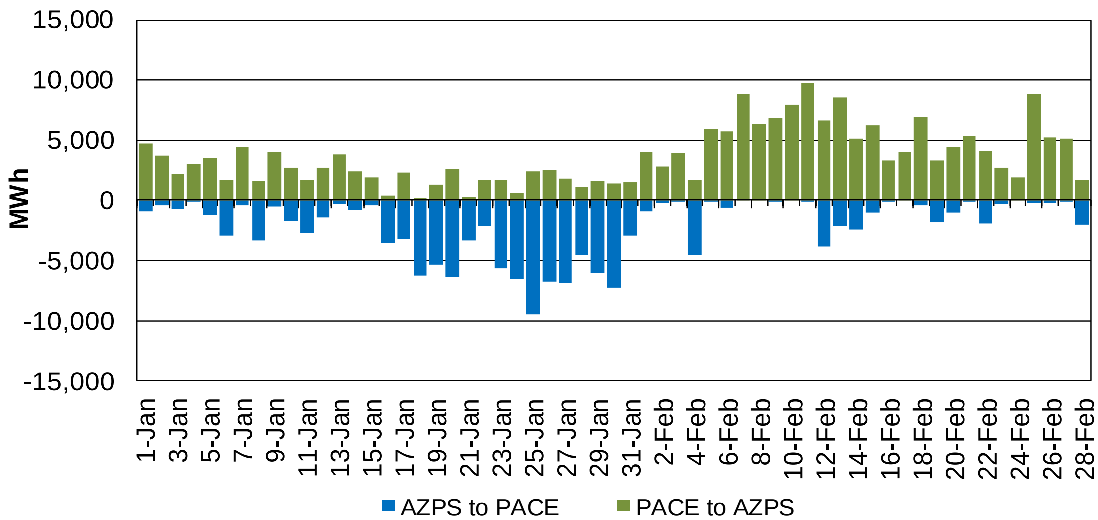


Figure 57 shows the daily volume of EIM transfer between PACW and PSEI in FMM.

Figure 57: EIM Transfer between PACW and PSEI in FMM

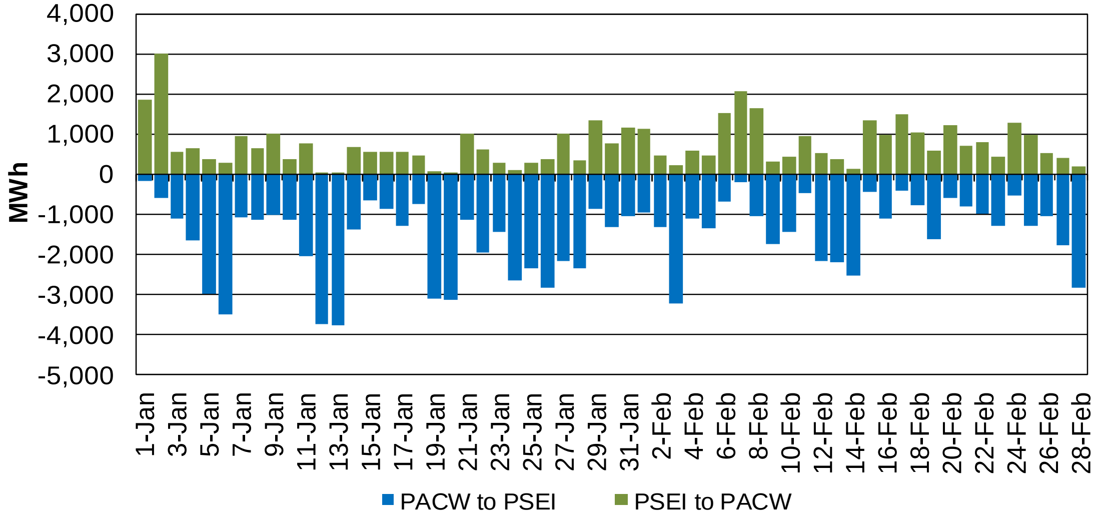


Figure 58 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. Figure 59 shows the daily volume of EIM transfer between PACE and PACW in RTD. The EIM transfer from PACE to PACW trended downward this month.

Figure 58: EIM Transfer between CAISO and PAC in RTD

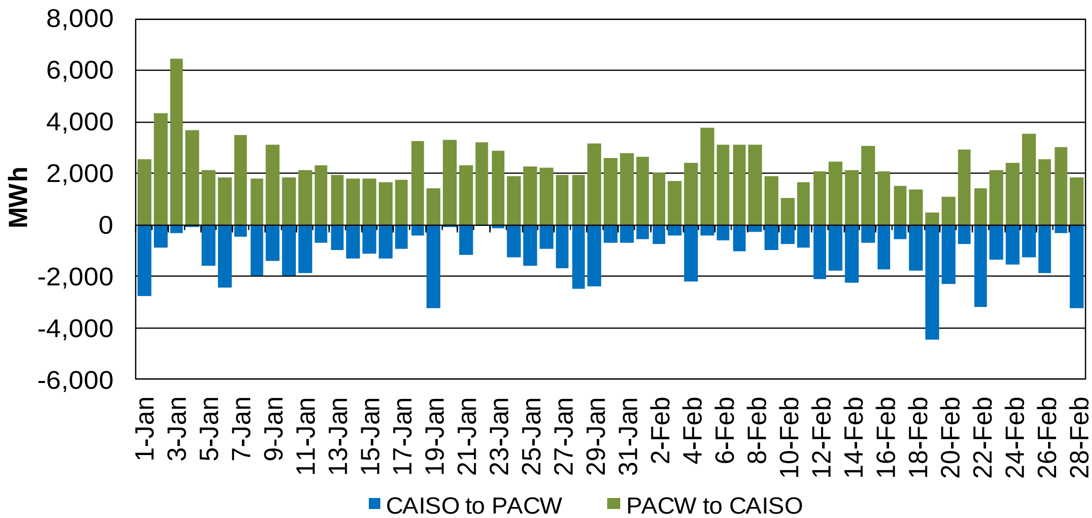


Figure 59: EIM Transfer between PACE and PACW in RTD

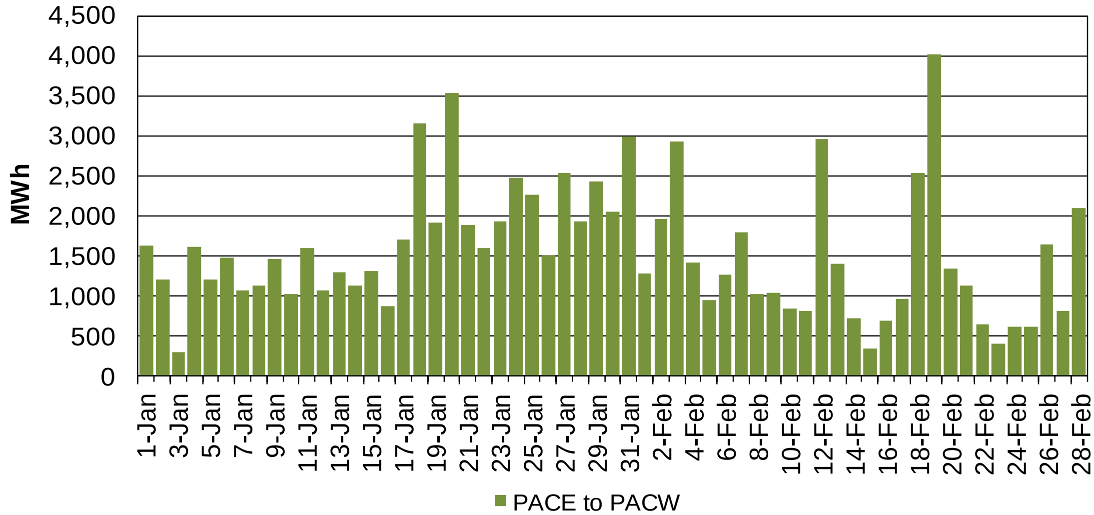


Figure 60 shows the daily EIM transfer volume between ISO and NEVP in RTD. The EIM transfer from NEVP to CAISO increased generally this month. Figure 61 shows the daily volume EIM transfer between PACE and NEVP in RTD.

Figure 60: EIM Transfer between CAISO and NEVP in RTD

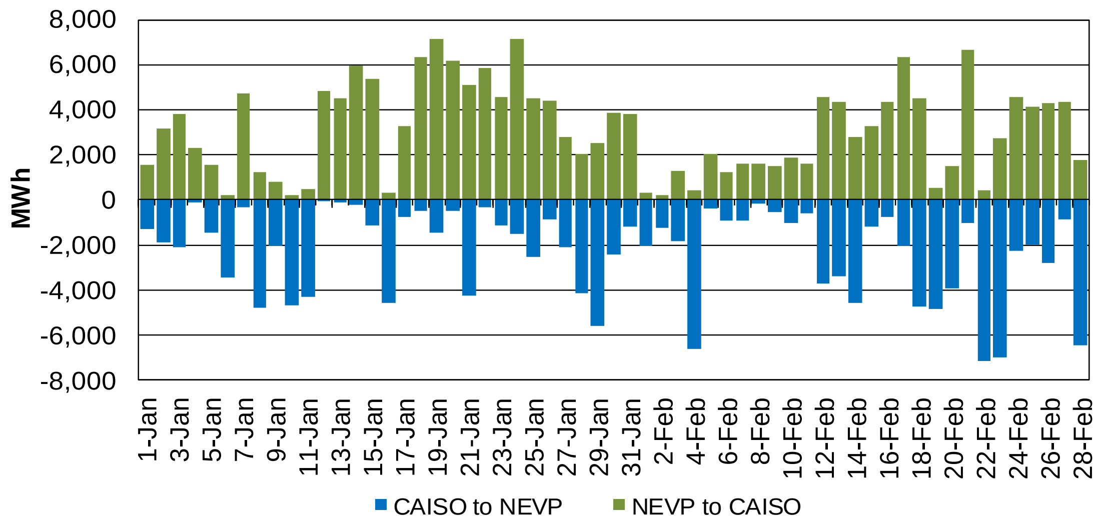


Figure 61: EIM Transfer between PACE and NEVP in RTD

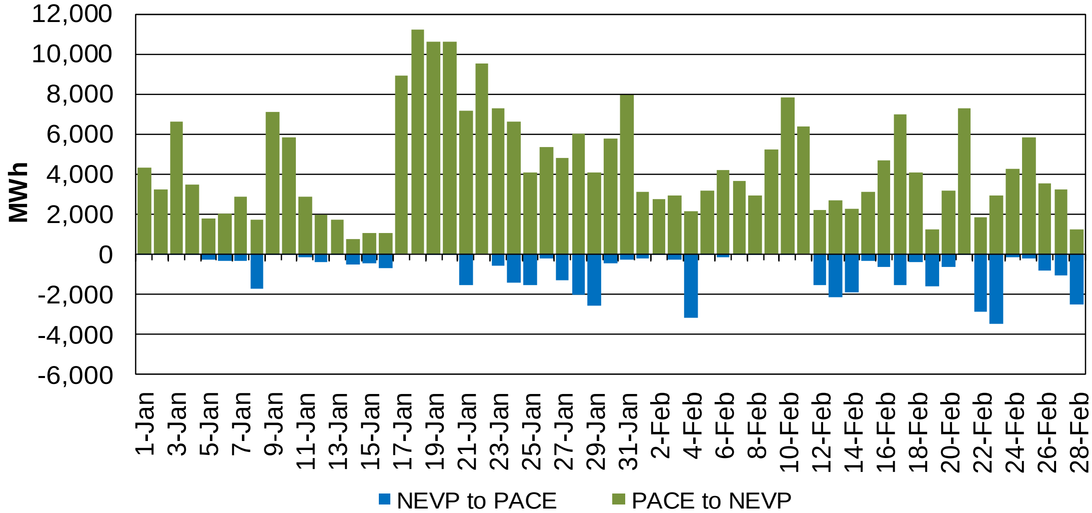


Figure 62 shows the daily volume EIM transfer between the ISO and AZPS in RTD. The EIM transfer from AZPS to ISO fell in the second half of this month. Figure 63 shows the daily volume EIM transfer between the PACE and AZPS in RTD. The EIM transfer from AZPS to PACE increased in February compared with January.

Figure 62: EIM Transfer between CAISO and AZPS in RTD

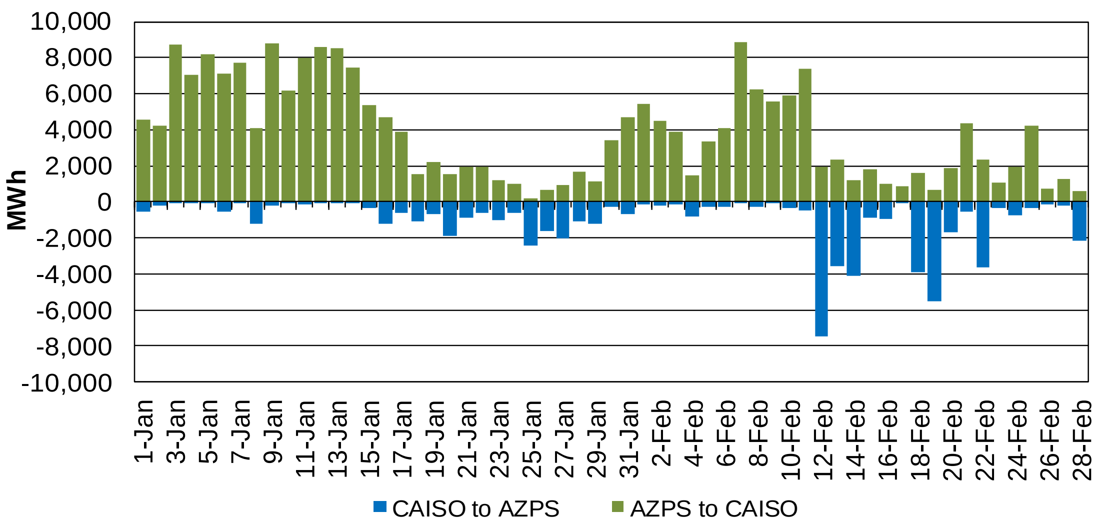


Figure 63: EIM Transfer between PACE and AZPS in RTD

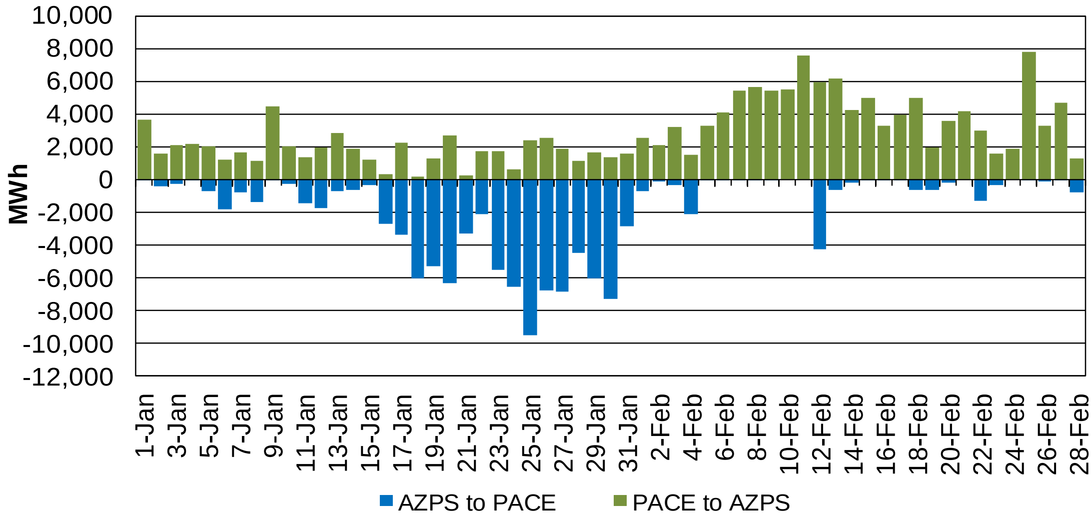


Figure 64 shows the daily volume EIM transfer between the PACW and PSEI in RTD.

Figure 64: EIM Transfer between PACW and PSEI in RTD

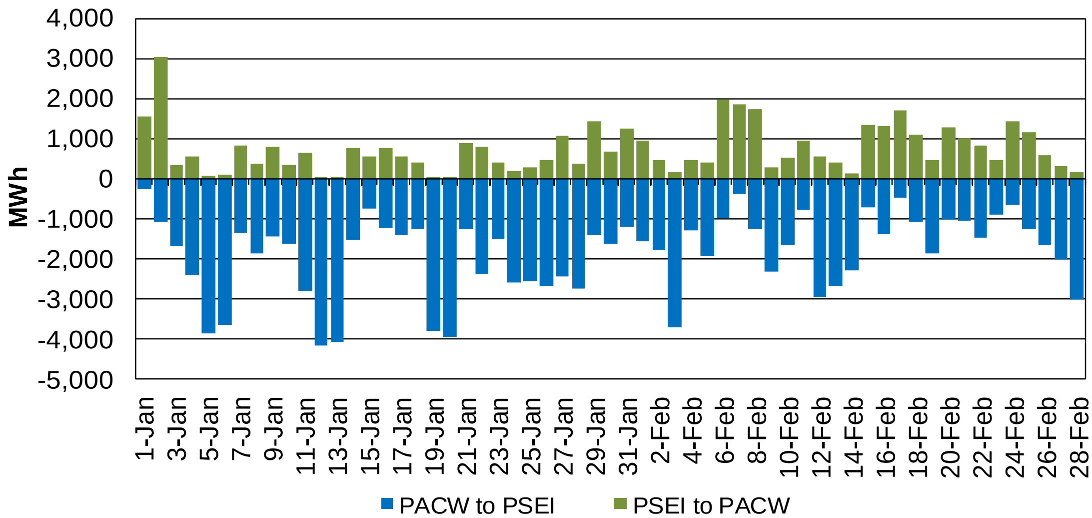


Figure 65 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was $0.27 million in February, decreasing from $1.30 million in January.

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

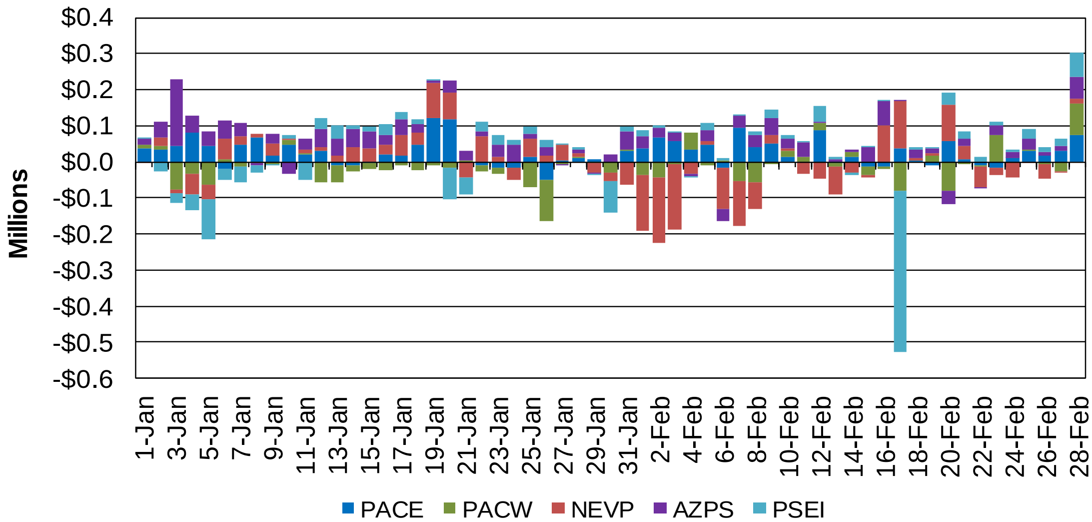


Figure 66 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO dropped to -$1.28 million in February from -$0.05 million in January.

Figure 66: EIM Real-Time Congestion Imbalance Offset by Area

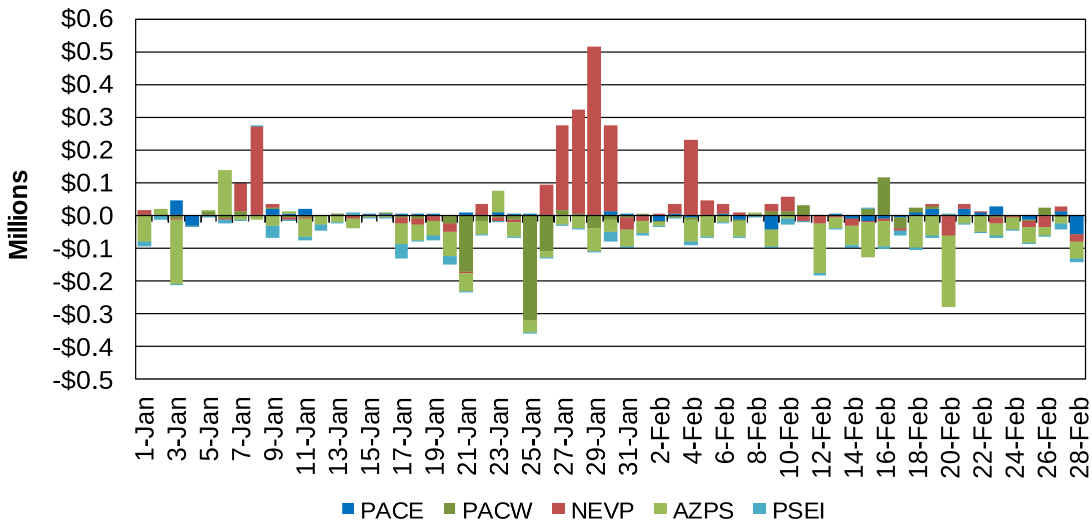


Figure 67 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR decreased to $0.68 million in February from $1.21 million in January.

Figure 67: EIM Bid Cost Recovery by Area

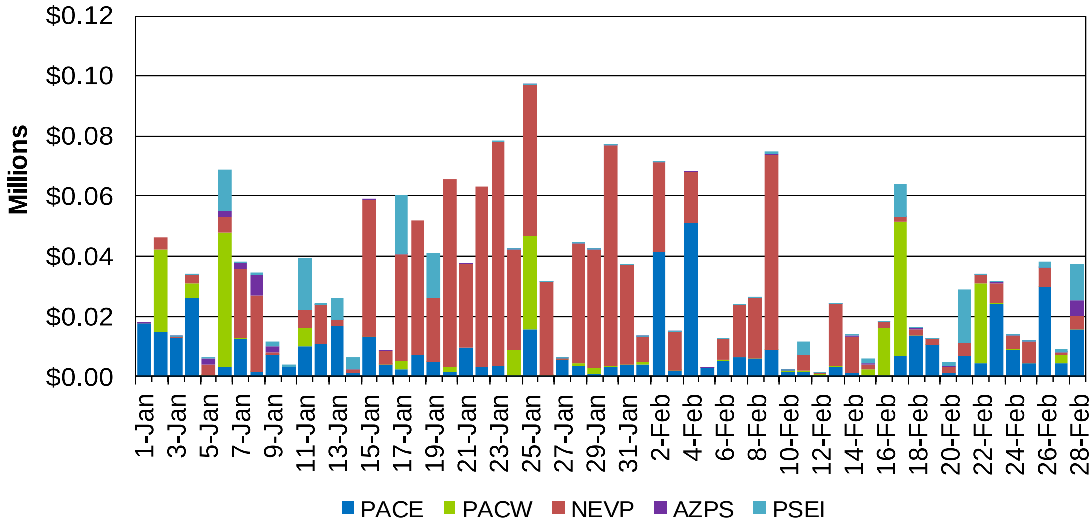


Figure 68 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping up uncertainty payment in February inched down to $1.12 million from $1.25 million in January.

Figure 68: Flexible Ramping Up Uncertainty Payment

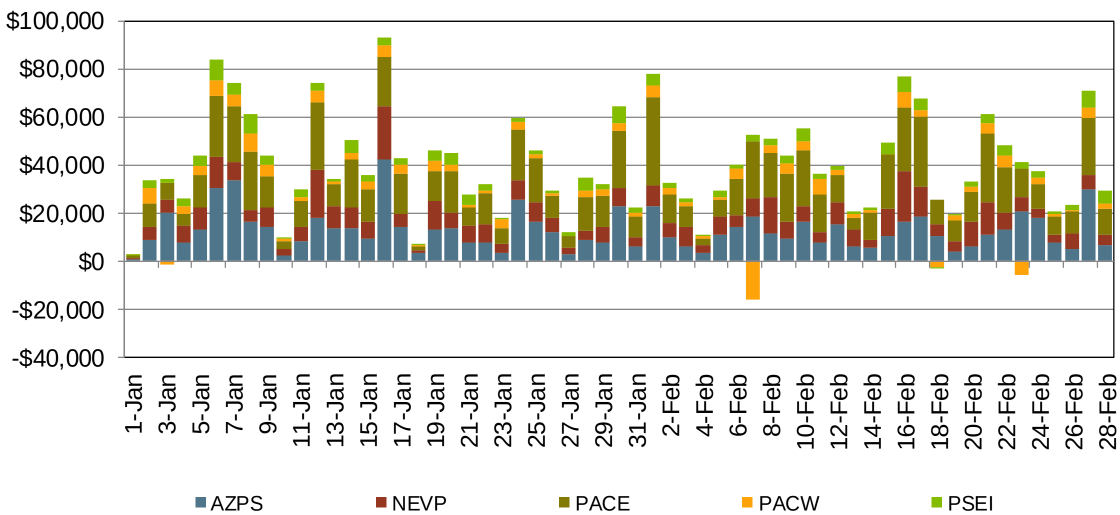


Figure 69 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total flexible ramping down uncertainty payment in February increased to $0.22 million from $0.15 million in January.

Figure 69: Flexible Ramping Down Uncertainty Payment

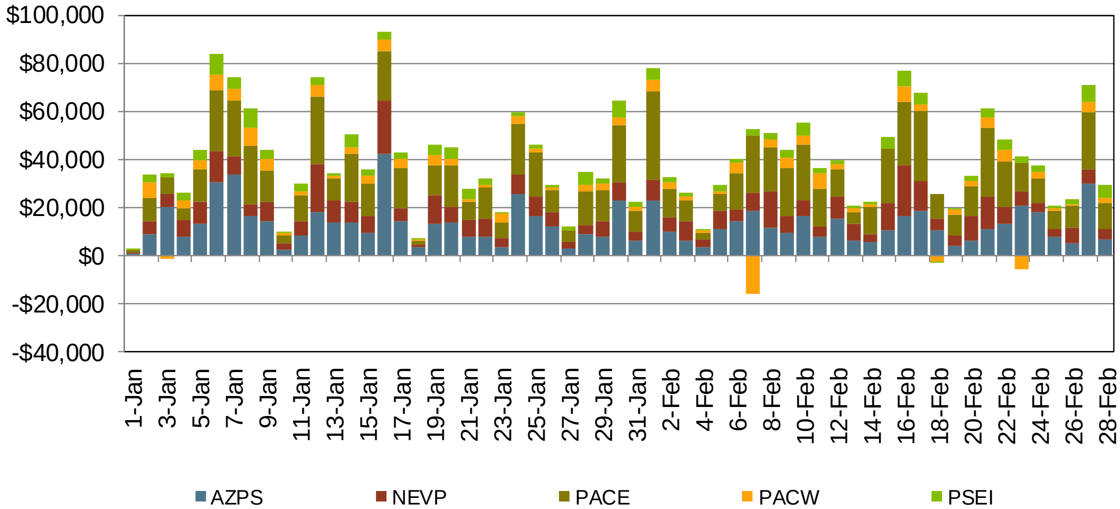
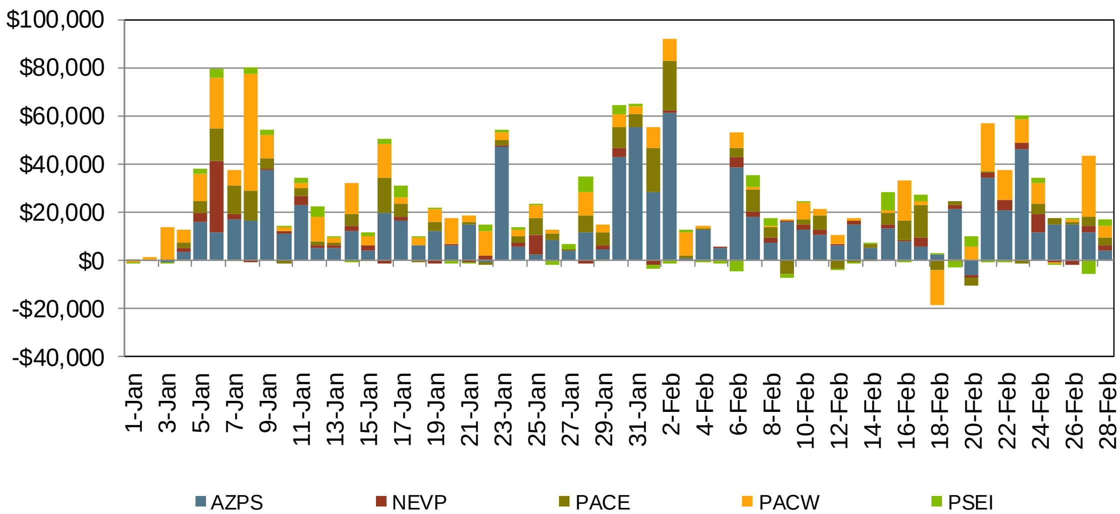


Figure 70 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, and PSEI respectively. Total forecast payment in February edged down to $0.72 million from $0.87 million in January.

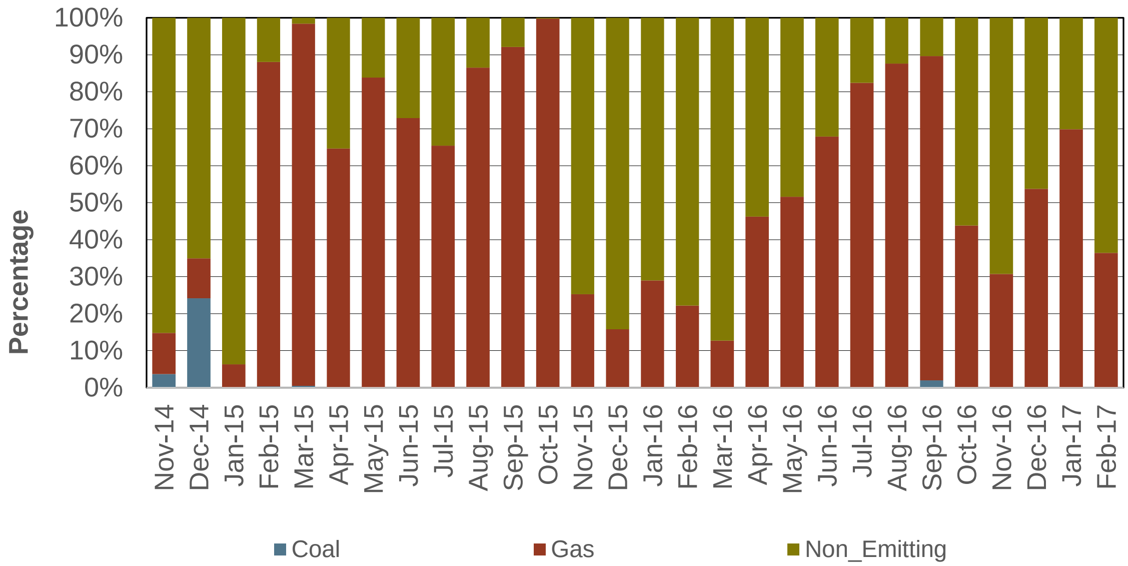
Figure 70: Flexible Ramping Forecast Payment



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].

In the first two months of EIM operations (November and December 2014), EIM startup issues related to processing GHG bid adder resulted in the dispatch of coal generation to support transfers into California. Once the adders were properly accounted for, beginning in February 2015, almost all of the EIM dispatches to support transfers into the ISO were from resources other than coal, as documented in Figure 71 and Table 7 below.

Figure 71: 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 7: EIM Transfer into ISO by Fuel Type

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