



California ISO
Your Link to Power

Market Performance Report October 2009

December 2, 2009

ISO Market Services

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Executive Summary

This report contains the highlights of the month of October 2009. 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/179d/179ddbce22760.html>.

Highlights for October 2009:

- The average energy demand was 5.7 percent lower than one year ago.
- Natural gas prices increased significantly in October for the first three weeks and then dropped a bit in the week of October 25.
- The day-ahead on-peak bilateral contract prices increased substantively in October, following the trend of natural gas prices.
- The day-ahead market saw an increasing trend in the energy prices in the first three weeks of October, thanks largely to the rising natural gas prices.
- Real-time energy prices were generally stable in October except for a few days.
- The cumulative total congestion rent for interties in October was approximately \$11.32 million, and the cumulative total congestion rent for branch group and market scheduling limit was approximately \$2.67 million.
- Net revenue adequacy for congestion revenue rights was in excess of \$0.74 million in October, a significant improvement with respect to September's deficit of \$5.2 million.
- The monthly ancillary service average cost to load in October increased to \$0.31/MWh from \$0.27/MWh in September.
- The total RUC procurement cost increased to \$13,893 in October from September's \$3,007.
- The total volume of exceptional dispatches in October reduced significantly by 80 percent to approximately 83,000 MWh, from approximately 424,000 MWh in September.

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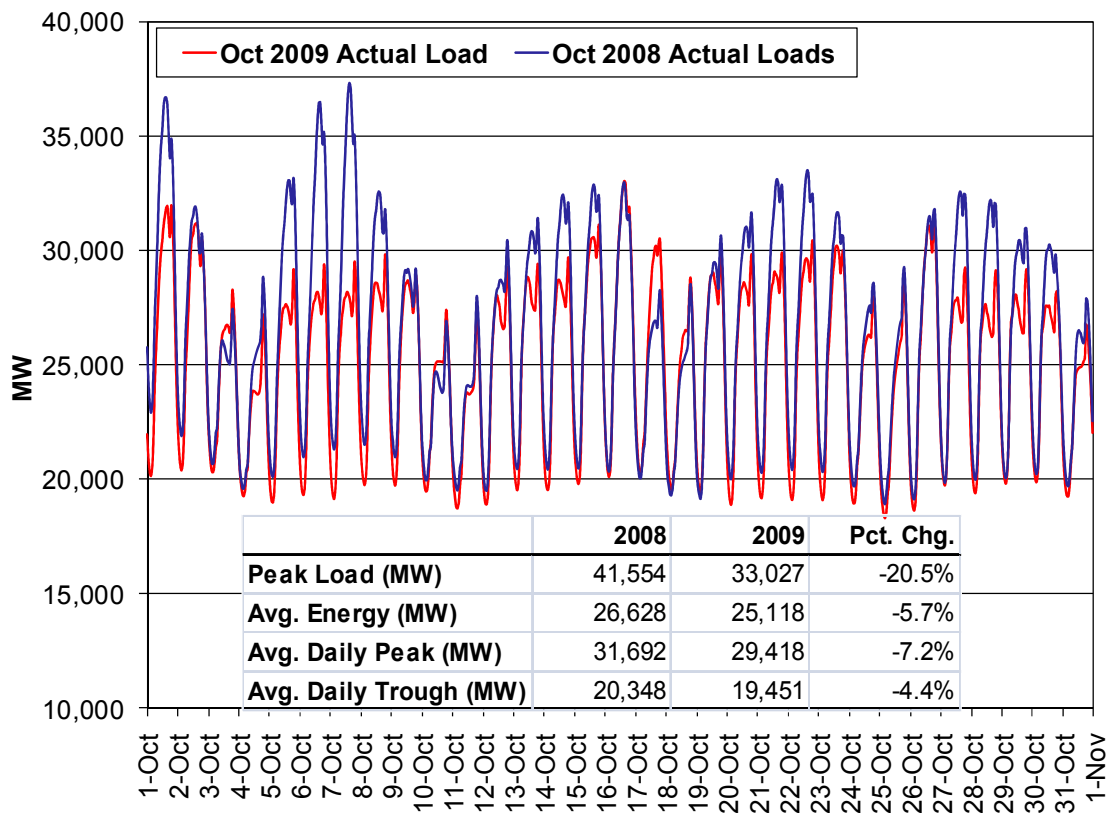
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Market Characteristics

Loads

October 2009 saw typically mild autumn load patterns. The peaks and troughs of load curves were lower than October 2008 for most days of this month, largely due to mild weather. The peak load was only 33,027 MW in October, which was 20.5 percent lower than one year ago. Average energy demand in this month was 5.7 percent below October’s average energy demand in 2008.

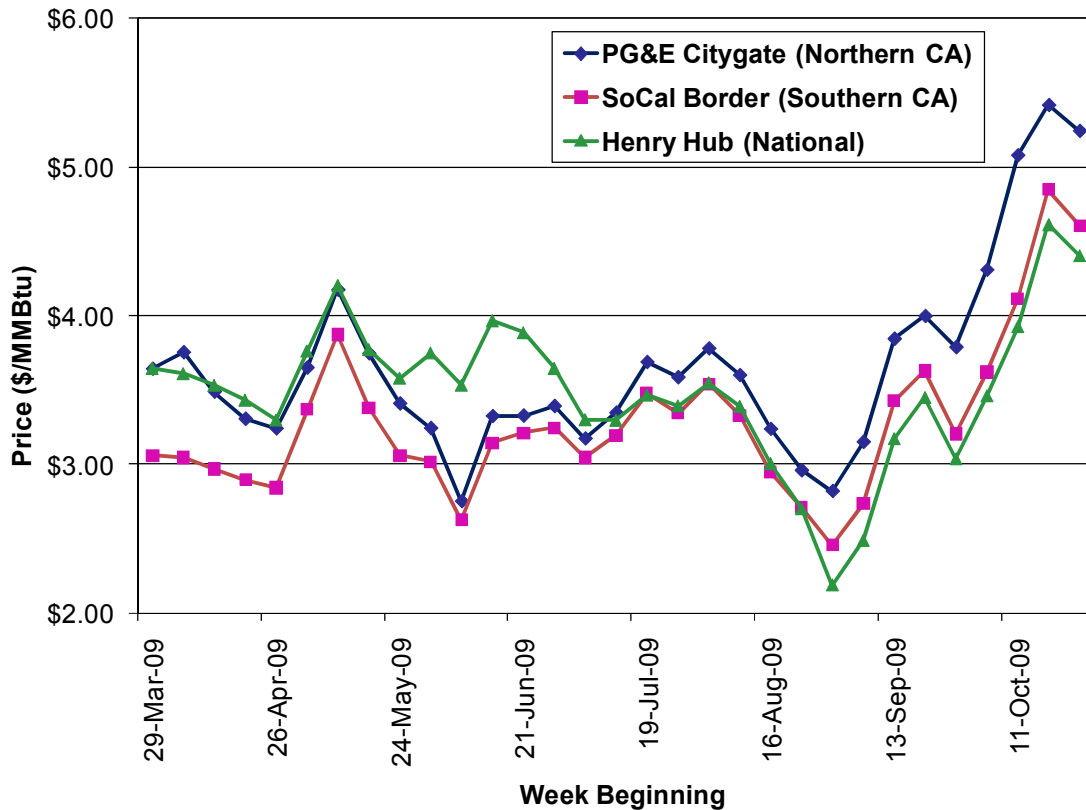
Figure 1: System Load Comparison – October 2009 vs. October 2008



Natural Gas Prices and Inventories

Natural gas prices increased significantly in October for the first three weeks and then dropped a bit in the week of October 25. According to the Energy Information Administration (EIA), the price increase in this month can be attributed to cooler weather, rising crude oil prices, and injection demand for natural gas to exploit future profits. Warmer than normal temperatures and ample production contributed to the price decline in the week of October 25. The California Composite Average gas price increased approximately 32.6 percent to \$4.68 per MMBtu on October 30 from \$3.53 per MMBtu on October 1. As of October 30, the working gas in underground storage in the West went up to 514Bcf, which is 14.2 percent above the five-year average.

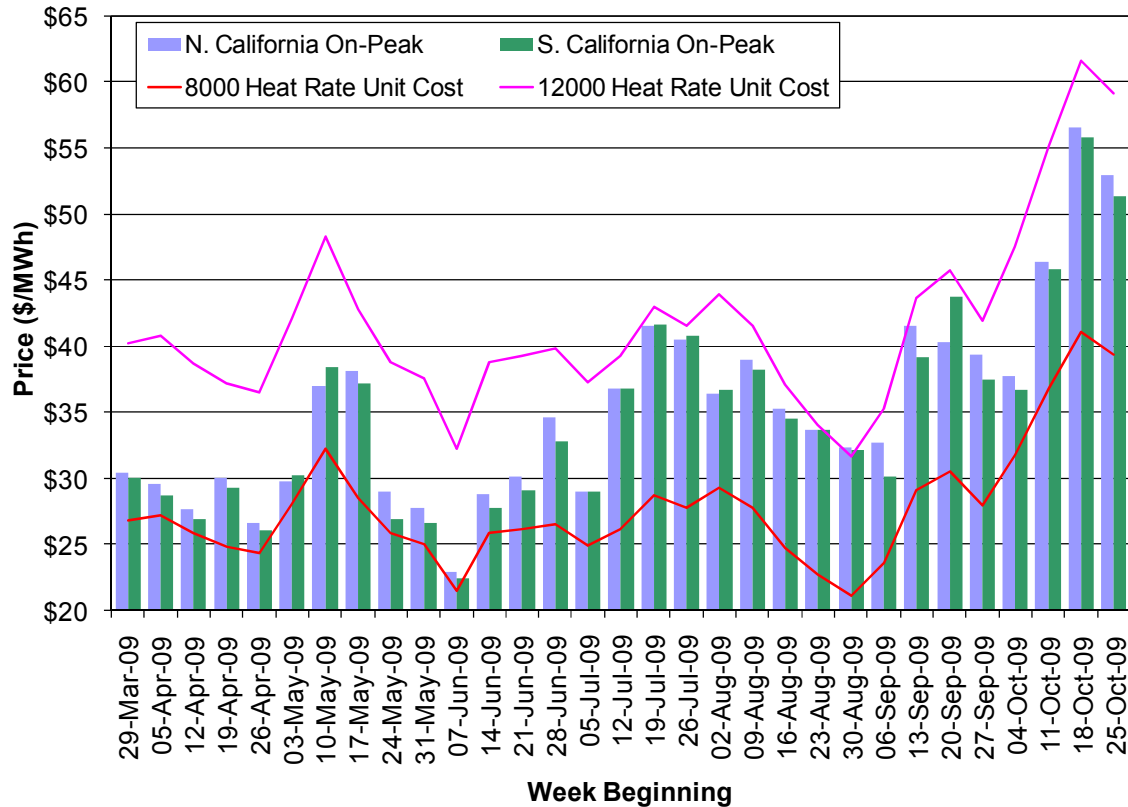
Figure 2: Weekly Average Natural Gas Spot Prices – March 2009 to September 2009



Bilateral Electricity Prices

The day-ahead on-peak power prices increased substantively in October, following the trend of natural gas prices. Figure 3 compares weekly average on-peak prices for Northern and Southern California with the nominal gas costs for two reference gas turbine generators.

Figure 3: Daily Peak-Hour Bilateral Contract Prices – Weekly Averages



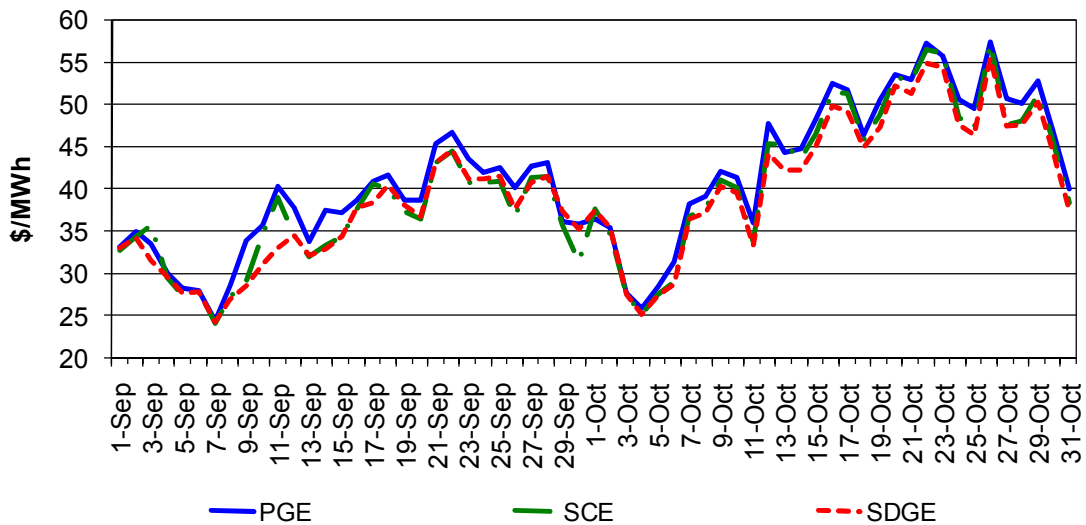
Market Performance Metrics

Energy

Day-Ahead Prices

The day-ahead market saw an increasing trend in the energy prices in the first three weeks of October, thanks largely to the rising natural gas prices. The prices in three default Load Aggregation Points (LAPs) converged well with a few exceptions. On October 24, 25, 27, and 28, the energy prices in the PG&E area were elevated by congestion on Path 26. This branch group was derated due to the outage of Midway-Vincent #3 500 kV line. As shown in Figure 4, the daily average prices were moderate for the month, falling into the range between \$25/MWh and \$57/MWh.

Figure 4: Day-Ahead Weighted Average LAP Prices (All Hours)



Real-Time Prices

Real-time energy prices were generally stable in October except for a few days, as shown in Figure 5. On October 1 and 2, the prices in the SCE and SDG&E area were elevated by congestion on a nomogram, which was created to account for a forced outage of a power station in the southern California. From October 11 to October 13, the prices in the PG&E area were elevated by congestion on the Los Banos North branch group. For the month of October, the daily average real-time energy prices for three default LAPs fell into the range between \$23/MWh and \$98/MWh.

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

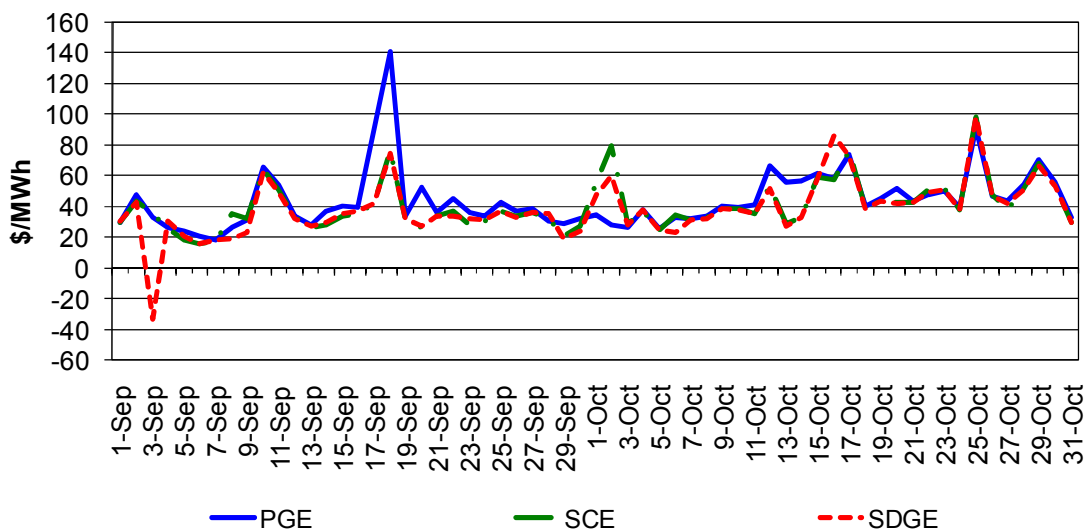
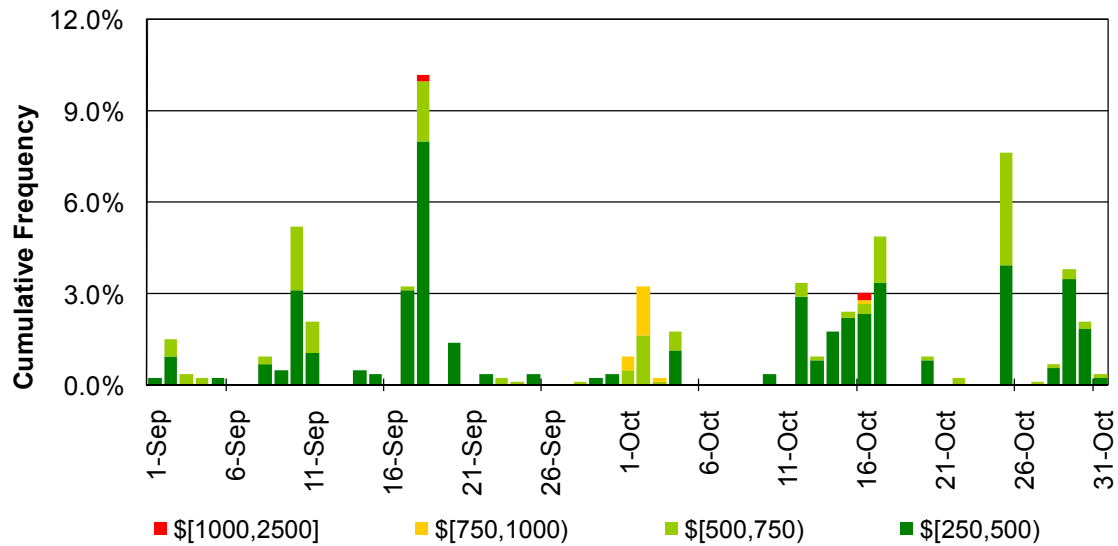


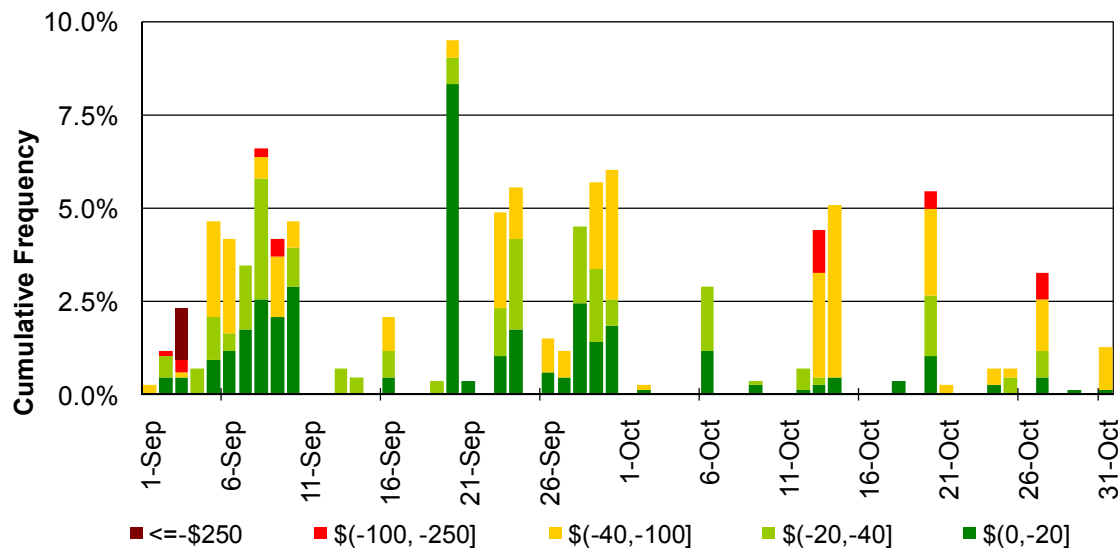
Figure 6 on the next page shows the daily frequency of price spikes by price range for all three default LAPs in the five-minute Real-Time Dispatch (RTD). In percentage terms, the frequency of prices over \$250/MWh increased from 0.95 percent in September to 1.24 percent in October. Extreme prices (over \$1000/MWh) remained constant, with only two occurrences (0.007 percent) in both September and October. As shown in Figure 6, two extreme price events occurred on October 16, due to the binding of a nomogram which was created to account for a planned outage of transmission lines in southern California. The congestion on this nomogram resulted in prices above \$1000/MWh in the SDG&E area where only limited resources were available to provide energy.

Figure 6: Daily Frequency of RTD LAP Positive Price Spikes



Similarly, Figure 7 shows the daily frequency of negative prices by price range for all three default LAPs in the five-minute RTD. These negative prices were mainly observed as a result of congestion on either Path 26 or Los Banos North branch groups. The frequency of negative prices declined from 2.49 percent in September to 0.82 percent in October. As winter approaches peak loads decline, and the corresponding decline in negative price occurrences is driven by the lessening of over generation events. Over generation events in turn are caused by generation units sitting at their minimum levels waiting to meet the peak load later in the day. As winter approaches many of these units simply switch off, thus lessening the over-generation issues and negative prices.

Figure 7: Daily Frequency of RTD LAP Negative Price Spikes



Congestion

Congestion Rents on Interties

Figure 8 below illustrates daily Integrated Forward Market (IFM) congestion rents by intertie for September and October 2009. The cumulative total congestion rent for interties in October was approximately \$11.32 million, up slightly from \$11.19 million in September. Most of the congestion occurred on Palo Verde (75 percent), El Dorado (16 percent) and PACI (8 percent) interties.

Figure 8: IFM Congestion Rents by Intertie (Import)

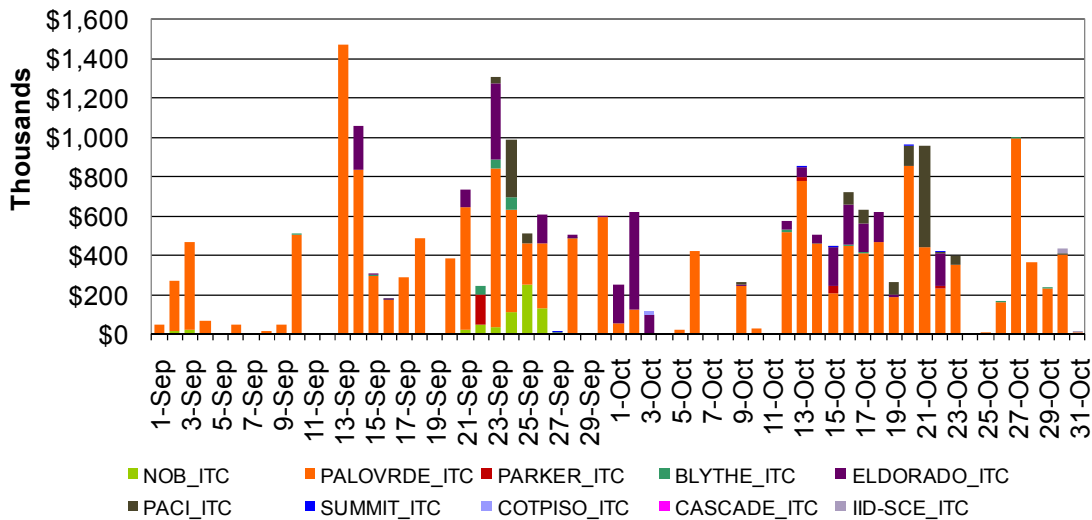


Table 1 shown on the next page provides a breakout of the IFM cleared value (MW), average shadow price (\$/MWh) and number of congested hours by intertie. In October, Palo Verde intertie was congested almost all days during the latter half of the month when scheduling coordinator were trying to arbitrage the price difference between the Palo Verde tie point and the Southern California zonal price. The average shadow price on Palo Verde intertie was \$10/MWh in October, which was significantly lower than \$21/MWh in September. Even though the average shadow price reduced by 52 percent in October, the total congestion rents on Palo Verde intertie were nearly the same, with \$8.5 million in October compared with \$8.9 million in September. The congestion rents are calculated as the sum of the product of shadow price and flow limit for all hours. In September, the flow limit was derated to half of its nominal value, whereas, in October there was no significant derates on the intertie and the flow limit was almost double the value in September.

The majority of congestion on Eldorado intertie occurred during the third week of October. Congestion rents on these days were primarily driven by path capacity derates motivated by a combination of scheduled and forced outages. Almost 70 percent of congestion on PACI occurred on October 20 and 21 due to a planned outage of the Table Mountain-Tesla 500kV line.

Table 1: IFM Congestion Statistics by Intertie (Import)

Intertie	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
BLYTHE_ITC	189	14	18
CASCADE_ITC	0	51	22
COTPISO_ITC	23	59	16
ELDORADO_ITC	1217	7	200
IID-SCE_ITC	586	4	13
NOB_ITC	228	18	10
PACI_ITC	2223	5	73
PALOVRDE_ITC	2663	10	351
PARKER_ITC	180	24	16
SUMMIT_ITC	7	38	66

Congestion Rents on Branch Group and Market Scheduling Limit

Figure 9 illustrates IFM congestion rents on selected branch group and market scheduling limit. For the month of October, the total congestion rent for branch group and market scheduling limit was approximately \$2.67 million, down significantly from \$5.39 million in September. Of the total, the vast majority of rents occurred on the Mead (37 percent), Inter Mountain DC- Adelanto branch group (25 percent) and Four Corners market scheduling limit (10 percent).

Figure 9: IFM Daily Congestion Rents by Branch Group and Market Scheduling Limit

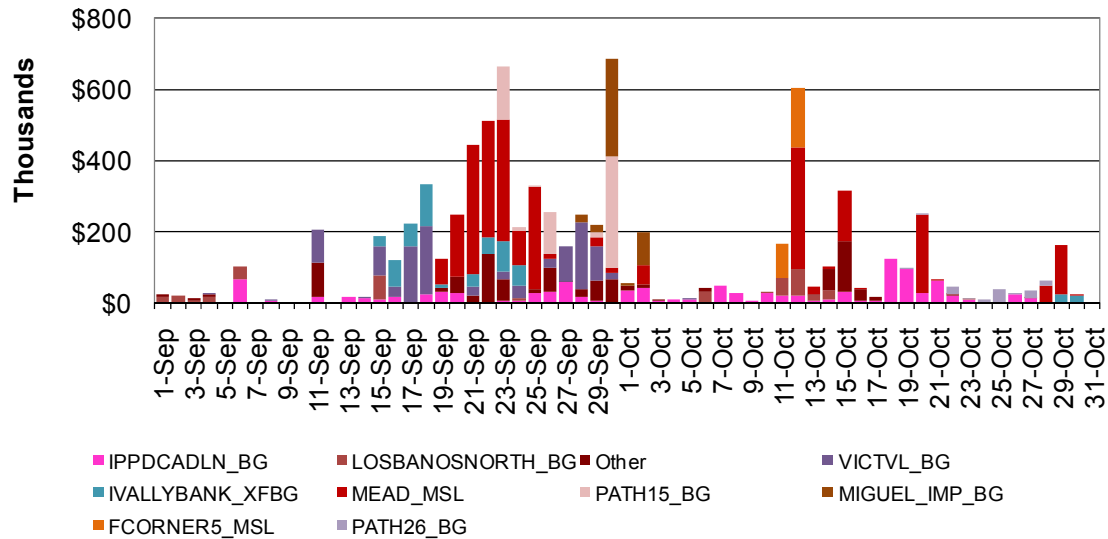


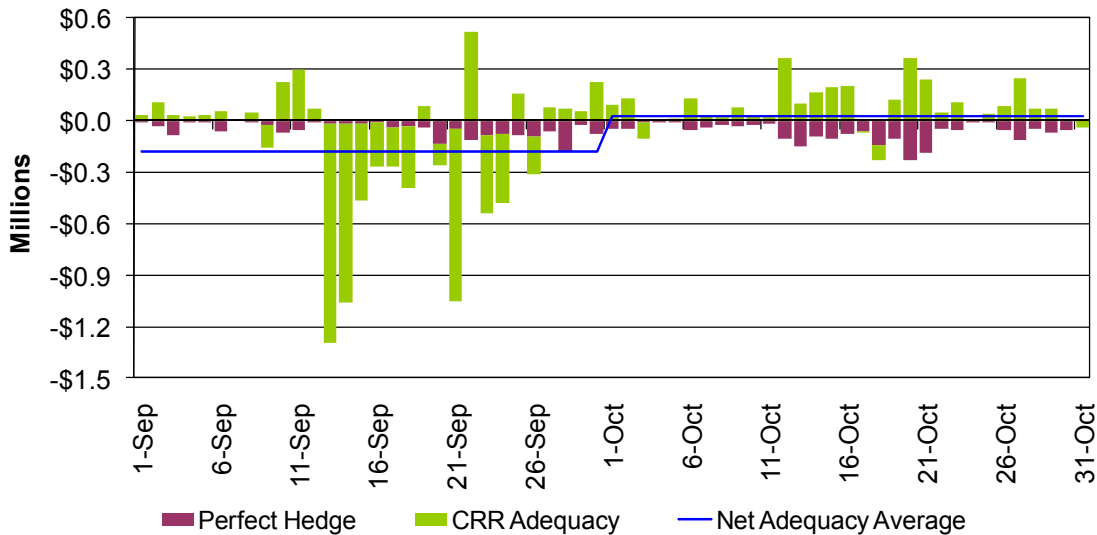
Table 2: IFM Congestion Statistics by Branch Group and Market Scheduling Limit

Branch Group / Market Scheduling Limit	Average Cleared Value (MW)	Shadow Price (\$/MWh)	Number of Congested Hours
ADLANTOSP_MSL	1217	3	24
FCORNER5_MSL	840	17	19
IPPDCADLN_BG	647	4	261
IVALLYBANK_XFBG	900	3	16
LOSBANOSNORTH_BG	1216	7	23
LUGO_VINCENT_BG	3090	3	10
MEAD_MSL	1460	7	94
MIGUEL_IMP_BG	1900	6	9
MKTPCADLN_MSL	556	5	26
PATH26_BG	853	4	33
SDGEIMP_BG	2109	3	5
VICTVL_BG	2640	1	1
WSTWGMEAD_MSL	127	14	3

Congestion Revenue Rights

Figure 10 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of September and October 2009. In comparison to the daily average revenue deficit of \$175,246 for September, October saw a daily average revenue surplus of \$25,817.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in 10 out of 31 days of the month, with the most significant deficiencies observed on October 3, 17 and 18. On October 3, the Captain Jack ISO intertie was derated to account for three overlapping outages. Outages that affected this intertie were also accommodated in the network model used in the CRR monthly process for October by means of pro-rata derates. The inclusion of the outages in the CRR model, however, does not guarantee that revenue adequacy will be attained in every day of the outage period because the extent and duration of outages affecting the energy market vary over time, while the same outages are modeled with a single value for the whole month in the CRR market. The expectation with pro-rata derates is, in contrast, that deficiencies in some days will be offset by surpluses in other days, helping to attain an overall adequacy. Similarly, revenue deficiencies on October 17 and 18 were due to derates, up to 40 percent on occasion, on the Palo Verde intertie to reflect the outage related to the Imperial Valley-North Gila 500 kV line that was overlapping with outages of the Serrano-Valley 500 kV and Navajo-Westwing 500 kV lines.

For the month of October, the outages provided under the 30-day rule were considered as pro-rata derates if the outage had duration of 10 days or less, or modeled explicitly as outages otherwise. Also, the global derating factor used for October was of 15 percent. Although there were several outages in the month, these two factors were sufficient to attain CRR revenue adequacy.

The monthly summary is provided in Table 3. Overall, the total dollars collected from the IFM were sufficient to cover the net payments to CRR holders and the cost of the perfect hedge. About 12.8 percent of congestion rents were needed to cover the cost of the perfect hedge. On net, total congestion revenues were in excess of \$0.74 million, a significant improvement with respect to September's deficit of \$5.2 million. The auction revenues credited to the balancing account for October were \$1.64 million, resulting in a net surplus of \$2.38 million to be allocated to measured demand.

Table 3: CRR Adequacy Statistics for October

Concept	Amount
IFM Congestion Rents	\$15,145,321.34
CRR Payments	\$12,454,525.62
CRR Adequacy	\$2,690,795.72
Perfect Hedge	-\$1,941,527.17
Net Revenue Adequacy	\$749,268.55
Revenue Adequacy Ratio	105.20%
Annual Auction Revenues	960,787.04
Monthly Auction Revenues	676,767.00
Monthly Net Balance	\$2,386,822.59

Ancillary Services

IFM (Day-Ahead) Average Price

In the IFM market for each trading interval, the ISO procures four types of ancillary services: regulation up, regulation down, spin and non-spin. The spin and non-spin ancillary services are collectively called operating reserves, and the regulation up and regulation down ancillary services are known as regulation reserves. The hourly operating reserve requirement is usually calculated as 6 percent of day-ahead load forecast for on-peak hour and 6.25 percent of day-ahead load forecast for off-peak hours. The regulation requirements were usually fixed at 350 MW per hour until October 2. Starting from October 3, the ISO has developed an internal procedure to determine regulation requirements on an hourly basis. This new procedure was created to procure regulation capacity in line with the expected operating conditions throughout the operating day to increase the efficiency of the markets and enhance the reliability of the system. Figure 11 below shows the daily average day-ahead ancillary service requirement for September and October 2009. Energy demand (load) dropped in October from September as temperatures dropped in the state of California due to the arrival of the fall season. This decrease in energy demand drove down the requirement for operating reserves. The regulation requirements also decreased in October from September.

Figure 11: IFM (Day-Ahead) Ancillary Services Average Requirement

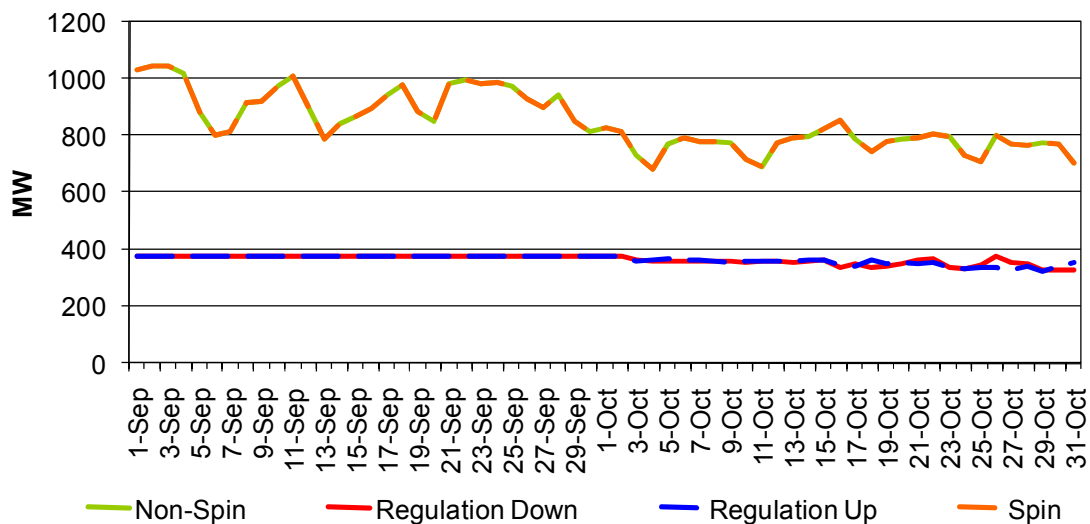
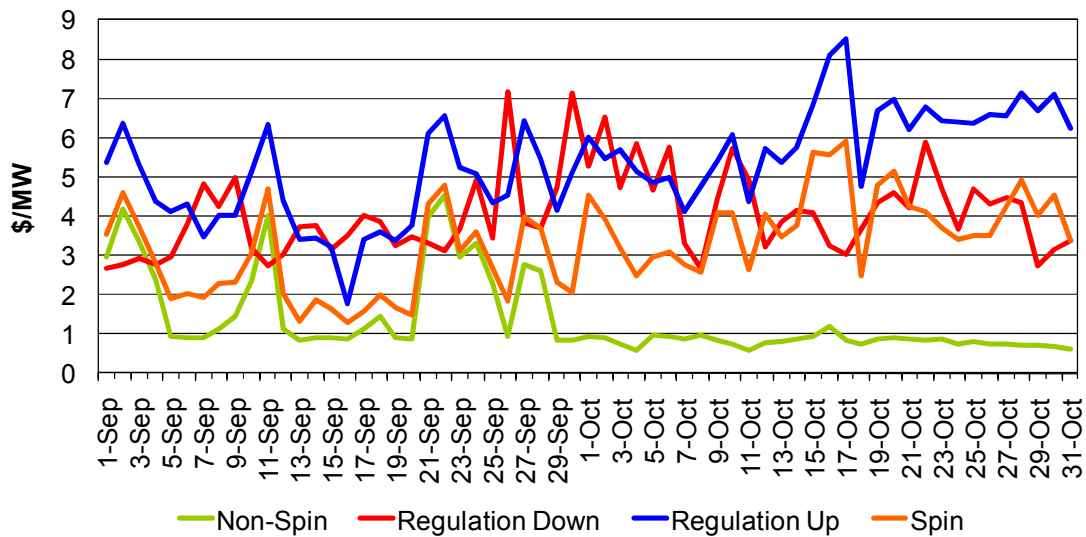


Table 4 shows the monthly IFM average ancillary service procurements and prices for September and October 2009. The average procurement quantity for all four types of ancillary services decreased in October compared with the month of September due to the decrease in requirements for the reasons mentioned in the previous paragraph. The average prices for regulation up, regulation down and spin increased, whereas the average price for non-spin declined. As mentioned in the previous section, the day-ahead energy price had an increasing trend in October from the month of September. This increase in energy price drove up the opportunity cost¹ to provide upward ancillary service, which includes regulation up, spin and non-spin. The increase in monthly average regulation up and spin price was attributed to the increase in opportunity costs to provide ancillary services. Figure 12 below shows the daily IFM average prices for September and October 2009.

Table 4: Average Ancillary Service Procurement and Price

	Average Procured				Average Price			
	Reg Up	Reg Dn	Spin	Non-Spin	Reg Up	Reg Dn	Spin	Non-Spin
Oct-09	353.22	351.37	771.06	771.63	\$ 6.06	\$ 4.31	\$ 3.89	\$ 0.81
Sep-09	375.00	375.00	930.69	917.75	\$ 4.54	\$ 3.82	\$ 2.67	\$ 1.95
	-5.81%	-6.30%	-17.15%	-15.92%	33.59%	12.72%	45.80%	-58.30%

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

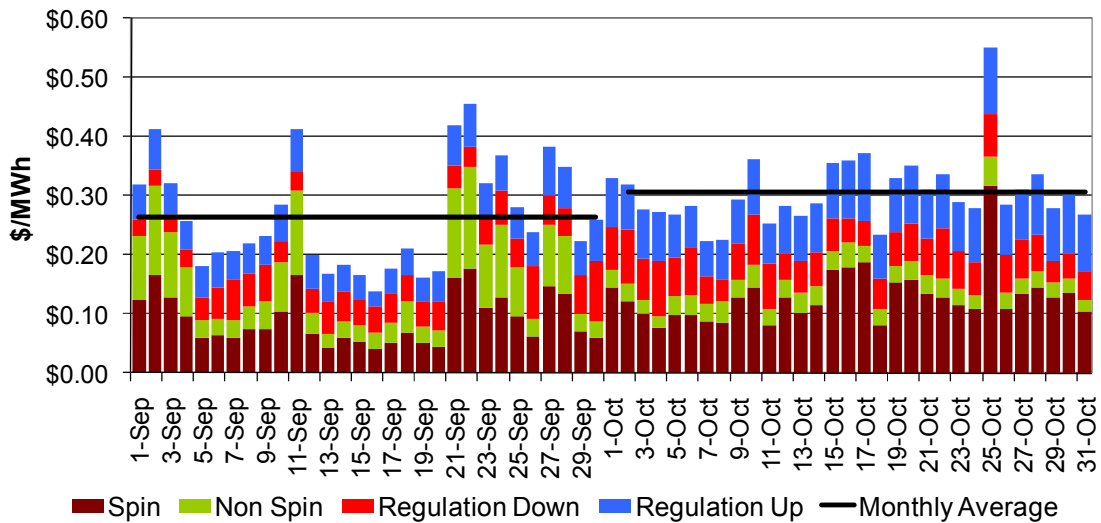


¹ The concept of opportunity cost is explained in detail in Section 4.3 of the Market Operations Business Practice Manual.

AS Cost to Load

Figure 13 below shows the total system (day-ahead and real-time) average cost to load for ancillary services procured in September and October 2009. The monthly average cost to load in October increased to \$0.31/MWh, up slightly from \$0.27/MWh in September. There was a significant increase in cost to load for ancillary service on October 25. It was due to the increase in real-time energy prices from hours ending 18 to 20 which translated into higher opportunity cost for regulation up and spinning reserves.

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

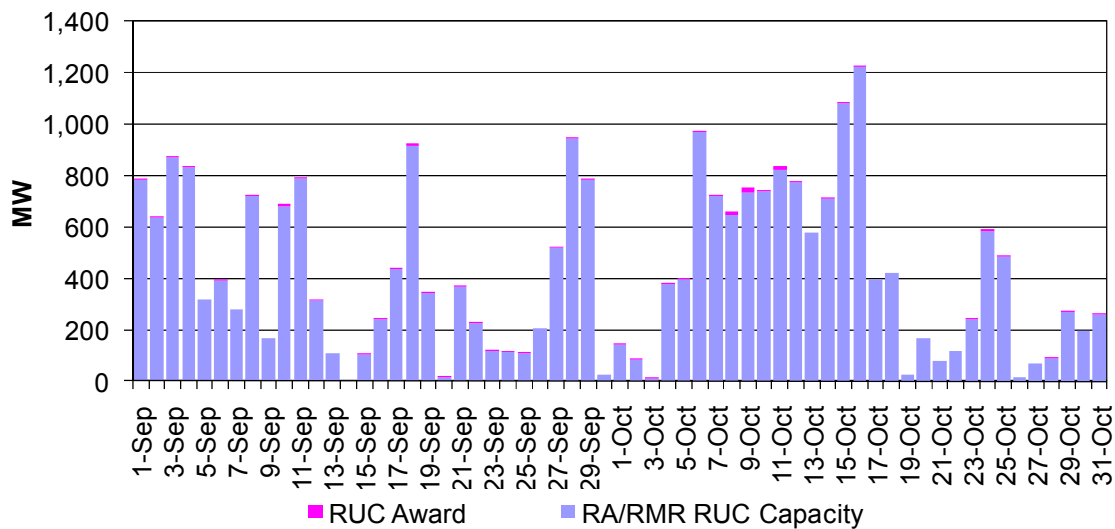


Residual Unit Commitment

RA/RMR RUC Capacity vs. RUC Award

Figure 14 shows the daily average RA/RMR RUC capacity and RUC award for September and October 2009. The monthly average RUC capacity for October increased 9 percent to 436 MW from September's 400 MW. And the percentage of RUC capacity procured from RA or RMR units slightly declined to 99.3 percent in October from 99.4 percent in September.

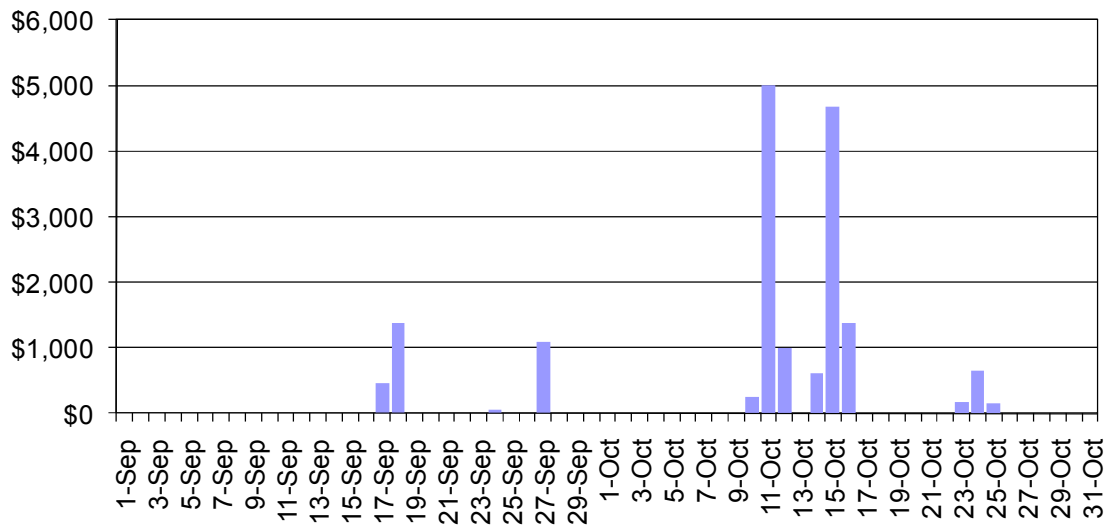
Figure 14: RA/RMR RUC Capacity vs. RUC Award (All Hours)



Total RUC Cost

Figure 15 shows the daily cost of RUC procurement for each trading day in September and October 2009. The total RUC procurement cost increased to \$13,893 in October from September's \$3,007. This was because more RUC capacity was procured from non-RA/RMR units in October than in September, and it was procured at higher prices. About 70 percent of RUC cost of the month occurred on two days, October 11th and October 15th, while G-217 was binding, elevating the LMPs in that area.

Figure 15: Total RUC Cost



Exceptional Dispatch

For the months of September and October 2009, Figure 16 shows the volume of exceptional dispatch broken out by market type: day-ahead, real-time incremental dispatch and real-time decremental dispatch. The total volume of exceptional dispatches in October reduced significantly by 80 percent to approximately 83,000 MWh, from approximately 424,000 MWh in September. 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.

Figure 16: Total Exceptional Dispatch Volume (MWh) by Market Type

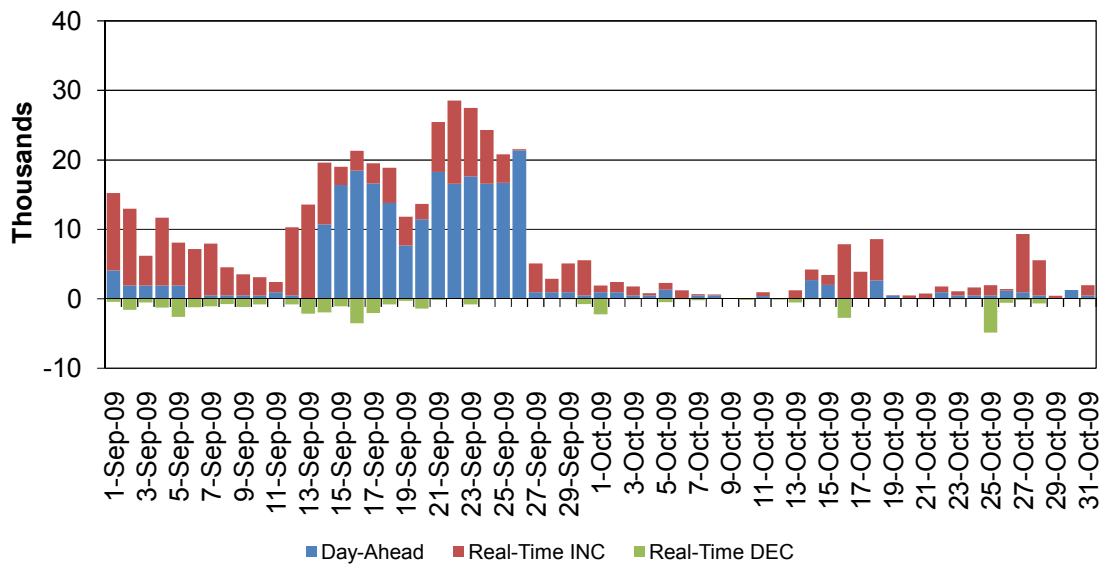
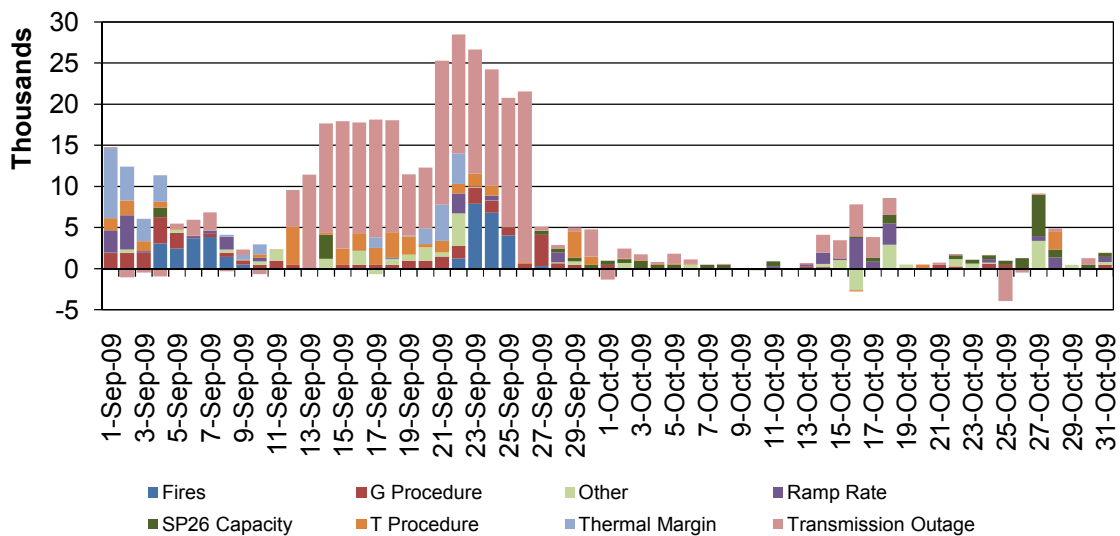


Figure 17 shows the volume of exceptional dispatch broken out by reason². The majority of exceptional dispatch volume in September was driven by transmission outages (58 percent), fires (9 percent) and transmission procedures (9 percent). On most days in September, real-time exceptional dispatches in the Fresno area (T-129) were issued to account for constraints related to remedial action schemes which were not fully modeled in the system. This resulted in exceptional dispatches limiting some pump run time and constraining some hydroelectric generation online. From September 14 to 26, there was an increase in day-ahead market exceptional dispatches due the forced outage of the Southwest Power Link (SWPL) between Hassayampa and North Gila in Arizona. SWPL is a primary conduit of power into San Diego, and its outage caused derates on the Palo Verde intertie, affecting imports coming into the southern California. The majority of exceptional dispatch volume in October was due to capacity requirements in the SP26 area (29 percent) and ramp rate reasons (22 percent).

Figure 17: Total Exceptional Dispatch Volume (MWh) by Reason



² For details regarding the reason of exceptional dispatch please read the White paper on exceptional dispatch published on the CAISO website.

Figure 18 shows the total exceptional dispatch as a percent of load and it also shows the average percentage for each month. In October the monthly average percentage dropped to 0.43 percent, down significantly from 1.84 percent in September.

Figure 18: Total Exceptional dispatch as Percent of Load

