Market Performance Report
October 2013

November 27, 2013

ISO Market Quality and Renewable Integration

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Executive Summary[1]

The market performance in October 2013 is summarized as follows.

- The peak loads were generally below September driven by lower temperature.
- In the day-ahead market, SDG&E prices were elevated by the transmission congestion in the second half of this month. In the real-time market, SCE and SDG&E prices were elevated in a few days due to the transmission congestion.
- Total congestion rent for interties in October was $4.92 million, higher than the $3.63 million in September. Most of the congestion rents accrued on PACI (23 percent) and Palo Verde (61 percent) interties.
- The congestion revenue rights market continued to experience revenue deficit, with revenue adequacy level at 56.39 percent.
- The monthly average ancillary service cost to load rose to $0.23/MWh in October from $0.17/MWh in September. There was no scarcity event in October.
- The cleared virtual demand and virtual supply were generally lower in October than September. The profits from convergence bidding rose to $1.12 million in October from $0.97 million in September.
- Total bid cost recovery payment in October dropped to $5.35 million from $7.11 million in September.
- Total volume of exceptional dispatch in October decreased to 34,117 MWh from 70,154 MWh in September. The monthly average of total exceptional dispatch volume (MWh) as a percentage of load declined to 0.18 percent in October from 0.33 percent in September.

[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**.

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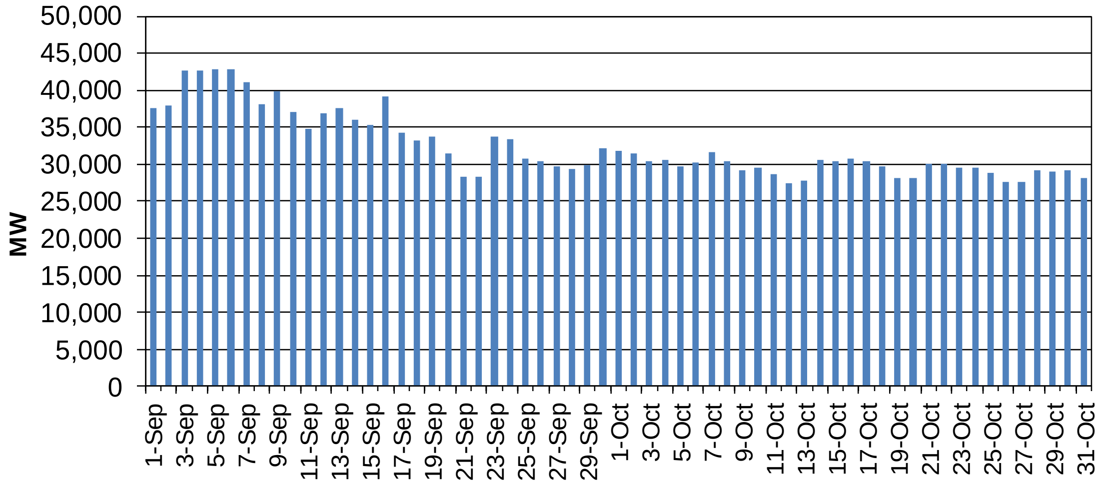
Market Characteristics

Loads

The peak loads in October were generally below September driven by lower temperature.

Figure 1: System Peak Load



Direct Market Performance Metrics

Energy

Day-Ahead Prices

Daily prices of the four DLAPs are shown in Figure 2. The binding constraints along with the associated DLAP locations and the occurrence dates are listed in Table 1.

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

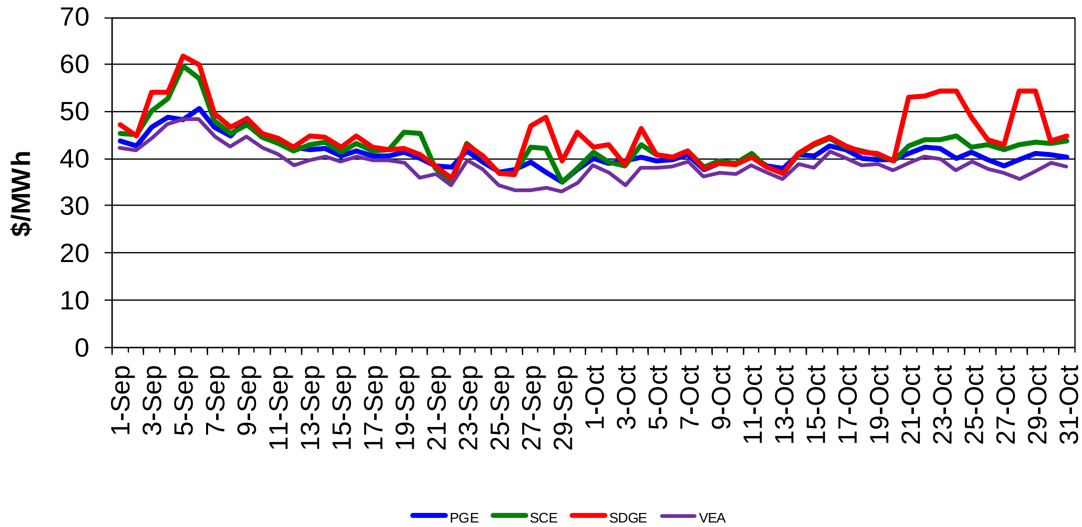


Table 1: Day-Ahead Transmission Constraints

DLAP	Date	Transmission Constraint
SDG&E	October 21-25	SLIC 2138237 TL50003_CFE_NG
SDG&E	October 28-29	SLIC 2164068 TL50001_NG, SOUTHLUGO_RV_BG

Real-Time Prices

Daily prices of the four DLAPs are shown in Figure 3. SCE and SDG&E LMPs were elevated from October 21-25 due to transmission congestion. The binding constraints along with the associated DLAP locations and the occurrence dates are listed in Table 2.

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

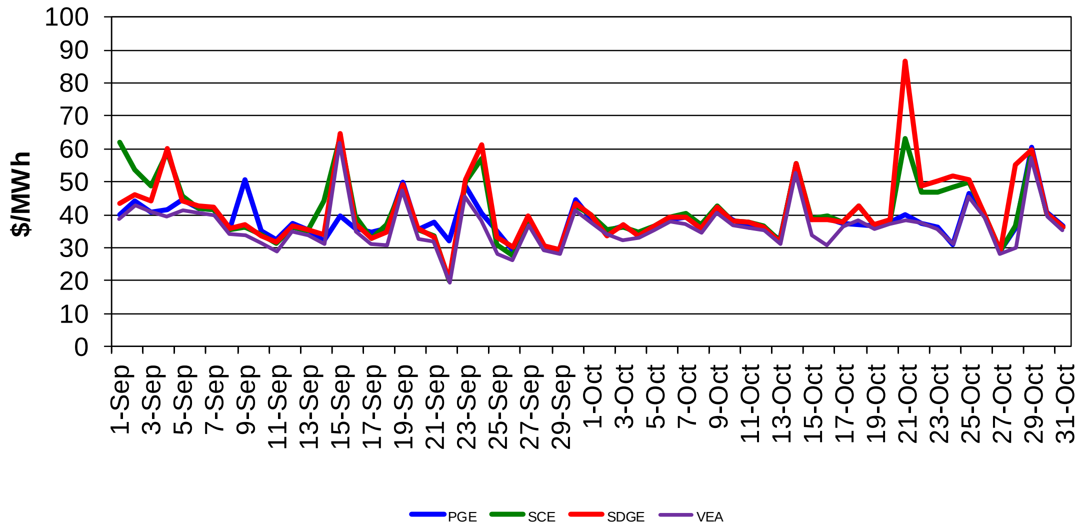
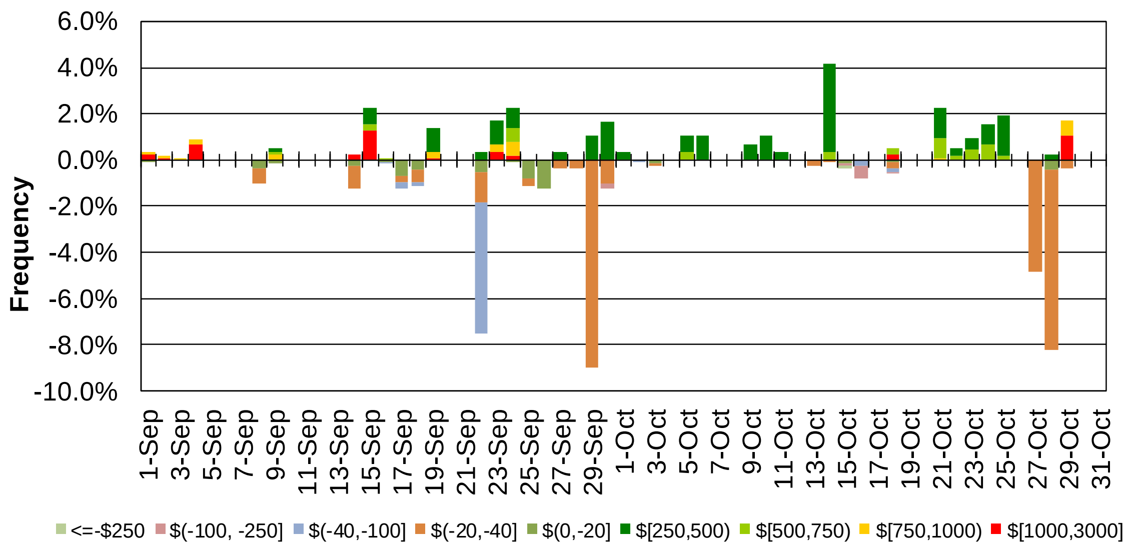


Table 2: Real-Time Transmission Constraints

DLAP	Date	Transmission Constraint
SCE, SDG&E	October 21, 23	SLIC 2138237 TL50003_CFE_NG, SOUTH_OF_LUGO NG
SCE, SDG&E	October 22, 24, 25	SOUTH_OF_LUGO

Figure 4 below shows the daily frequency of positive price spikes and negative prices by price range for the default LAPs in the five-minute real-time market. The cumulative frequency of prices above $250/MWh was 2.37 percent in October, increasing from 1.78 percent in September.

Figure 4: Daily Frequency of RTD LAP Positive Price Spikes and Negative Price



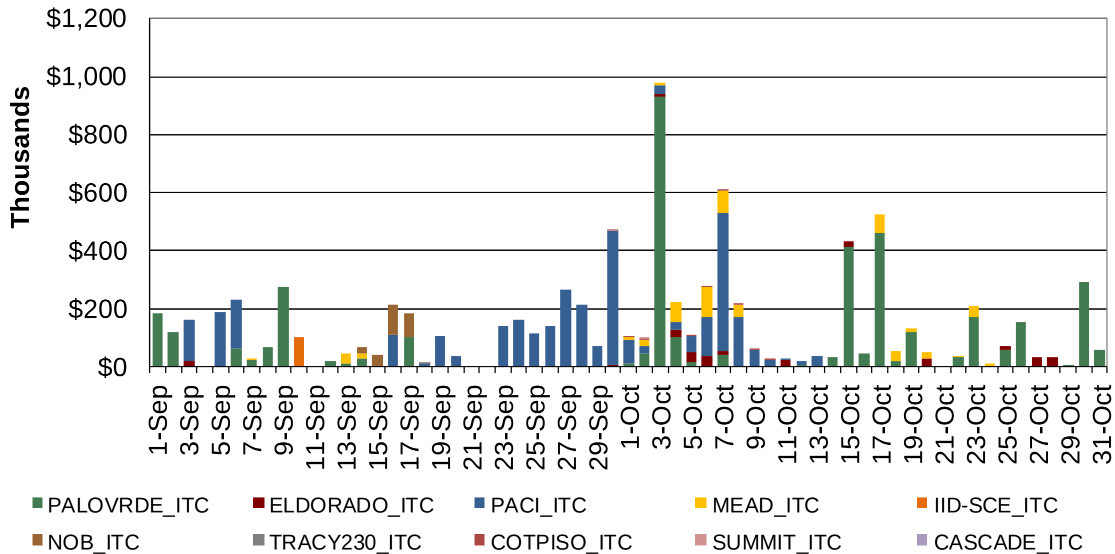
Congestion

Congestion Rents on Interties

Figure 5 below illustrates daily integrated forward market congestion rents by interties. The cumulative total congestion rent for interties in October was $4.92 million, higher than the $3.63 million in September. Most of the congestion rents in October accrued on PACI (23 percent) and Palo Verde (61 percent).

Total congestion rent on PACI intertie decreased to $1.14 million in October from $2.32 million in September. PACI was derated this month due to various line and equipment outages. Total congestion rent on Palo Verde intertie increased to $2.99 million in October from $0.88 million in September. Palo Verde intertie was derated in October due to Devers-Palo Verde capacitor being bypassed in conjunction with Olinda-Tracy 500 kV line clearance.

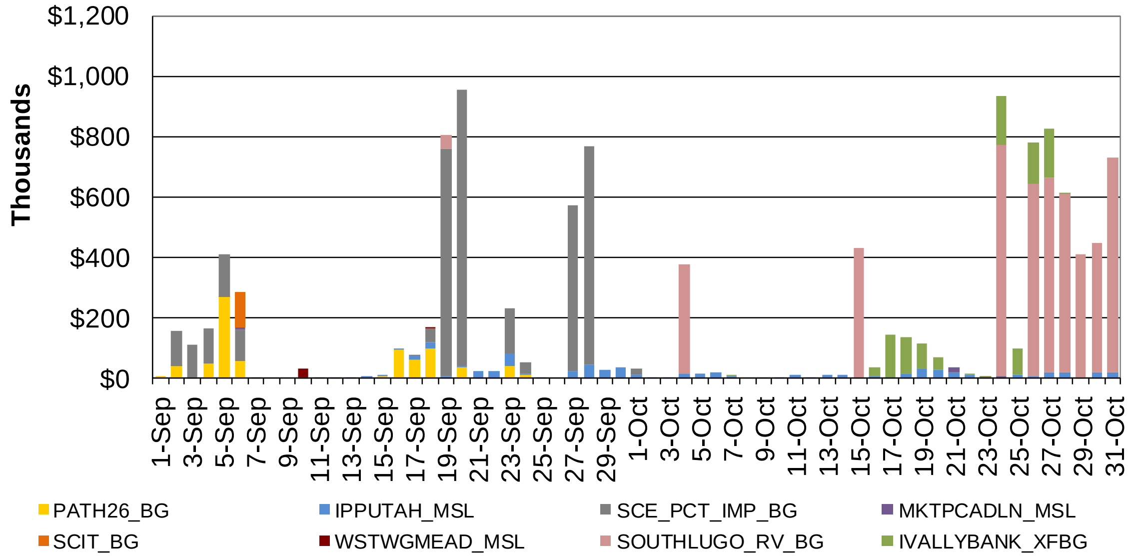
Figure 5: IFM Congestion Rents by Interties (Import)



Congestion Rents on Branch Groups and Market Scheduling Limits

Figure 6 illustrates congestion rents on selected branch groups and market scheduling limits in the integrated forward market. Total congestion rents for branch groups and market scheduling limits increased to $6.34 million in October from $5.17 million in September. Most of the congestion rents in October accrued on South of Lugo branch group (79 percent) and IVALLYBANK_XFBG (15 percent). The congestion rent on South of Lugo branch group rose to $4.98 million in October from $0.05 million in September.

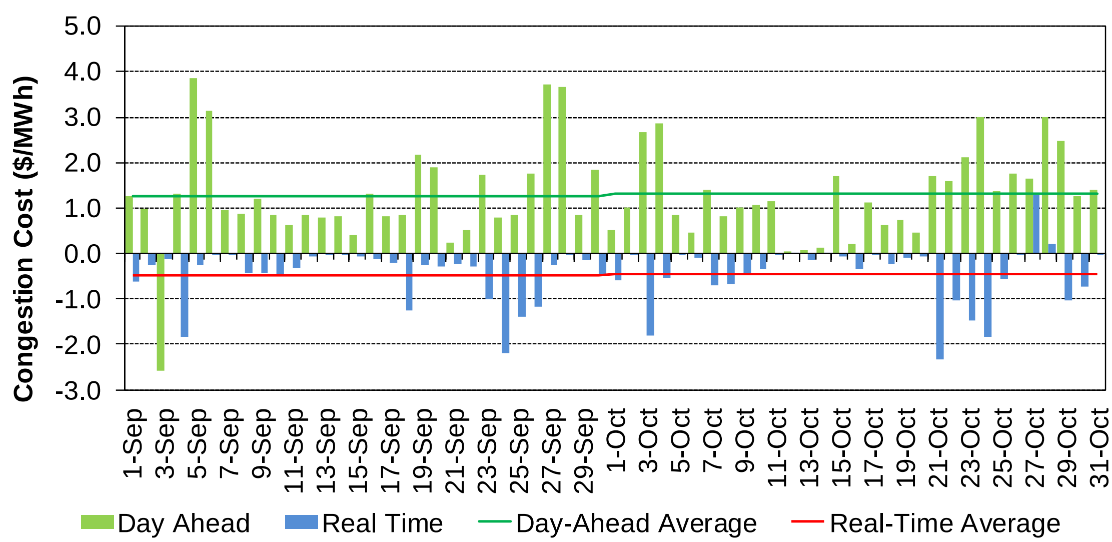
Figure 6: IFM Congestion Rents by Branch Groups and Market Scheduling Limits



Average Congestion Cost per Load Served

This metric quantifies the average congestion cost for serving one megawatt of load in the ISO system. Figure 7 shows the daily and monthly averages for the day-ahead and real-time markets respectively.

Figure 7: Average Congestion Cost per Megawatt of Served Load

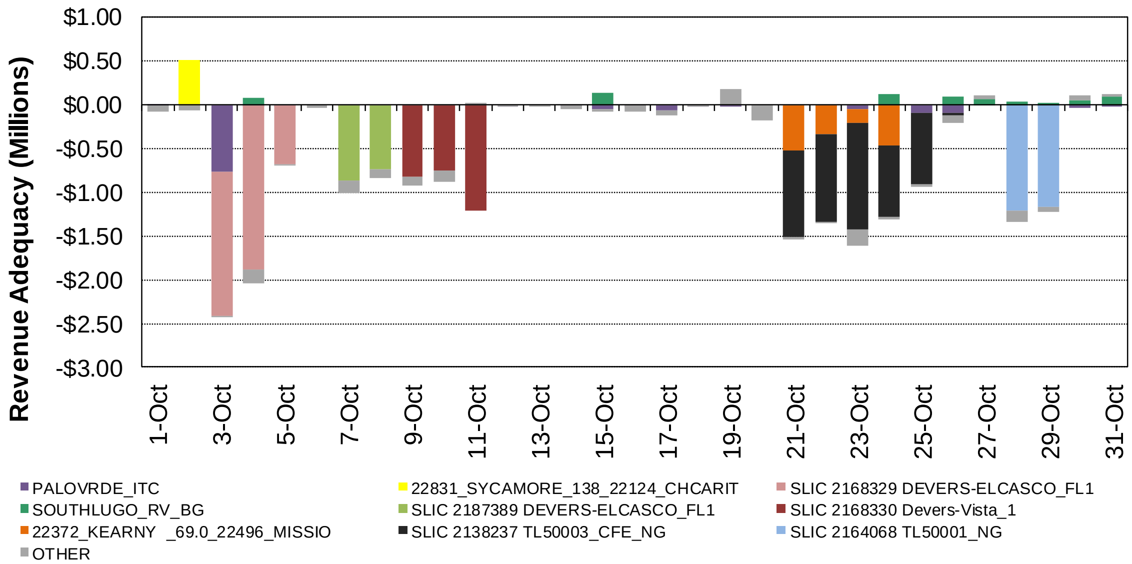


The average congestion cost per MWh of load served in the integrated forward market edged up to $1.31/MWh in October from $1.27/MWh in September. The average congestion cost per load served in the real-time market went to -$0.46/MWh in October from -$0.48/MWh in September.

Congestion Revenue Rights

Figure 8 illustrates the daily revenue adequacy for congestion revenue rights (CRRs) broken out by transmission element. The average CRR revenue deficit in October was $604,054, increasing from the average revenue deficit of $345,768 in September.

Figure 8: Daily Revenue Adequacy of Congestion Revenue Rights

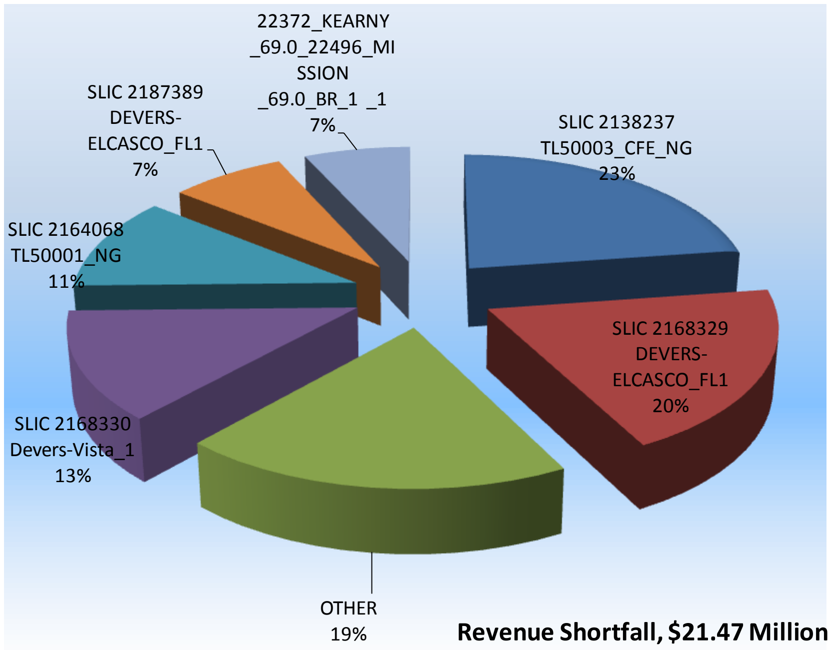


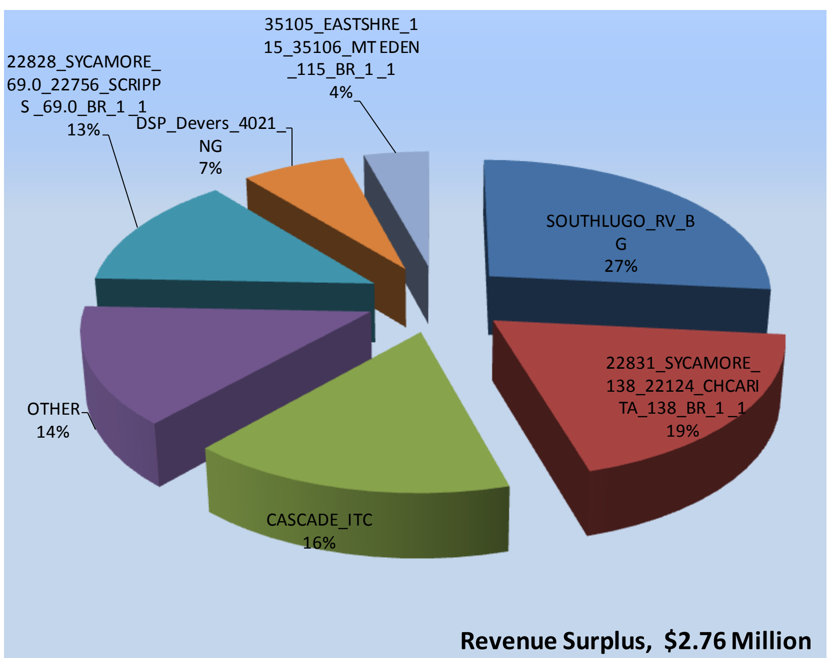
Overall, October 2012 experienced CRR revenue deficit. Revenue shortfalls were observed in 25 days this month.

- A nomogram (SLIC 2138237 TL50003_CFE_NG) was binding for six days in the IFM market, resulting in revenue shortfall of approximately $4.88 million.
- A nomogram (SLIC 2168329 DEVERS-ELCASCO_FL1) was binding for three days, resulting in revenue shortfall of approximately $4.21 million.
- Palo Verde intertie was binding for most days of this month and resulted in revenue shortfall of approximately $1.17 million.

The shares of the revenue surplus and deficit accruing on various congested transmission elements in May are shown in Figure 9 and the monthly summary for CRR revenue adequacy is provided in Table 3.

Figure 9: CRR Revenue Adequacy by Transmission Element





Overall, the total amount collected from the integrated forward market was not sufficient to cover the net payments to congestion revenue right holders and the cost of the exemption for existing rights. Out of the total congestion rents, 2.86 percent was used to cover the cost of exemptions for existing rights. The net total congestion revenues in October were in deficit by $18.73 million, in comparison to the deficit of $10.37 million in September. The auction revenues credited to the balancing account for October were $7.12 million. The balancing account for October had a net deficit of approximately $11.40 million, which will be allocated to measured demand.

Table 3: CRR Revenue Adequacy Statistics

Concept	Amount
IFM Congestion Rents	$24,921,679.70
Existing Right Exemptions	-$711,654.45
Available Congestion Revenues	$24,210,025.26
CRR Payments	$42,935,696.95
CRR Revenue Adequacy	-$18,725,671.69
Revenue Adequacy Ratio	56.39%
Annual Auction Revenues	$2,926,383.07
Monthly Auction Revenues	$4,192,221.49
CRR Settlement Rule	$213,674.84
Allocation to Measured Demand	-$11,393,392.29

Ancillary Services

IFM (Day-Ahead) Average Price

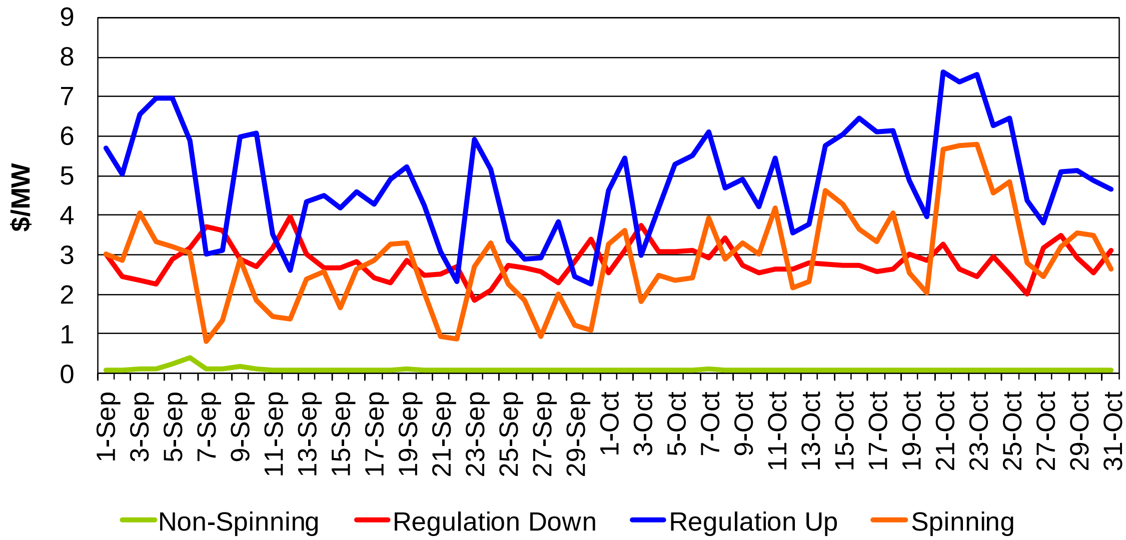
Table 4 shows the monthly IFM average ancillary service procurements and the monthly average prices. In October the monthly average procurement decreased for all four types of ancillary services.

Table 4: 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
Oct-13	347	323	796	801	$5.27	$2.86	$3.45	$0.08
Sep-13	354	337	922	926	$4.39	$2.77	$2.24	$0.11
Percent Change	-2.10%	-4.30%	-13.60%	-13.46%	19.87%	3.47%	54.46%	-23.35%

The monthly average prices increased for regulation up, regulation down, and spinning reserve in October. Figure 10 shows the daily IFM average ancillary service prices. The average prices were relatively stable this month.

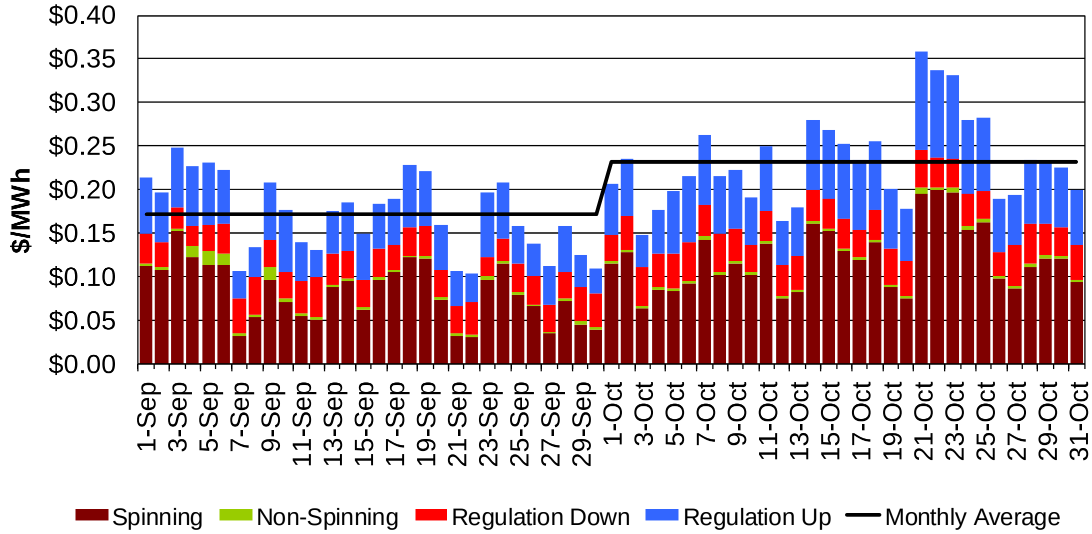
Figure 10: IFM (Day-Ahead) Ancillary Service Average Price



Ancillary Service Cost to Load

The monthly average cost to load rose to $0.23/MWh in October from $0.17/MWh in September.

Figure 11: System (Day-Ahead and Real-Time) Average Cost to Load



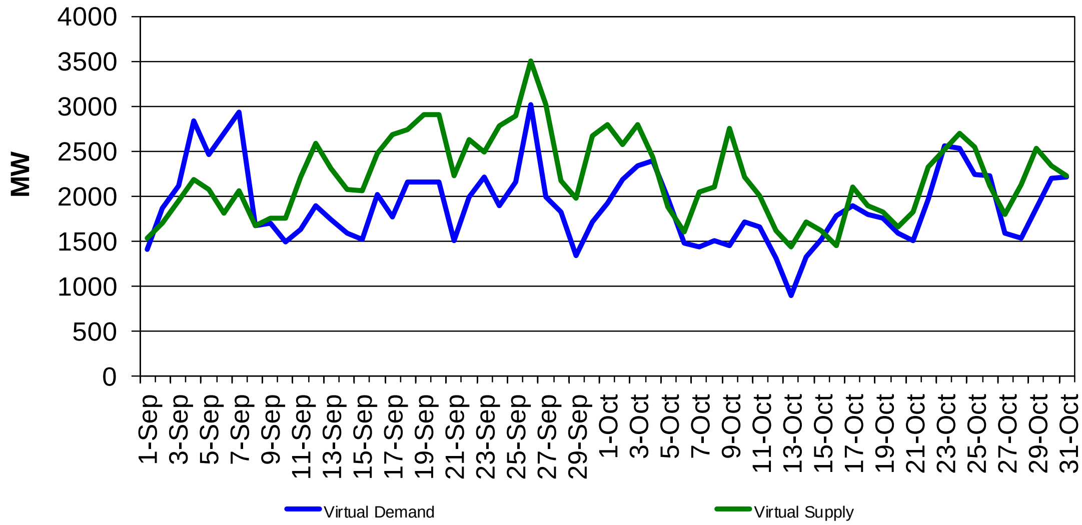
Scarcity Events

Reserve scarcity pricing is a mechanism that will allow prices for reserves and energy to rise automatically when there is inadequate supply in the market to meet the minimum procurement requirements of reserves and regulation on the ISO grid. The ancillary services scarcity pricing mechanism is triggered when the California ISO is not able to procure the target quantity of one or more ancillary services in the IFM and real-time market runs. In October, there was no scarcity event.

Convergence Bidding

Figure 12 below shows the daily average volume of cleared virtual bids in IFM for virtual supply and virtual demand. The cleared virtual demand and virtual supply were generally lower in October than September.

Figure 12: Cleared Virtual Bids



Convergence bidding tends to cause the day-ahead market and real-time market prices to move closer together, or "converge". Figure 13 shows the energy prices (namely the energy component of the LMP) in IFM, HASP, and RTD.

Figure 13: IFM, HASP, and RTD Prices

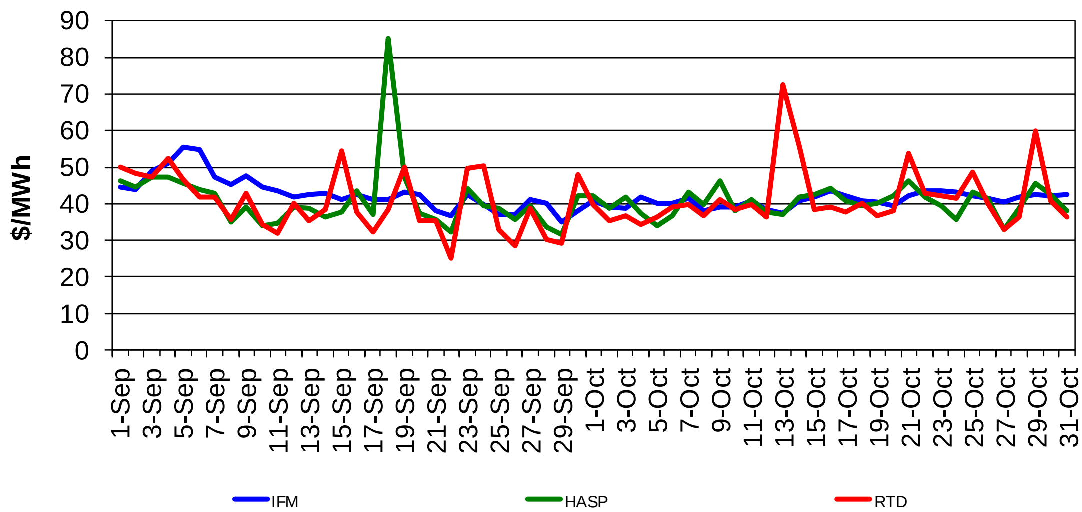
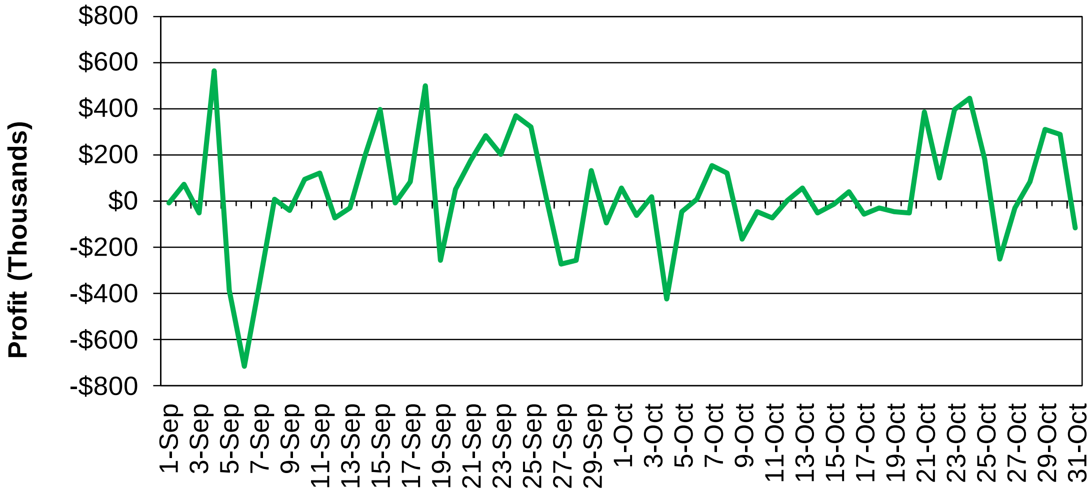


Figure 14 shows the profits that convergence bidders receive from convergence bidding. The daily profit is the sum of three settlement charge codes (CC6013, CC6053, and CC6473). The total profits from convergence bidding increased to $1.12 million in October from $0.97 million in September.

Figure 14: Convergence Bidding Profits



Indirect Market Performance Metrics

Bid Cost Recovery

Figure 15 shows the daily uplift costs due to exceptional dispatch payments (charge codes CC6488, CC6482, and CC6470). The monthly uplift costs in October increased to $0.46 million from $0.07 million in September.

Figure 15: Exceptional Dispatch Uplift Costs

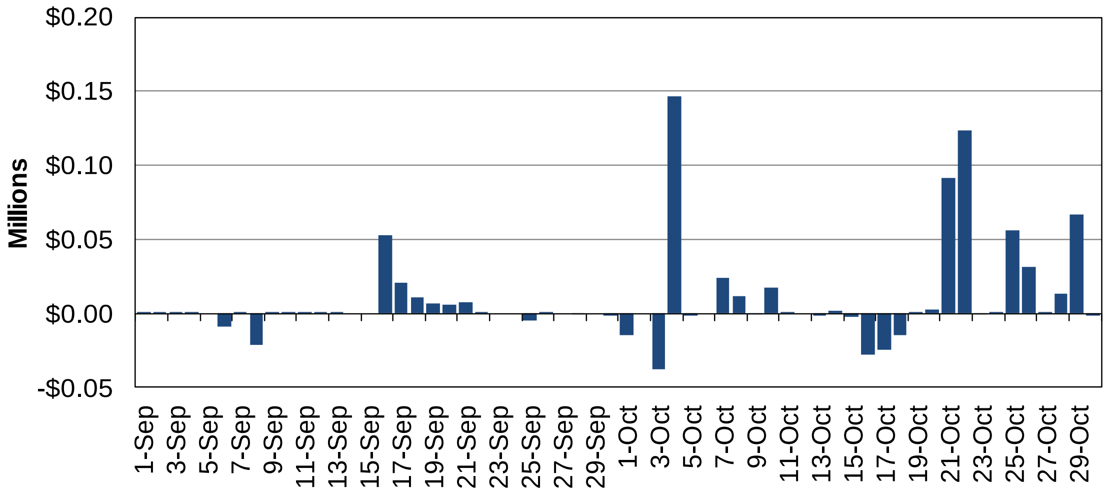


Figure 16 shows the allocation of bid cost recovery payment in the IFM, RUC and RTM markets. The total bid cost recovery for October dropped to $5.35 million from $7.11 million in September. Out of the total monthly bid cost recovery payment for the three markets in October, the IFM market contributed 26 percent, RTM contributed 49 percent and RUC contributed 25 percent of the total bid cost recovery payment.

Figure 16: Bid Cost Recovery Allocation

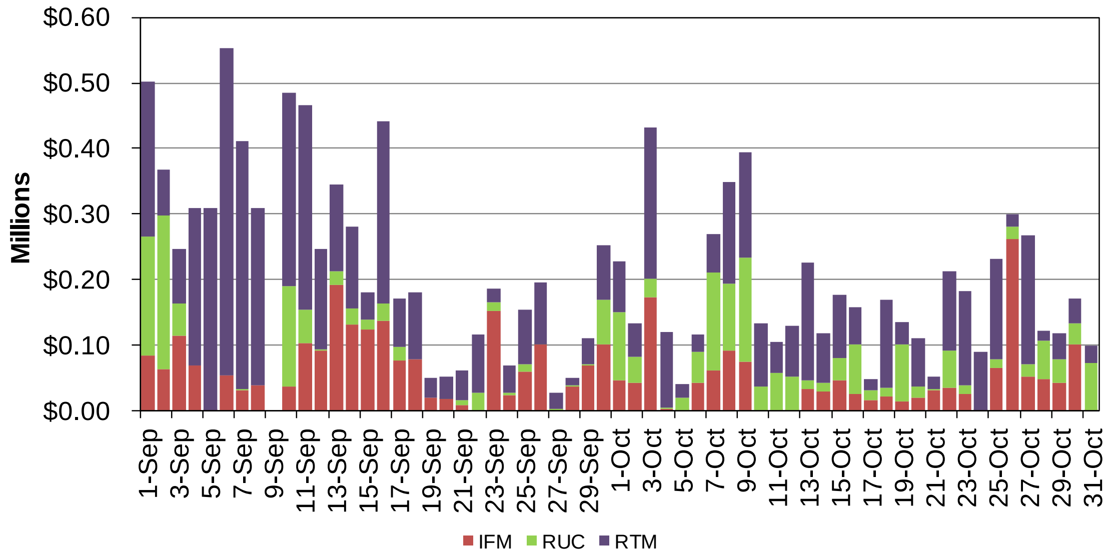


Figure 17 shows the bid cost recovery allocation in RUC. The RUC cost in October was driven mainly by minimum load cost (MLC). The monthly average BCR allocation in RUC for October was approximately $65,409.

Figure 17: Bid Cost Recovery Allocation in RUC

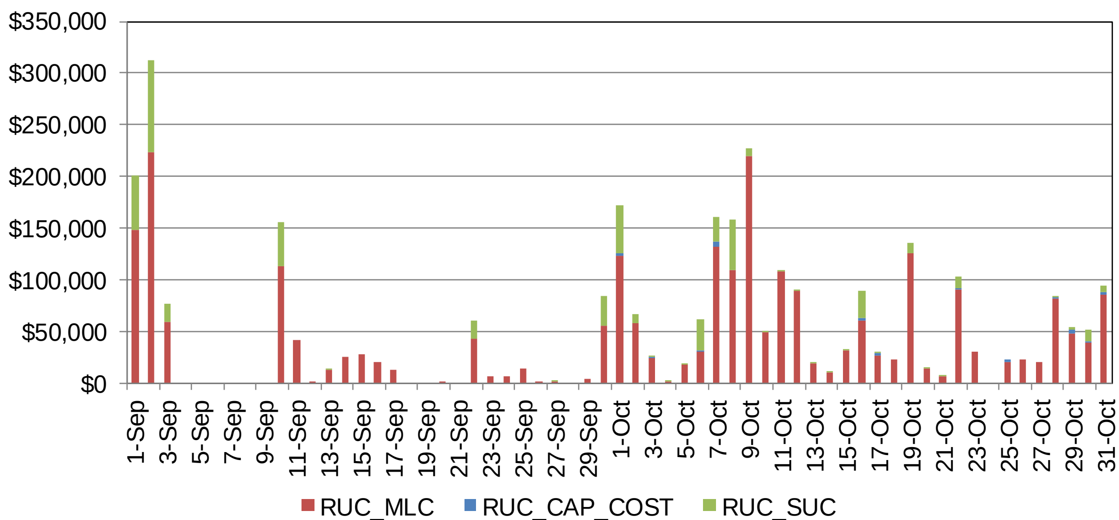


Figure 18 shows the bid cost recovery allocation in RTD. The minimum load cost (MLC) and energy cost contributed largely to the BCR in October. The monthly average BCR allocation in RTD for October was approximately $77,756.

Figure 18: Bid Cost Recovery Allocation in RTD

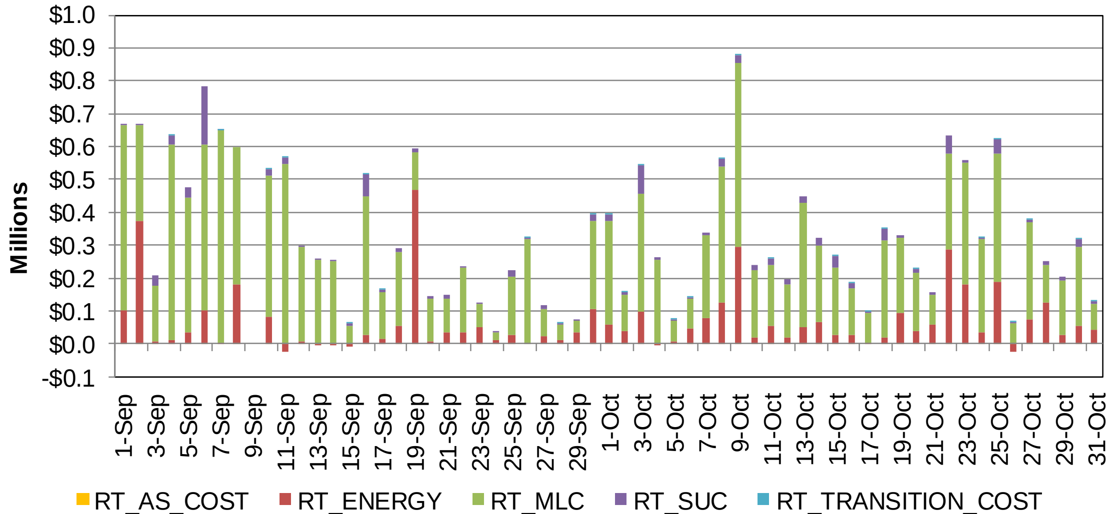
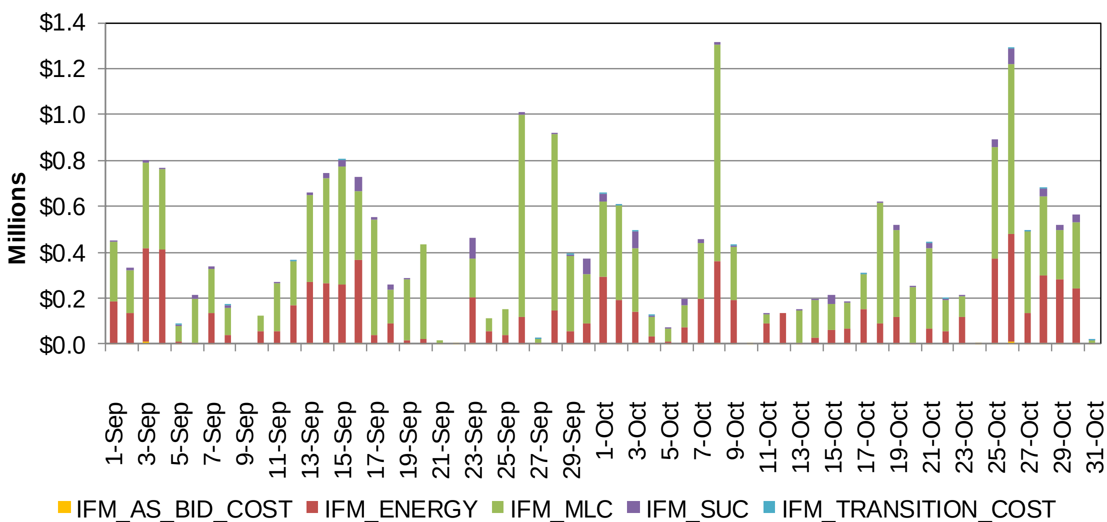


Figure 19 shows the bid cost recovery allocation in IFM. The monthly average BCR allocation in IFM for October was approximately $32,111. The Minimum Load Cost (MLC) and energy cost contributed largely to the BCR in IFM in October.

Figure 19: Bid Cost Recovery Allocation in IFM



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 in the event of a market disruption, to prevent a market disruption, or to minimize the extent of a market disruption.

Table 5 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 May. The ISO markets include IFM, RUC, real-time unit commitment (RTUC) and RTD processes. The total number of market disruptions in October was 55. Figure 20 shows the frequency of IFM, HASP (RTUC interval 2), RTUC (intervals 1, 3 and 4), and RTD failures.

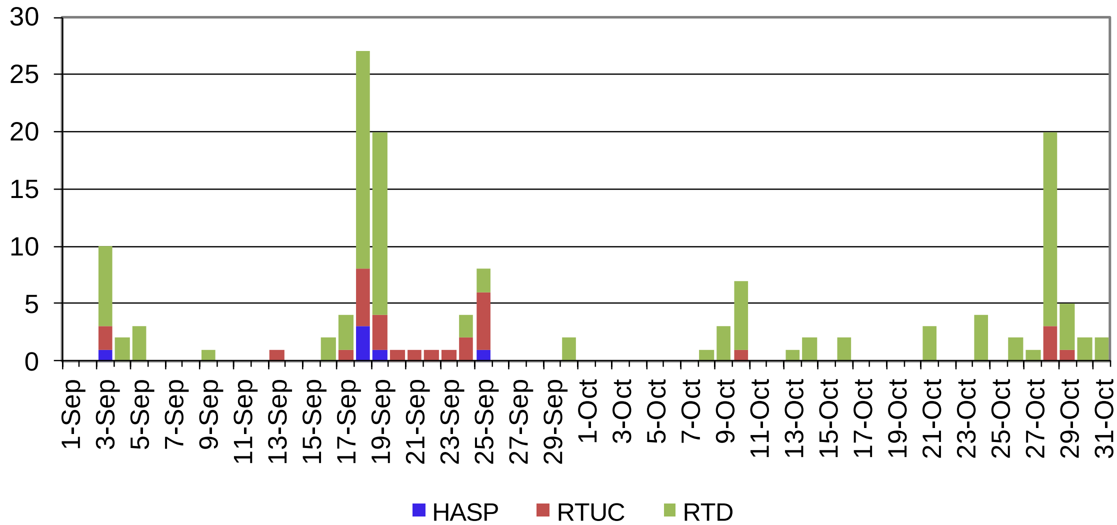
Table 5: Summary of Market Disruption

Type of CAISO Market	Market Disruption or Reportable	Removal of Bids (including Self-Schedules)
Day-Ahead		
IFM	0	0
RUC	0	0
Real-Time		
Real-Time Unit Commitment Interval 1	1	0
Real-Time Unit Commitment Interval 2	0	0
Real-Time Unit Commitment Interval 3	3	0
Real-Time Unit Commitment Interval 4	1	0
Real-Time Dispatch	50	0

On October 28, there were 20 market disruptions, including three RTUC and 17 RTD disruptions due to application not running, driven by software issue.

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

Figure 20: Frequency of Market Disruption



Manual Market Adjustment

Exceptional Dispatch

Figure 21 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: i) a unit commitment at physical minimum, ii) an incremental dispatch above the day-ahead schedule, and iii) a decremental dispatch below the day-ahead schedule.

The total volume of exceptional dispatch in October decreased to 34,117 MWh from 70,154 MWh in September.

Figure 21: Total Exceptional Dispatch Volume (MWh) by Market Type

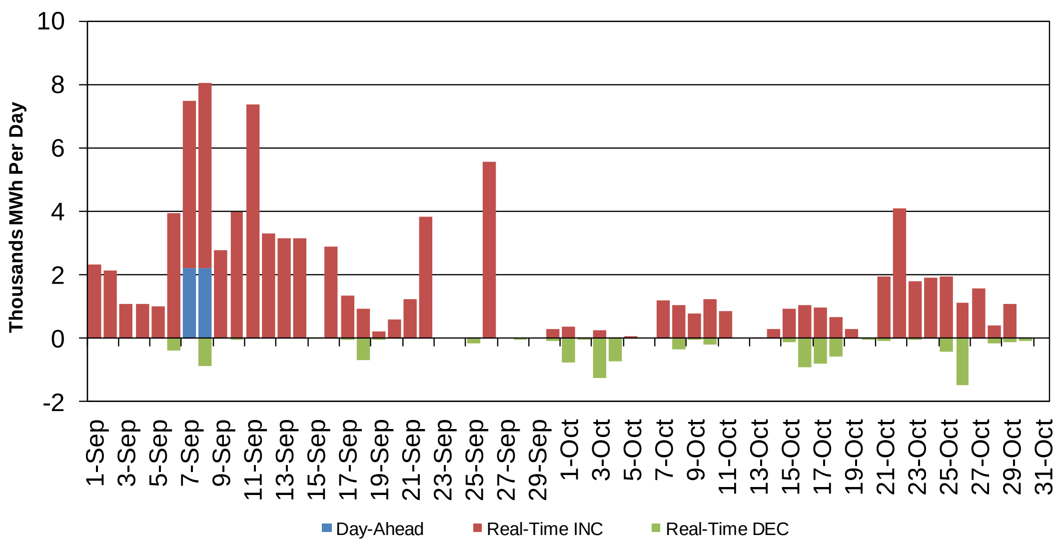


Figure 22 shows the volume of the exceptional dispatch broken out by reason.[3] The majority of the exceptional dispatch volumes in October were driven by transmission outage (66 percent), system energy (11 percent), and 6510 (8 percent).

[3] For details regarding the reason of exceptional dispatch please read the white paper on exceptional dispatch published on the ISO website: **http://www.caiso.com/1c89/1c89d76950e00.html**. For the description of the operating procedure, please read the operating procedures index list at **http://www.caiso.com/Documents/OperatingProcedureIndex.pdf**.

Figure 22: Total Exceptional Dispatch Volume (MWh) by Reason

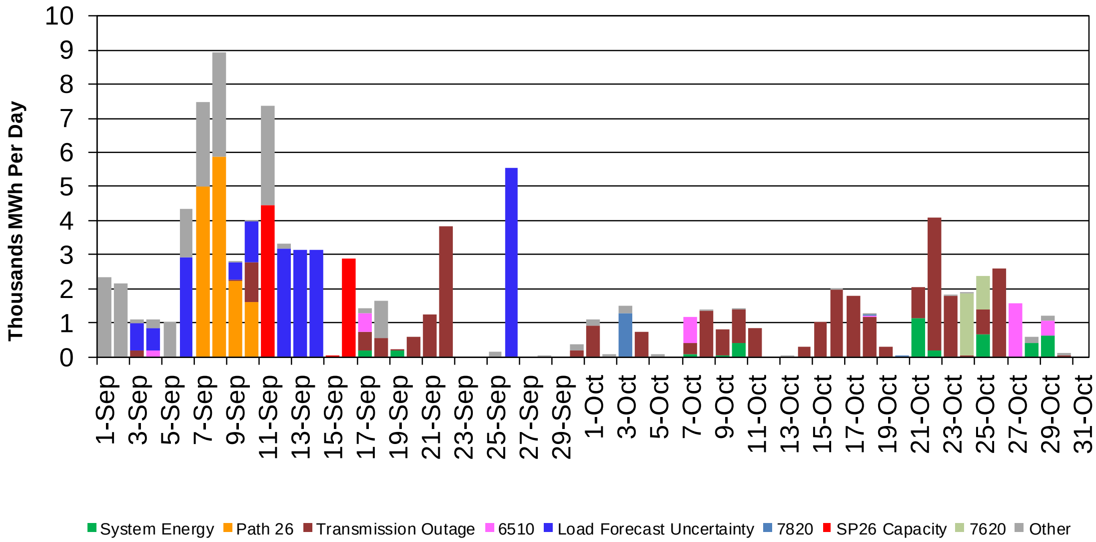


Figure 23 shows the total exceptional dispatch volume as a percent of load, along with the monthly average. The monthly average percentage declined to 0.18 percent in October from 0.33 percent in September.

Figure 23: Total Exceptional Dispatch as Percent of Load