



Market Performance Report January 2019

April 17, 2019

ISO Market Quality and Renewable Integration

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

Executive Summary¹

The market performance in January 2019 is summarized below.

CAISO area performance,

- Peak loads for ISO area continued to be low levels in January due to cold weather.
- Across all market, such as the integrated forward market (IFM), the fifteen-minute market (FMM) and real-time market (RTD), the market observed price separation with higher prices in the SDGE area due to transmission congestion.
- Congestion rents for interties skidded to \$5.19 million from \$14.48 million in December. Majority of the congestion rents in January accrued on Malin (13 percent) intertie, NOB (12 percent) intertie, and Palo Verde (46 percent) intertie.
- In the congestion revenue rights (CRR) market, congestion revenue rights auction efficiency 1B became in effect on January 1, 2019. The balancing account for January had a surplus of approximately \$7.37 million, which was allocated to measured demand.
- The monthly average ancillary service cost to load increased to \$0.62/MWh from \$0.47/MWh in December. There were 17 scarcity events in this month.
- The cleared virtual supply was well above the cleared demand throughout this month. The profits from convergence bidding declined to \$3.02 million from \$5.28 million in November.
- The bid cost recovery dropped to \$8.61 million from \$12.83 million in November.
- The real-time energy offset increased to -\$1.50 million from -\$4.43 million in December. The real-time congestion offset cost rose to \$2.22 million from -\$0.73 million in December.
- The volume of exceptional dispatch fell to 19,056 MWh from 55,010 MWh in December. The main contributors to the monthly volume were voltage support and planned transmission outage. The monthly average of total exceptional dispatch volume as a percentage of load percentage was 0.11 percent in January, decreasing from 0.32 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, the prices were generally quiet in January. In RTD, the prices for AZPS, IPCO, NEVP, and PACE were elevated on January 15 due to upward load adjustment and reduction in import.
- The monthly average prices in FMM for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were \$32.88, \$29.12, \$32.74, \$35.41, \$30.32, \$29.60, \$30.58, and \$29.47 respectively.
- The monthly average prices in RTD for EIM entities (AZPS, BCHA, IPCO, NEVP, PACE, PACW, PGE and PSEI) were \$33.54, \$29.89, \$33.86, \$36.04, \$31.28, \$29.91, \$30.85 and \$29.55 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 \$0.68 million, -\$3.63 million and -\$2.05 million respectively.

TABLE OF CONTENTS

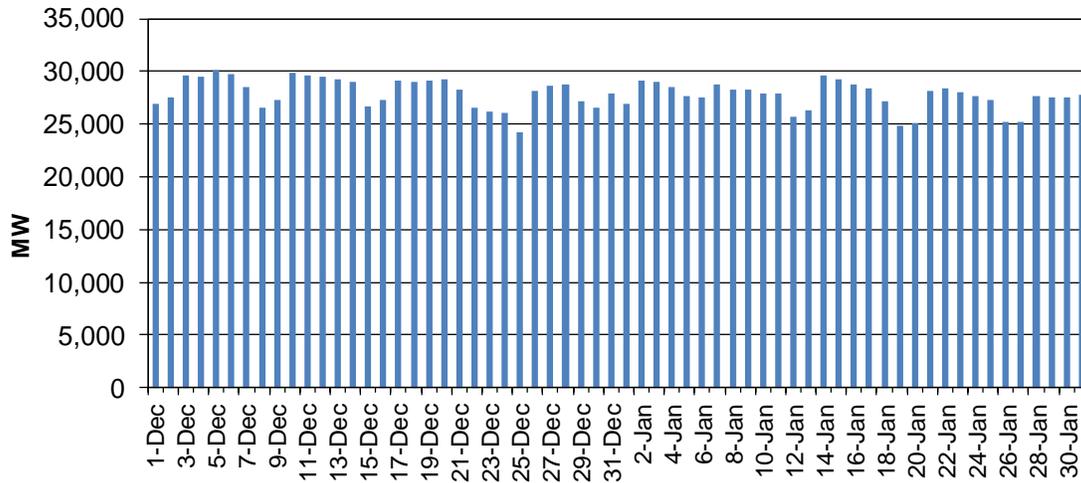
Executive Summary	2
Market Characteristics	5
Loads	5
Resource Adequacy Available Incentive Mechanism.....	6
Direct Market Performance Metrics.....	7
Energy.....	7
Day-Ahead Prices.....	7
Real-Time Prices	8
Congestion	11
Congestion Rents on Interties.....	11
Congestion Revenue Rights.....	12
Ancillary Services	15
IFM (Day-Ahead) Average Price.....	15
Ancillary Service Cost to Load.....	16
Scarcity Events	16
Convergence Bidding.....	17
Renewable Generation Curtailment	18
Flexible Ramping Product	19
Flexible Ramping Product Payment.....	20
Indirect Market Performance Metrics	21
Bid Cost Recovery.....	21
Real-time Imbalance Offset Costs.....	32
Market Software Metrics.....	33
Market Disruption.....	33
Manual Market Adjustment.....	35
Exceptional Dispatch	35
Energy Imbalance Market.....	37

Market Characteristics

Loads

Peak loads for ISO area continued to be low levels in January due to cold weather.

Figure 1: System Peak Load



Resource Adequacy Available Incentive Mechanism

Resource Adequacy Availability Incentive Mechanism (RAAIM) was activated on November 1, 2016 to track the performance of Resource Adequacy (RA) Resources. RAAIM is used to determine the availability of resources providing local and/or system Resource Adequacy Capacity and Flexible RA Capacity each month and then assess the resultant Availability Incentive Payments and Non-Availability Charges through the CAISO’s settlements process. Table 1 below shows the monthly average actual availability, total non-availability charge, and total availability incentive payment.² Starting from May 2018, the ISO reports the system RA average actual availability and flexible RA average actual availability separately.

Table 1: Resource Adequacy Availability and Payment

	Total Non-availability Charge	Total Availability Incentive Payment	Average Actual Availability	Flexible Average Actual Availability	System Average Actual Availability
Jan18	\$921,031	-\$921,031	97.66%		
Feb18	\$1,945,971	-\$1,793,865	95.83%		
Mar18	\$3,151,376	-\$1,589,703	93.27%		
Apr18	\$2,913,679	-\$1,608,256	93.01%		
May18	\$6,004,496	-\$2,254,847		92.43%	91.22%
Jun18	\$5,182,422	-\$2,618,787		95.08%	92.09%
Jul18	\$2,085,852	-\$2,692,615		94.54%	95.18%
Aug18	\$3,943,252	-\$2,808,202		91.28%	96.88%
Sep18	\$1,456,190	-\$2,905,748		98.08%	97.35%
Oct18	\$2,452,681	-\$2,259,888		95.33%	96.33%
Nov18	\$1,482,568	-\$2,031,607		97.27%	96.94%
Dec18	\$1,361,756	-\$2,101,835		97.68%	96.75%
Jan19	\$1,430,981	-\$1,430,981		98.25%	96.70%

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. The prices for all four DALPs were generally quiet in January.

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

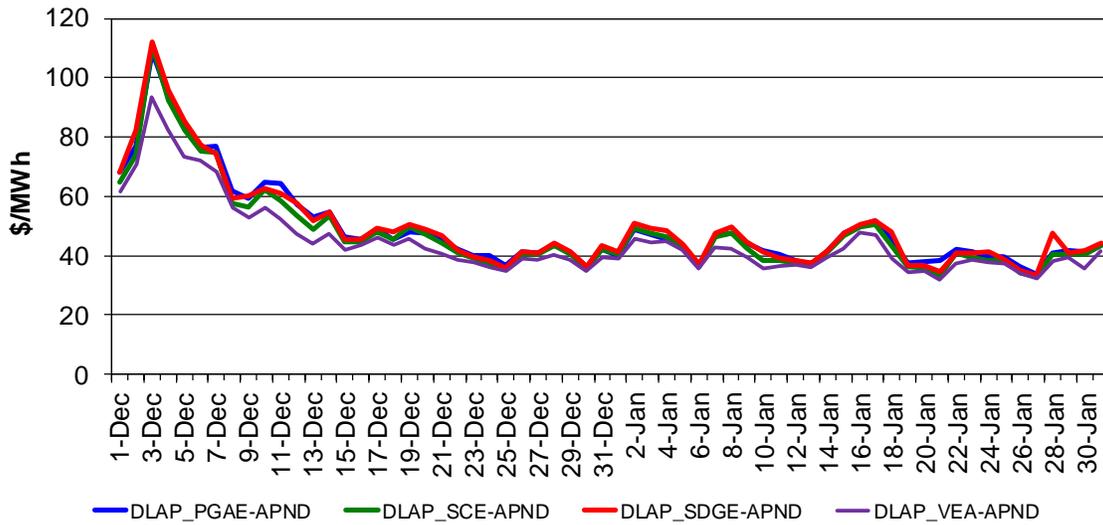


Table 2: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDGE	January 28	OMS 6791208_TL23054_55_NG MIGUEL_BKs_MXFLW_NG

Real-Time Prices

FMM daily prices of the four DLAPs are shown in Figure 3. Table 3 lists the binding constraints along with the associated DLAP locations and the occurrence dates when the binding constraints resulted in relatively high or low DLAP prices.

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

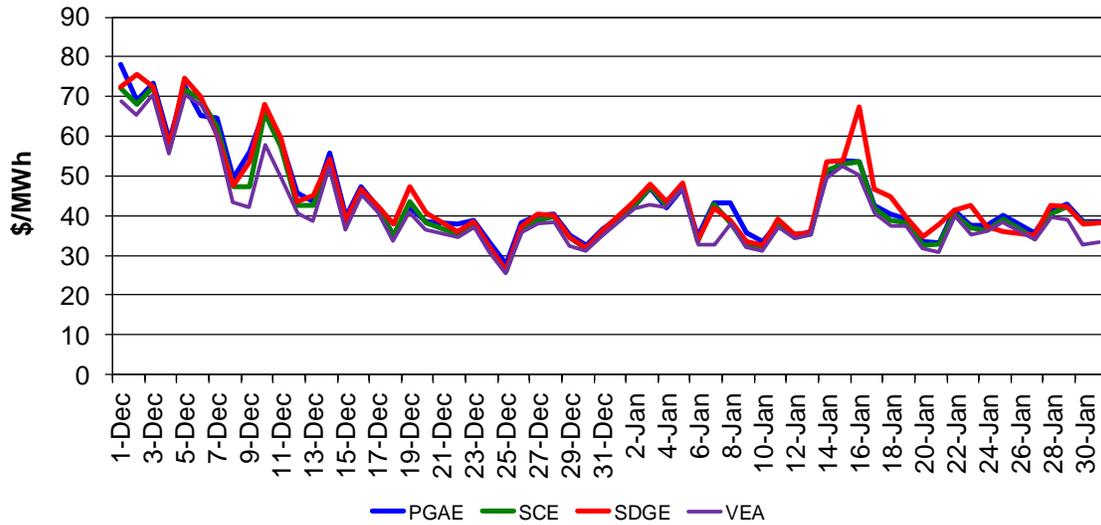
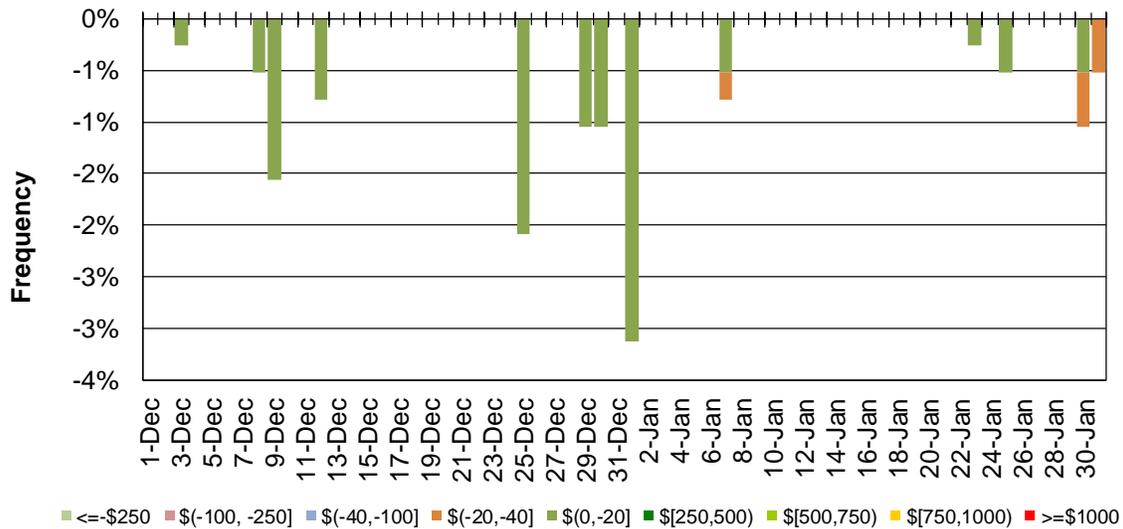


Table 3: FMM Transmission Constraints

DLAP	Date	Transmission Constraint
SDGE	January 16	7820_TL 230S_OVERLOAD_NG

Figure 4 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in the FMM. The cumulative frequency of prices above \$250/MWh was 0 percent in January, unchanging from December. The cumulative frequency of negative prices inched down to 0.20 percent in January from 0.24 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 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)

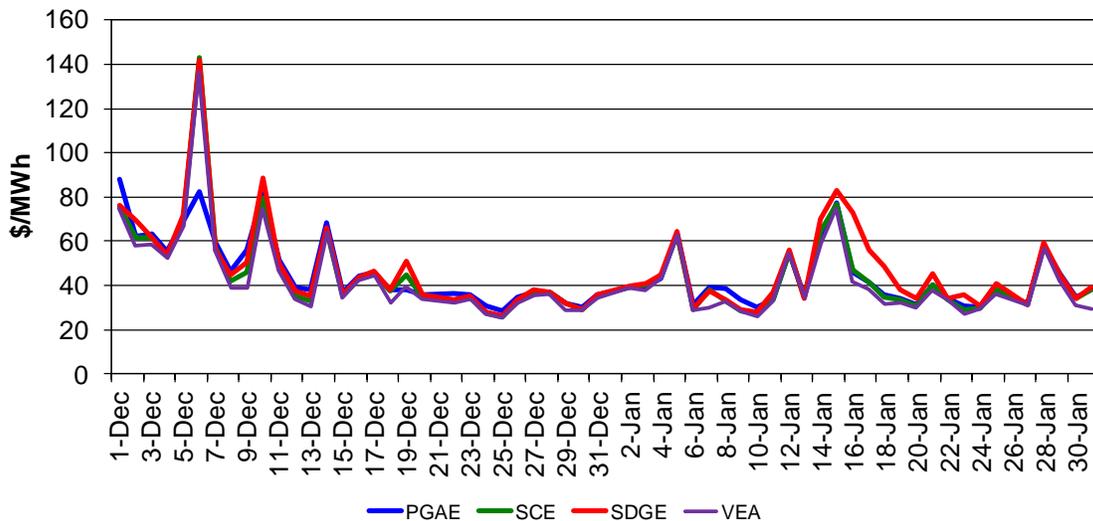


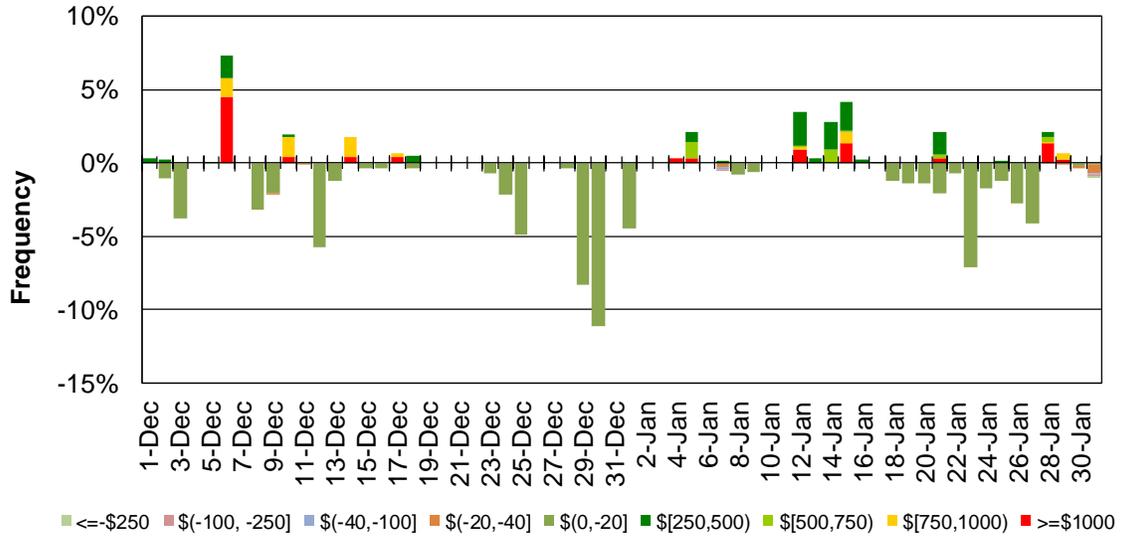
Table 4: RTD Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	January 14-18	7820_TL 230S_OVERLOAD_NG

Figure 6 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in RTD. The cumulative frequency of prices above \$250/MWh increased to 0.60 percent in January from 0.41 percent

in December. The cumulative frequency of negative prices fell to 1.02 percent in January from 1.48 percent in December.

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



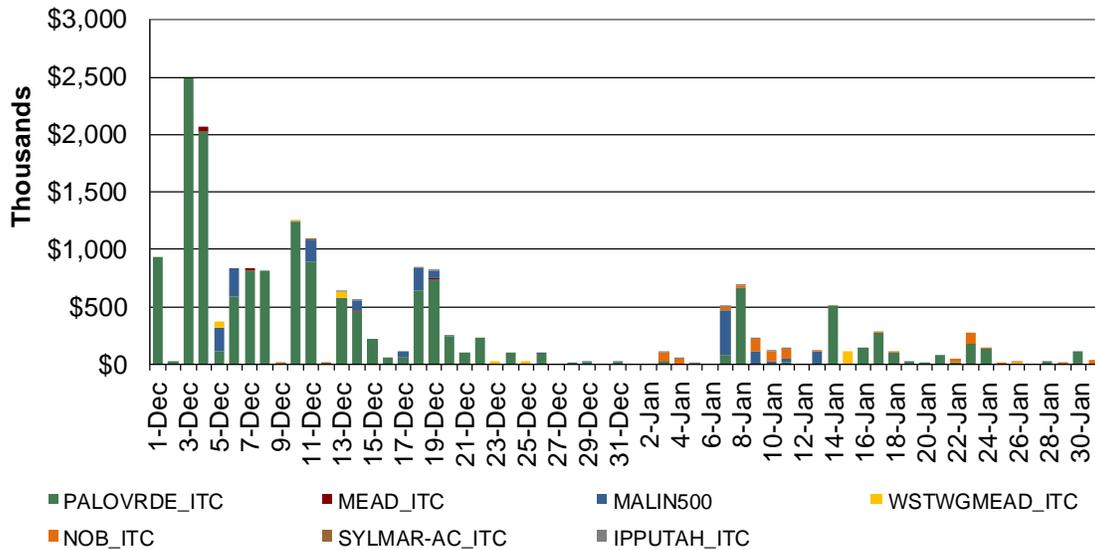
Congestion

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 \$5.19 million from \$14.48 million in December. Majority of the congestion rents in January accrued on Malin (13 percent) intertie, NOB (12 percent) intertie, and Palo Verde (46 percent) intertie.

The congestion rent on Malin decreased to \$0.65 million in January from \$1.07 million in December. The congestion rent on Nob increased to \$0.66 million in January from \$2,849 in December. The congestion rent on Palo Verde dropped to \$2.38 million in January from \$13.46 million in December.

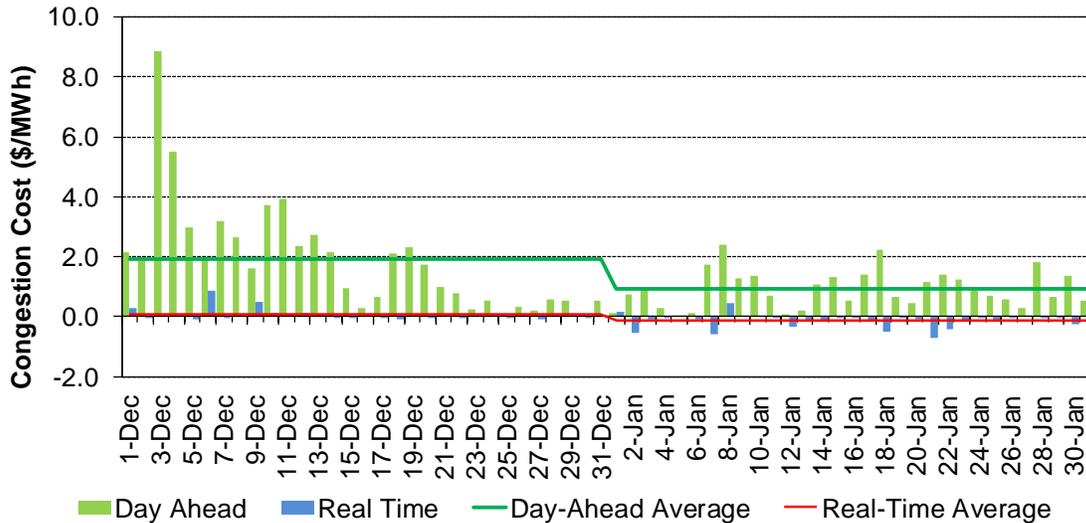
Figure 7: IFM Congestion Rents by Interties (Import)



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 \$0.93/MWh in January from \$1.93/MWh in December. The average congestion cost per load served in the real-time market decreased to -\$0.13/MWh in January from \$0.06/MWh in December.

Congestion Revenue Rights

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

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

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

Figure 9: Daily CRR Notional Value by Transmission Element

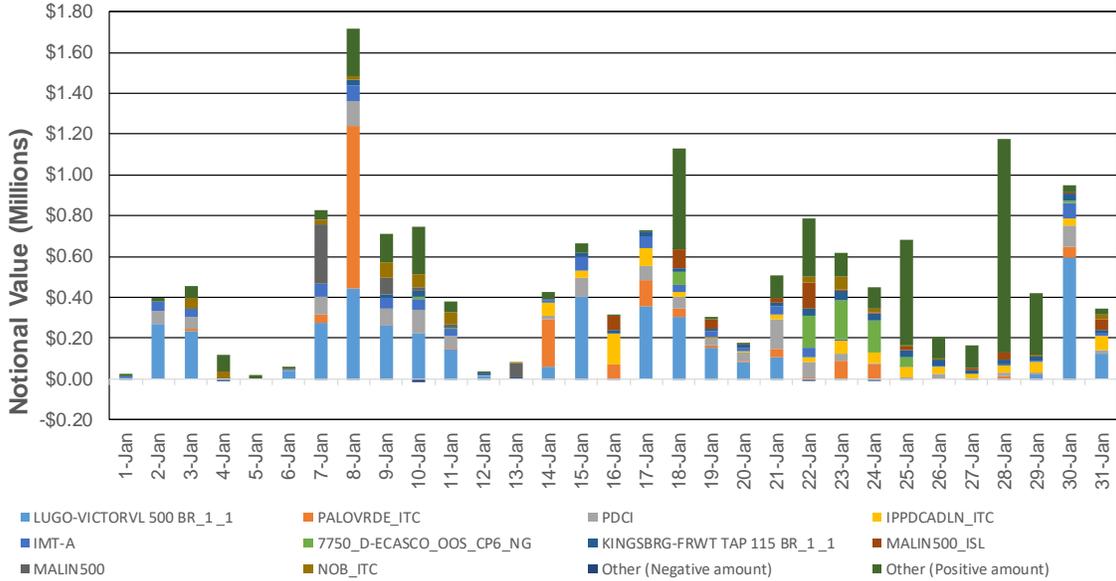
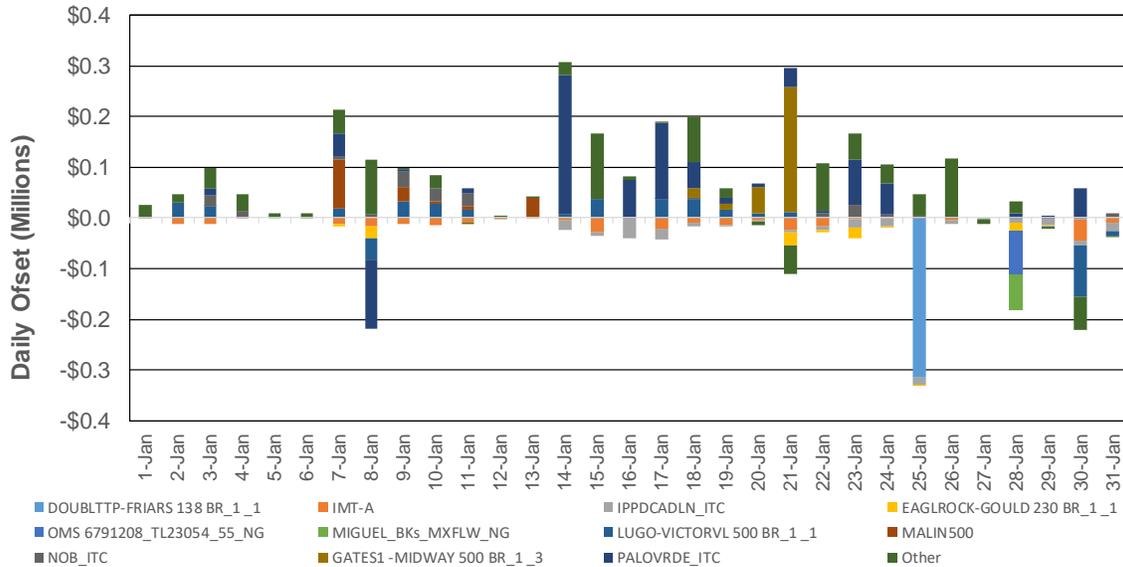


Figure 10 illustrates the daily CRR offset value in the corresponding month for the transmission elements that experienced congestion during the month.

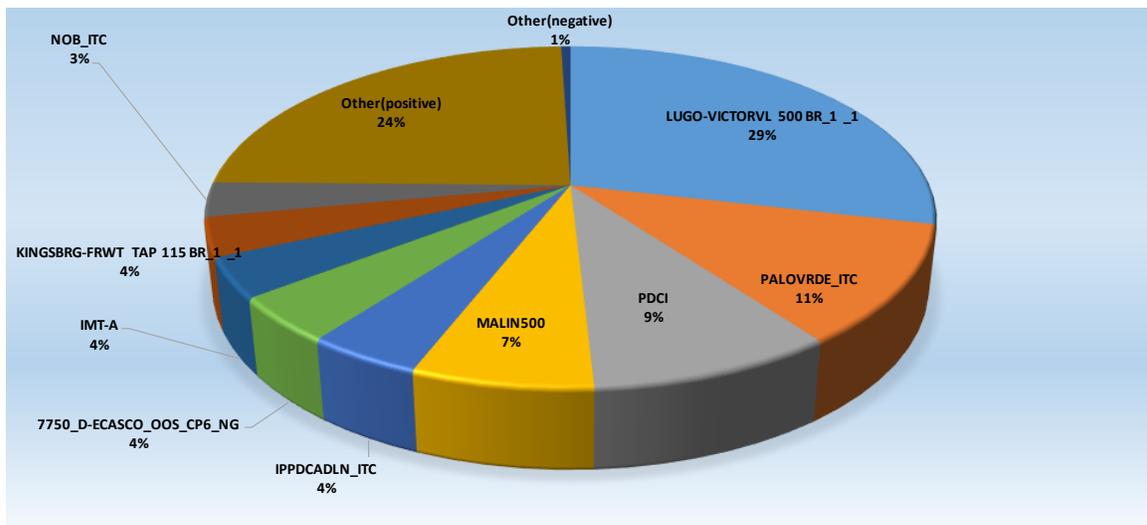
Figure 10: Daily CRR Offset Value by Transmission Element



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

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

Figure 11: CRR Payment by Transmission Element



Net balancing surplus in January was \$1.92 million. The auction revenues credited to the balancing account for January were \$5.45 million. As a result, the balancing account for January had a surplus of approximately \$7.37 million, which was allocated to measured demand.

Table 5: CRR Revenue Adequacy Statistics

IFM Congestion Rents	\$16,161,092.67
CRR Notional value	\$15,553,287.53
CRR Deficit	-\$1,292,528.78
CRR Surplus	\$2,675,445.08
CRR Payment	\$14,245,664.46
Net Balancing Surplus	\$1,915,428.21
Annual Auction Revenues	\$1,919,466.65
Monthly Auction Revenues	\$3,531,628.23
CRR Settlement Rule	-\$16,252.00
Allocation to Measured Demand	\$7,366,523.08

Ancillary Services

IFM (Day-Ahead) Average Price

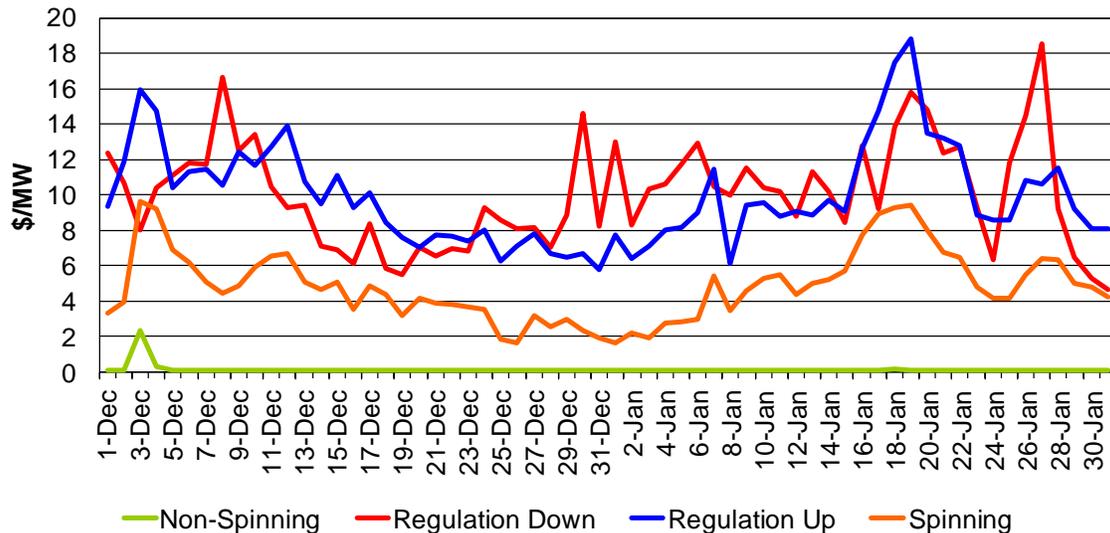
Table 6 shows the monthly IFM average ancillary service procurements and the monthly average prices. In January the monthly average procurement increased for regulation down, spinning and non-spinning reserves.

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
Jan-19	312	381	831	839	\$10.20	\$10.84	\$5.19	\$0.11
Dec-18	320	375	733	736	\$9.61	\$9.29	\$4.49	\$0.19
Percent Change	-2.22%	1.67%	13.38%	14.06%	6.14%	16.68%	15.55%	-40.17%

The monthly average prices increased for regulation up, regulation down, and spinning reserve in January. Figure 12 shows the daily IFM average ancillary service prices. The average prices for regulation up and regulation down were high on January 16-21 due to high opportunity cost of energy. January 27 also saw high price for regulation down, driven by high opportunity cost of energy.

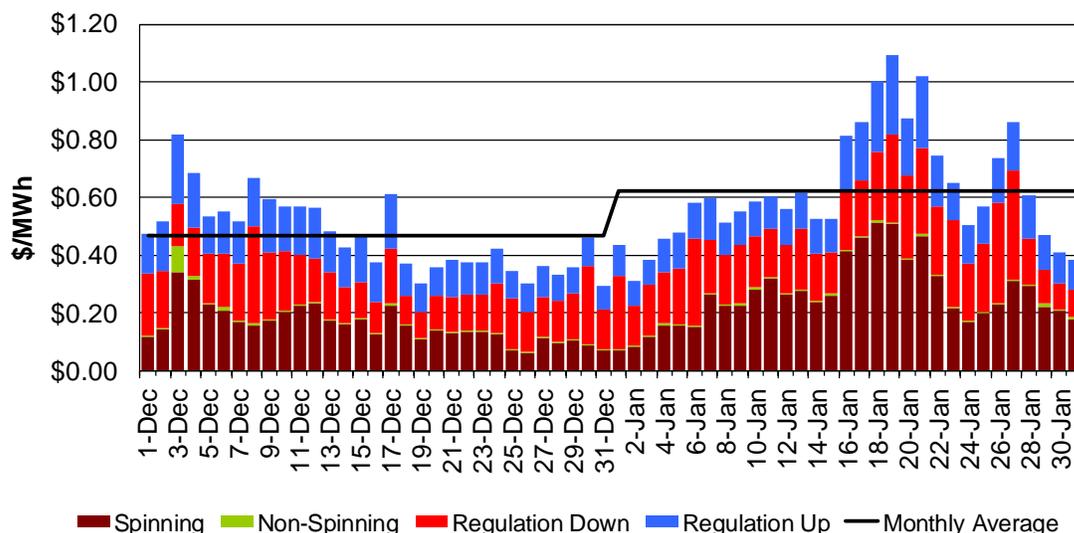
Figure 12: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load increased to \$0.62/MWh in January from \$0.47/MWh in December. The average cost was high on January 16-21 and 27 due to high regulation up and regulation down prices, which were discussed in previous section.

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



Scarcity Events

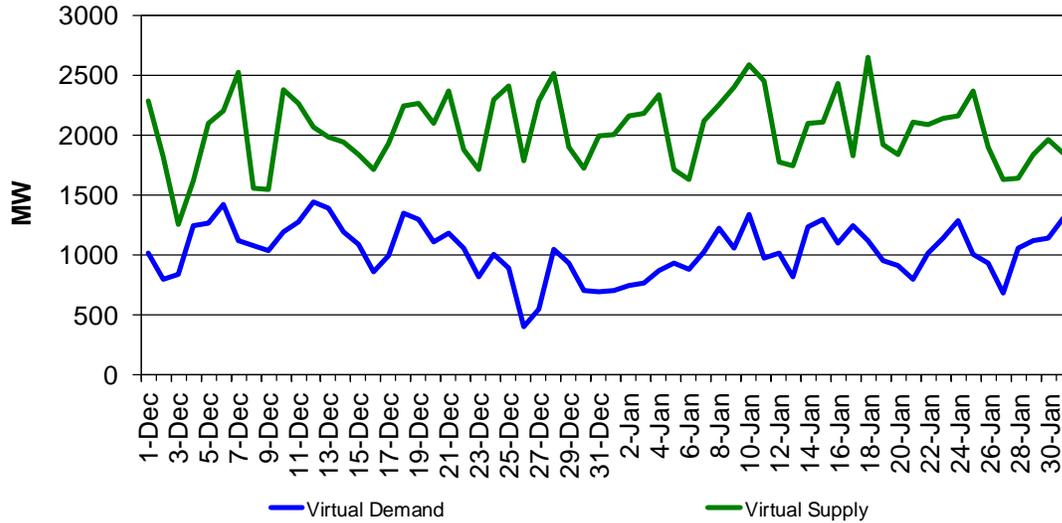
The ancillary services scarcity pricing mechanism is triggered when the ISO is not able to procure the target quantity of one or more ancillary services in the IFM and real-time market runs. The scarcity events in January are shown in the table below.

Date	Hour Ending	Interval	Ancillary Service	Region	Shortfall (MW)	Percentage of Requirement
Jan 2	19	4	Regulation Up	SP26_EXP	7.3	7%
Jan 2	20	1	Regulation Up	SP26_EXP	3.4	3.3%
Jan 2	20	3	Regulation Up	SP26_EXP	7.3	7%
Jan 2	24	2,4	Regulation Up	SP26_EXP	0.1	0.1%
Jan 4	17	2	Regulation Down	SP26_EXP	0.5	0.3%
Jan 6	21	1	Regulation Down	SP26_EXP	0.06	0.1%
Jan 9	6	2	Regulation Down	SP26_EXP	3	2%
Jan 9	6	4	Regulation Down	SP26_EXP	0.4	0.3%
Jan 18	16	4	Regulation Down	SP26_EXP	1.2	1%
Jan 19	4	1	Regulation Up	SP26_EXP	1.1	1%
Jan 20	14	4	Regulation Up	SP26_EXP	1.2	1%
Jan 20	17	4	Regulation Up	SP26_EXP	2.3	1.7%
Jan 23	22	4	Regulation Down	SP26_EXP	4.2	4%
Jan 26	13	2	Regulation Up	SP26_EXP	0.2	0.2%
Jan 27	1	2	Regulation Up	SP26_EXP	1.6	1.5%
Jan 27	11	2-4	Regulation Up	SP26_EXP	0.2	0.2%
Jan 31	22	2	Regulation Down	SP26_EXP	7	6.7%

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 the 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

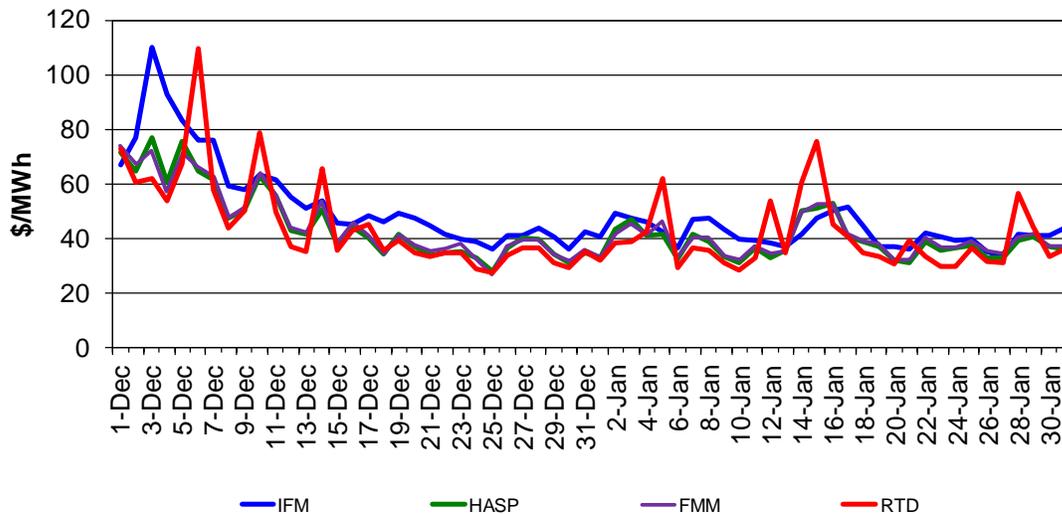
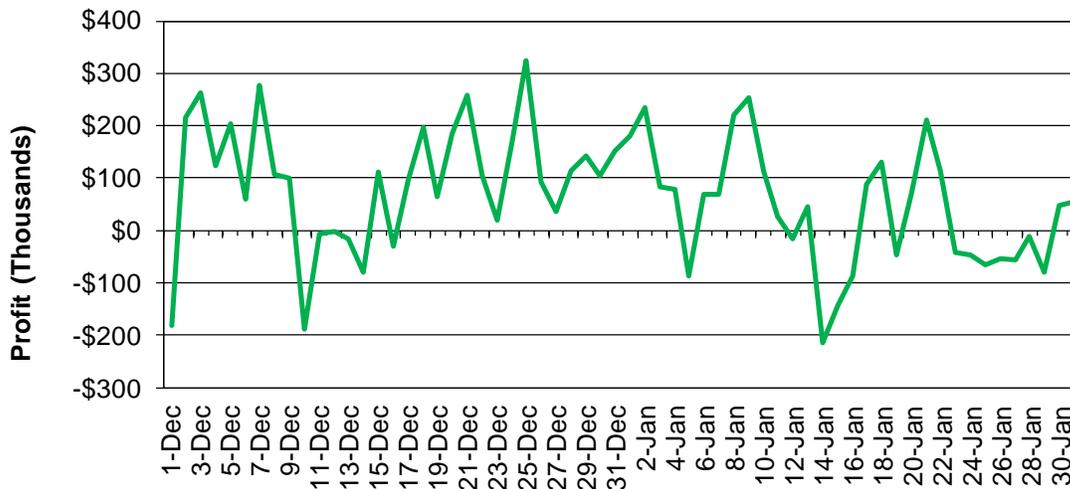


Figure 16 shows the profits that convergence bidders receive from convergence bidding. The total profits from convergence bidding in January fell to \$1.13 million from \$3.02 million in December.

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 show, the renewable curtailment increased slightly in January. The majority of the curtailments was economic and was mainly due to local congestion.

Figure 17: Renewable Curtailment by Reason

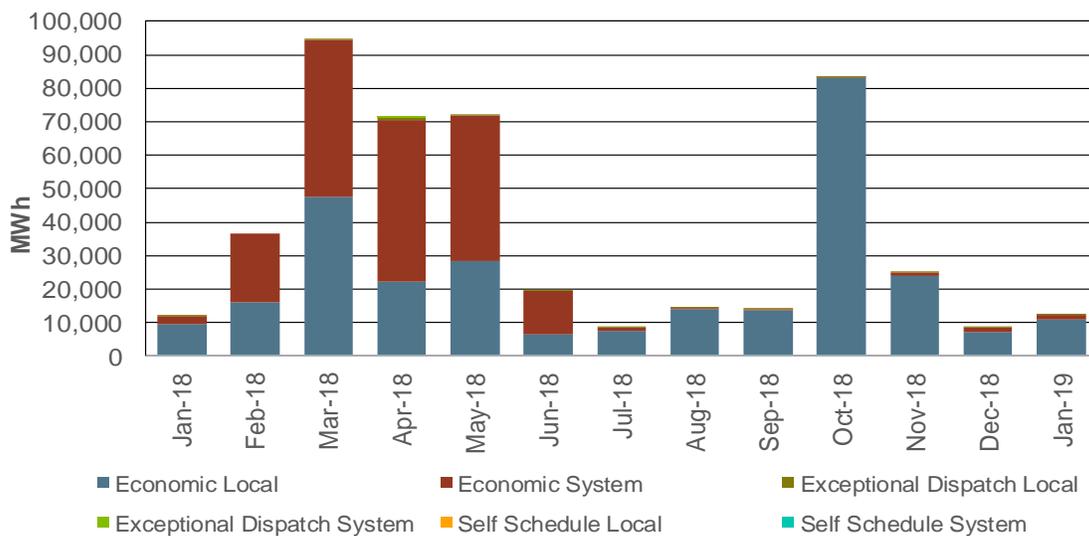
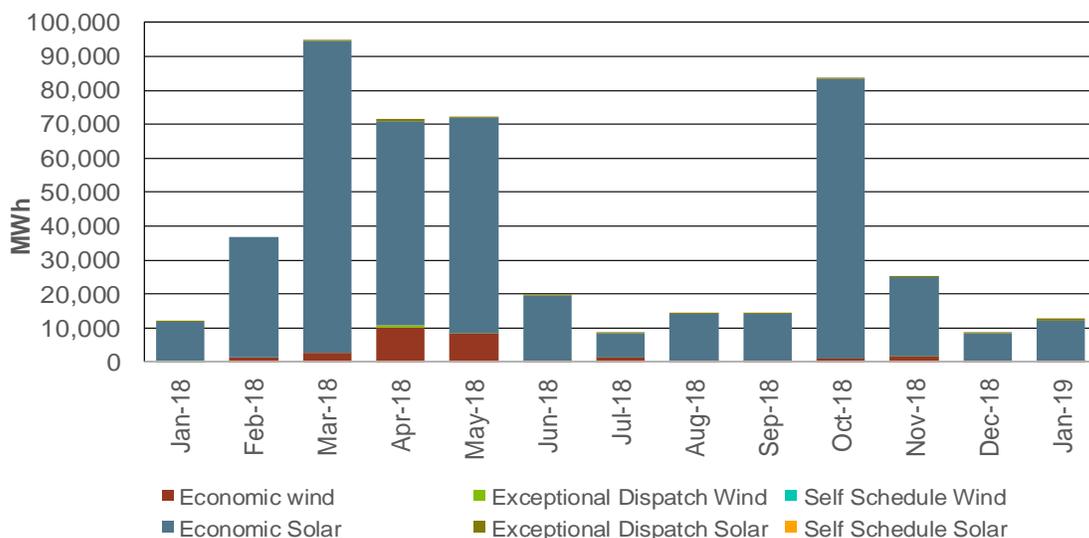


Figure 18: Renewable Curtailment by Resource Type



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 \$0.13 million in January from \$0.20 million in December. Flexible ramping down uncertainty payment decreased to -\$9,160 in January from \$73 in December.

Figure 19: Flexible Ramping Up/down Uncertainty Payment

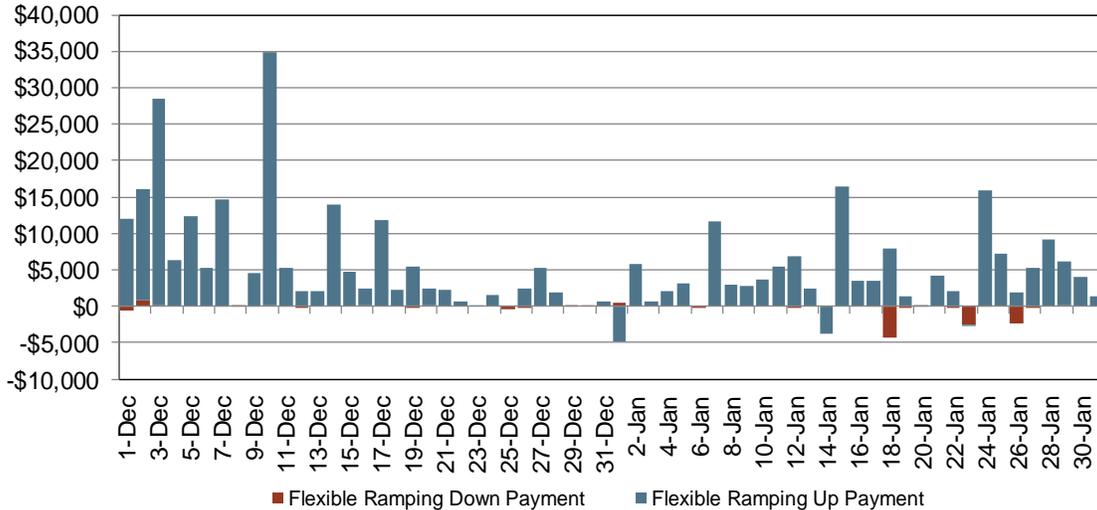
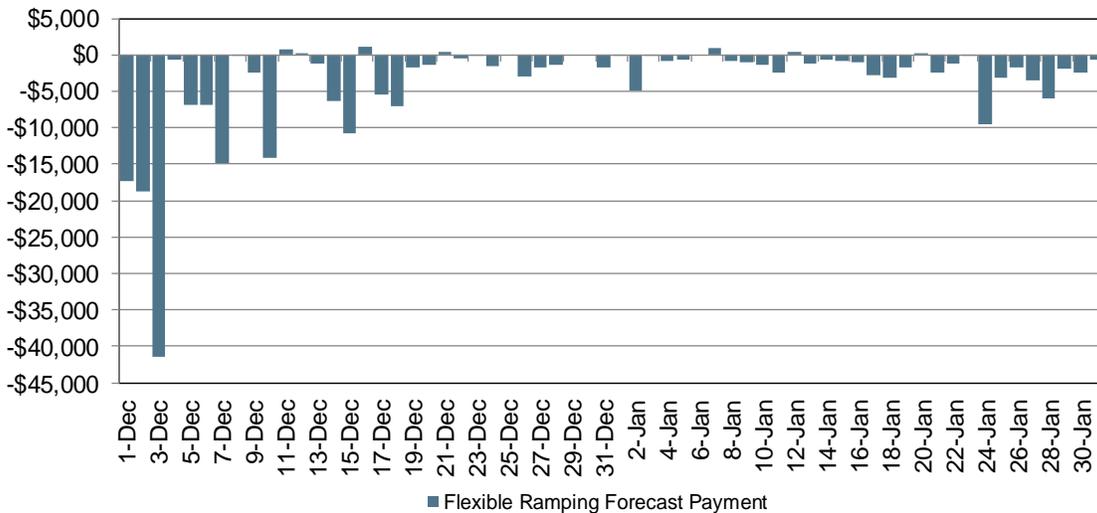


Figure 20 shows the flexible ramping forecast payment. Flexible ramping forecast payment rose to -\$0.05 million this month from -\$0.16 million observed in December.

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 January dropped to \$0.18 million from \$2.12 million in December.

Figure 21: Exceptional Dispatch Uplift Costs

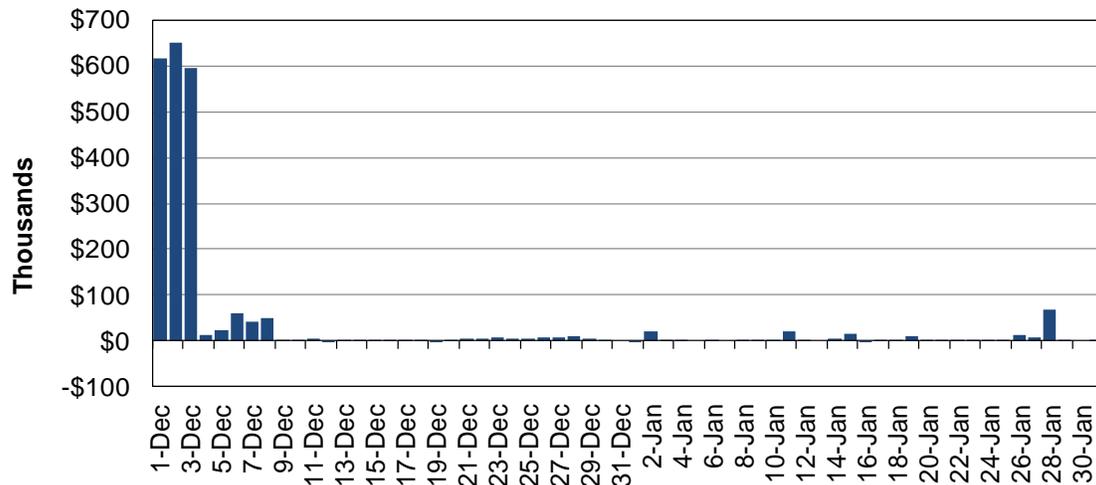


Figure 22 shows the allocation of bid cost recovery payment in the IFM, residual unit commitment (RUC) and RTM markets. The total bid cost recovery for January slid to \$4.52 million from \$8.40 million in December. Out of the total monthly bid cost recovery payment for the three markets in January, the IFM market contributed 23 percent, RTM contributed 69 percent, and RUC contributed 8 percent of the total bid cost recovery payment.

Figure 22: Bid Cost Recovery Allocation

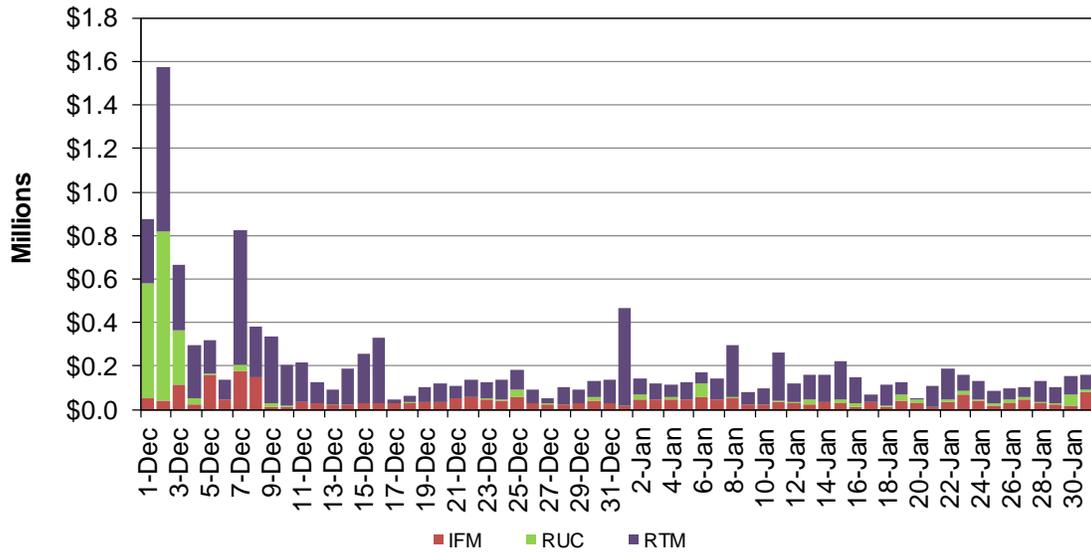


Figure 23 and Figure 24 show the daily and monthly BCR cost by local capacity requirement area (LCR) respectively.

Figure 23: Bid Cost Recovery Allocation by LCR

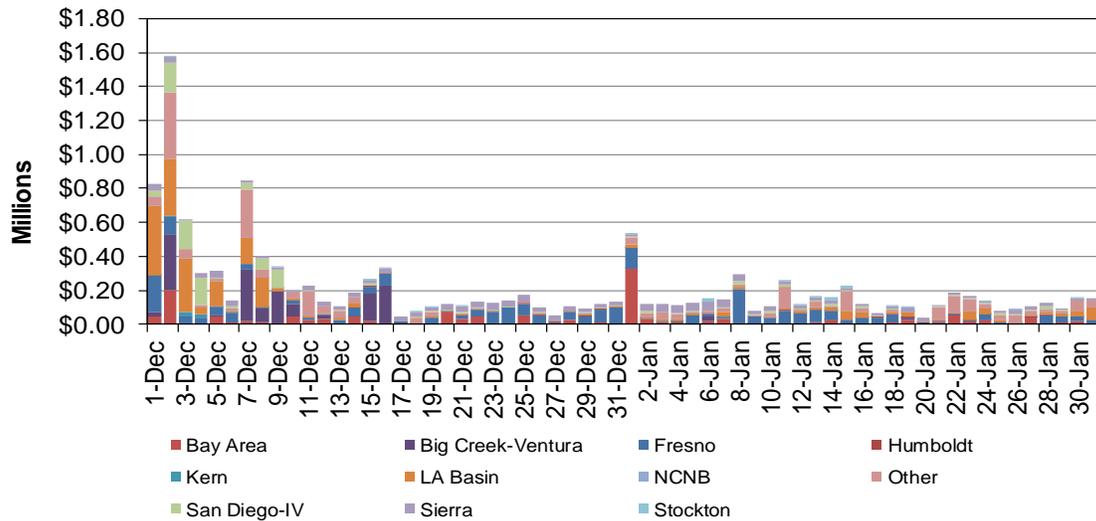


Figure 24: Monthly Bid Cost Recovery Allocation by LCR

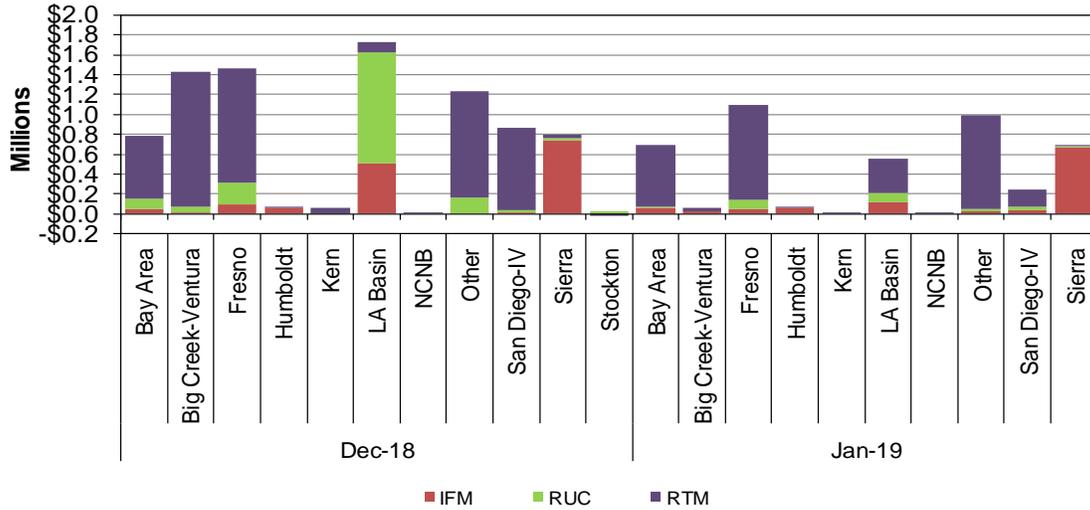


Figure 25 and Figure 26 show the daily and monthly BCR cost by utility distribution company (UDC) respectively.

Figure 25: Bid Cost Recovery Allocation by UDC

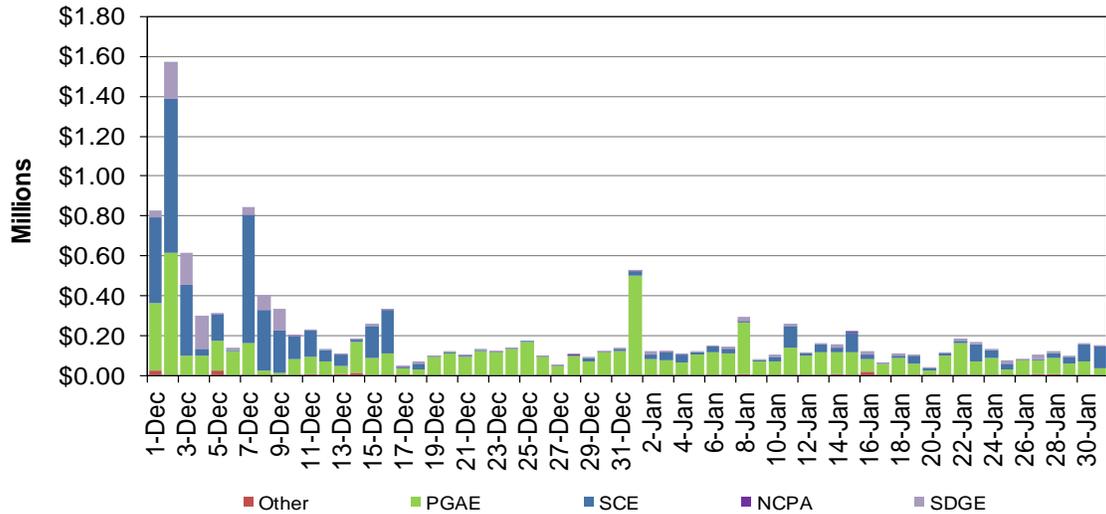


Figure 26: Monthly Bid Cost Recovery Allocation by UDC

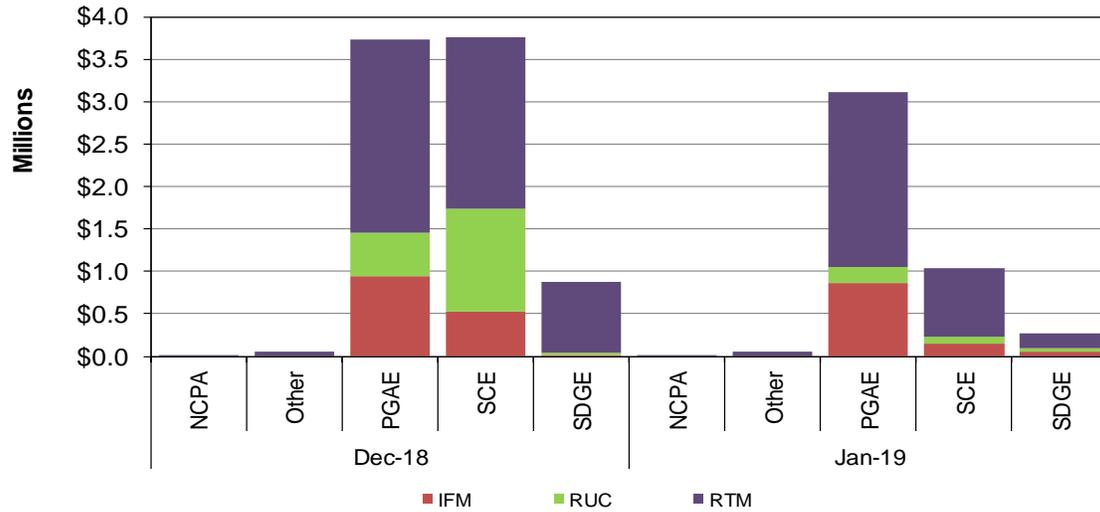


Figure 27 shows the cost related to BCR by cost type in RUC.

Figure 27: Cost in RUC

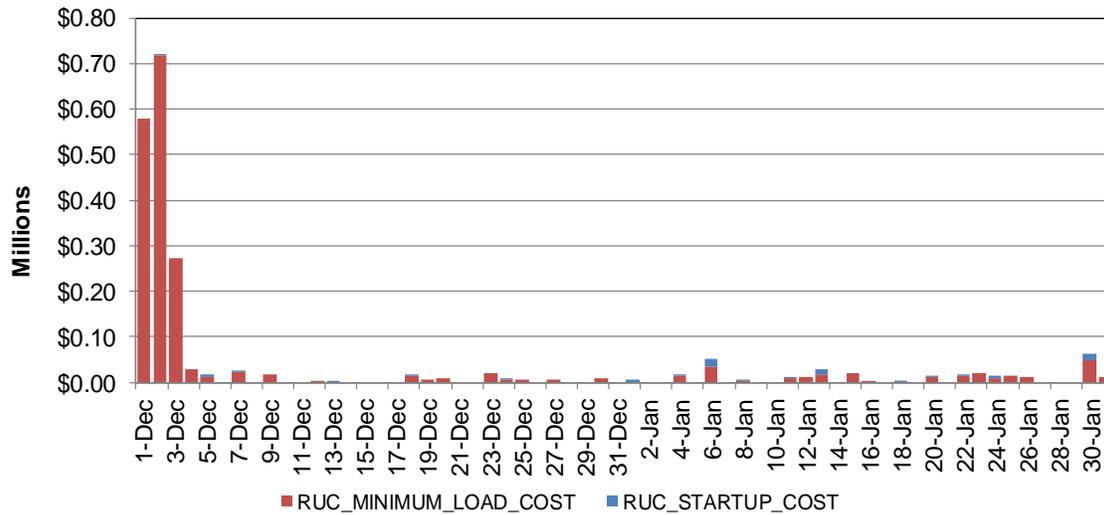


Figure 28 and Figure 29 show the daily and monthly cost related to BCR by type and LCR in RUC respectively.

Figure 28: Cost in RUC by LCR

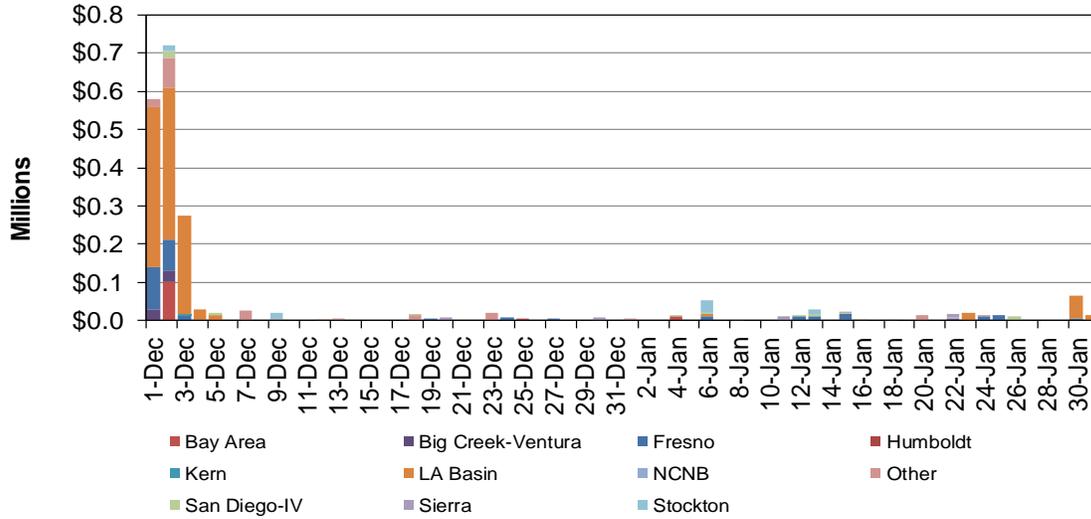


Figure 29: Monthly Cost in RUC by LCR

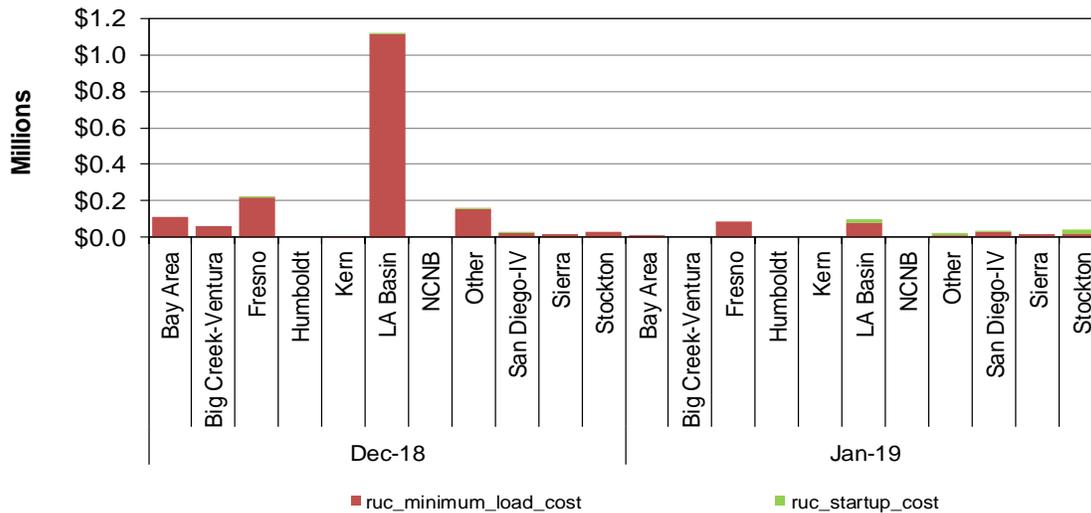


Figure 30 and Figure 31 show the daily and monthly cost related to BCR by type and UDC in RUC respectively.

Figure 30: Cost in RUC by UDC

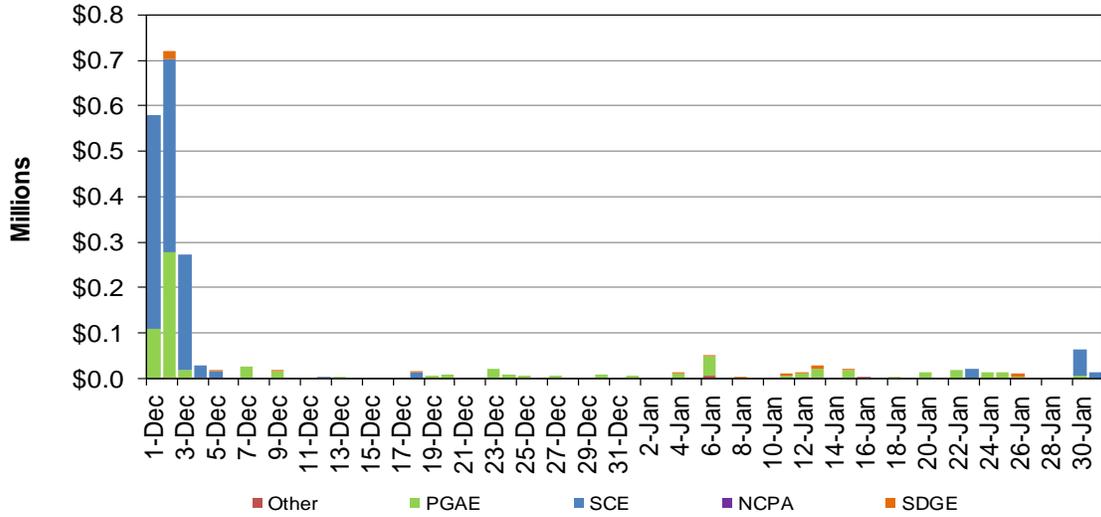


Figure 31: Monthly Cost in RUC by UDC

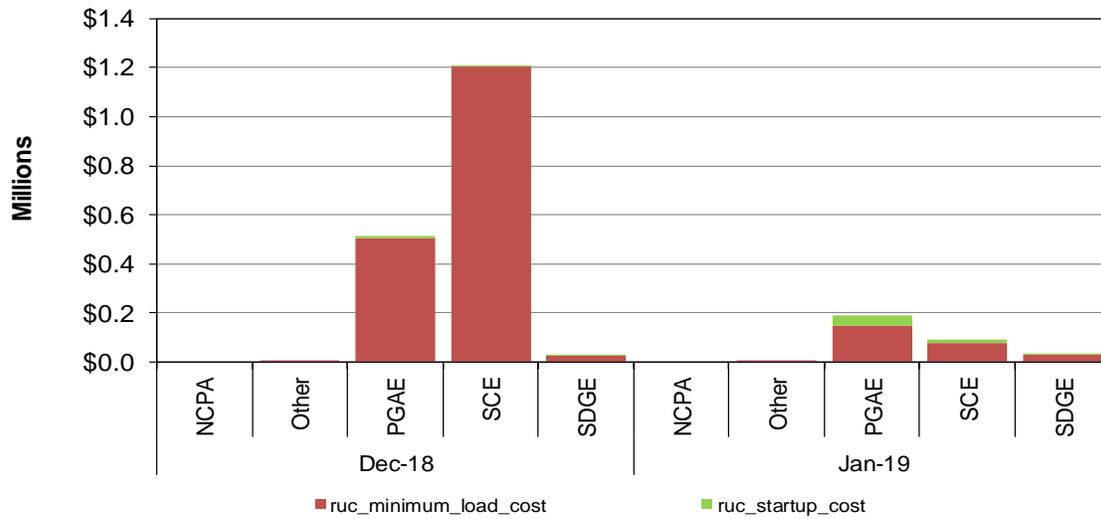


Figure 32 shows the cost related to BCR in real time by cost type. Minimum load cost contributed largely to the real time cost this month.

Figure 32: Cost in Real Time

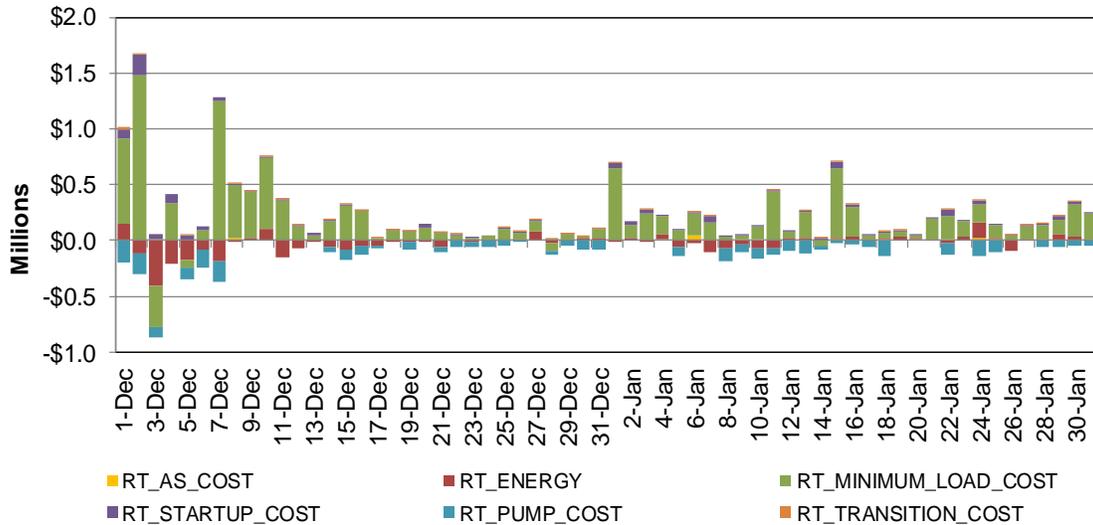


Figure 33 and Figure 34 show the daily and monthly cost related to BCR by type and LCR in real time respectively.

Figure 33: Cost in Real Time by LCR

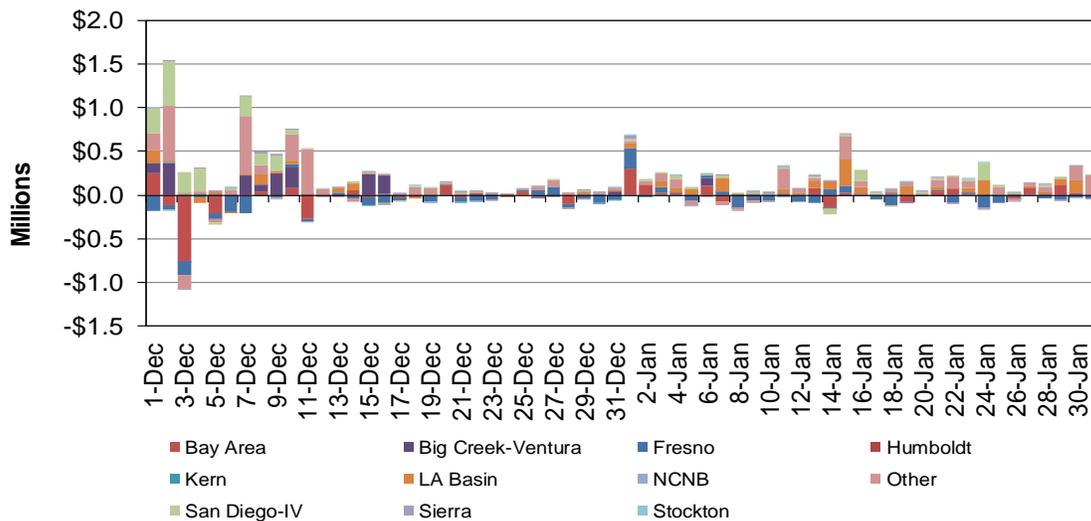


Figure 34: Monthly Cost in Real Time by LCR

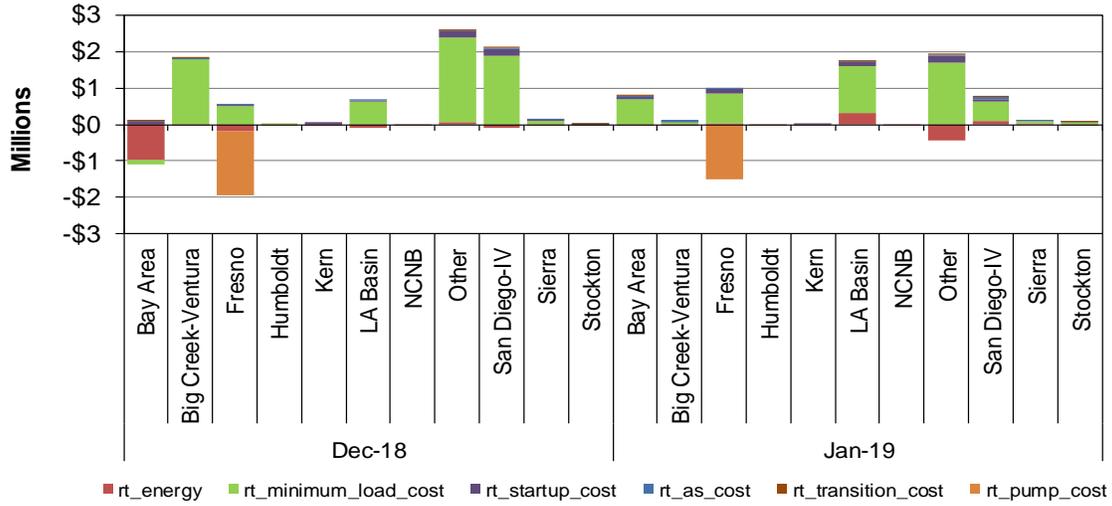


Figure 35 and Figure 36 show the daily and monthly cost related to BCR by type and UDC in Real Time respectively.

Figure 35: Cost in Real Time by UDC

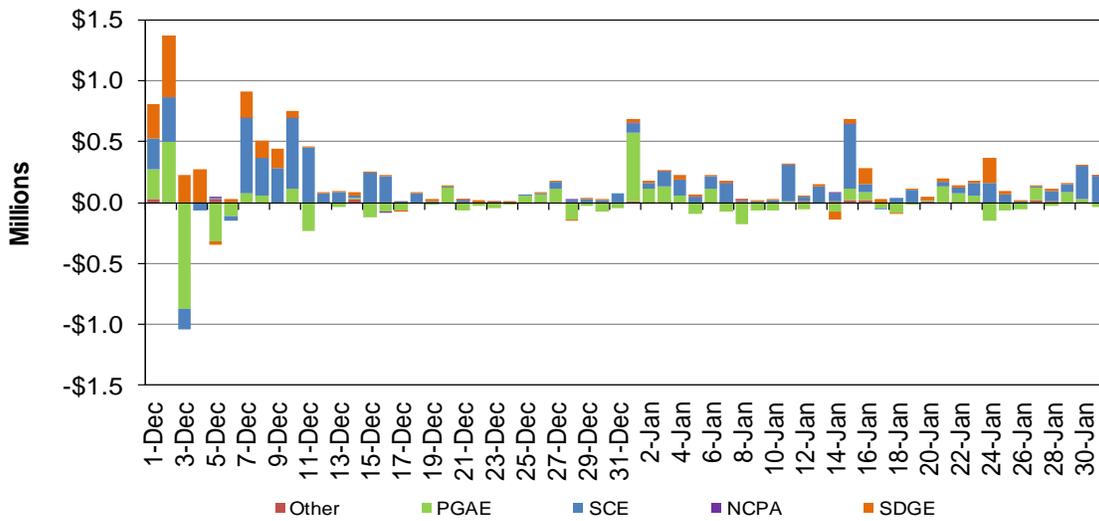


Figure 36: Monthly Cost in Real Time by UDC

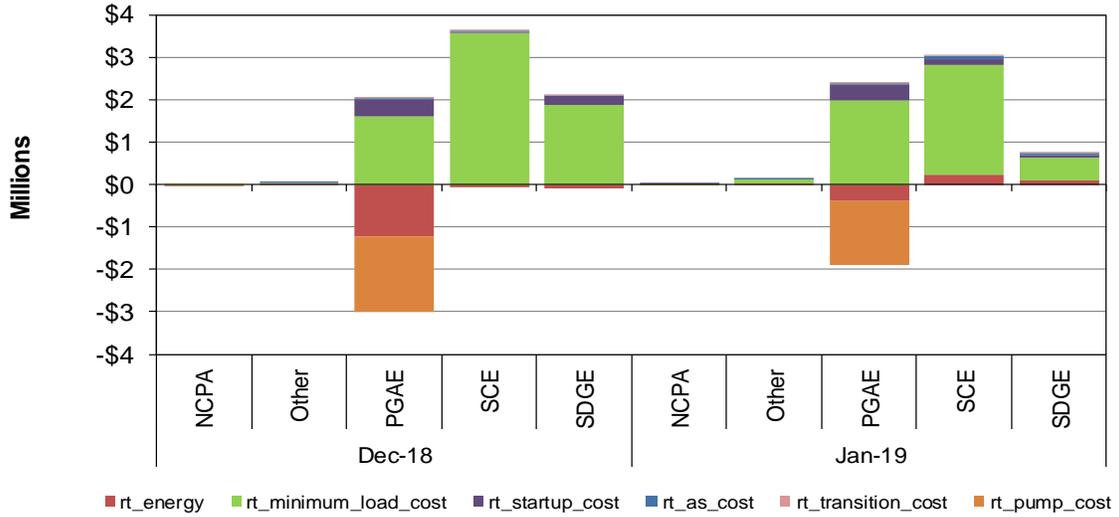


Figure 37 shows the cost related to BCR in IFM by cost type.

Figure 37: Cost in IFM

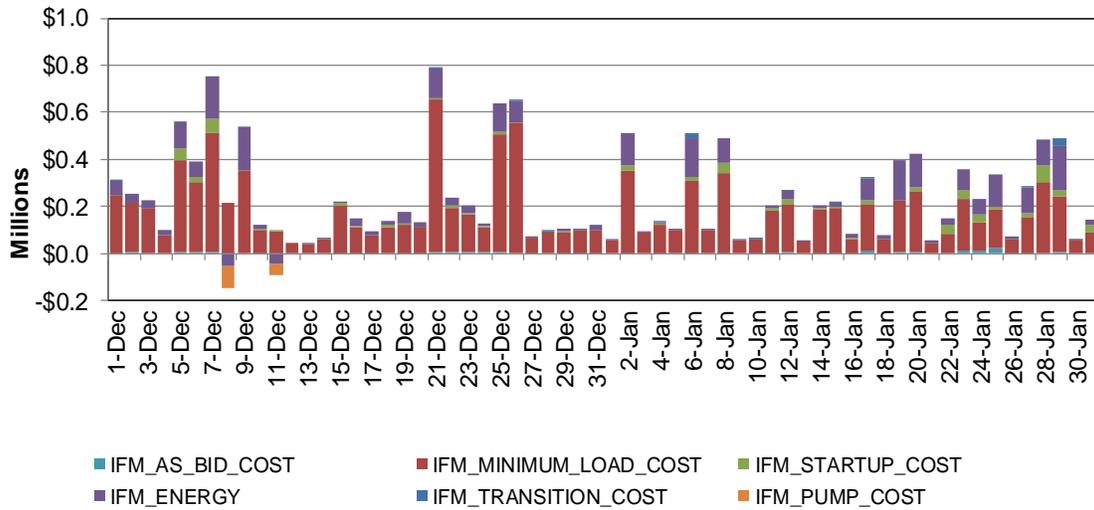


Figure 38 and Figure 39 show the daily and monthly cost related to BCR by type and location in IFM respectively.

Figure 38: Cost in IFM by LCR

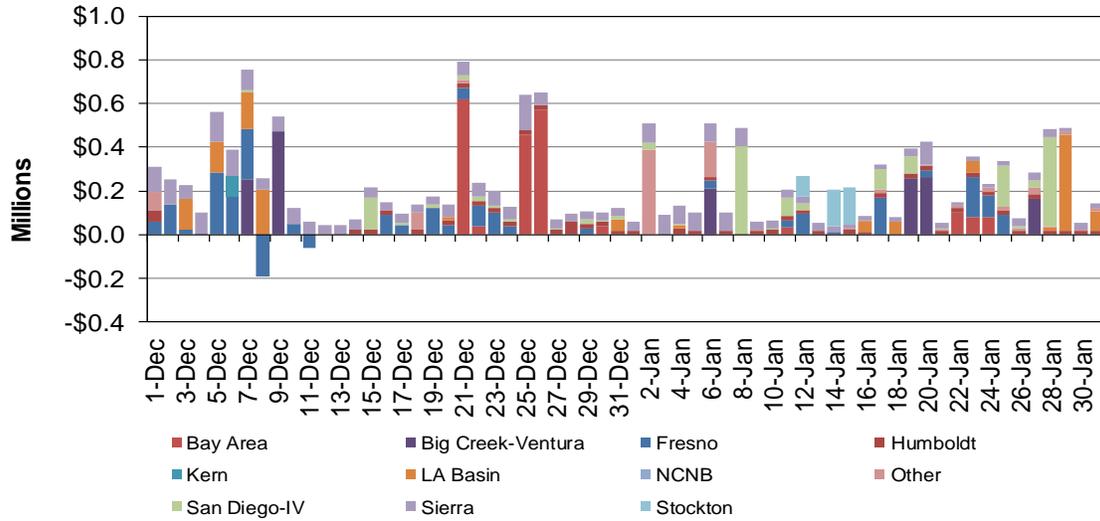


Figure 39: Monthly Cost in IFM by LCR

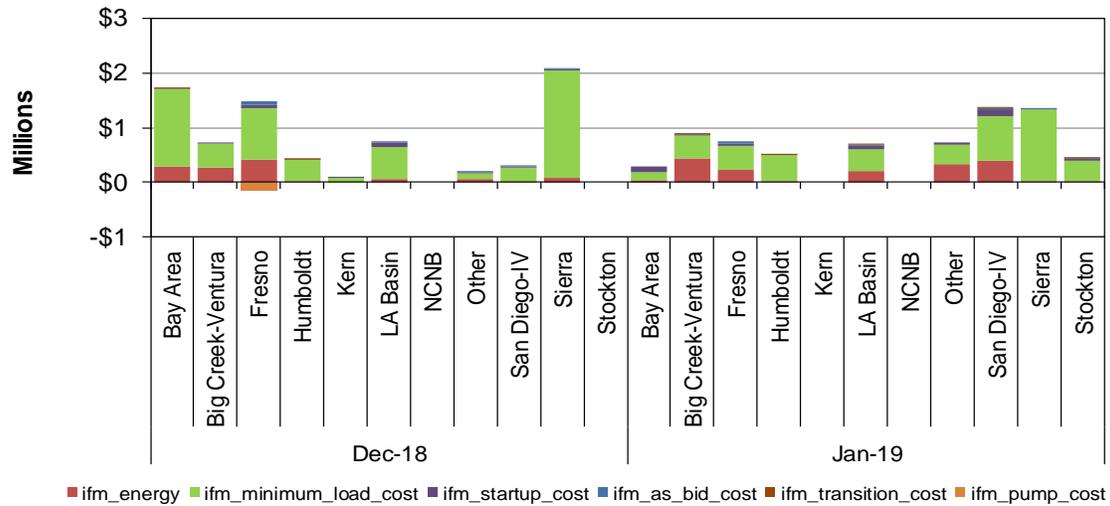


Figure 40 and Figure 41 show the daily and monthly cost related to BCR by type and UDC in IFM respectively.

Figure 40: Cost in IFM by UDC

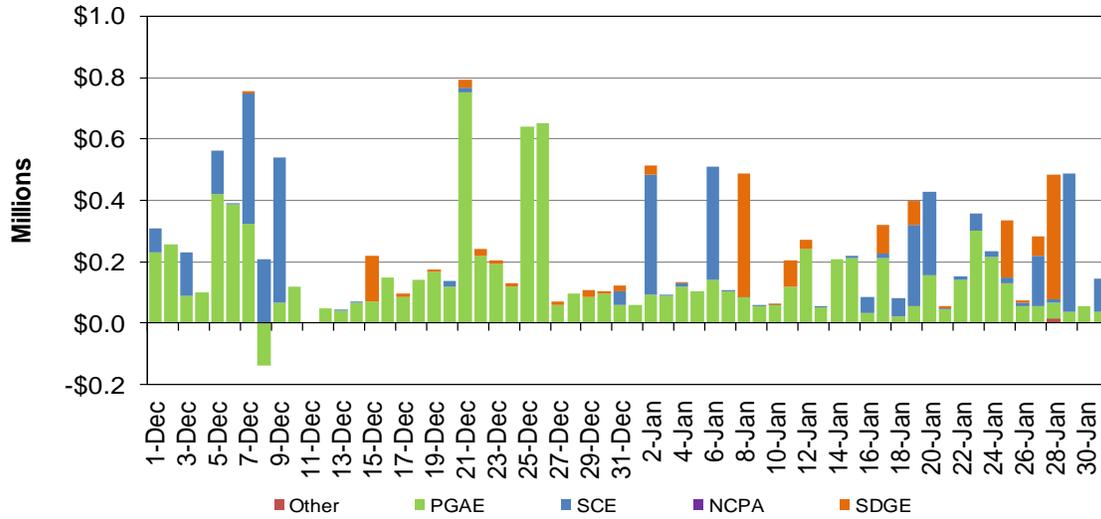
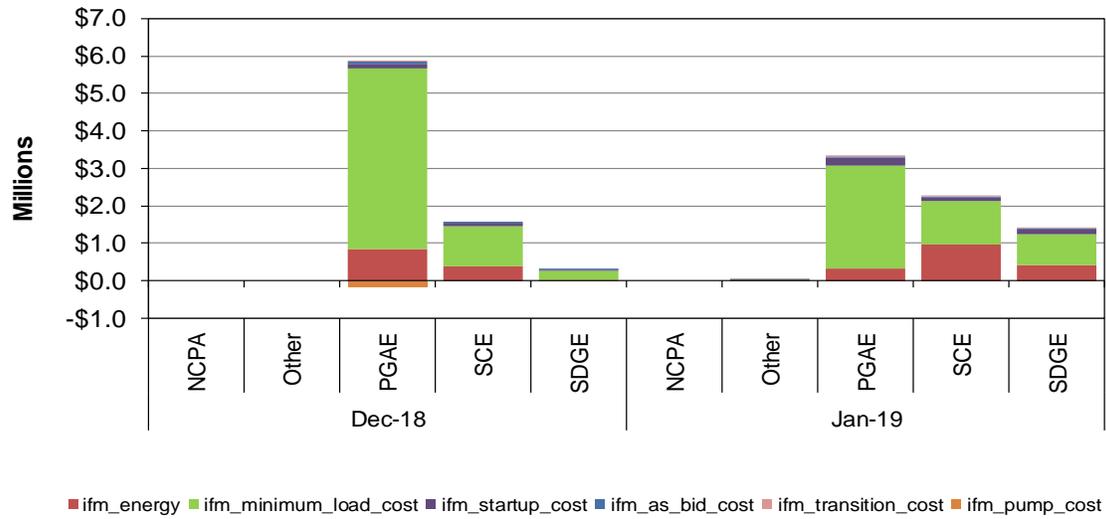


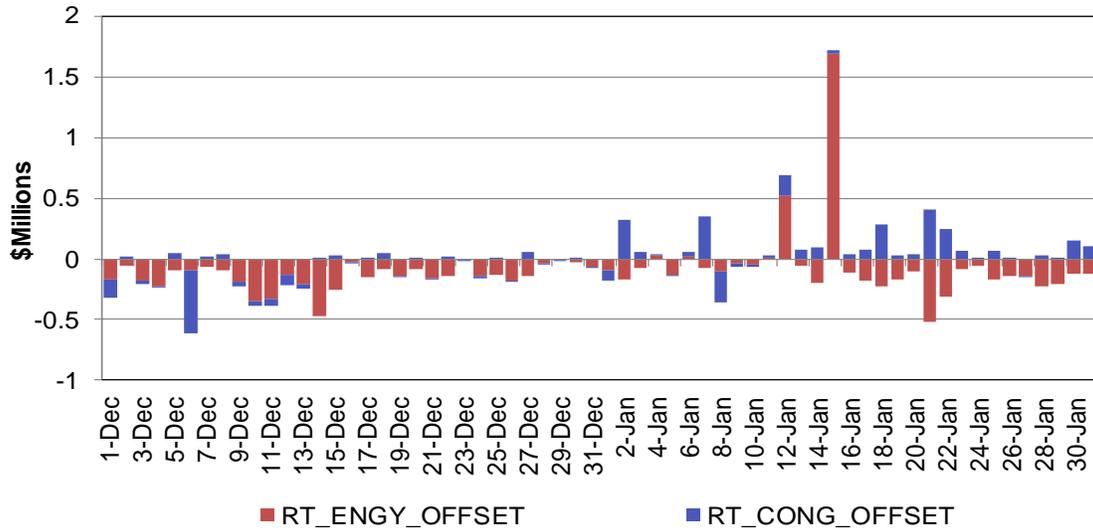
Figure 41: Monthly Cost in IFM by UDC



Real-time Imbalance Offset Costs

Figure 42 shows the daily real-time energy and congestion imbalance offset costs. Real-time energy offset cost increased to -\$1.50 million in January from -\$4.43 million in December. Real-time congestion offset cost rose to \$2.22 million in January from -\$0.73 million in December.

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.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 64 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

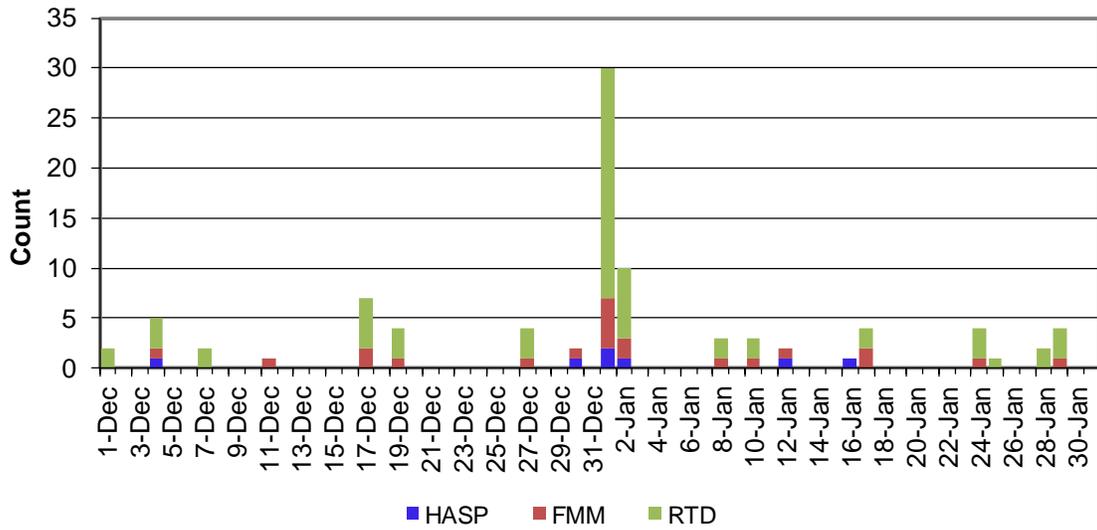
Table 7: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	
RUC	0	0
Real-Time		
FMM Interval 1	5	0
FMM Interval 2	5	0
FMM Interval 3	1	0
FMM Interval 4	8	0
Real-Time Dispatch	45	0

Figure 43 shows the frequency of IFM, HASP (FMM interval 2), FMM (intervals 1, 3 and 4), and RTD failures. On January 1, two HASP, five FMM and 23 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 43: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 44 shows the daily volume of exceptional dispatches, broken out by market type: real-time incremental dispatch and real-time decremental dispatch. The real-time exceptional dispatches are among one of the following types: a unit commitment at physical minimum; an incremental dispatch above the day-ahead schedule and a decremental dispatch below the day-ahead schedule.

The total volume of exceptional dispatch in January fell to 19,056 MWh from 55,010 MWh in December.

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

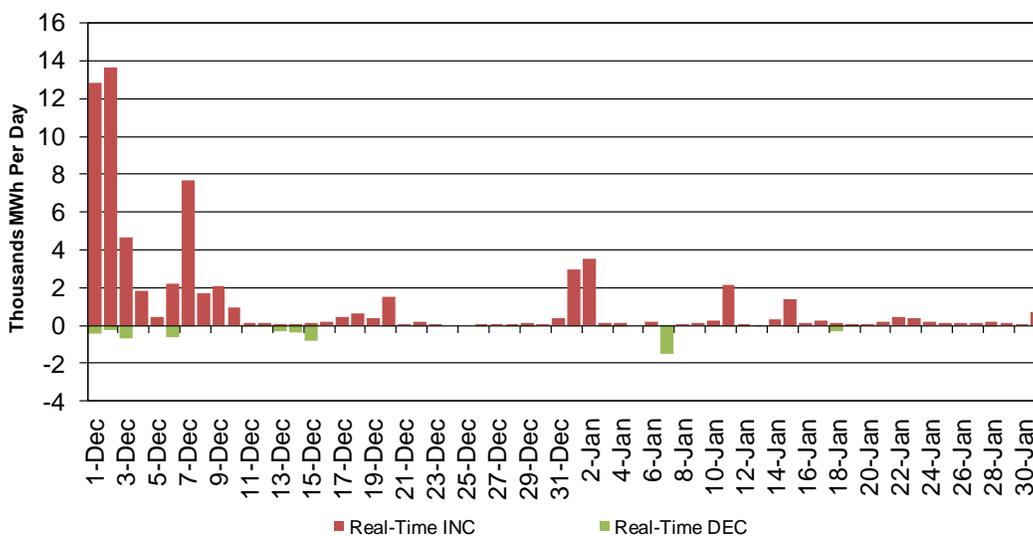


Figure 45 shows the volume of the exceptional dispatch broken out by reason.⁴ The majority of the exceptional dispatch volumes in January were driven by operating procedure number and constraint (16 percent), planned transmission outage (22 percent), voltage support (21 percent), and unplanned outage (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 45: Total Exceptional Dispatch Volume (MWh) by Reason

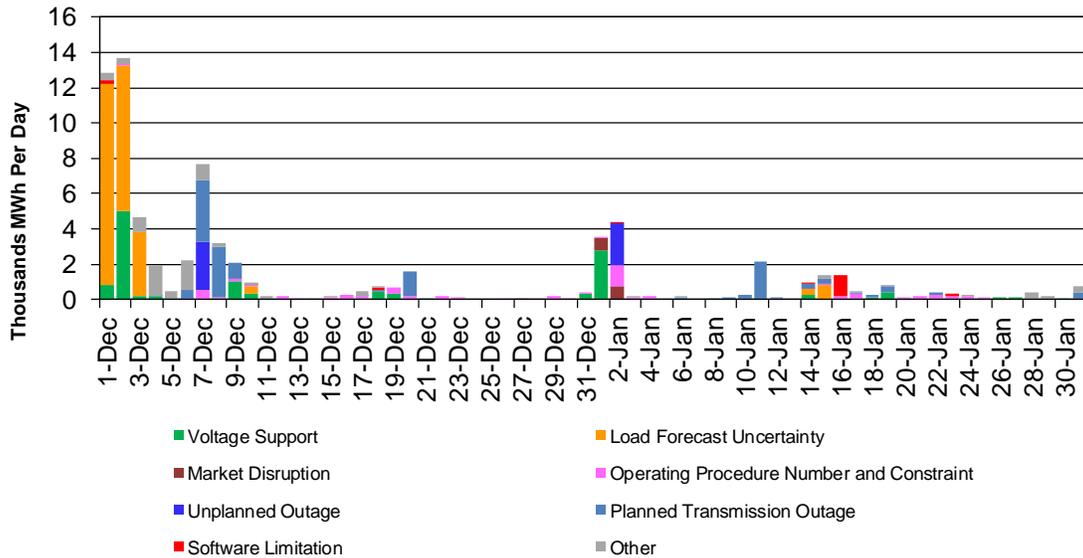
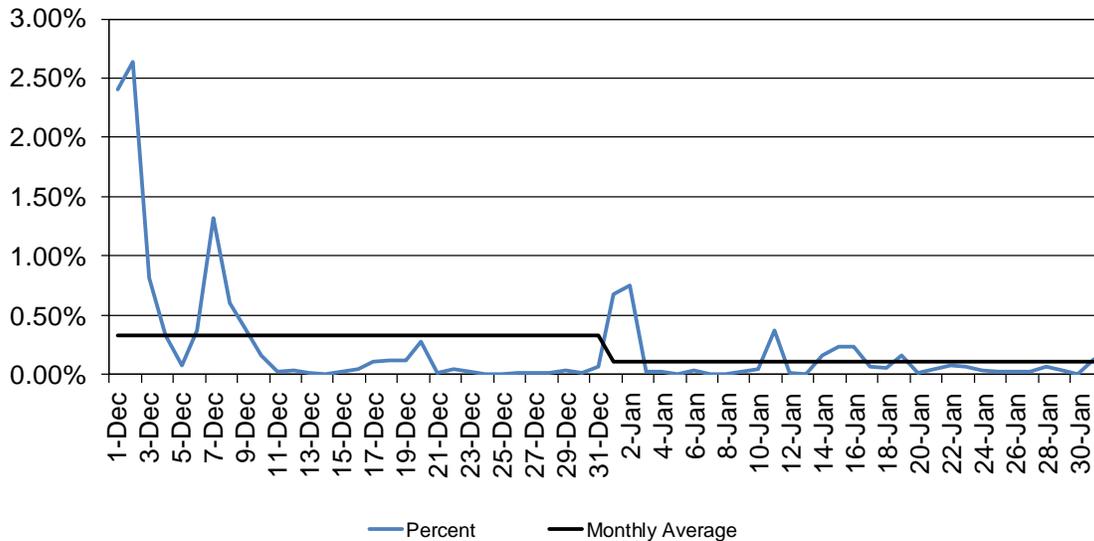


Figure 46 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage was 0.11 percent in January, decreasing from 0.32 percent in December.

Figure 46: Total Exceptional Dispatch as Percent of Load



Energy Imbalance Market

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

On December 1, 2015, NV Energy, the Nevada-based utility successfully began participating in the western Energy Imbalance Market (EIM). On October 1, 2016, Phoenix-based Arizona Public Service (AZPS) and Puget Sound Energy (PSEI) of Washington State successfully began full participation in the western Energy Imbalance Market.

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

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

Figure 47 shows daily simple average ELAP prices for PacifiCorp east (PACE), PacifiCorp West (PACW), NV Energy (NEVP), Arizona Public Service (AZPS), Puget Sound Energy (PSEI), Portland General Electric Company (PGE), Idaho Power (IPCO), and Powerex (BCHA) for all hours in FMM. The prices were generally quiet in January.

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

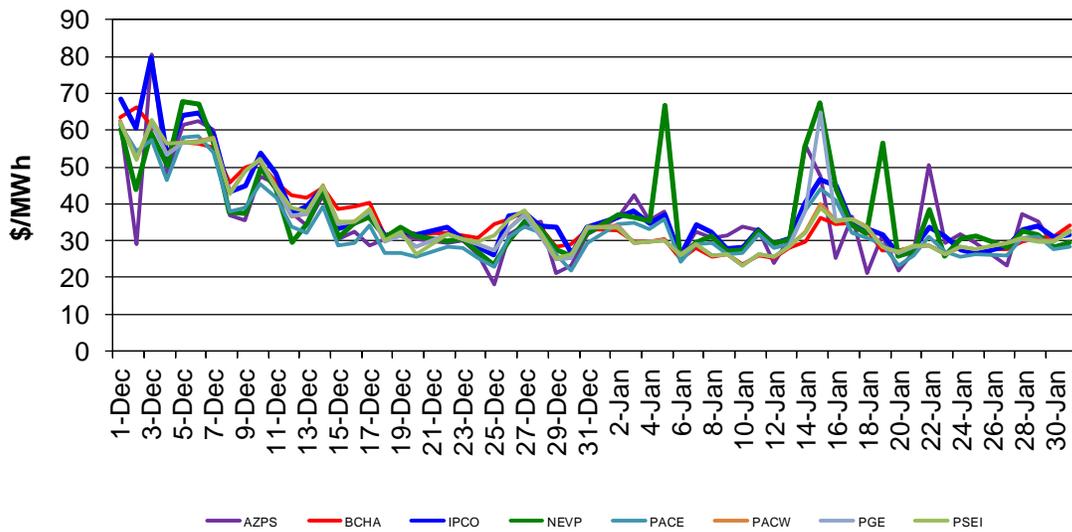


Figure 48 shows daily simple average ELAP prices for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA for all hours in RTD. The price for NEVP, was elevated on January 5 due to renewable deviation and reduction in net import. On January 15, the prices for AZPS, IPCO, NEVP, and PACE were elevated due to upward load adjustment and reduction in import.

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

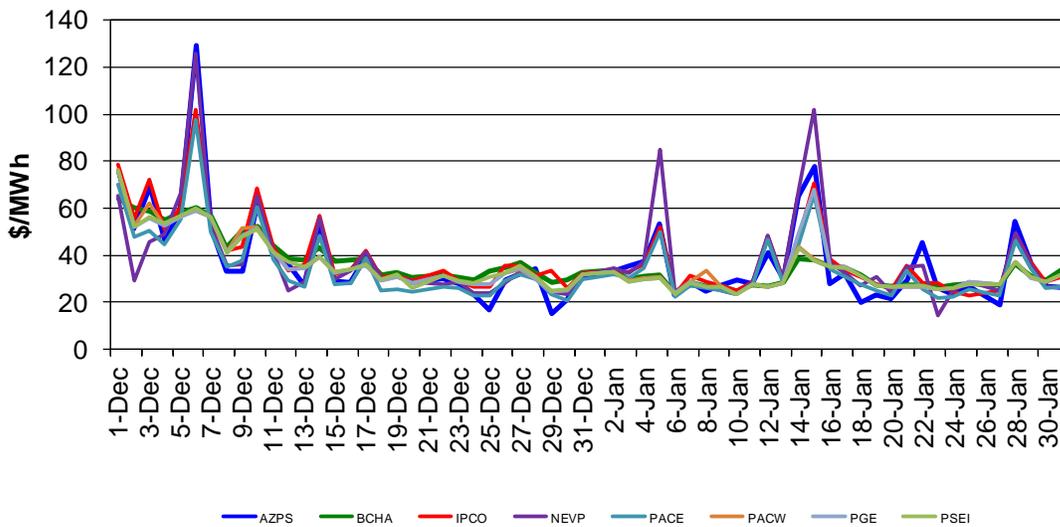


Figure 49 shows the daily price frequency for prices above \$250/MWh and negative prices in FMM for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above \$250/MWh increased to 0.18 percent in January from 0.05 percent in December. The cumulative frequency of negative prices inched up to 0.29 percent in January from 0.24 percent in December.

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

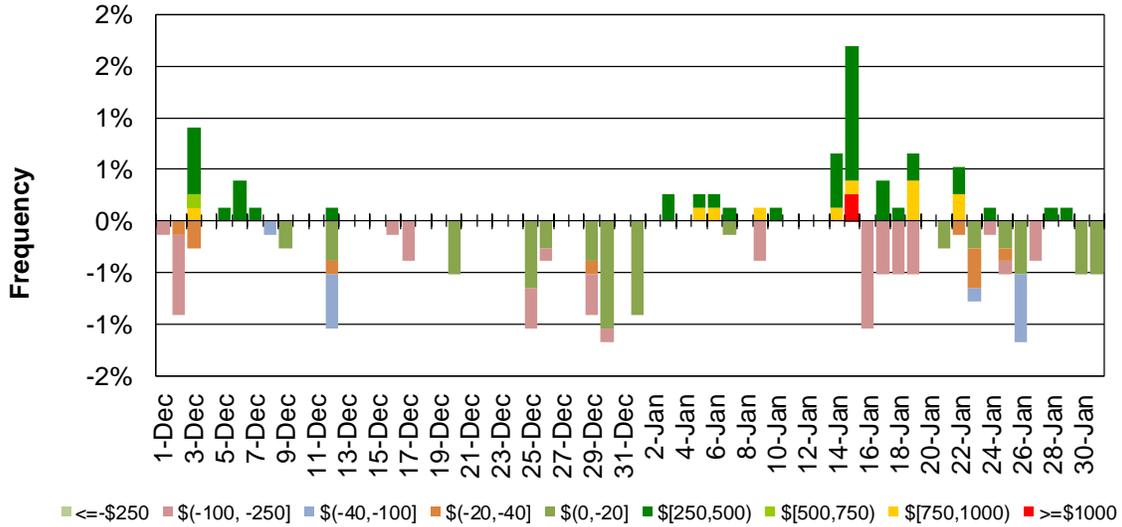


Figure 50 shows the daily price frequency for prices above \$250/MWh and negative prices in RTD for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA. The cumulative frequency of prices above \$250/MWh increased to 0.49 percent in January from 0.24 percent in December. The cumulative frequency of negative prices increased to 0.74 percent in January from 0.65 percent in December.

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

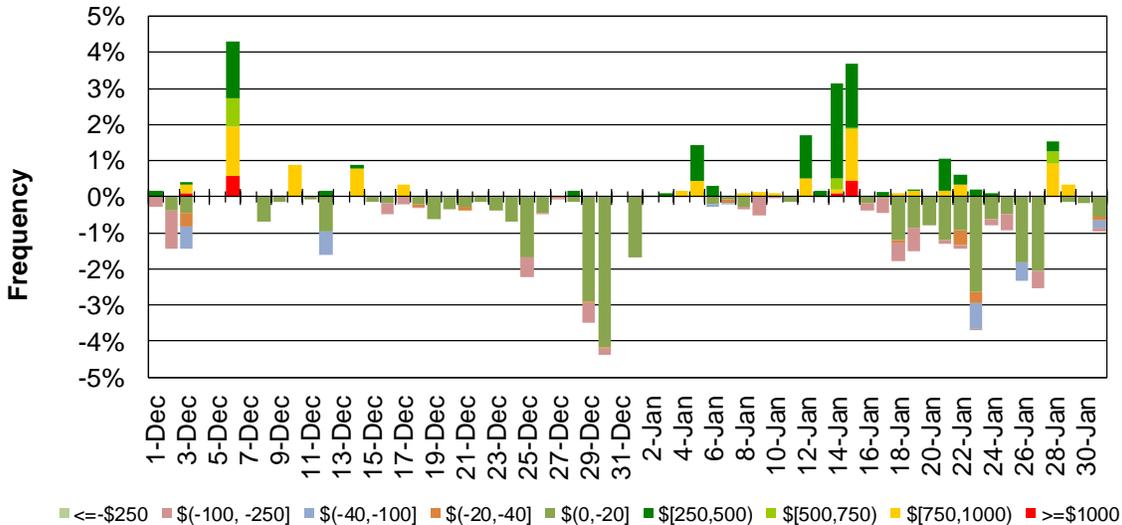


Figure 51 shows daily real-time imbalance energy offset cost (RTIEO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTIEO edged down to -\$3.63 million in January from -\$3.15 million in December.

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

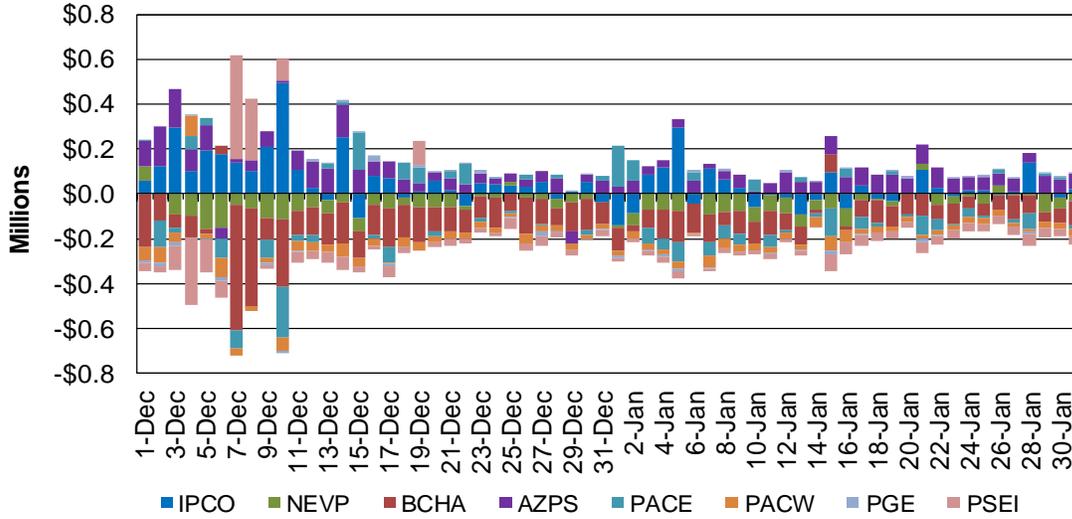


Figure 52 shows daily real-time congestion offset cost (RTCO) for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total RTCO declined to -\$2.05 million in January from -\$1.58 million in December.

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

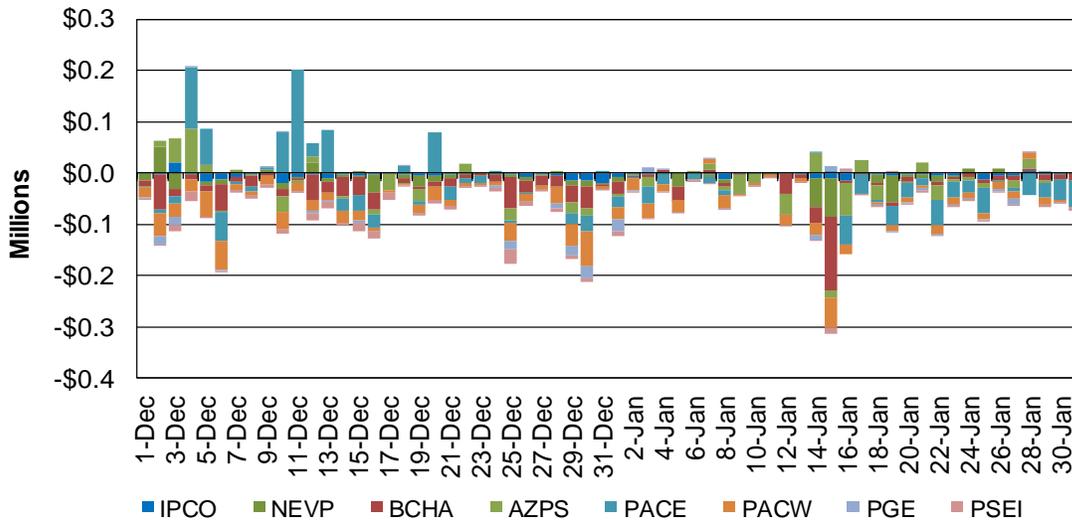


Figure 53 shows daily bid cost recovery for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total BCR rose to \$0.68 million in January from \$0.48 million in December.

Figure 53: EIM Bid Cost Recovery by Area

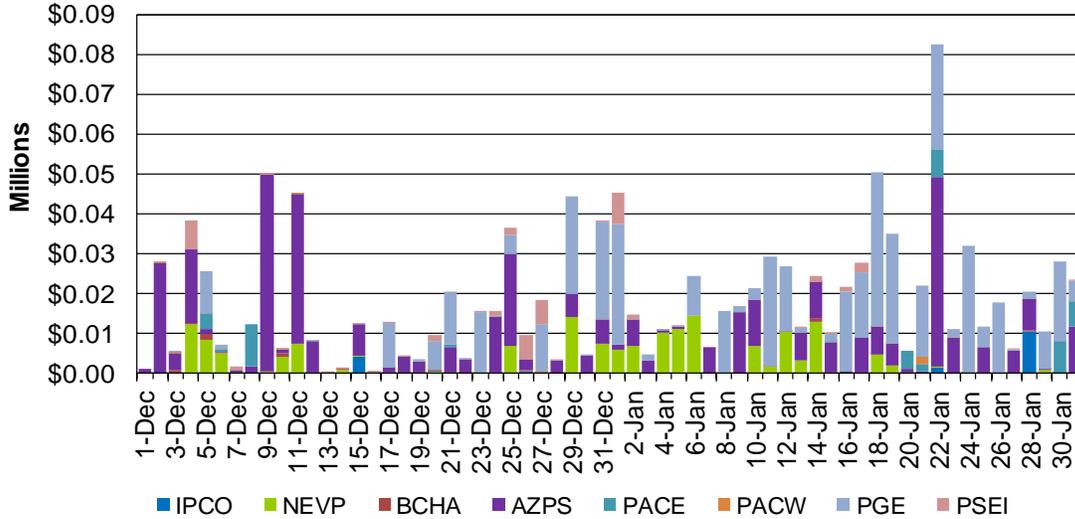


Figure 54 shows the flexible ramping up uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping up uncertainty payment in January decreased to \$0.13 million from \$0.31 million in December.

Figure 54: Flexible Ramping Up Uncertainty Payment

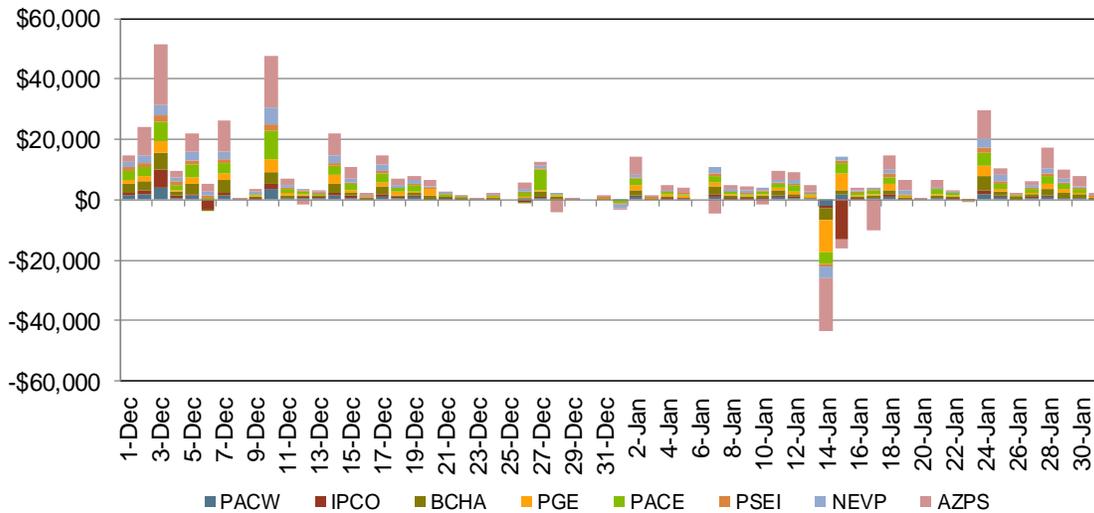


Figure 55 shows the flexible ramping down uncertainty payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total flexible ramping down uncertainty payment in January dropped to -\$11,833 from \$1,725 in December.

Figure 55: Flexible Ramping Down Uncertainty Payment

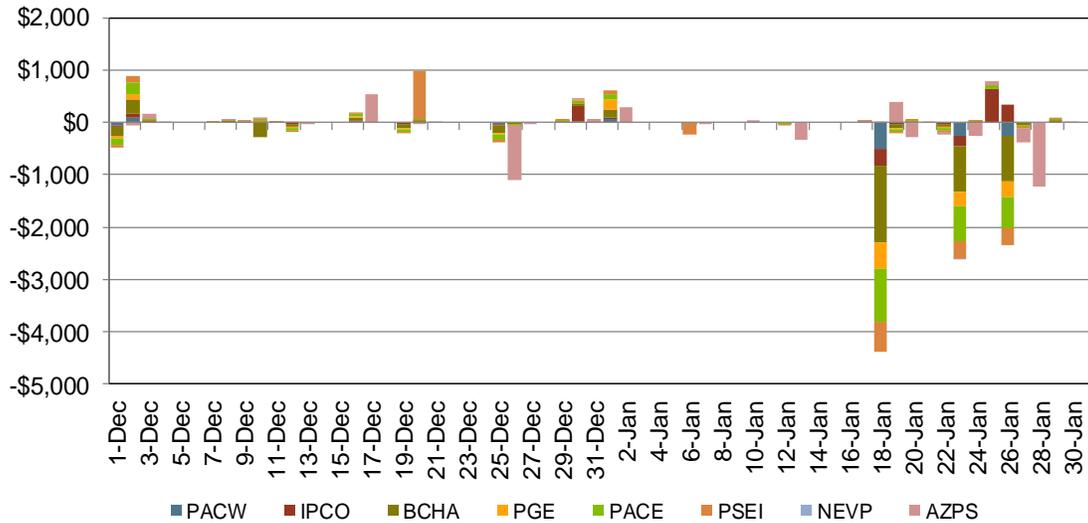
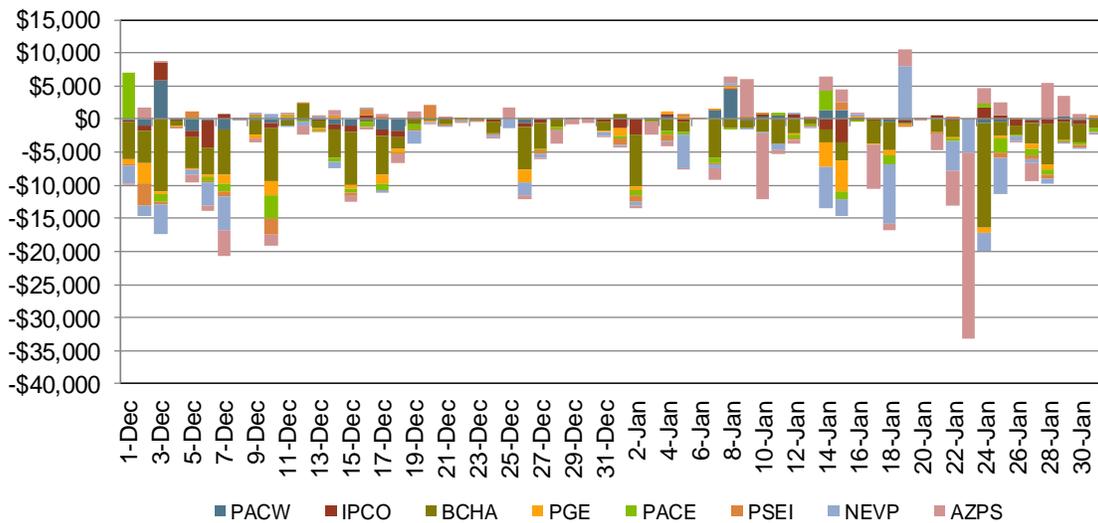


Figure 56 shows the flexible ramping forecast payment for PACE, PACW, NEVP, AZPS, PSEI, PGE, IPCO, and BCHA respectively. Total forecast payment in January inched down to -\$0.18 million from -\$0.16 million in December.

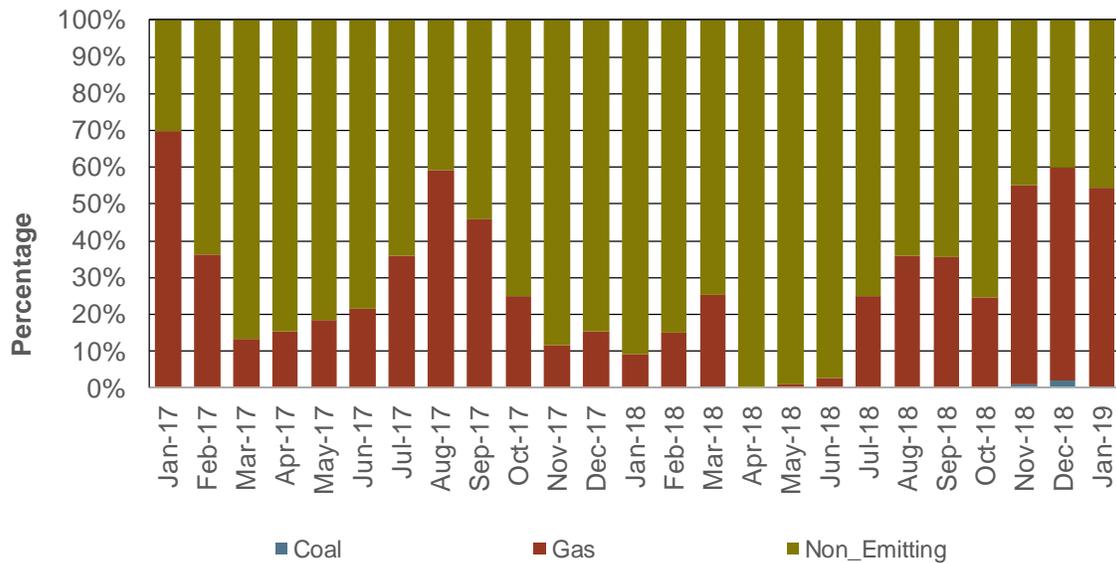
Figure 56: Flexible Ramping Forecast Payment



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 57 and Table 8 below.

Figure 57: 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-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%
May-18	0.00%	1.09%	98.91%	100%
Jun-18	0.00%	2.89%	97.11%	100%
Jul-18	0.00%	25.04%	74.96%	100%
Aug-18	0.00%	35.87%	64.13%	100%
Sep-18	0.00%	35.50%	64.50%	100%
Oct-18	0.00%	24.51%	75.49%	100%
Nov-18	1.16%	53.81%	45.03%	100%
Dec-18	2.00%	57.77%	40.23%	100%
Jan-19	0.46%	53.87%	45.67%	100%