Market Performance Report
January 2017

February 28, 2017

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in January 2017 is summarized below.

CAISO area performance,

- Peak loads for ISO continued to be low in January due to low temperature.
- In the integrated forward market (IFM), SDG&E DLAP prices was elevated on January 29 due to transmission congestion. In the fifteen-minute market (FMM), SCE, SDG&E and VEA DLAP prices were depressed in a few days due to the congestion on path 15. In the real-time market (RTD), SDG&E DLAP prices were elevated in a couple of days driven by transmission congestion.
- Congestion rents for interties skidded to $2.70 million from $7.12 million in December. Majority of the congestion rents in January accrued on MALIN500 (77 percent) intertie and NOB (22 percent) intertie.
- In the congestion revenue rights market, revenue adequacy rose to 52.21 percent from 47.99 percent in December. The nomogram 23040_CROSSTRIP contributed largely to the revenue shortfall. This nomogram was enforced to avoid potential post-contingency flow in the underlying 230 kV line for the N-1 loss of the 500 kV line.
- The monthly average ancillary service cost to load rose to $0.50/MWh from $0.43/MWh in December. There were no ancillary service scarcity events in January.
- The cleared virtual supply was well above cleared demand in most days of January. The profits from convergence bidding increased to $1.54 million in January from $0.68 million in December.
- The bid cost recovery inched up to $5.67 million from $5.51 million in December.
- The real-time energy offset cost increased to $5.55 million in January from -$0.86 million in December. The real-time congestion offset cost increased to $2.23 million from -$0.29 million in December.
- The volume of exceptional dispatch rose to 58,848 MWh from 35,251 MWh in January, largely driven by voltage support and operating procedure number and constraint. The monthly average of total exceptional dispatch volume as a percentage of load increased to 0.32 percent in January from 0.20 percent in December.

[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 NEVP and PACW areas were elevated on January 6 due to higher load forecast and generation outage. In the RTD market, the prices for NEVP and PACE were elevated on January 19-20, driven by Malin outage, higher load forecast, and renewable deviation.
- Bid cost recovery, real-time imbalance energy offset, and real-rime congestion offset costs for EIM entities (PACE, PACW, NEVP, AZPS, and PSEI) were $1.21 million, $1.30 million and -$0.49 million respectively.

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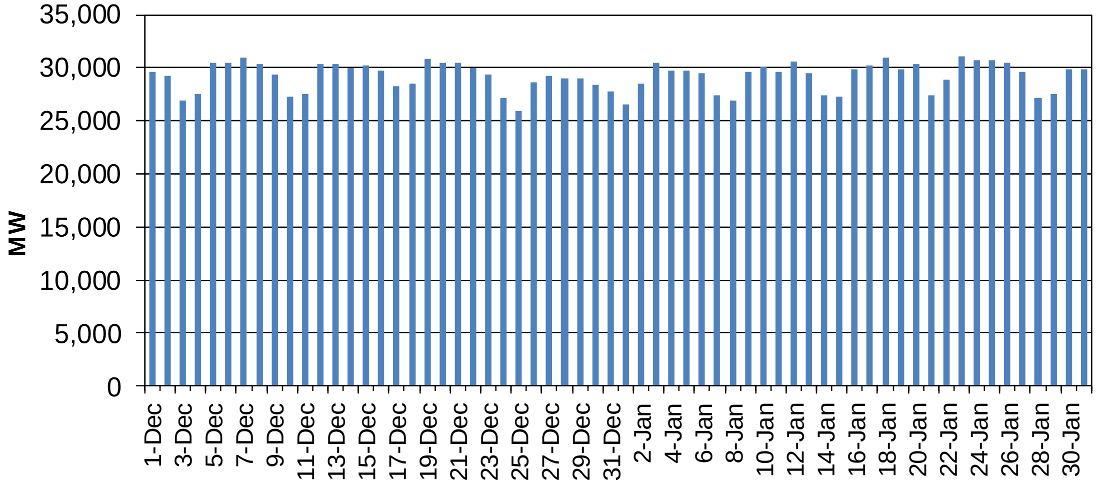
Market Characteristics

Loads

Peak loads for ISO was continued to be low in January due to low temperature.

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)

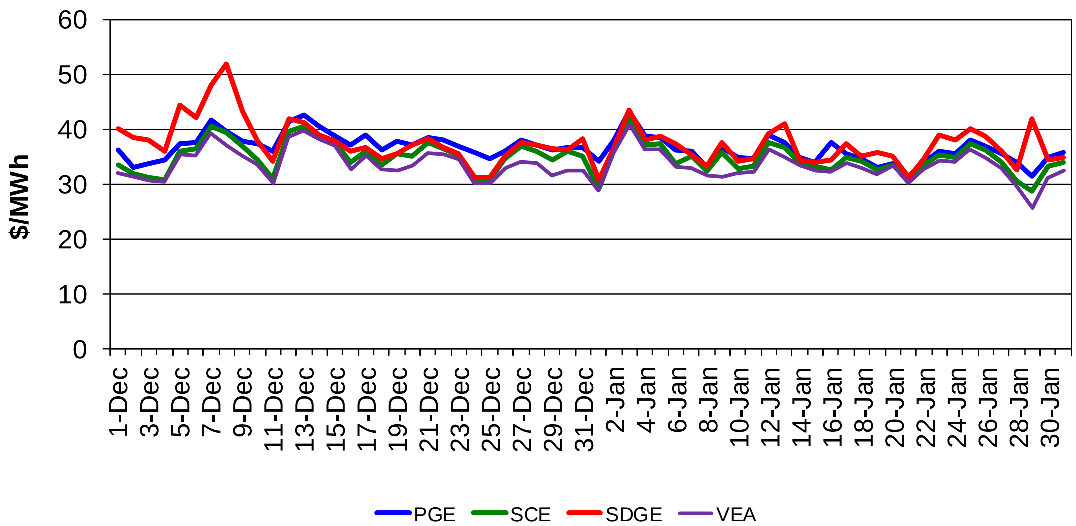


Table 1: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	January 29	OMS 4622069 TL50003

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.

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

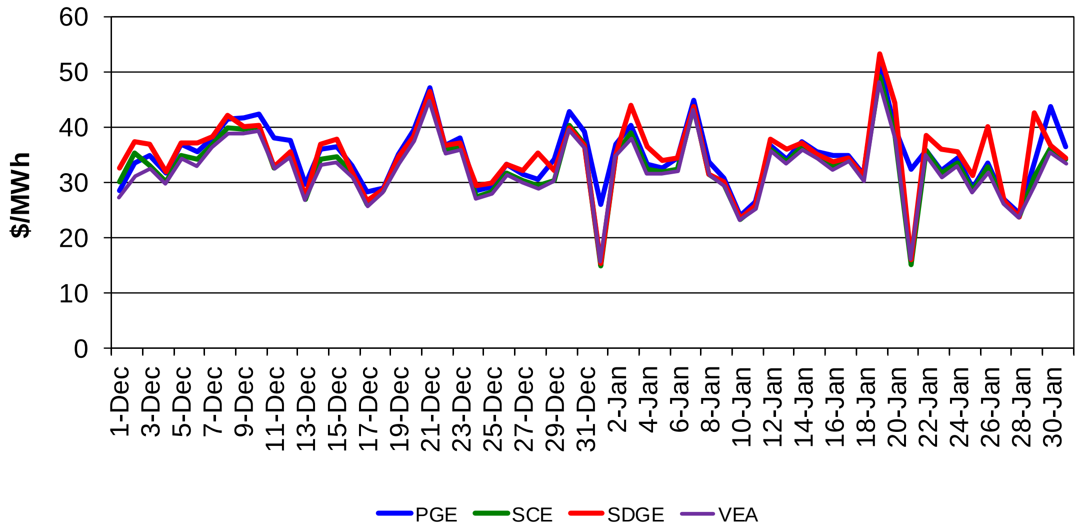
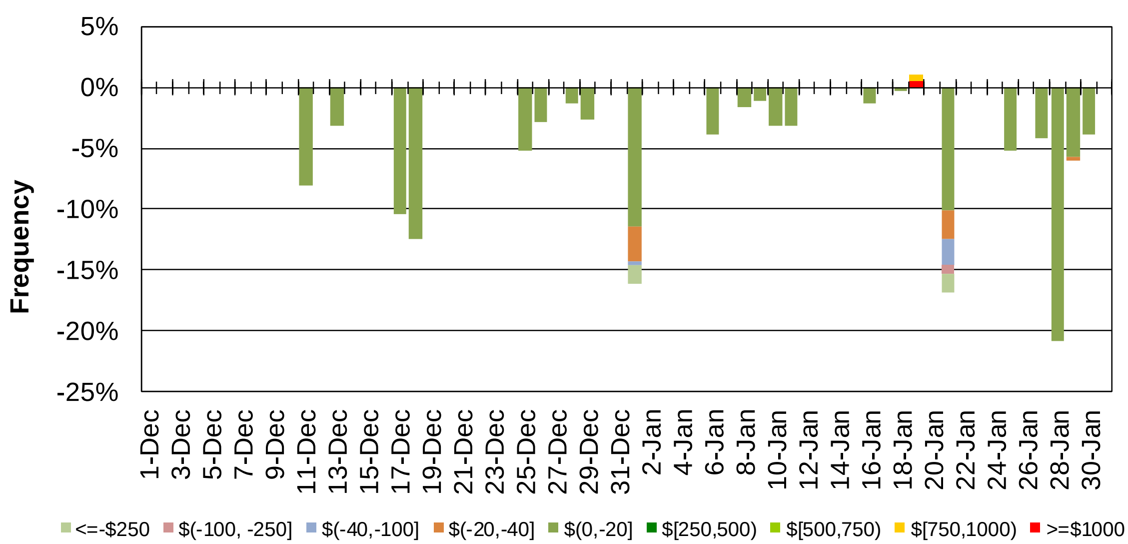


Table 2: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E, VEA	January 1, 21, 30	PATH15_S-N
SDG&E	January 29	OMS 4622069 TL50003

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 up to 0.03 percent in January from 0 percent in December. The cumulative frequency of negative prices increased to 2.82 percent in January from 1.49 percent in December.

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)

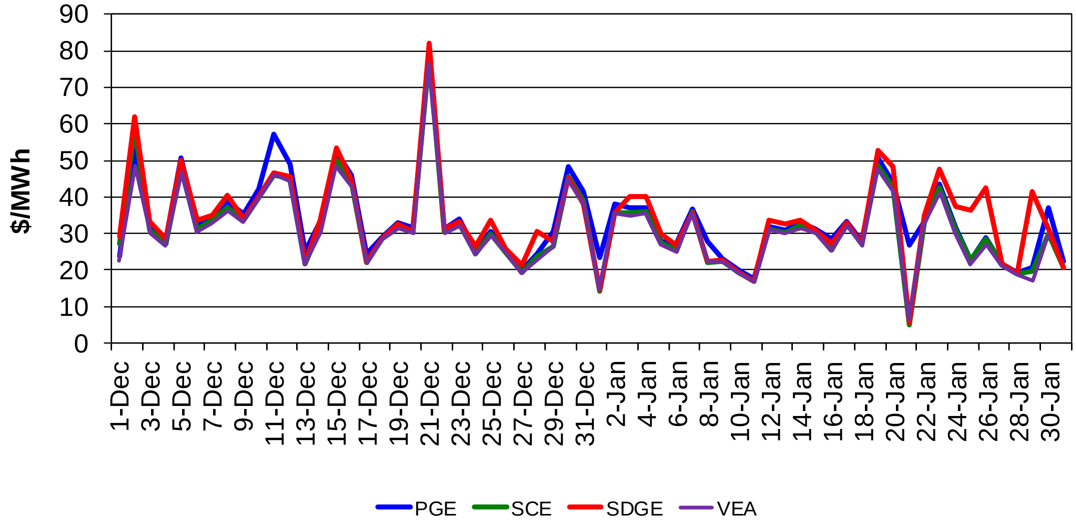
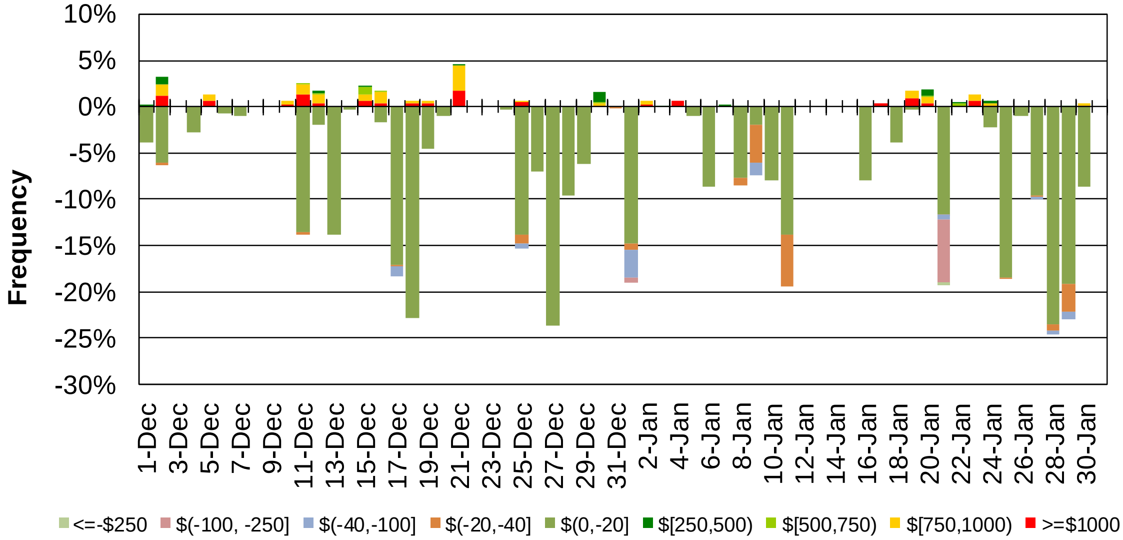


Table 3: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E, VEA	January 21	PATH15_S-N
SDG&E	January 23-26	23040_CROSSTRIP
SDG&E	January 29	OMS 4622069 TL50003

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 fell to 0.28 percent in January from 0.71 percent in December. The cumulative frequency of negative prices increased to 6.58 percent in January from 5.02 percent in December.

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



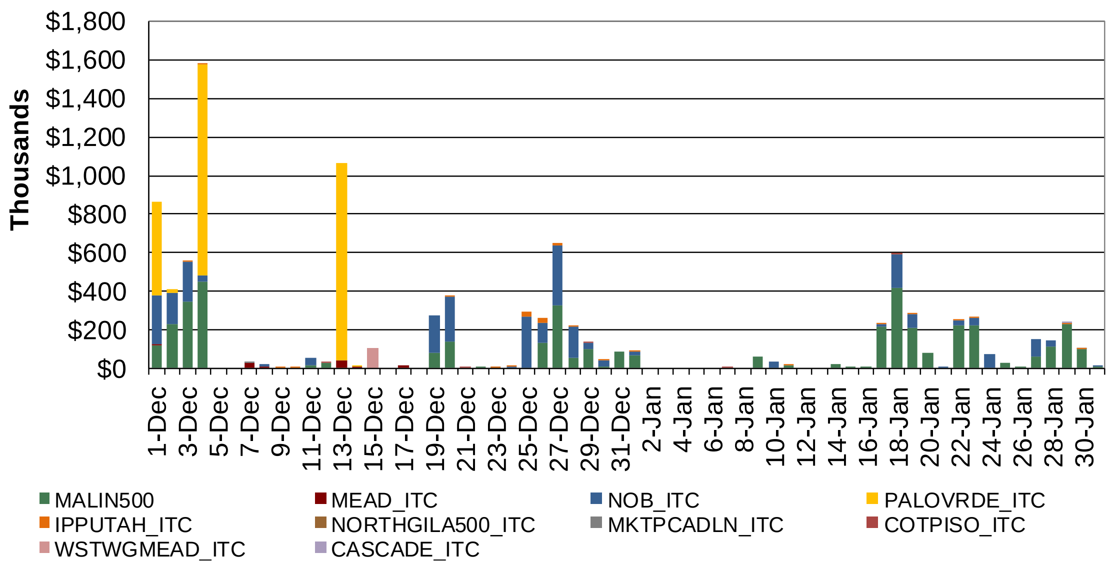
Congestion

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 January skidded to $2.70 million from $7.12 million in December. Majority of the congestion rents in January accrued on MALIN500 (77 percent) intertie and NOB (22 percent) intertie.

The congestion rent on MALIN500 inched down to $2.07 million in January from $2.12 million in December. The congestion rent on NOB decreased to $0.58 million in January from $2.01 million in December.

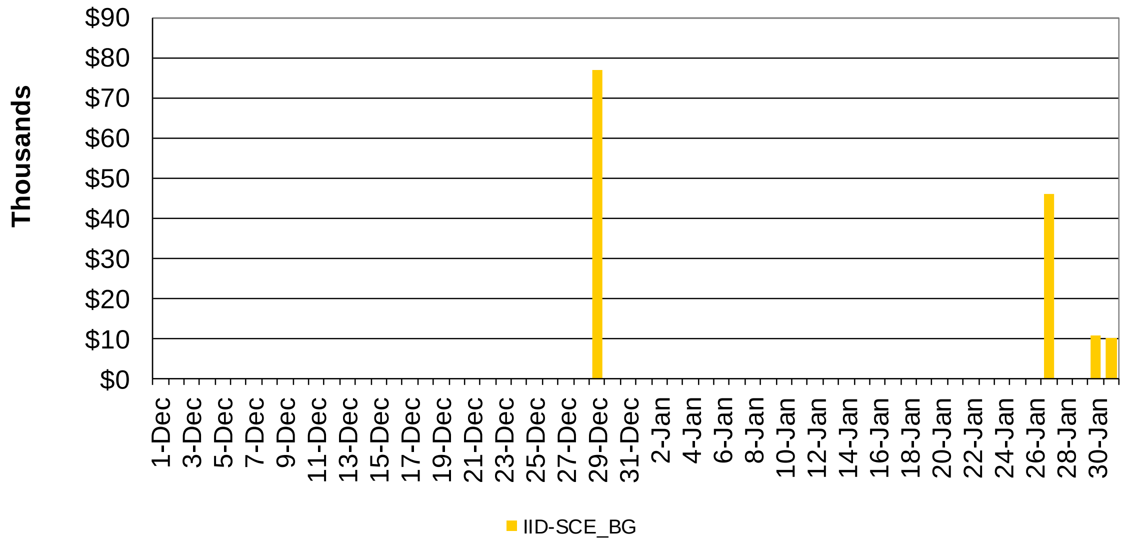
Figure 7: IFM Congestion Rents by Interties (Import)



Congestion Rents on Branch Groups

Figure 8 illustrates the IFM congestion rents on selected branch groups. Total congestion rents for branch groups edged down to $0.07 million in January from $0.08 million in December.

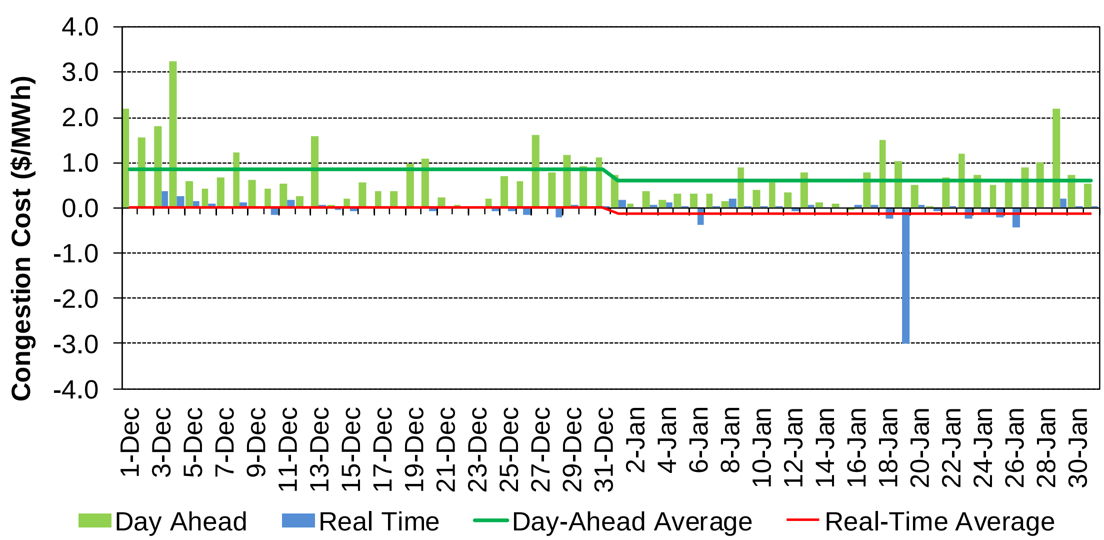
Figure 8: IFM Congestion Rents by Branch Group



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

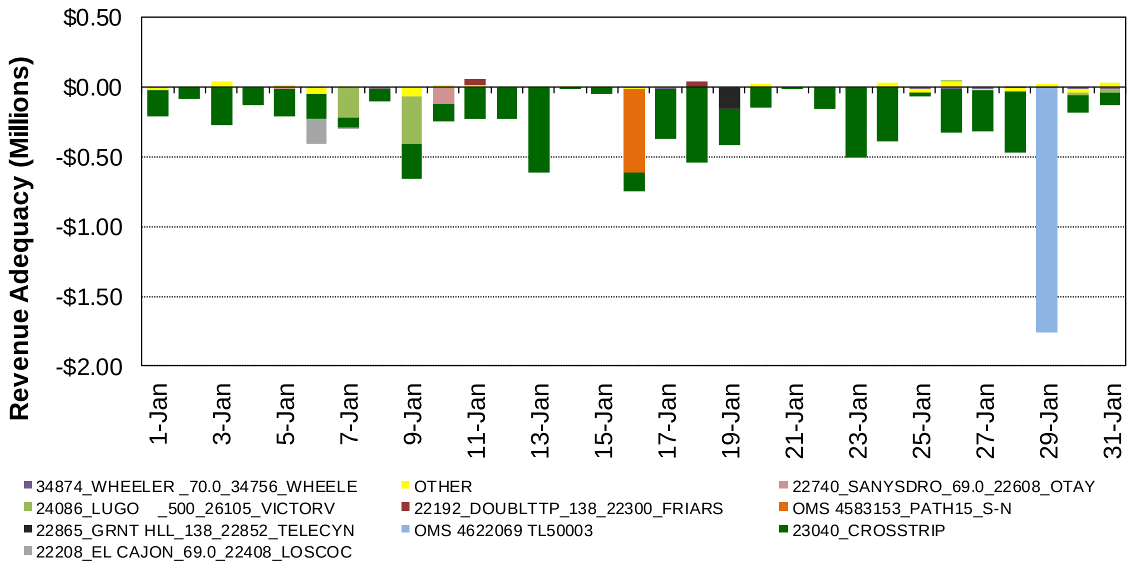


The average congestion cost per MWh of load served in the integrated forward market fell to $0.60/MWh in January from $0.84/MWh in December. The average congestion cost per load served in the real-time market went to -$0.12/MWh in January from $0.01/MWh in December.

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 January dropped to $325,911 from the average revenue deficit of $526,772 in December.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights

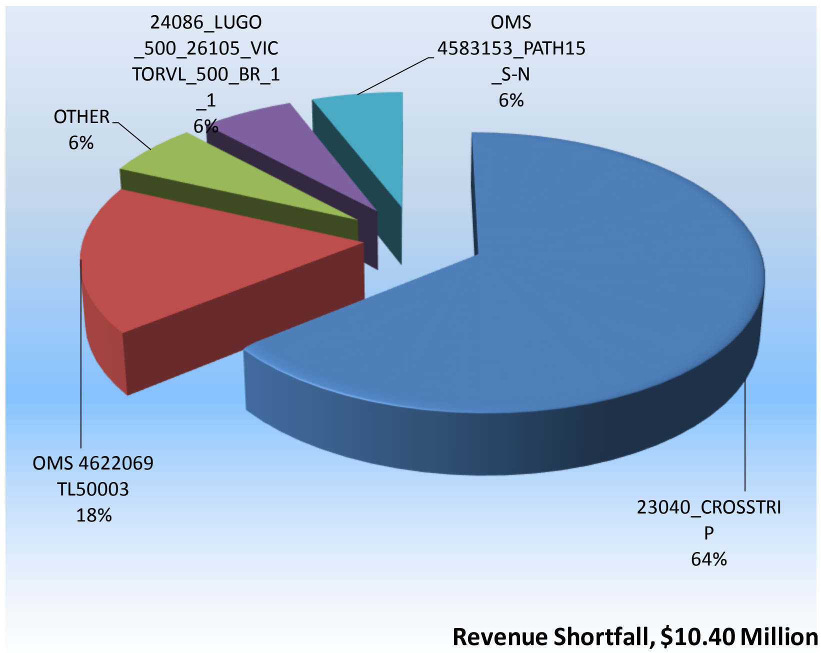


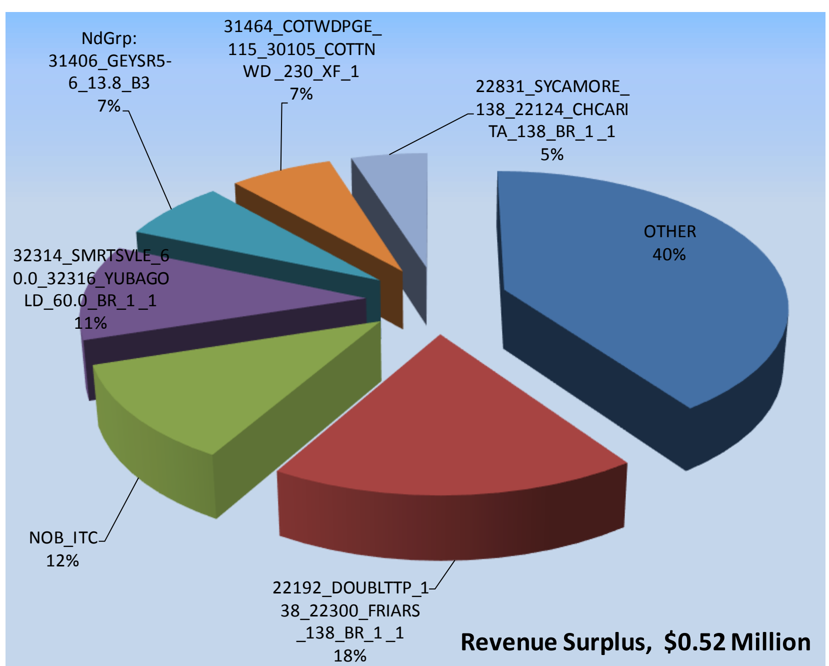
Overall, January experienced a CRR revenue deficit. Revenue shortfalls were observed throughout this month. The main reasons are shown below.

- The nomogram 23040_CROSSTRIP was binding in most days of this month, resulting in revenue shortfall of $6.48 million. This nomogram was enforced to avoid potential post-contingency flow in the underlying 230 kV line for the N-1 loss of the 500 kV line.
- The nomogram OMS 4622069 TL50003 was binding in one day, resulting in revenue shortfall of $1.76 million. This nomogram was created for the forced outage of Ocotillo-Suncrest 500 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 52.21 percent in January. Out of the total congestion rents, 2.61 percent was used to cover the cost of existing right exemptions. Net total congestion revenues in January were in deficit by $10.10 million, compared to the deficit of $16.33 million in December. The auction revenues credited to the balancing account for January were $6.51 million. As a result, the balancing account for January had a deficit of approximately $3.58 million, which will be allocated to measured demand.

Table 4: CRR Revenue Adequacy Statistics

IFM Congestion Rents	$11,332,074.55
Existing Right Exemptions	-$295,792.78
Available Congestion Revenues	$11,036,281.77
CRR Payments	$21,139,515.72
CRR Revenue Adequacy	-$10,103,233.94
Revenue Adequacy Ratio	52.21%
Annual Auction Revenues	$3,498,310.43
Monthly Auction Revenues	$3,014,927.29
CRR Settlement Rule	$10,037.79
Allocation to Measured Demand	-$3,579,958.44

Ancillary Services

IFM (Day-Ahead) Average Price

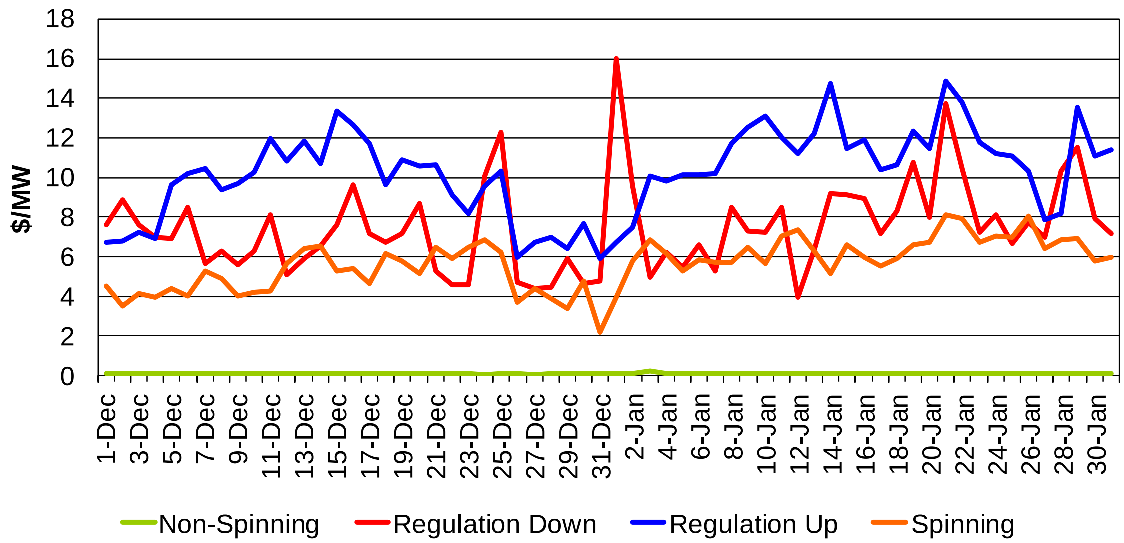
Table 5 shows the monthly IFM average ancillary service procurements and the monthly average prices. In January the monthly average procurement decreased for regulation up and regulation down.

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
Jan-17	331	386	743	746	$11.14	$8.23	$6.35	$0.09
Dec-16	337	403	717	736	$9.31	$6.72	$4.91	$0.08
Percent Change	-1.67%	-4.09%	3.54%	1.35%	19.68%	22.41%	29.33%	10.69%

The monthly average prices increased for all four types of ancillary services in January. Figure 12 shows the daily IFM average ancillary service prices. Regulation down prices were high on January 1 due to high opportunity cost of energy.

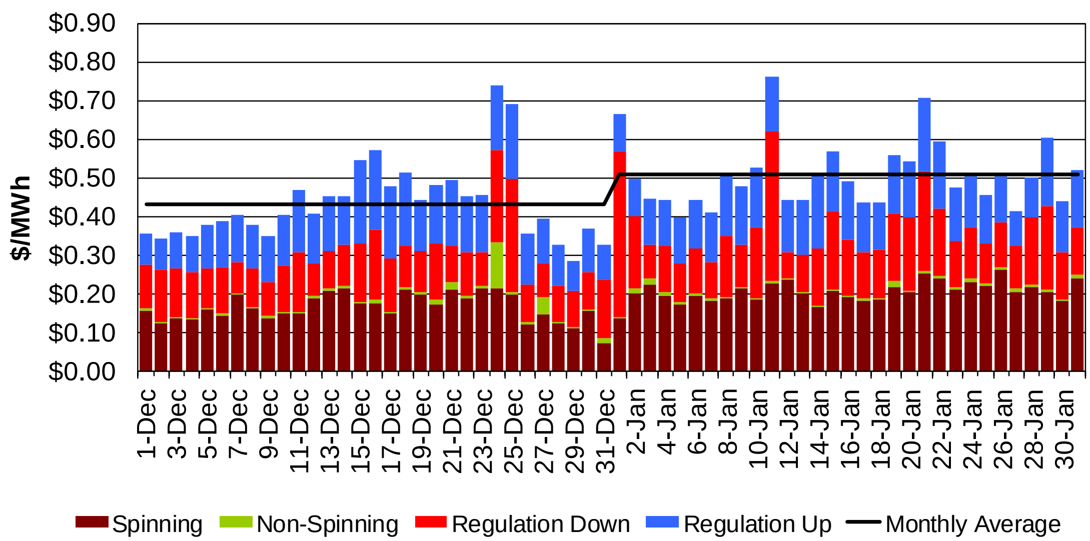
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load rose to $0.50/MWh in January from $0.43/MWh in December. The average cost was relatively high on January 1, driven by high regulation down prices in day-ahead market. It was also high on January 11 due to high regulation up and regulation down prices in real-time market. January 21 saw relatively high average cost due to high regulation up and regulation down prices in day-ahead market.

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



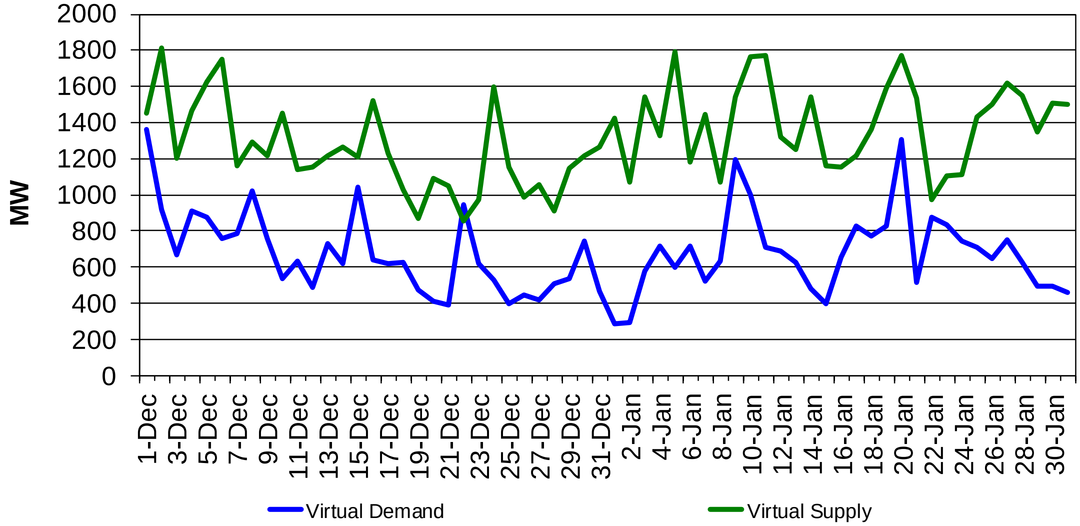
Scarcity Events

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. There was no scarcity event in January.

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 in most days of January.

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

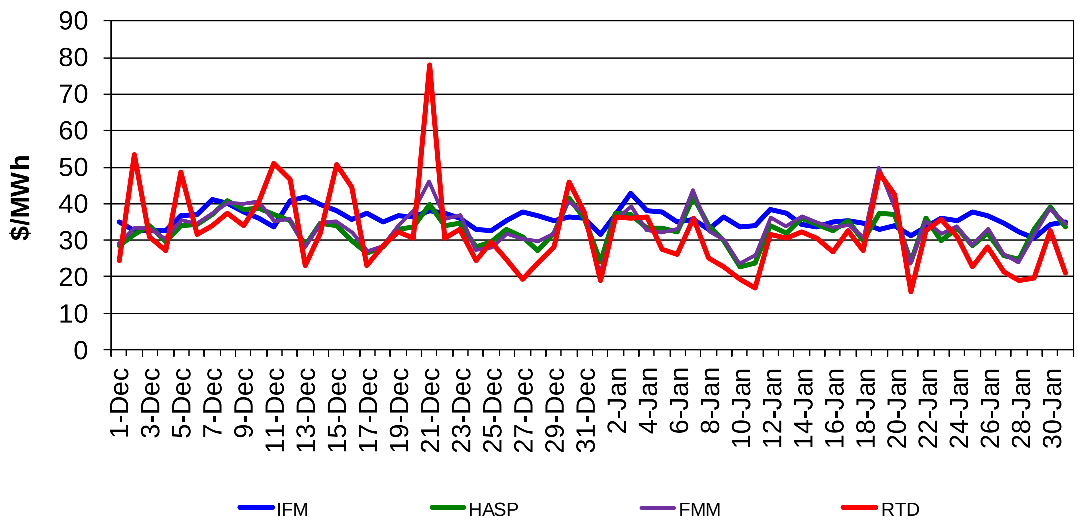
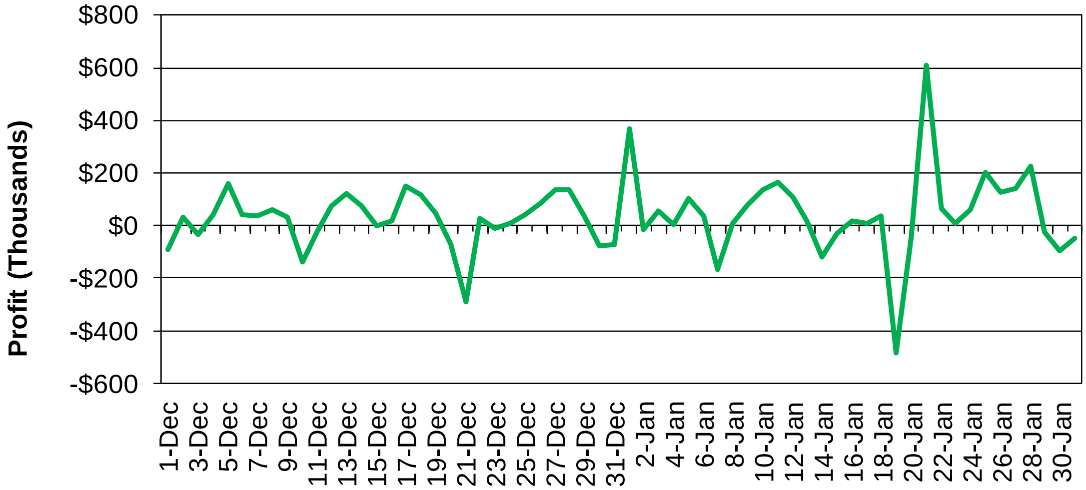


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding increased to $1.54 million in January from $0.68 million in December.

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 January. The majority of the curtailments was economic.

Figure 17: Renewable Curtailment by Reason

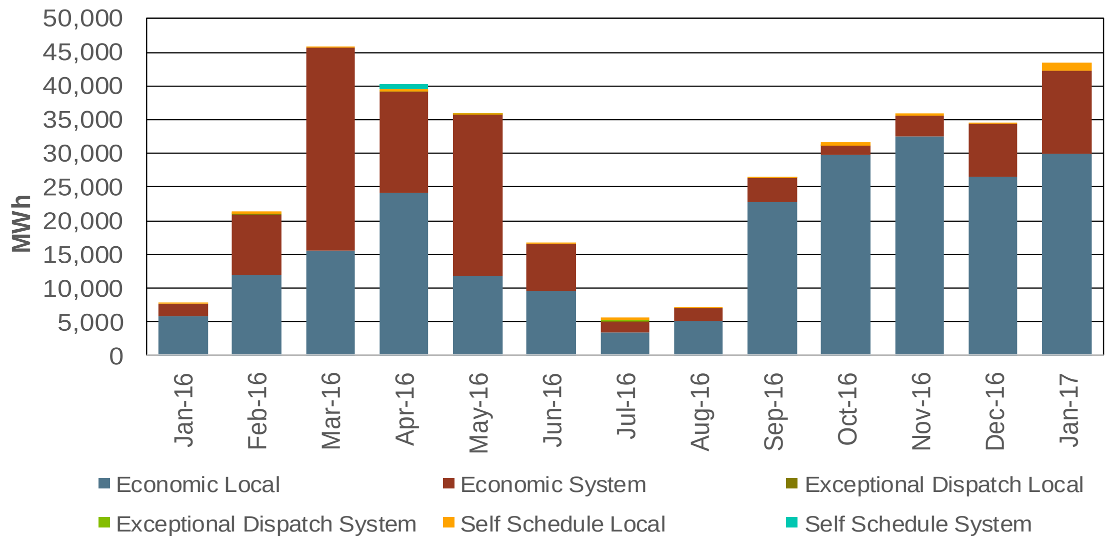
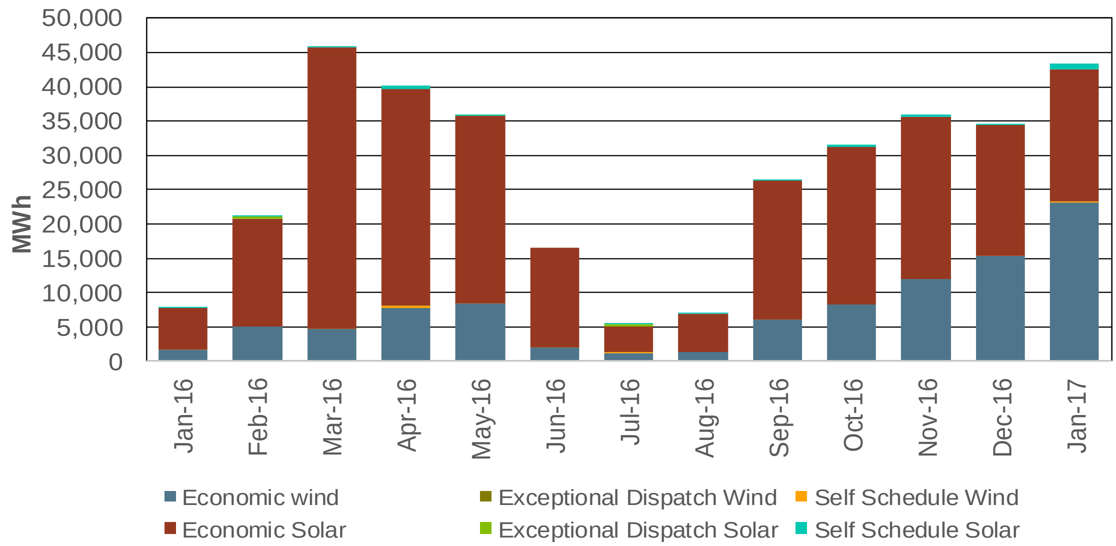


Figure 18: Renewable Curtailment by Resource Type



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 19 shows the daily uplift costs due to exceptional dispatch payments. The monthly uplift costs in January decreased to $164,983 from $168,052 in December. The exceptional dispatch cost was high on January 10, driven by the exceptional dispatches issued for planned transmission outage and constraint.

Figure 19: Exceptional Dispatch Uplift Costs

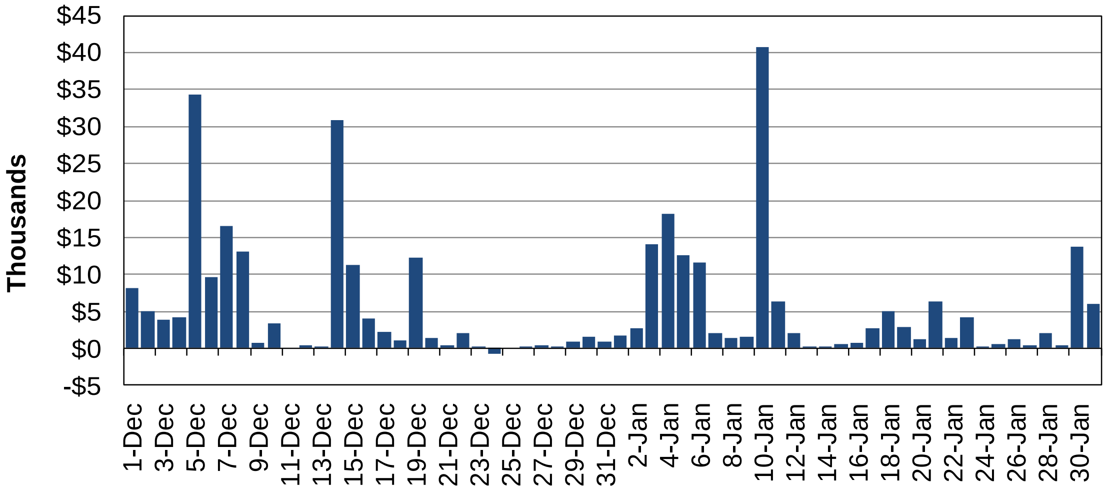


Figure 20 shows the allocation of bid cost recovery payment in the IFM, real-time unit commitment (RUC) and RTM markets. The total bid cost recovery for January inched up to $5.67 million from $5.51 million in December. Out of the total monthly bid cost recovery payment for the three markets in January, the IFM market contributed 13 percent, RTM contributed 48 percent, and RUC contributed 39 percent of the total bid cost recovery payment.

Figure 20: Bid Cost Recovery Allocation

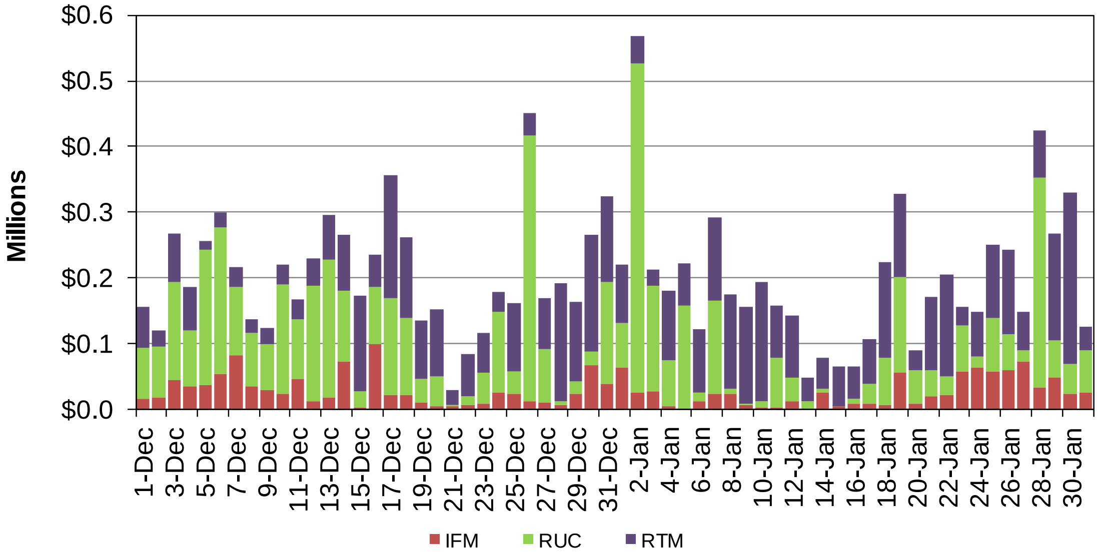


Figure 21 and Figure 22 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 21: Bid Cost Recovery Allocation by LCR

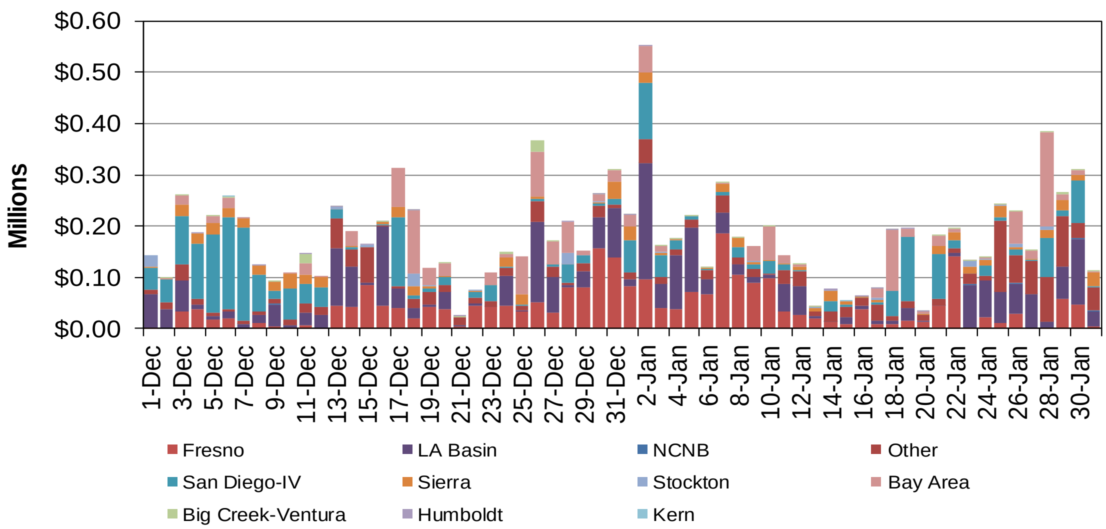


Figure 22: Monthly Bid Cost Recovery Allocation by LCR

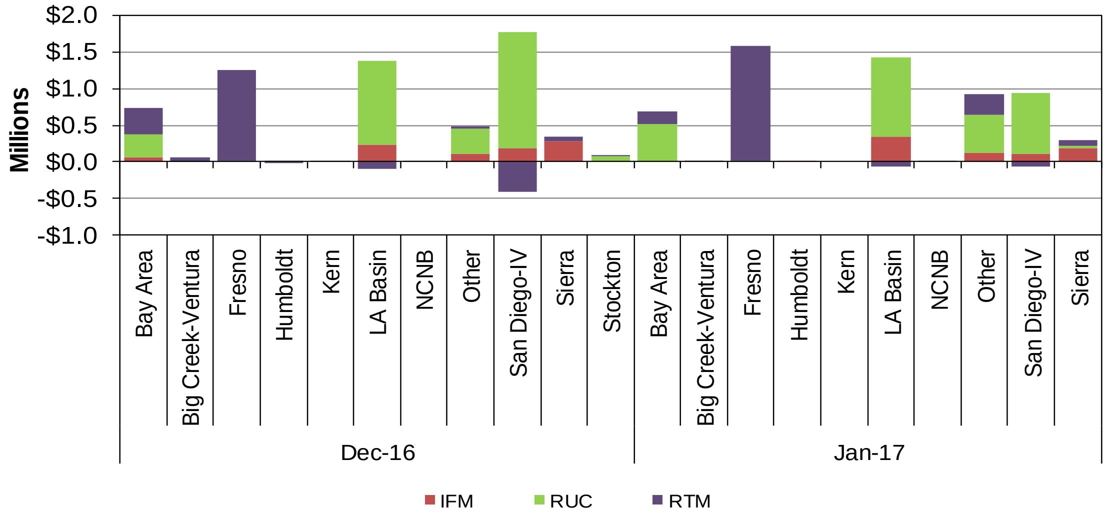


Figure 23 and Figure 24 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 23: Bid Cost Recovery Allocation by UDC

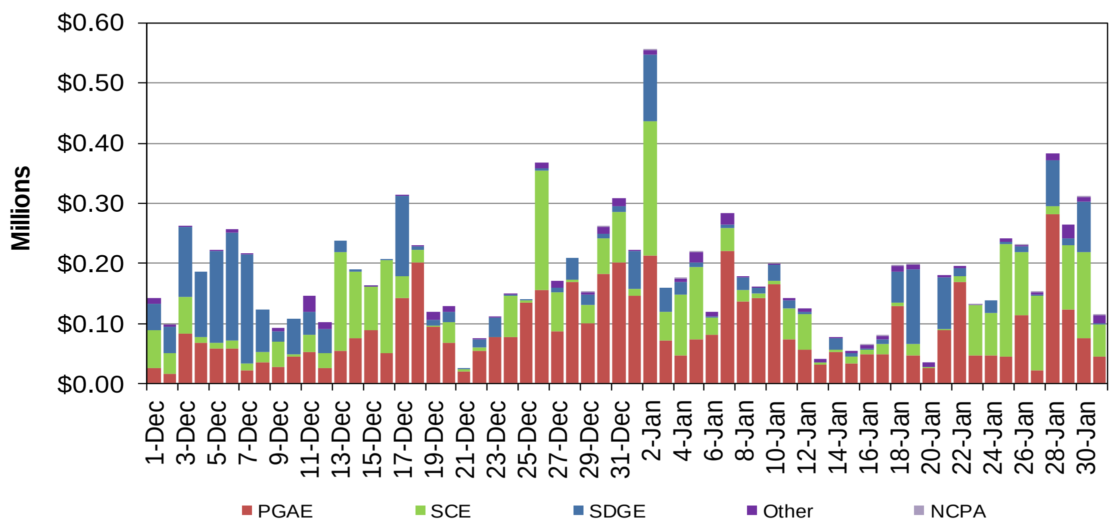


Figure 24: Monthly Bid Cost Recovery Allocation by UDC

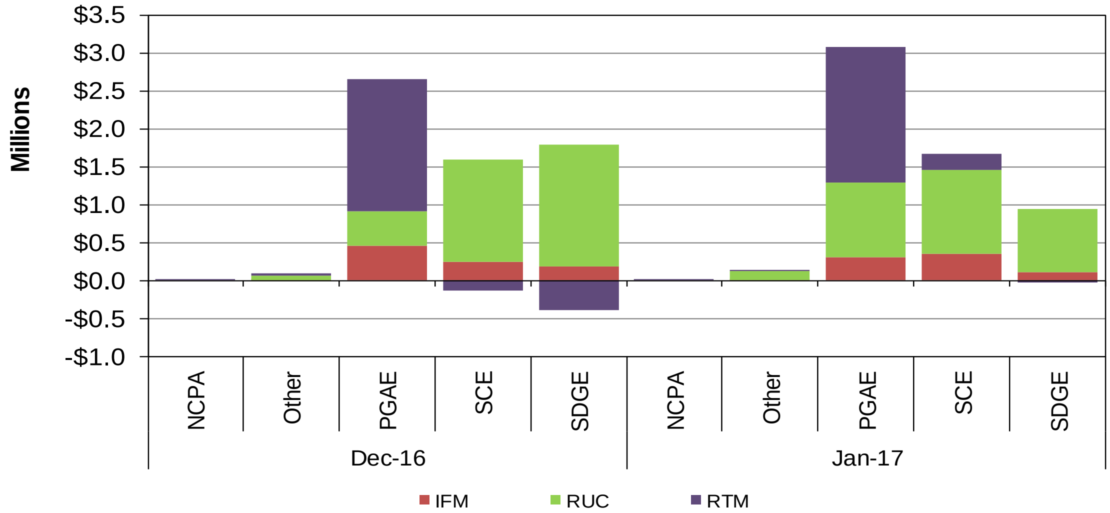


Figure 25 shows the cost related to BCR by cost type in RUC, which in January was mainly driven by minimum load cost (MLC) and start-up cost (SUC).

Figure 25: Cost in RUC

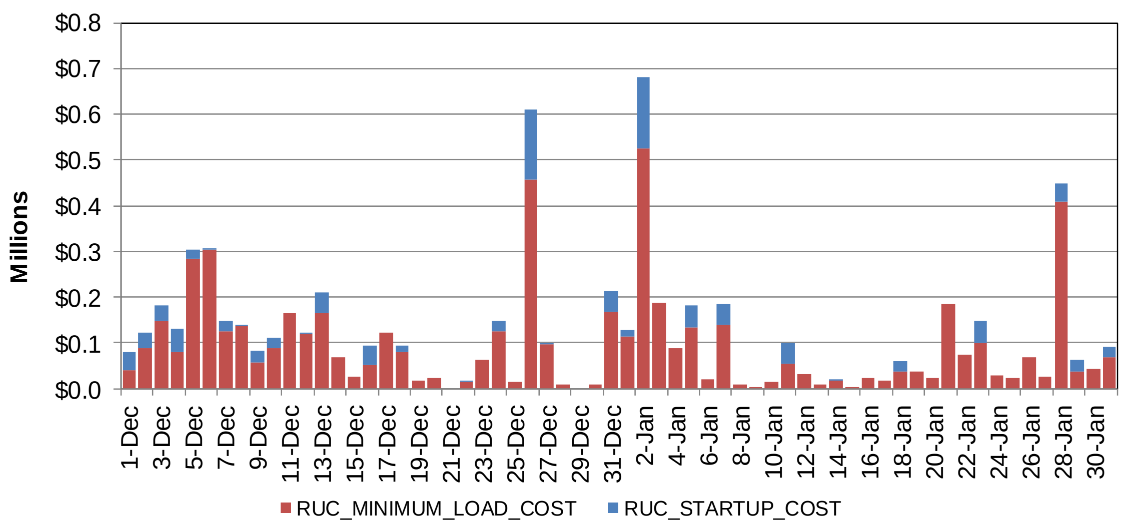


Figure 26 and Figure 27 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 26: Cost in RUC by LCR

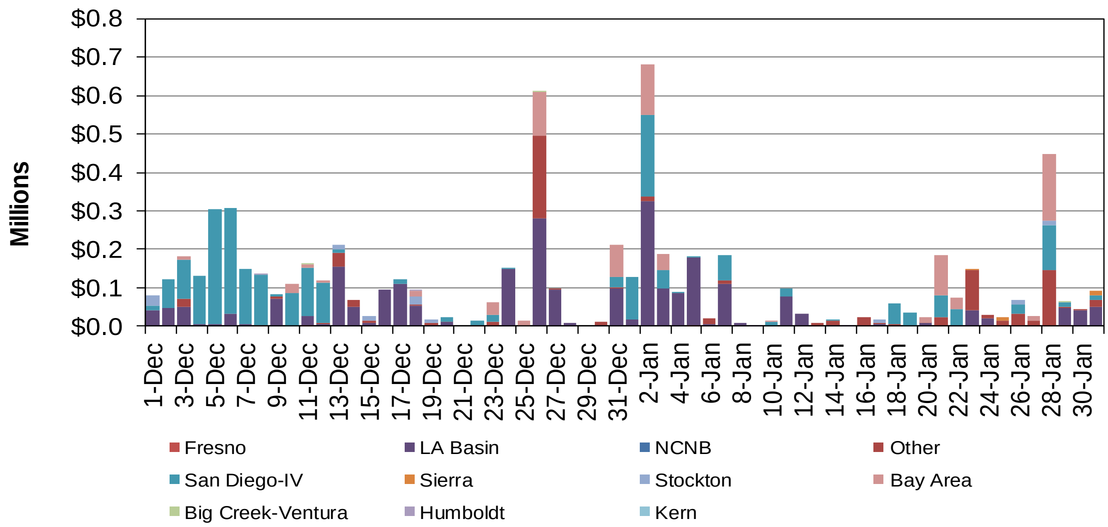


Figure 27: Monthly Cost in RUC by LCR

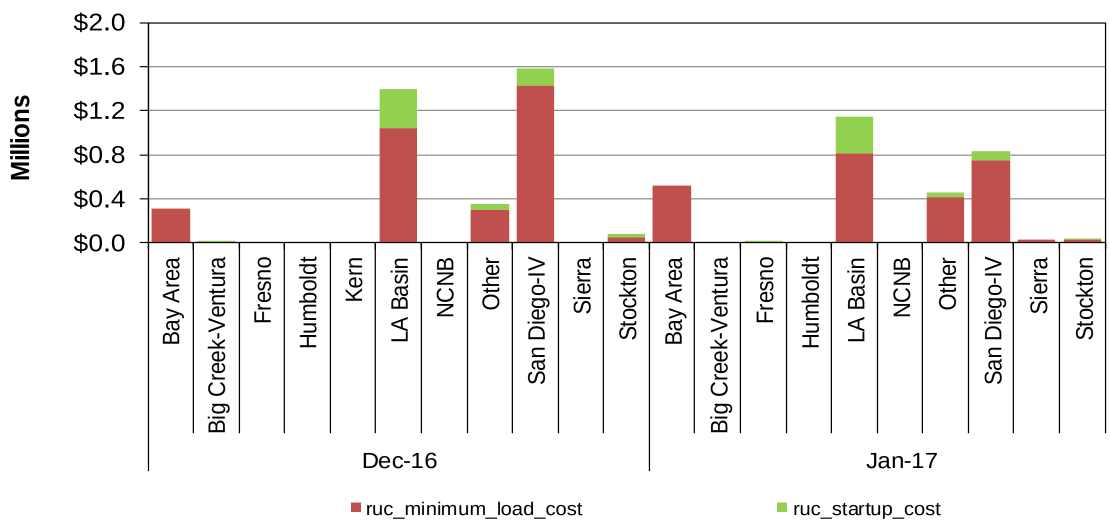


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 28: Cost in RUC by UDC

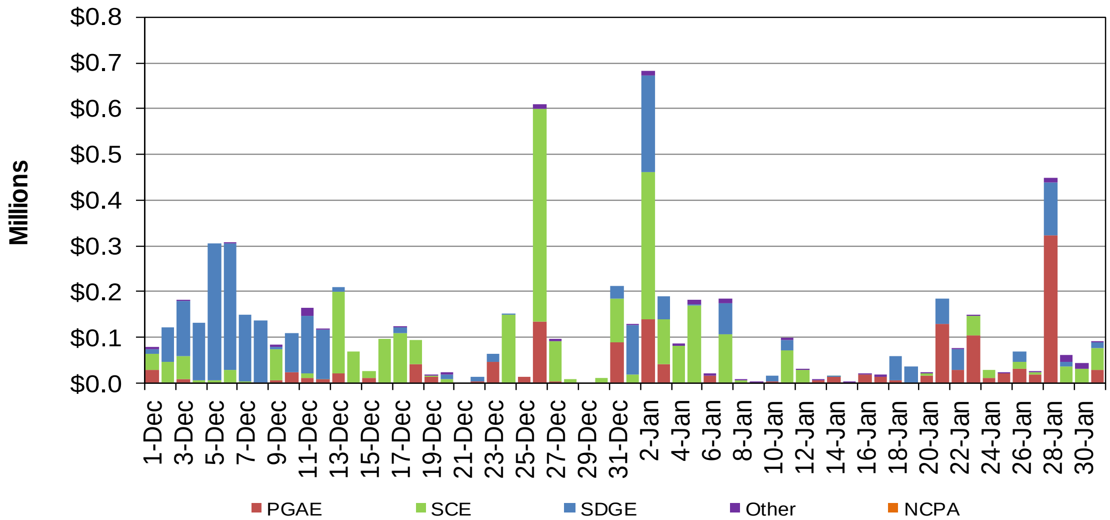


Figure 29: Monthly Cost in RUC by UDC

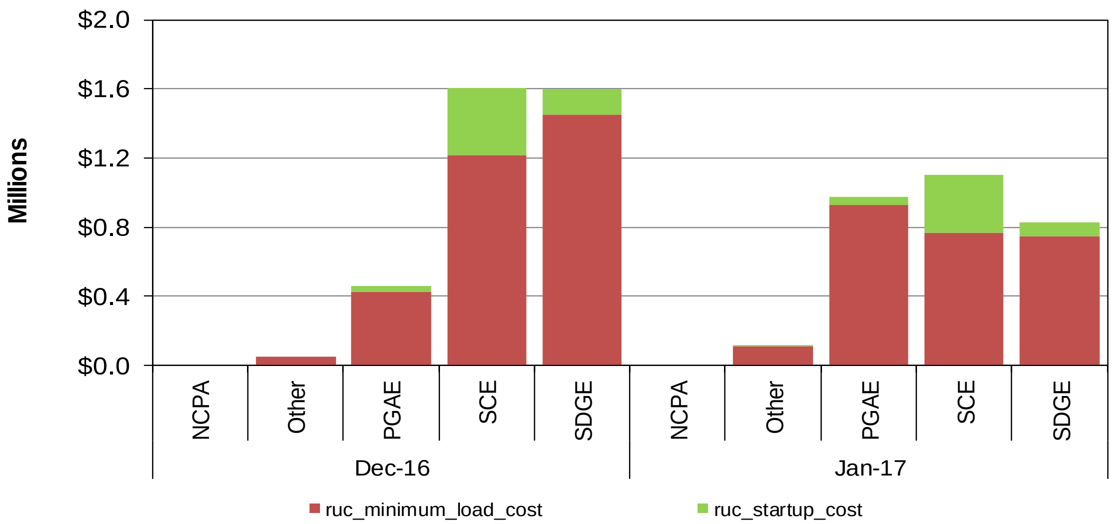


Figure 30 shows the cost related to BCR in real time by cost type. Minimum load cost and pump cost contributed mostly to the real time cost in January.

Figure 30: Cost in Real Time

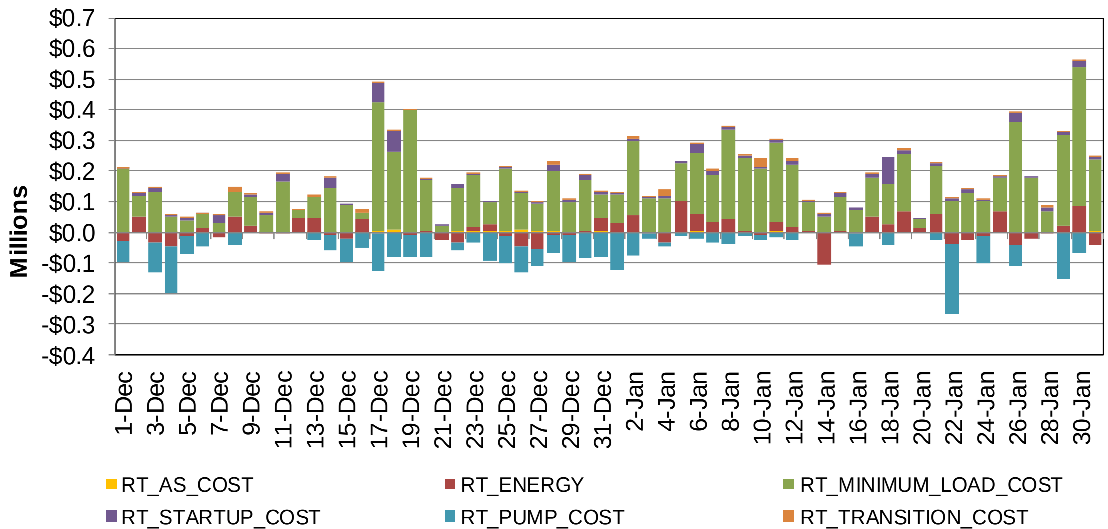


Figure 31 and Figure 32 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 31: Cost in Real Time by LCR

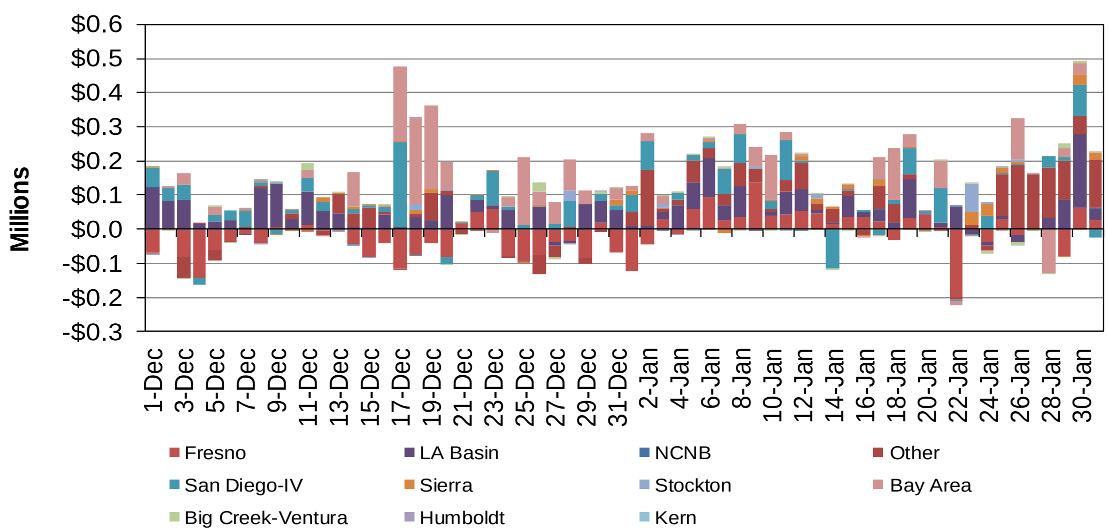


Figure 32: Monthly Cost in Real Time by LCR

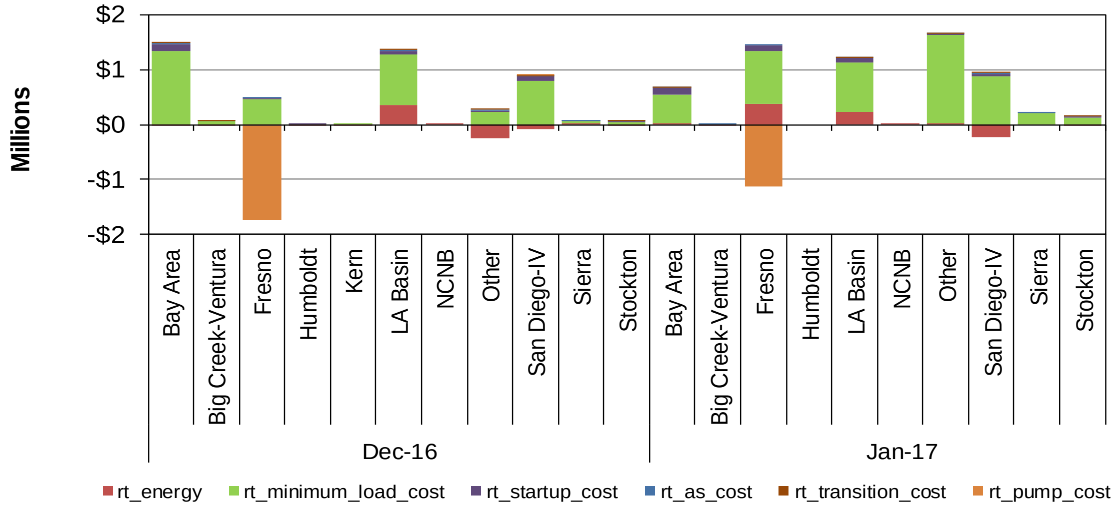


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 33: Cost in Real Time by UDC

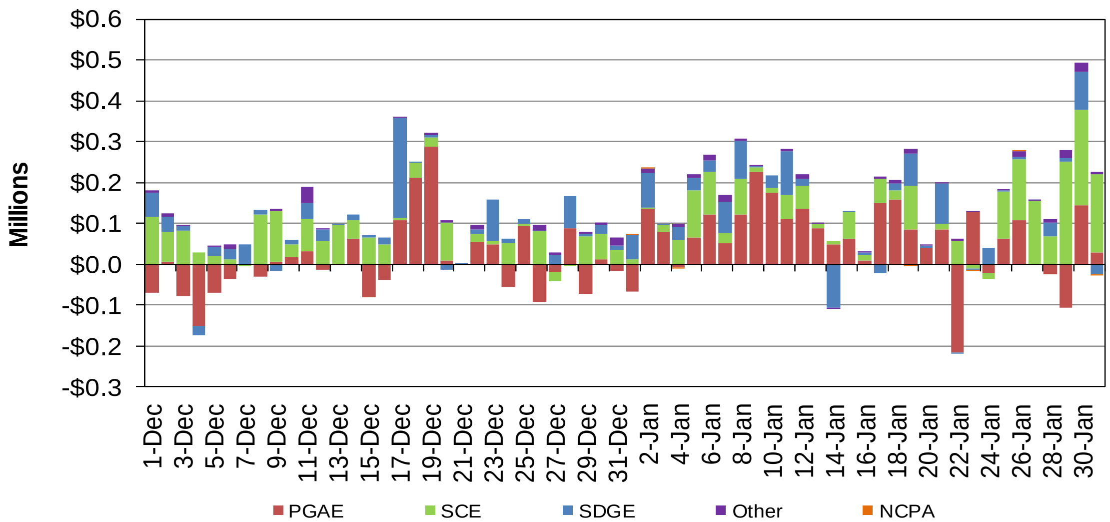


Figure 34: Monthly Cost in Real Time by UDC

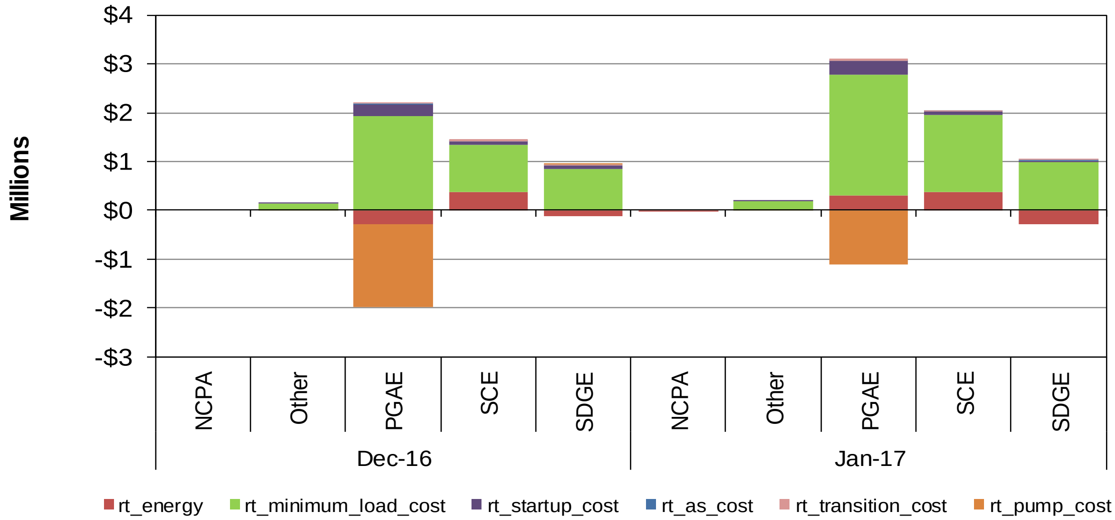


Figure 35 shows the cost related to BCR in IFM by cost type. Minimum Load cost and energy cost contributed largely to the cost in IFM in January.

Figure 35: Cost in IFM

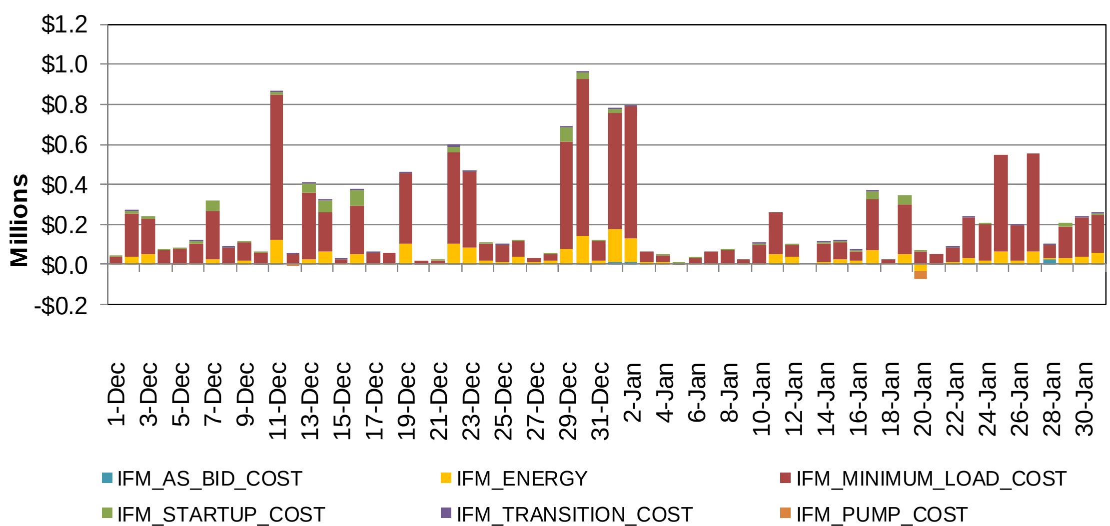


Figure 36 and Figure 37 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 36: Cost in IFM by LCR

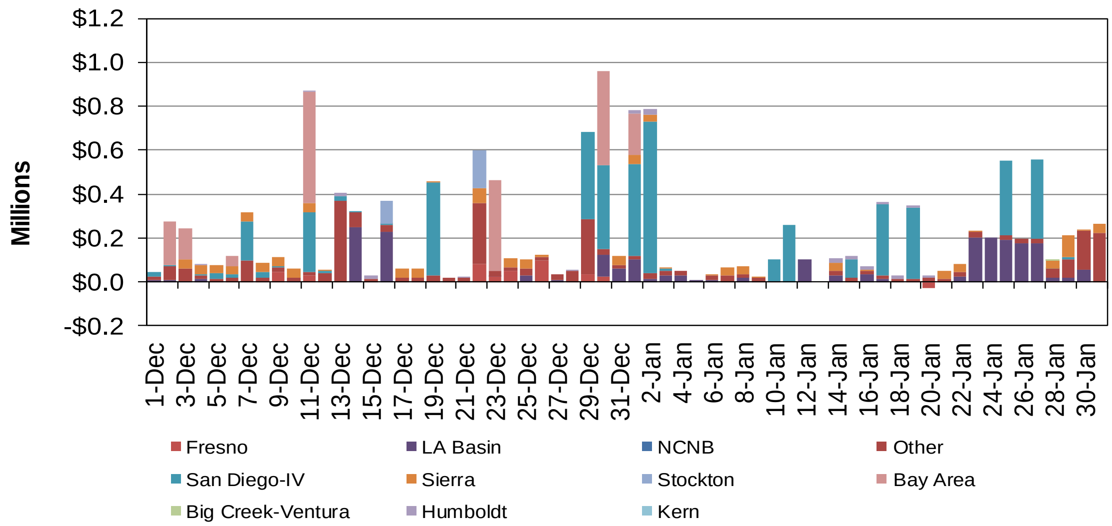


Figure 37: Monthly Cost in IFM by LCR

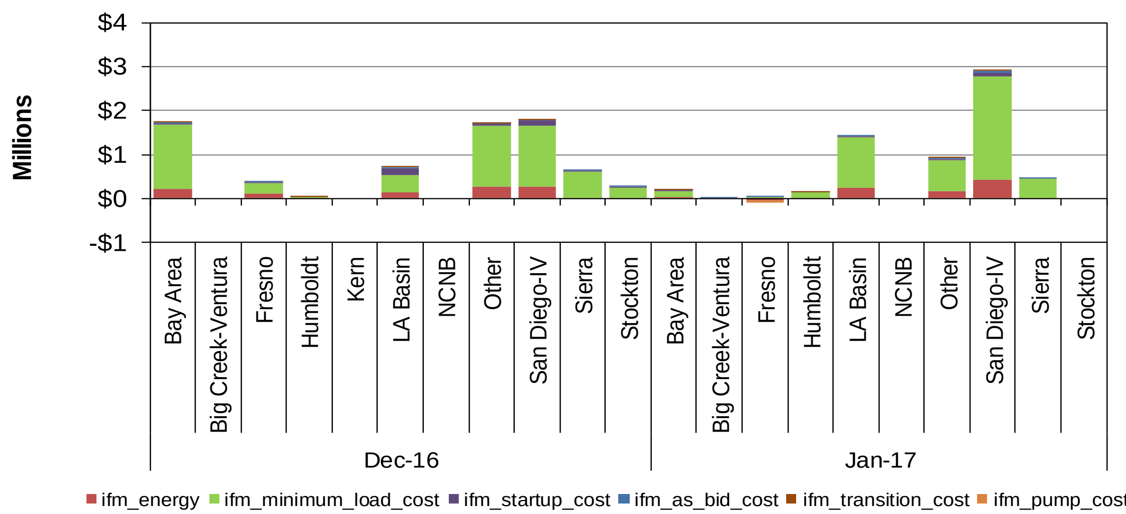


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 38: Cost in IFM by UDC

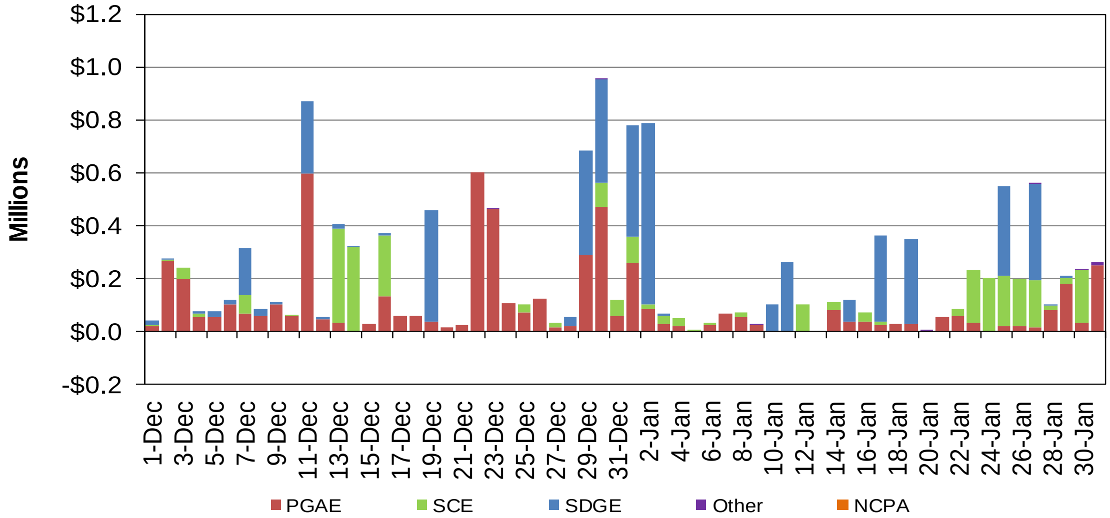
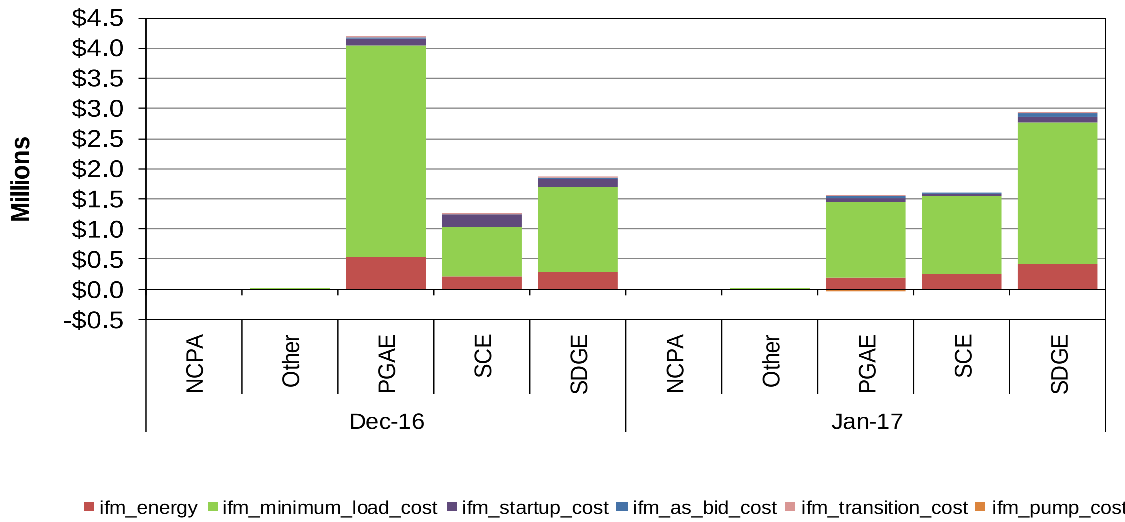


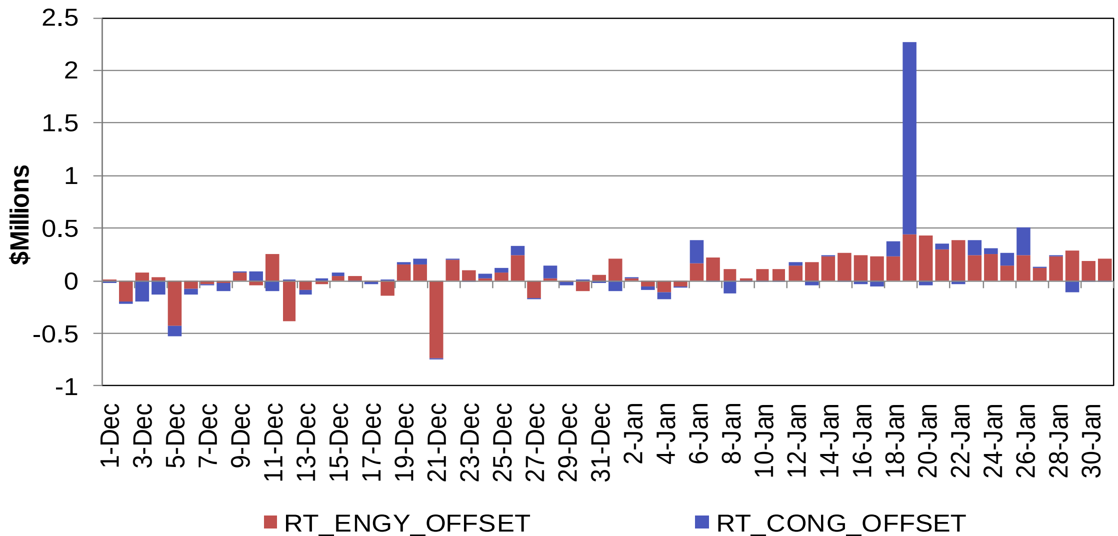
Figure 39: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 40 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost increased to $5.55 million in January from -$0.86 million in December. Real-time congestion offset cost rose to $2.23 million in January from -$0.29 million in December. The real-time congestion offset cost was high on January 19, driven by the transmission congestion in real-time market.

Figure 40: 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 35 market disruptions in January. 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.

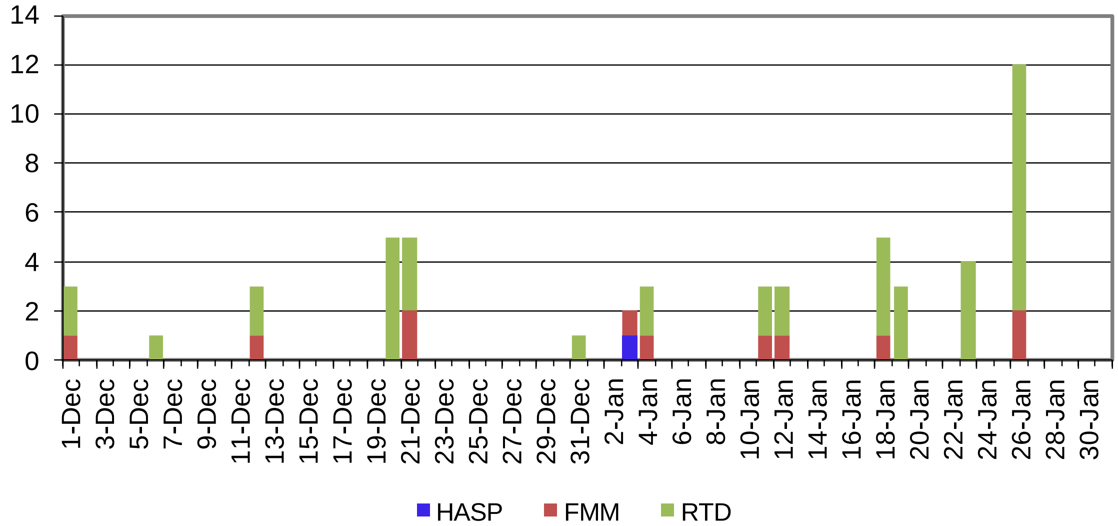
Table 6: Summary of Market Disruption

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	2	0
FMM Interval 4	4	0
Real-Time Dispatch	27	0

Figure 41 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On January 26, two FMM and ten RTD disruptions occurred due to application problem.

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

Figure 41: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 42 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 January rose to 58,848 MWh from 35,251 MWh in January.

Figure 42: Total Exceptional Dispatch Volume (MWh) by Market Type

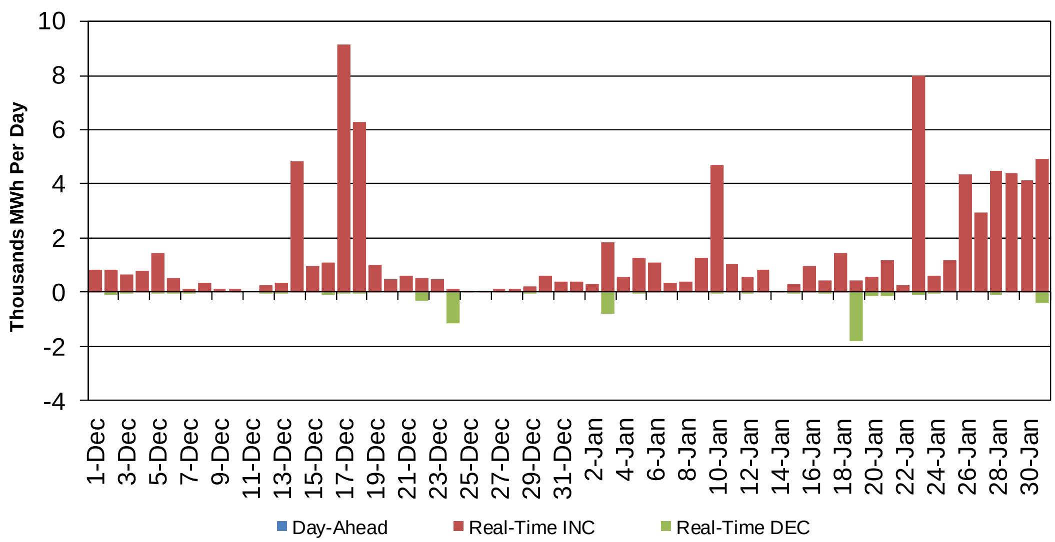


Figure 43 shows the volume of the exceptional dispatch broken out by reason.[3] The majority of the exceptional dispatch volumes in January were driven by voltage support (35 percent), operating procedure number and constraint (17 percent), planned transmission outage and constraint (13 percent), and software limitation (13 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 43: Total Exceptional Dispatch Volume (MWh) by Reason

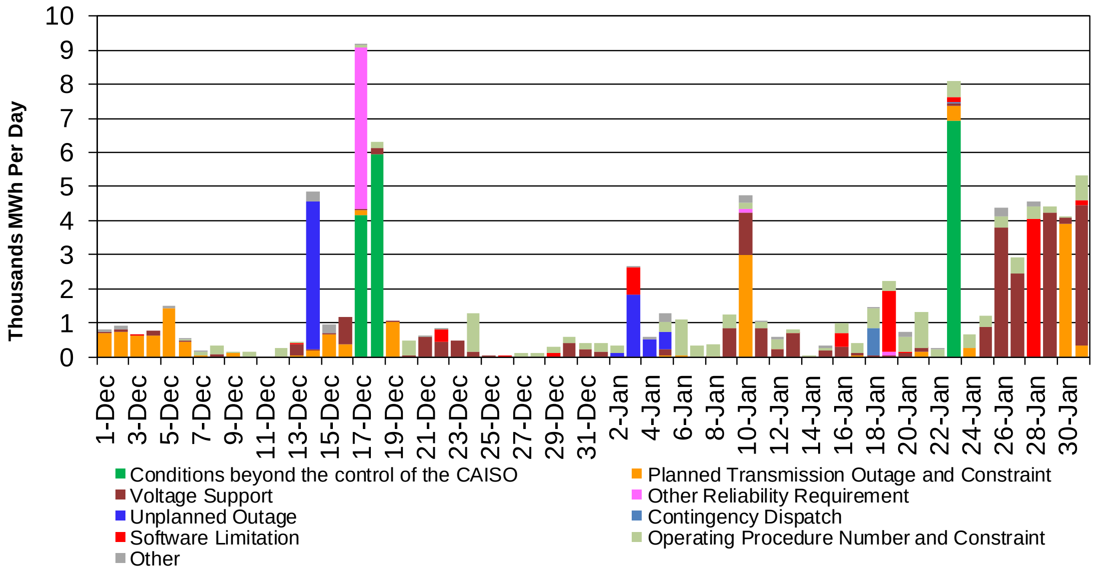
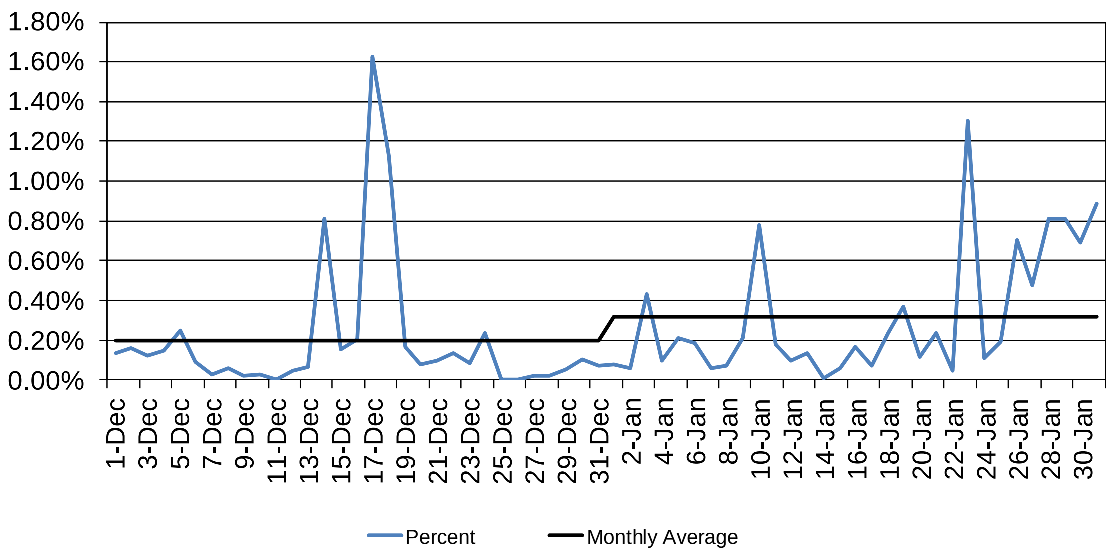


Figure 44 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage increased to 0.32 percent in January from 0.20 percent in December.

Figure 44: 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 45 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 January 6, the prices for NEVP and PACW were elevated by higher load forecast and generation outage.

Figure 45: EIM Simple Average LAP Prices (All Hours) in FMM

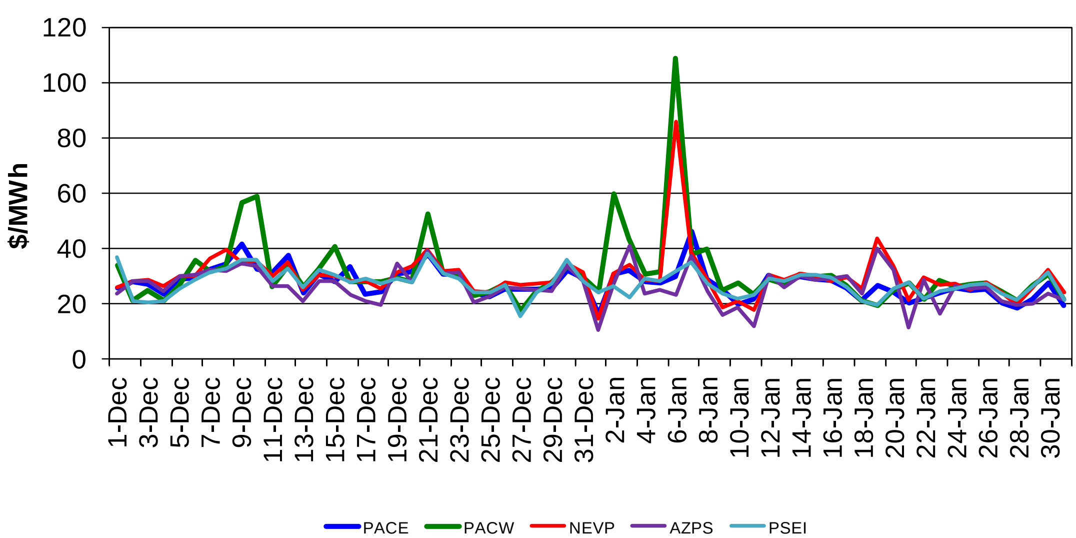


Figure 46 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS and PSEI for all hours in RTD. On January 6 and 26, the price for NEVP was elevated due to higher load forecast and generation outage. On January 19 and 20, the prices for NEVP and PACE were relatively high, driven by Malin outage, higher load forecast, and renewable deviation.

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

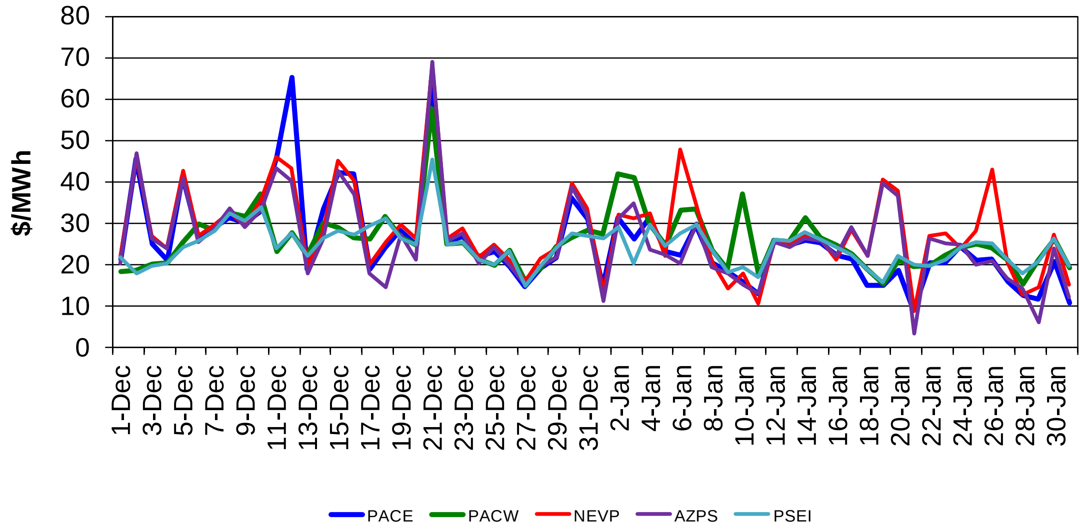


Figure 47 shows the daily price frequency for prices above $250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh increased to 0.23 percent in January from 0.19 percent in December. The cumulative frequency of negative prices rose to 2.53 percent in January from 1.33 percent in December.

Figure 47: Daily Frequency of EIM LAP Positive Price Spikes and Negative Prices in FMM

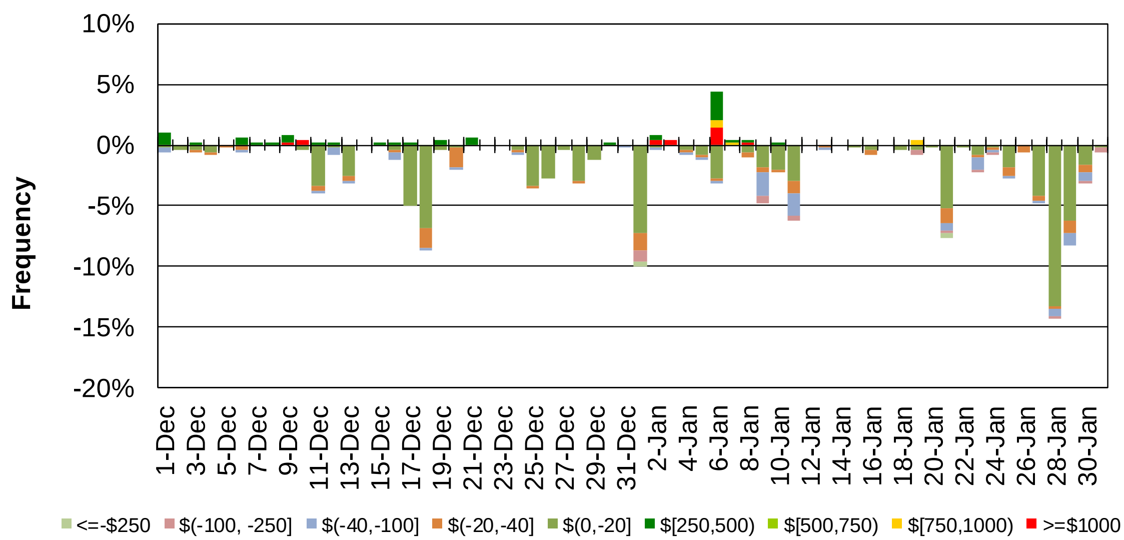


Figure 48 shows the daily price frequency for prices above $250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS and PSEI. The cumulative frequency of prices above $250/MWh fell to 0.19 percent in January from 0.47 percent in December. The cumulative frequency of negative prices increased to 5.69 percent in January from 3.64 percent in December.

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

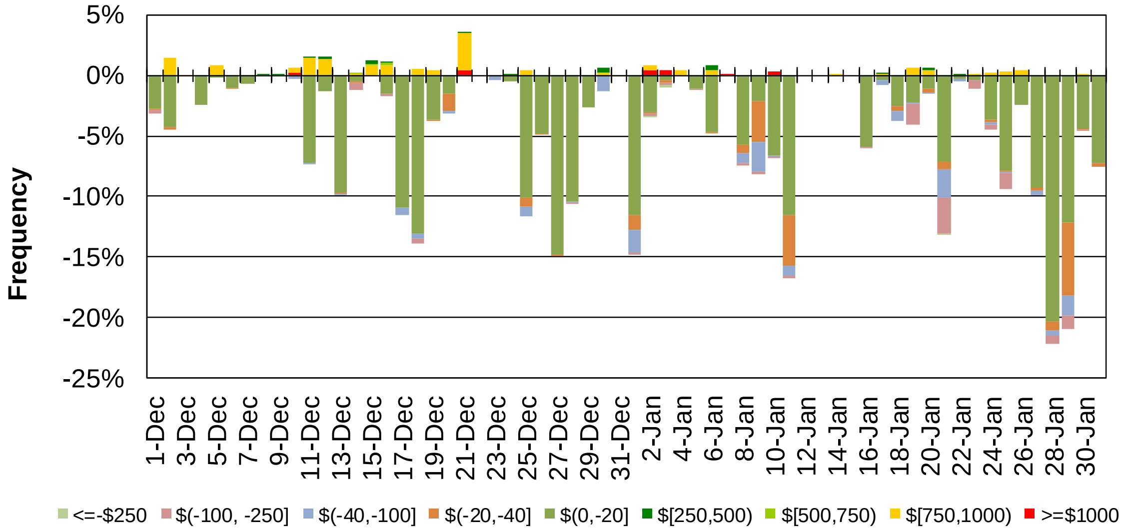


Figure 49 shows the daily volume of EIM transfer between ISO and PacifiCorp in FMM. The EIM transfer from PacifiCorp to ISO decreased this month.

Figure 50 shows the daily volume of EIM transfer between PACE and PACW in FMM. The EIM transfer from PACE to PACW increased in January

Figure 49: EIM Transfer between CAISO and PAC in FMM

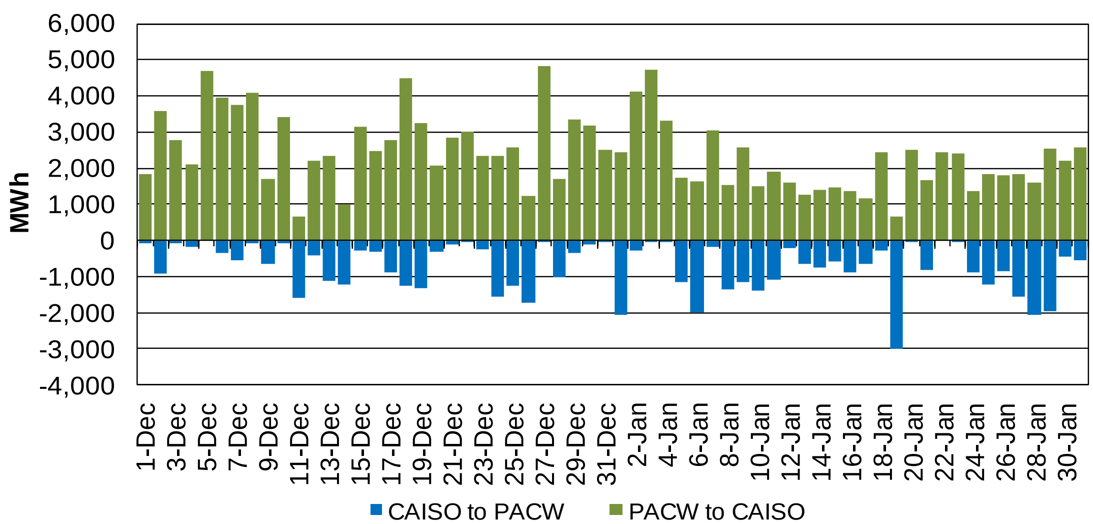


Figure 50: EIM Transfer between PACE and PACW in FMM

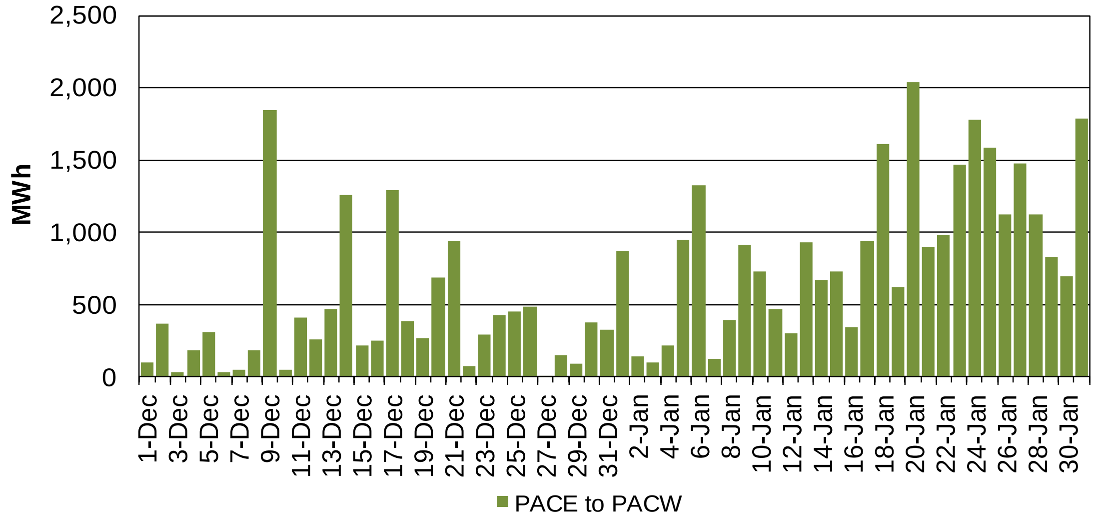


Figure 51 shows the daily volume of EIM transfer between CAISO and NEVP in FMM. The EIM transfer from NEVP to ISO increased in January compared with December. Figure 52 shows the daily volume of EIM transfer between PACE and NEVP in FMM. The EIM transfer from PACE to NEVP increased in the second half of this month.

Figure 51: EIM Transfer between CAISO and NEVP in FMM

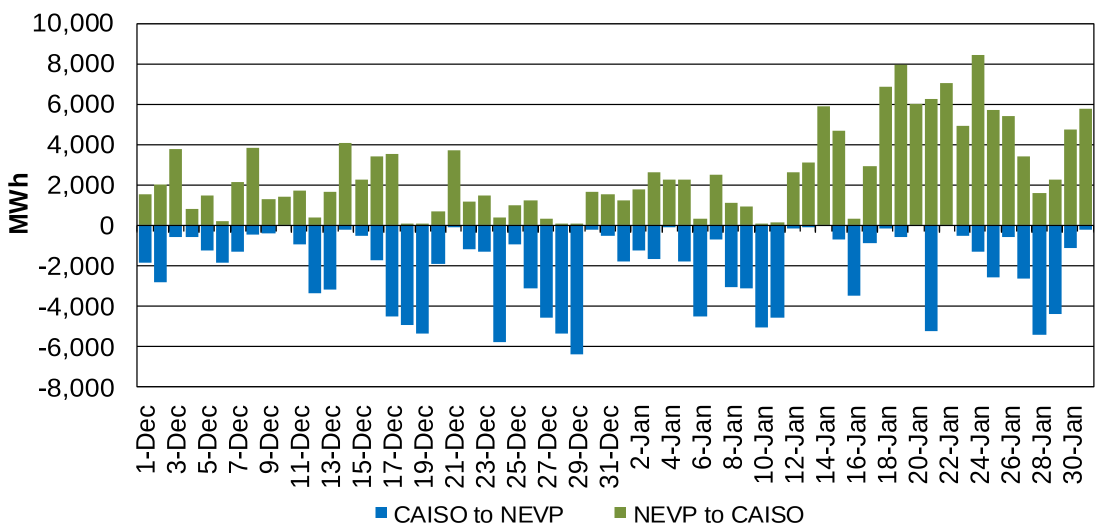


Figure 52: EIM Transfer between PACE and NEVP in FMM

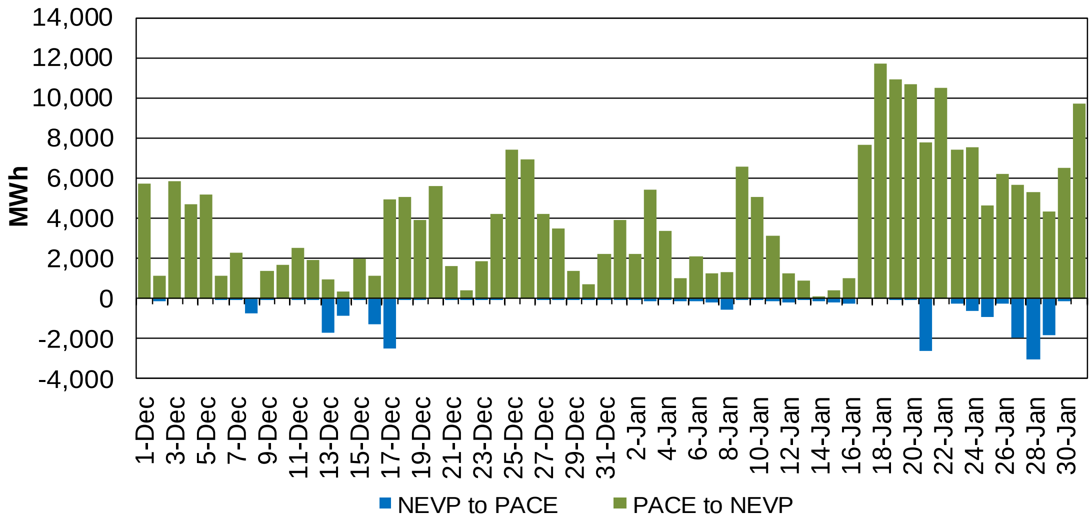


Figure 53 shows the daily volume of EIM transfer between ISO and AZPS in FMM. The EIM transfer from AZPS to ISO dropped in the second half of January. Figure 54 shows the daily volume of EIM transfer between PACE and AZPS in FMM. The EIM transfer from AZPS to PACE rose in January.

Figure 53: EIM Transfer between CAISO and AZPS in FMM

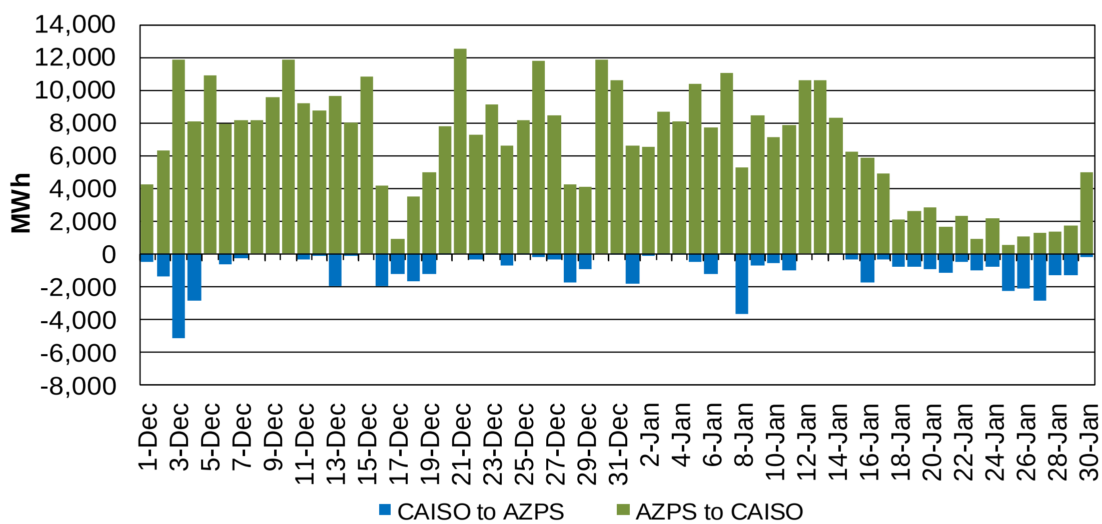


Figure 54: EIM Transfer between PACE and AZPS in FMM

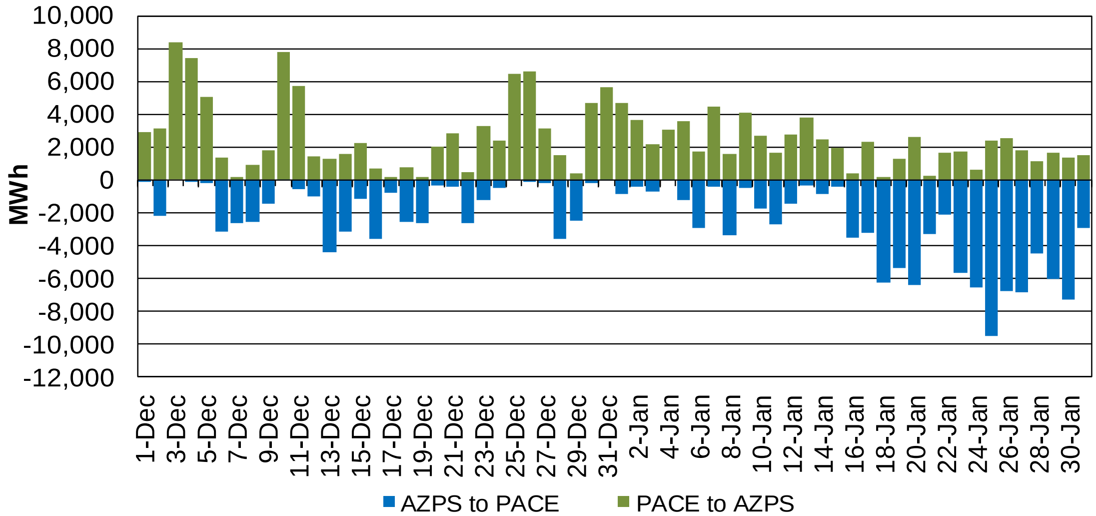


Figure 55 shows the daily volume of EIM transfer between PACW and PSEI in FMM. The EIM transfer from PSEI to PACW decreased this month compared with December.

Figure 55: EIM Transfer between PACW and PSEI in FMM

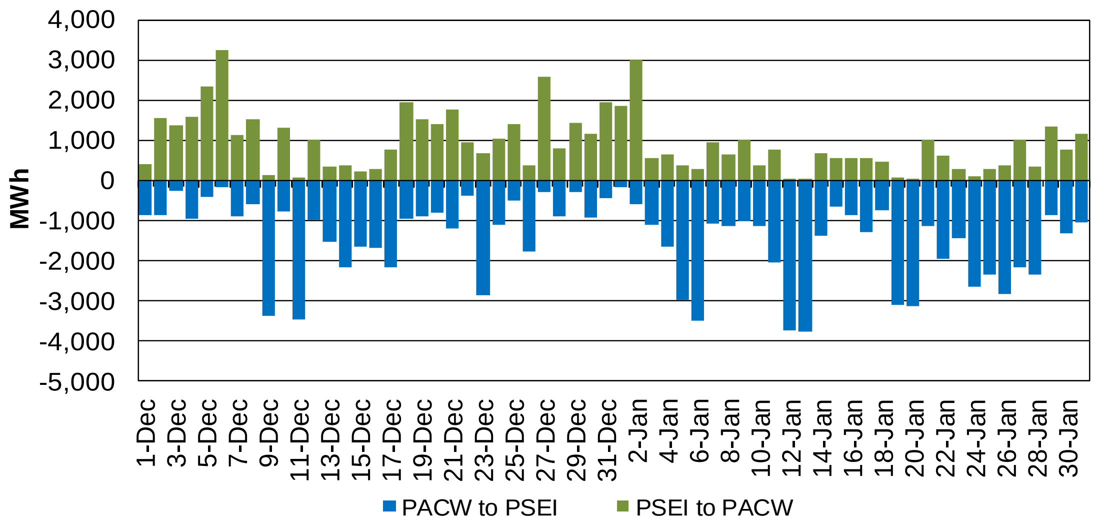


Figure 56 shows the daily volume of EIM transfer between ISO and PacifiCorp in RTD. Figure 57 shows the daily volume of EIM transfer between PACE and PACW in RTD. The EIM transfer from PACE to PACW trended upward this month.

Figure 56: EIM Transfer between CAISO and PAC in RTD

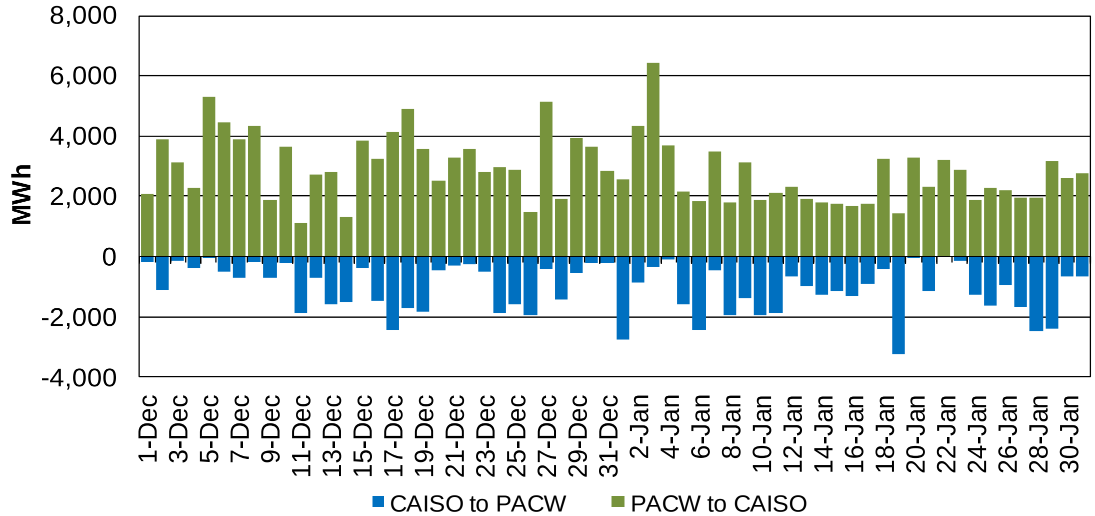


Figure 57: EIM Transfer between PACE and PACW in RTD

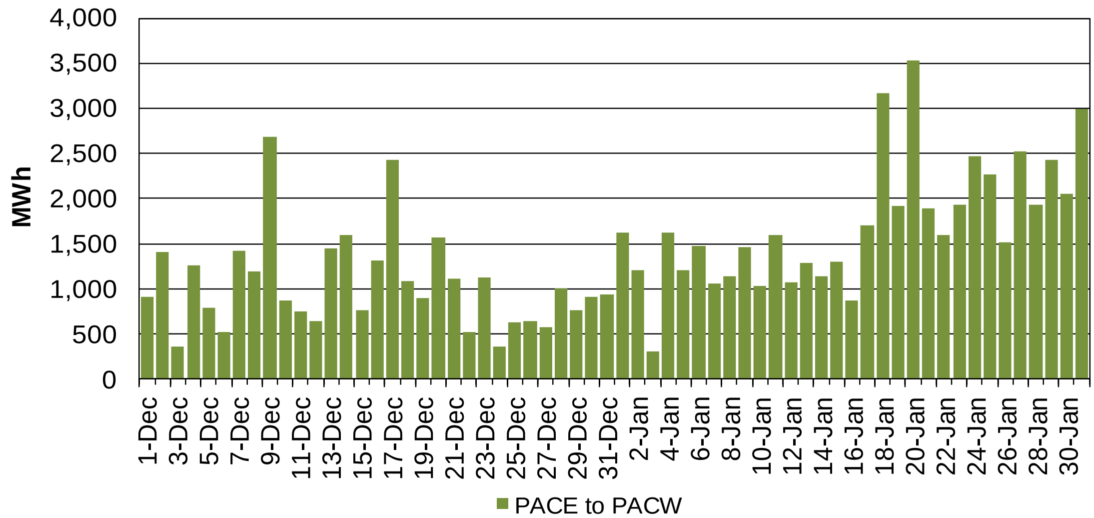


Figure 58 shows the daily EIM transfer volume between ISO and NEVP in RTD. Figure 59 shows the daily volume EIM transfer between PACE and NEVP in RTD. The EIM transfer from PACE to NEVP increased in the second half of this month.

Figure 58: EIM Transfer between CAISO and NEVP in RTD

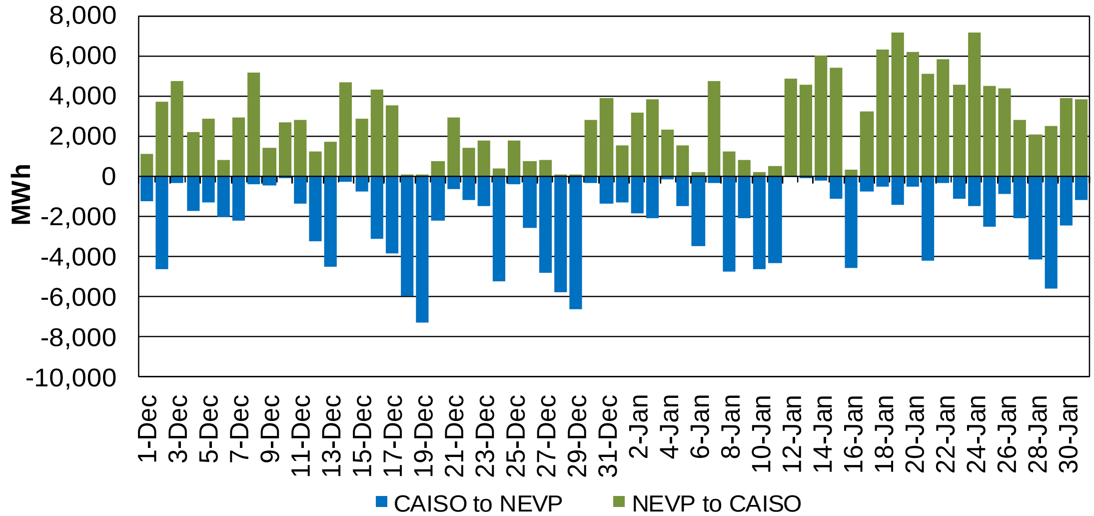


Figure 59: EIM Transfer between PACE and NEVP in RTD

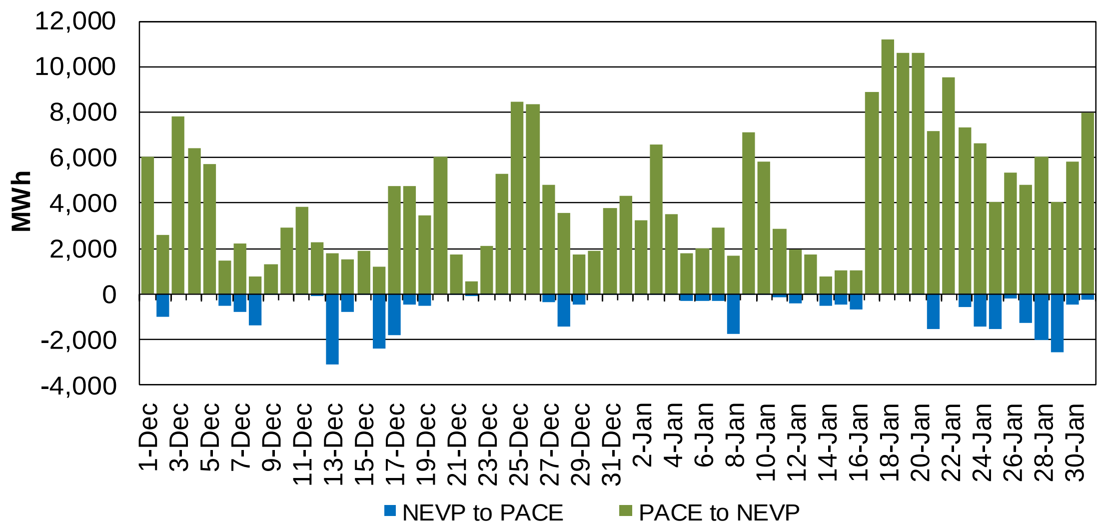


Figure 60 shows the daily volume EIM transfer between the ISO and AZPS in RTD. The EIM transfer from AZPS to ISO fell in the second half of this month. Figure 61 shows the daily volume EIM transfer between the PACE and AZPS in RTD. The EIM transfer from AZPS to PACE increased in January.

Figure 60: EIM Transfer between CAISO and AZPS in RTD

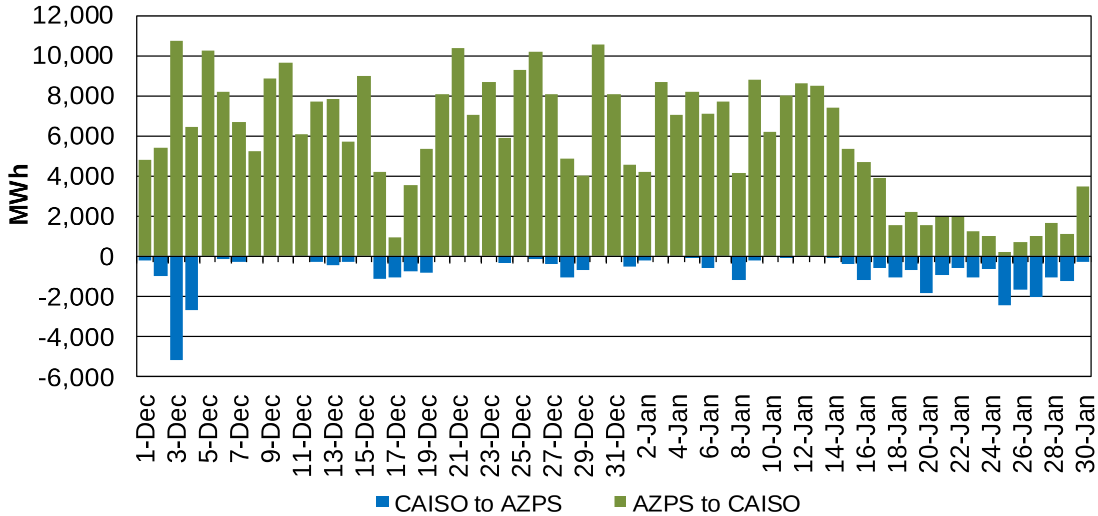


Figure 61: EIM Transfer between PACE and AZPS in RTD

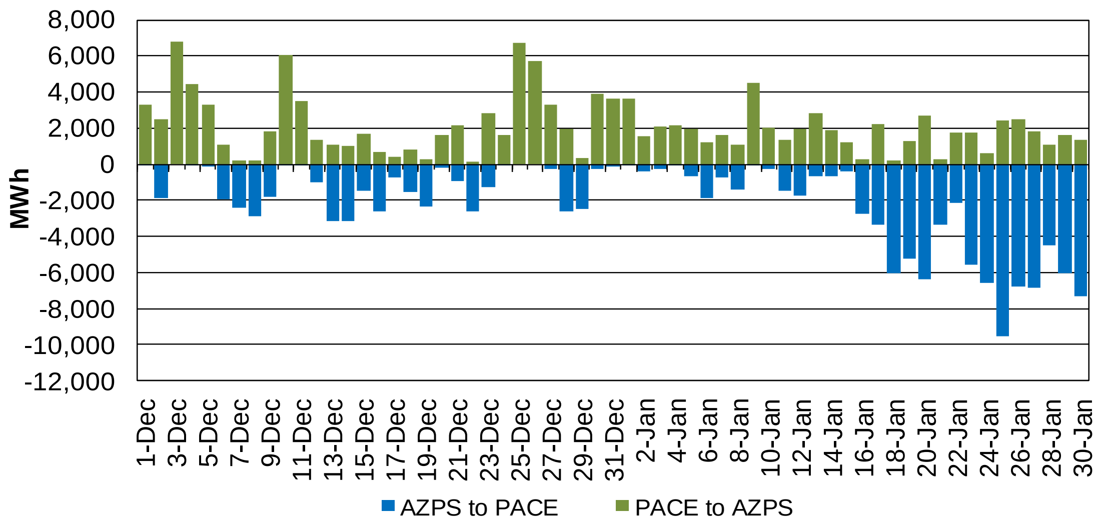


Figure 62 shows the daily volume EIM transfer between the PACW and PSEI in RTD. The EIM transfer from PSEI to PACW dropped this month compared with December.

Figure 62: EIM Transfer between PACW and PSEI in RTD

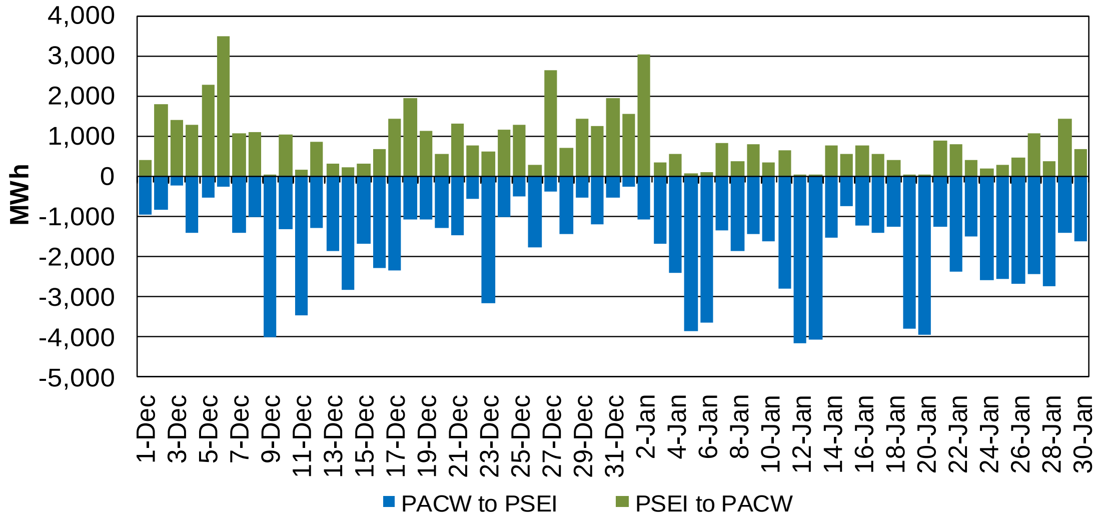


Figure 63 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTIEO was $1.30 million in January, decreasing from $3.03 million in December.

Figure 63: EIM Real-Time Imbalance Energy Offset by Area

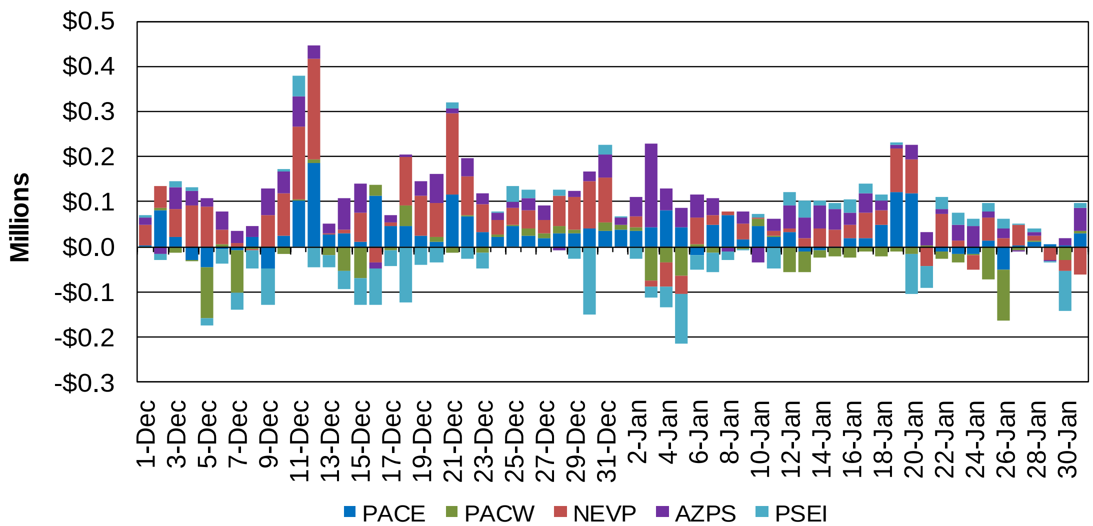


Figure 64 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS and PSEI respectively. Total RTCO fell to -$0.49 million in January from $1.39 million in December.

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

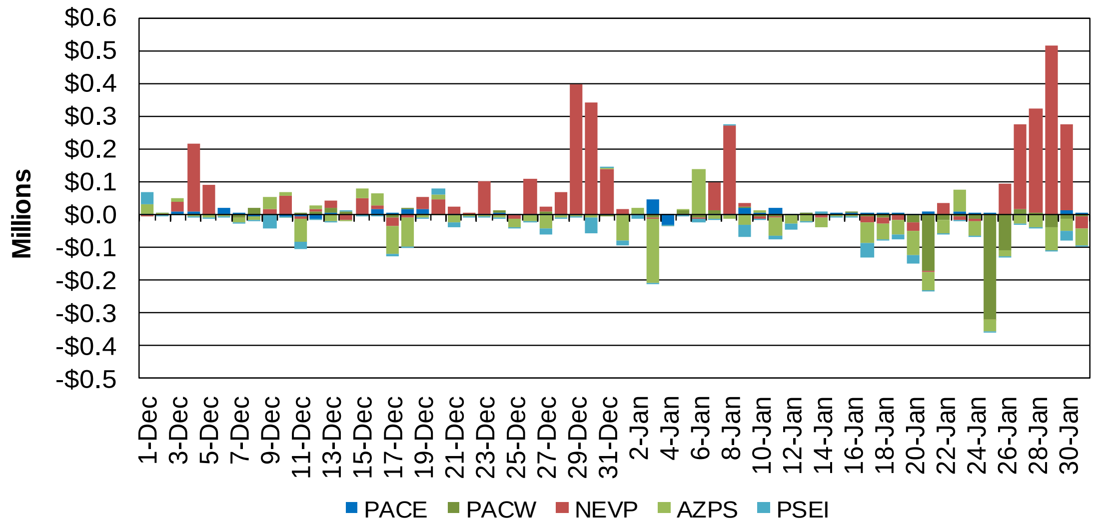
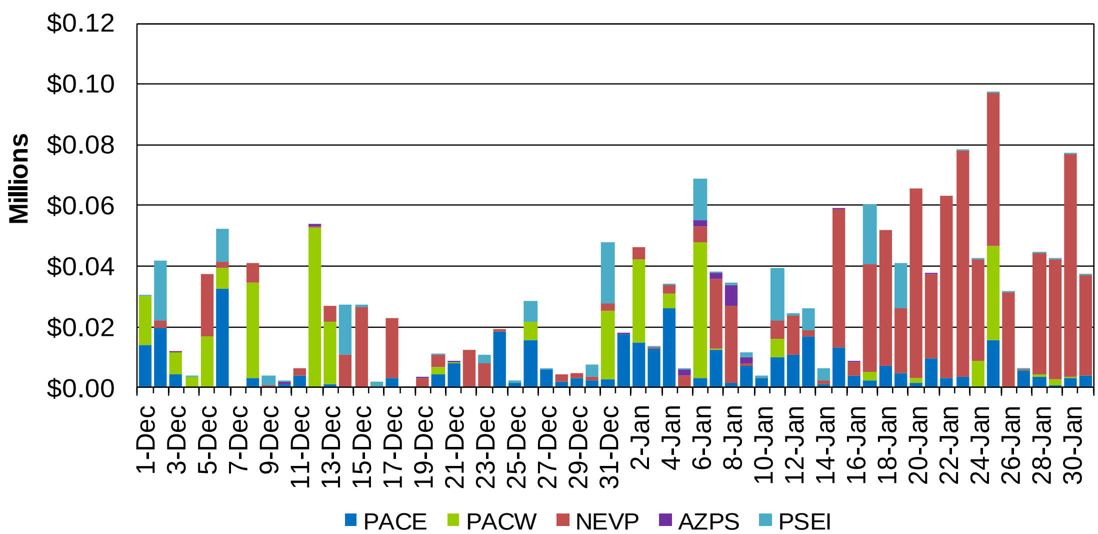


Figure 65 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS and PSEI respectively. Total BCR increased to $1.21 million in January from $0.56 million in December.

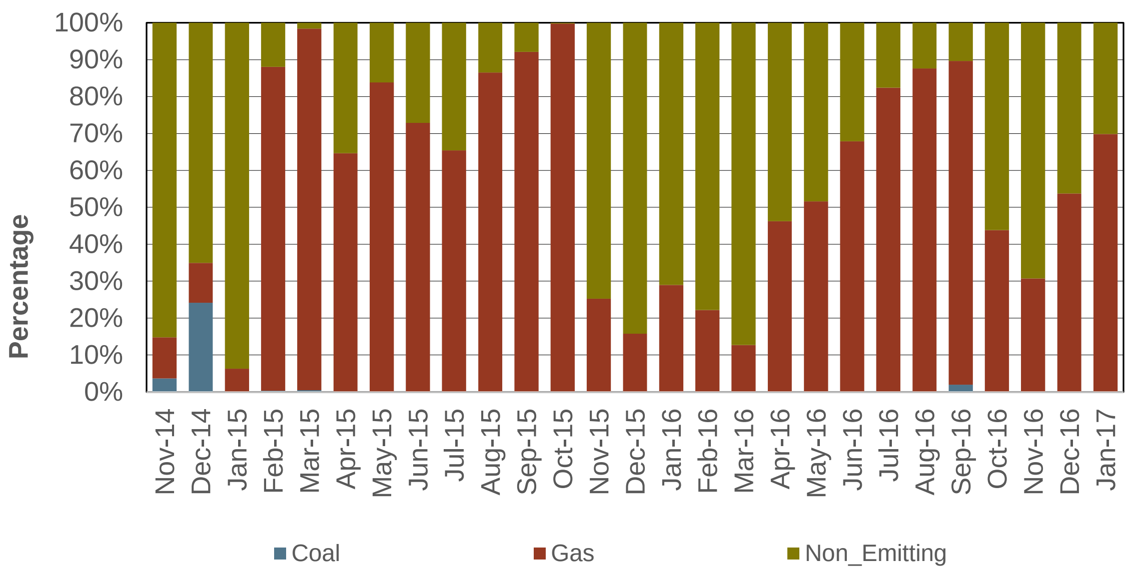
Figure 65: EIM Bid Cost Recovery by Area



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 January 2015, almost all of the EIM dispatches to support transfers into the ISO were from resources other than coal, as documented in Figure 66 and Table 7 below.

Figure 66: 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
14-Nov	3.66%	11.12%	85.22%	100%
14-Dec	24.18%	10.78%	65.04%	100%
15-Jan	0.07%	6.22%	93.71%	100%
15-Feb	0.32%	87.72%	11.96%	100%
15-Mar	0.48%	97.94%	1.58%	100%
15-Apr	0.12%	64.56%	35.32%	100%
15-May	0.00%	83.83%	16.17%	100%
15-Jun	0.00%	72.88%	27.12%	100%
15-Jul	0.00%	65.41%	34.59%	100%
15-Aug	0.02%	86.51%	13.48%	100%
15-Sep	0.00%	92.13%	7.87%	100%
15-Oct	0.10%	99.70%	0.20%	100%
15-Nov	0.00%	25.25%	74.75%	100%
15-Dec	0.00%	15.79%	84.21%	100%
16-Jan	0.00%	28.96%	71.04%	100%
16-Feb	0.00%	22.21%	77.79%	100%
16-Mar	0.00%	12.72%	87.28%	100%
16-Apr	0.00%	46.26%	53.74%	100%
16-May	0.00%	51.63%	48.37%	100%
16-Jun	0.00%	67.89%	32.11%	100%
16-Jul	0.00%	82.42%	17.58%	100%
16-Aug	0.00%	87.59%	12.41%	100%
16-Sep	1.98%	87.68%	10.34%	100%
16-Oct	0.00%	43.82%	56.18%	100%
16-Nov	0.00%	30.74%	69.26%	100%
16-Dec	0.00%	53.77%	46.23%	100%
17-Jan	0.00%	69.88%	30.12%	100%