



California ISO  
Your Link to Power

# Market Performance Report August 2009

September 25, 2009

ISO Market Services

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## Executive Summary

This report contains the highlights of the month of August 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 August 2009:

- The average energy demand in August 2009 was lower than one year ago.
- Natural gas prices declined significantly in August due to relatively moderate temperatures, robust supplies, and a slow economy.
- Day-ahead on-peak bilateral contract prices declined in August, mirroring the movement of natural gas prices.
- Day-ahead (IFM) average prices were stable for the three default LAPs for the month, varying between \$26 and \$43.
- Real-time energy prices were less volatile in August than in July, especially in the SDGE area.
- The cumulative total congestion rent for interties was approximately \$2.56 million for the month, and the cumulative total branch group congestion rent was approximately \$0.86 million.
- Total congestion revenues were in deficit of \$0.2 million to cover all payments to CRR holders and cost of the perfect hedge, a fair decline with respect to July's surplus of \$0.63 million.
- The monthly ancillary service average cost to load for August decreased to \$0.28/MWh, down from \$0.43/MWh in July.
- The total RUC procurement cost increased to \$24,888 in August from July's \$0.

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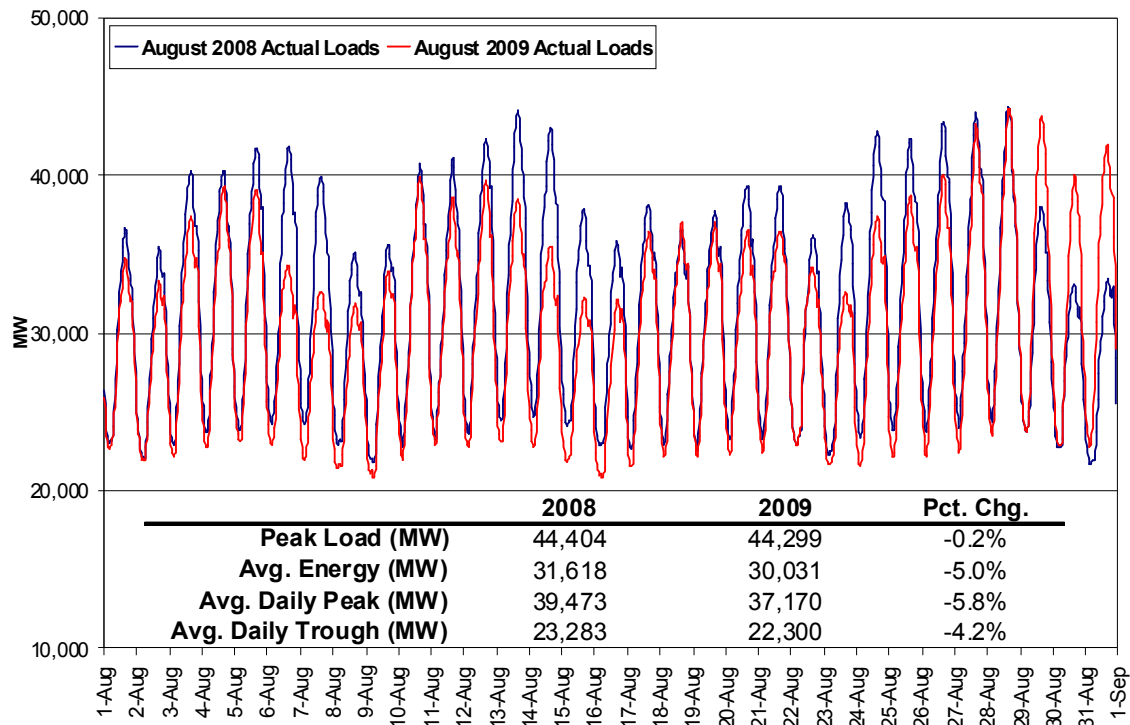
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## Market Characteristics

### Loads

August 2009 saw relatively mild temperatures with moderate summer loads. The average energy demand was 5 percent lower than in August 2008 and it was approximately 2.4 percent lower than the average demand in July 2009. The loads were significantly higher during the last week of this month due to warmer weather.

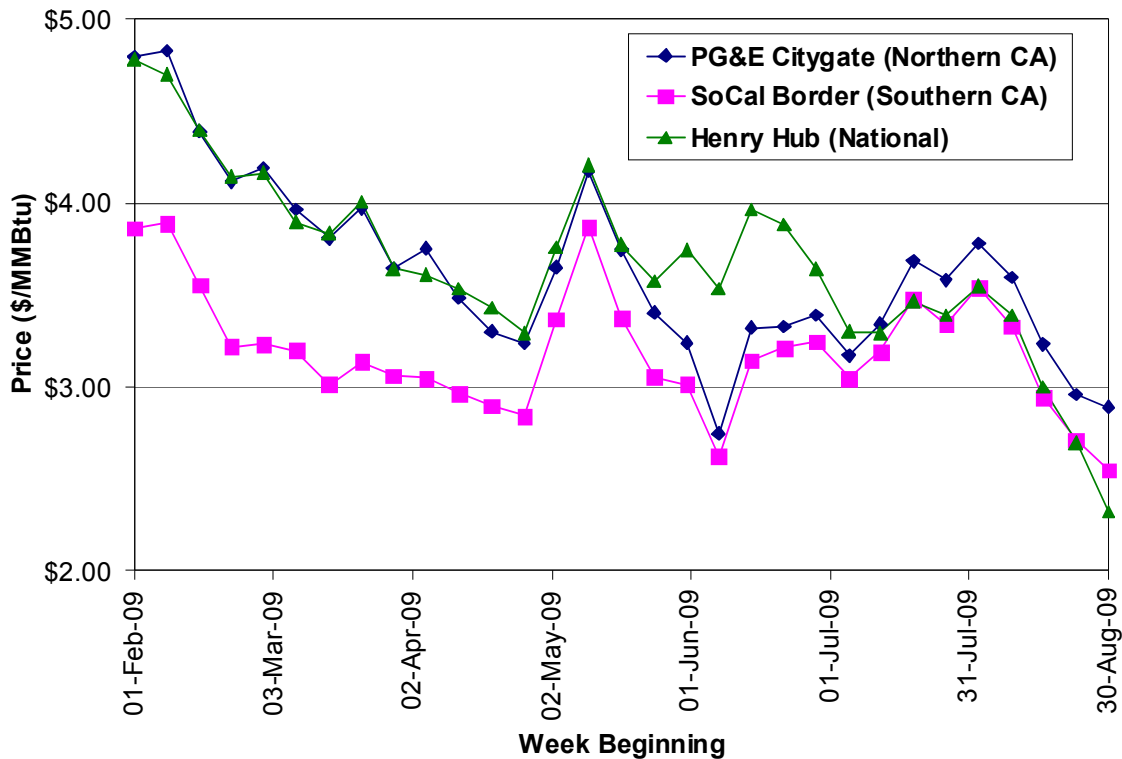
**Figure 1: System Load Comparison – August 2009 v. August 2008**



### Natural Gas Prices and Inventories

In August, natural gas prices declined significantly. According to the Energy Information Administration (EIA), the factors contributing to decreases in natural gas prices included relatively moderate temperatures, robust supplies, and a slow economy. The EIA also cited that hurricanes had not significantly interrupted the production in the Gulf of Mexico this season. The California Composite Average gas price posted a decrease this month, falling approximately 17 percent to \$2.7 per MMBtu on August 31<sup>st</sup> from \$3.27 per MMBtu on July 31<sup>st</sup>. As of August 28<sup>th</sup>, the working gas in underground storage in the West increased to 461 Bcf, which is 20 percent above the five-year average.

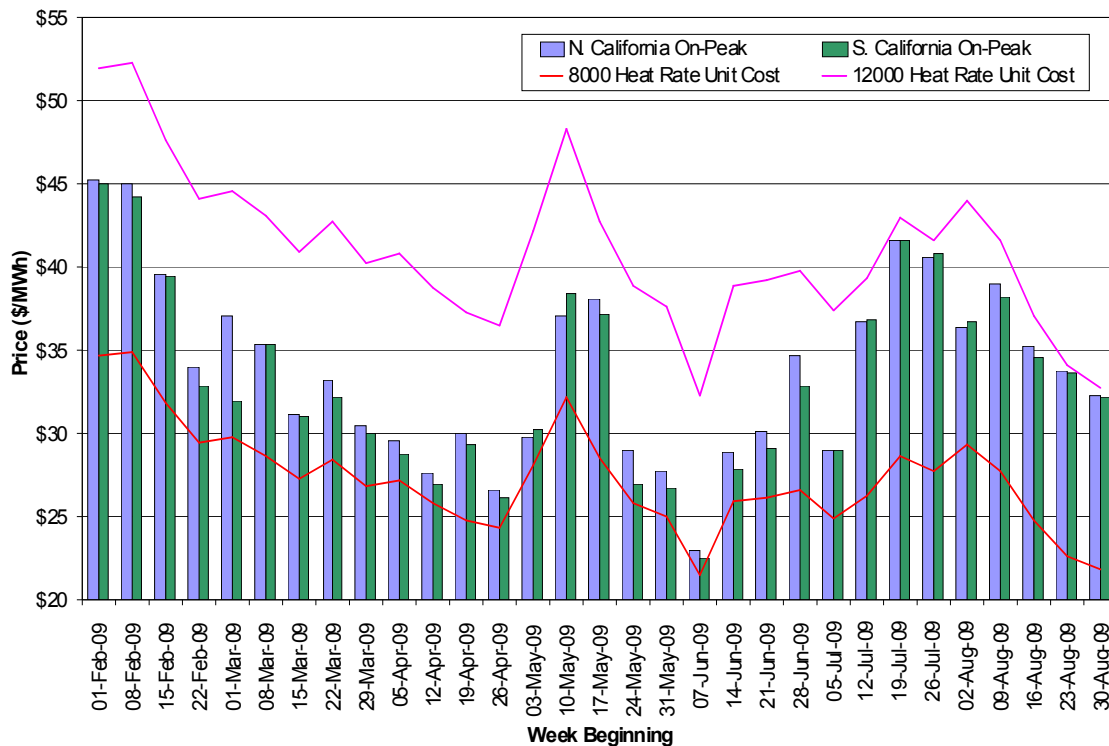
**Figure 2: Weekly Average Natural Gas Spot Prices – February 2009 to August 2009**



### Bilateral Electricity Prices

Mirroring the movement of natural gas prices, day-ahead on-peak power prices declined in August. As seen from Figure 3, the on-peak prices were close to the 12,000 Heat Rate Unit Cost curve, especially in late August. The load was higher in the last week of August due to higher temperatures, requiring more expensive units to come online to meet the demand. This drove up the day-ahead on-peak prices although the electricity prices were dampened by low 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**



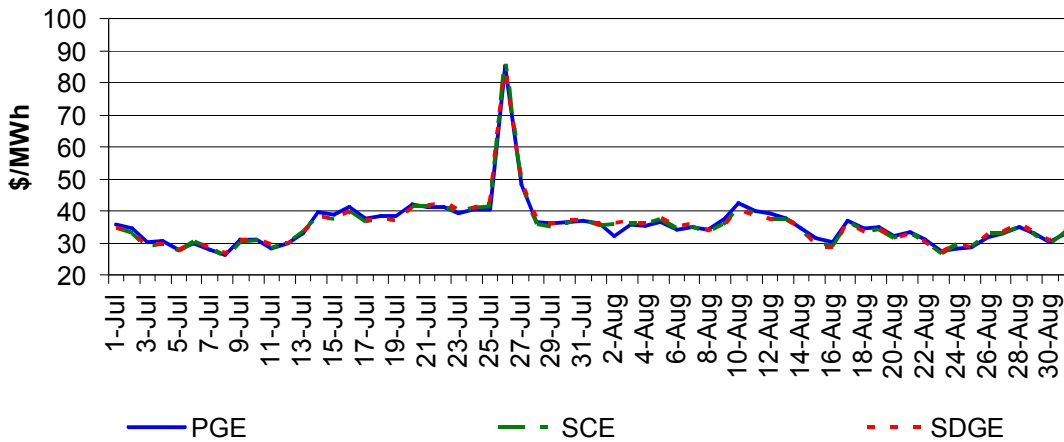
## Market Performance Metrics

### Energy

#### Day-Ahead Prices

Day-ahead daily weighted average prices were stable for the three default Load Aggregation Points (LAPs) in August, trending downward slightly. As shown in Figure 4, the daily average prices were relatively low due to mild weather, falling into the range between \$26 and \$43. On August 2<sup>nd</sup>, the daily average price for PG&E was depressed because of the congestion on Path 26.

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



**Real-Time Prices**

Real-time energy prices were less volatile in August than in July, especially in the SDGE area, as shown in Figure 5. However, the prices still had high volatilities on several days in August. On August 9<sup>th</sup>, the peak load pull and limited ramp capability, plus a loss of 120 MW due to trip of a generation unit and a -200 MW generation deviation, resulted in high energy prices in all default LAPs, with daily average prices around \$60/MWh. On August 26<sup>th</sup> and 27<sup>th</sup>, the load demand rose due to higher temperatures, contributing to the high prices in all default LAPs on these two days.

Congestion on certain branch groups elevated energy prices in one or two areas on several days in August. On August 24<sup>th</sup>, a planned outage caused de-rate on SOUTHLUGO\_RV branch group, resulting in congestion on this branch group, elevating prices in the SCE and SDGE area; on August 30<sup>th</sup>, congestion on the SDGE\_CFE import branch group elevated prices in the SDGE area; on August 31<sup>st</sup>, two 220 kV lines relayed due to the Station Fire, causing de-rate on Path 26, resulting in congestion on this branch group, elevating prices in the SCE and SDGE area, where on the same day, price in the SDGE area was further elevated by congestion on the SDGE\_CFE import branch group.

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

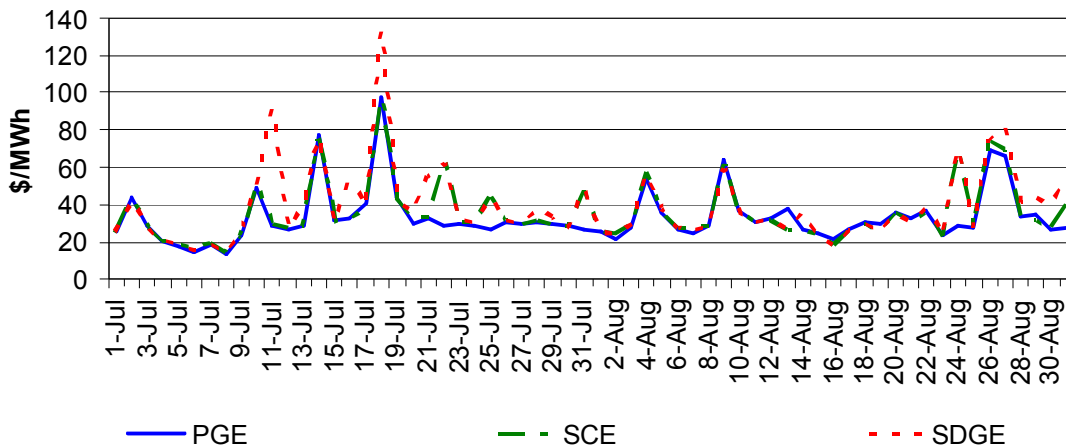
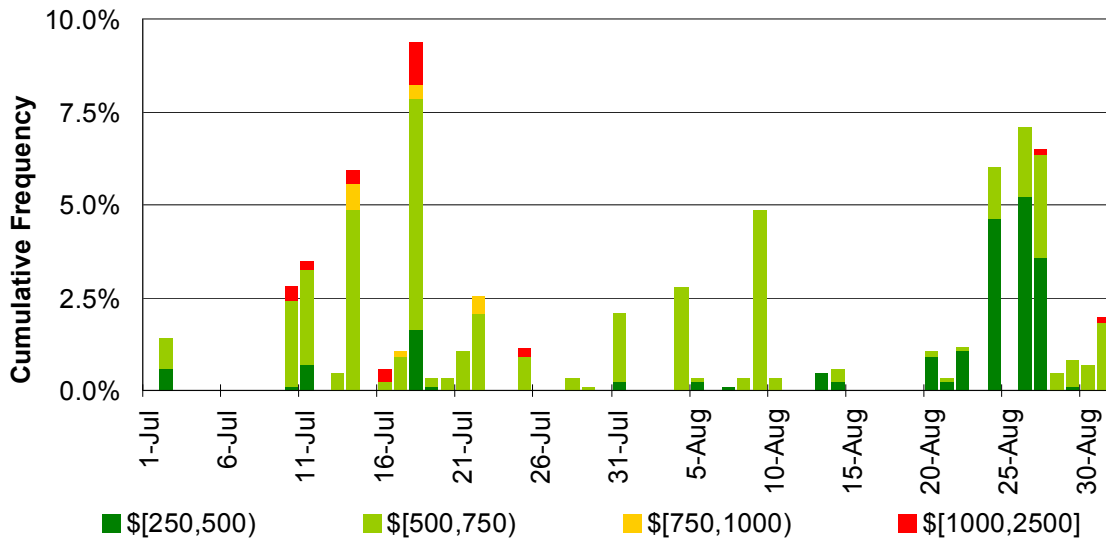


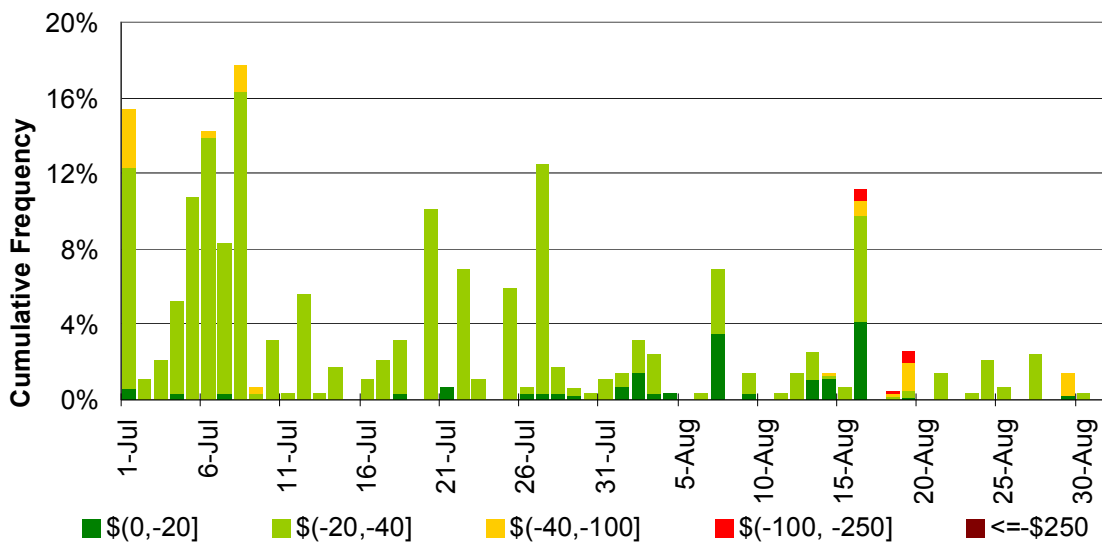
Figure 6 on the next page shows the daily frequency of price spikes by price range for all three default LAPs in the 5-minute Real-Time Dispatch (RTD). In percentage terms, the frequency of prices over \$250/MWh slightly increased from 1.06 percent in July to 1.15 percent in August. Nonetheless, less extreme prices (over \$1000/MWh) occurred on August, falling from 0.08 percent in July to 0.007 percent in August.

**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 5-minute RTD. These negative prices are mainly observed as a result of over-generation in the early morning hours when there are light loads and many units are operating at minimum loads and, thus, the system is more limited to ramp down. Frequency of negative prices saw a sharp decrease, falling from 4.3 percent in July to 1.4 percent in August.

**Figure 7: Daily Frequency of RTD LAP Negative Price Spikes**

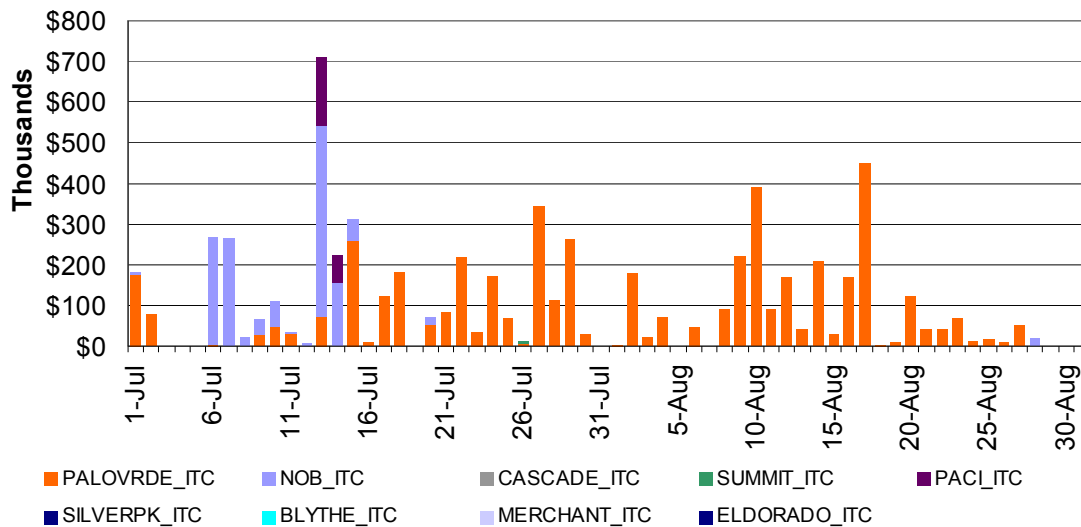


## Congestion

### Congestion Rents on Interties

Figure 8 below illustrates daily Integrated Forward Market (IFM) congestion rents by intertie for July and August 2009, while Table 1 provides a breakout of the IFM cleared value (MW), average shadow price (\$/MWh) and number of congested hours by intertie. The cumulative total congestion rent for interties in August 2009 was approximately \$2.56 million, down from \$3.98 million in July. Of the total, more than 99 percent of congestion costs occurred on Palo Verde intertie. The congestion on Palo Verde intertie was primarily driven by over scheduling, and the average shadow price for the month was \$4/MWh.

**Figure 8: IFM Congestion Rents by Intertie (Import)**



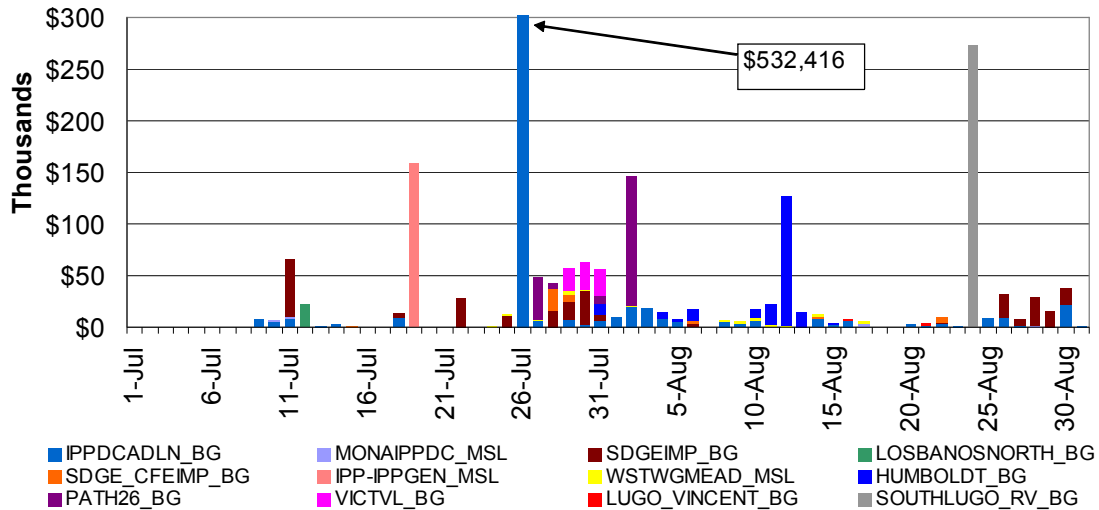
**Table 1: IFM Congestion Statistics by Intertie (Import)**

| Intertie     | Average Cleared Value (MW) | Shadow Price (\$/MWh) | Number of Congested Hours |
|--------------|----------------------------|-----------------------|---------------------------|
| BLYTHE_ITC   | 212                        | 3                     | 3                         |
| ELDORADO_ITC | 1555                       | 1                     | 1                         |
| NOB_ITC      | 318                        | 14                    | 10                        |
| PALOVRDE_ITC | 2817                       | 4                     | 242                       |

### Congestion Rents on Branch Groups

Figure 9 illustrates IFM congestion rents on selected branch groups. For the month of August, the total branch group congestion rent was approximately \$0.86 million, down from \$1.12 million in July. Of the total, the vast majority of rents occurred on the SOUTH\_LUGO branch group (32 percent), the HUMBOLDT branch group (22 percent), and the IPPDCADLN (17 percent).

**Figure 9: IFM Daily Congestion Rents by Branch Group**



**Table 2: IFM Congestion Statistics by Branch Group**

| Branch Group    | Average Cleared Value (MW) | Shadow Price (\$/MWh) | Number of Congested Hours |
|-----------------|----------------------------|-----------------------|---------------------------|
| HUMBOLDT_BG     | 45                         | 56                    | 78                        |
| IPPDCADLN_BG    | 647                        | 2                     | 113                       |
| LUGO_VINCENT_BG | 3150                       | 1                     | 2                         |
| MONAIPPDC_MSL   | 83                         | 4                     | 14                        |
| PATH26_BG       | 1700                       | 15                    | 5                         |
| SDGEIMP_BG      | 2647                       | 2                     | 22                        |
| SDGE_CFEIMP_BG  | 2084                       | 1                     | 3                         |
| SOUTHLUGO_RV_BG | 4150                       | 16                    | 4                         |
| WSTWGMEAD_MSL   | 185                        | 2                     | 41                        |

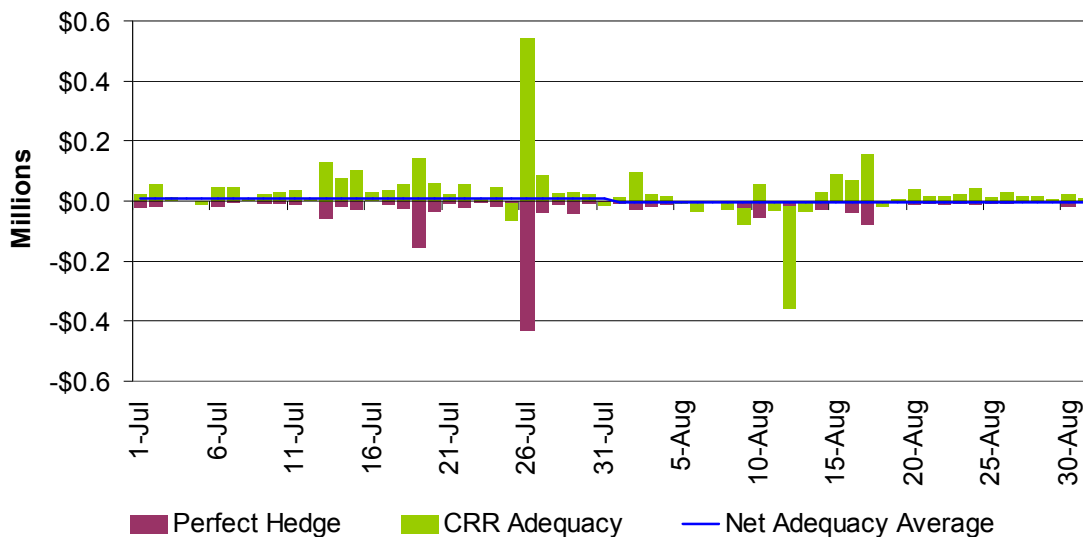
Table 2 provides a breakout of the IFM cleared value (MW), average shadow price (\$/MWh) and number of congested hours by branch group. The congestion

on the SOUTHLUGO\_RV branch group in August occurred on one day, August 24<sup>th</sup>, which was driven by significant de-rate on this branch group due to a scheduled outage on a nearby 500kV transformer bank.

**Congestion Revenue Rights**

Figure 10 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of July and August 2009. In comparison to the daily average surplus of \$20,587 for July, August saw daily average revenue deficit of \$6,649.

**Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights**



Revenue deficiencies were observed in 11 out of 31 days of the month, with the most significant deficiency occurring on August 12<sup>th</sup> when the HUMBOLDT branch group was binding throughout the day. For the month of August, the outages provided under the 30-day rule were considered as pro-rata derates if the outage was of 10 days duration or less, or modeled explicitly as outages otherwise. Also, the global derating factor used for August was of 15 percent. These elements, in conjunction, were marginally insufficient to attain CRR revenue adequacy.

Overall, the total dollars collected from the IFM were sufficient to cover approximately 96 percent of net payments to CRR holders and cost of the perfect hedge. Approximately 10 percent of congestion rents were needed to cover the cost of the perfect hedge. On net, total congestion revenues were in deficit of \$0.2 million, a fair decline with respect to July’s surplus of \$0.63 million. The auction revenues credited to the balancing account for August were \$1.83 million, and will be used to offset the \$0.2 million of revenue deficiency, leaving a net surplus of approximately \$1.62 million to be allocated to measured demand (see Table 3 on the next page).

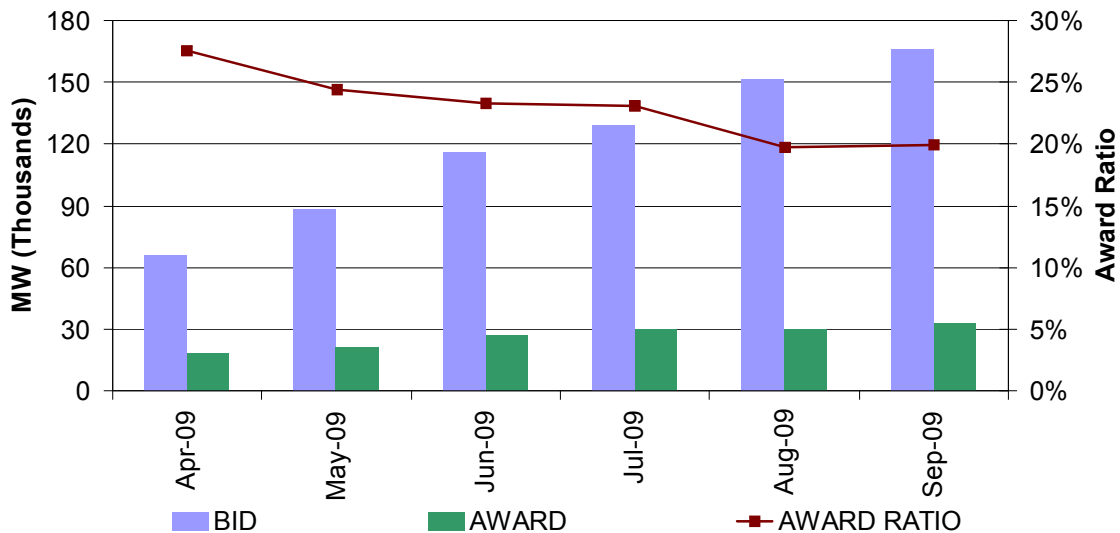
**Table 3: CRR Adequacy Statistics for August**

| Concept                  | Amount         |
|--------------------------|----------------|
| IFM Congestion Rents     | \$4,590,918.56 |
| CRR Payments             | \$4,340,979.94 |
| CRR Adequacy             | \$249,938.62   |
| Perfect Hedge            | -\$456,055.04  |
| Net Revenue Adequacy     | -\$206,116.42  |
| Revenue Adequacy Ratio   | 95.70%         |
| Annual Auction Revenues  | \$1,344,248.42 |
| Monthly Auction Revenues | \$486,569.36   |
| Monthly Net Balance      | \$1,624,701.36 |

**Monthly Auction for CRRs**

Figure 11 shows the trend of the MW volumes of the most recent six monthly CRR auctions. Since the first monthly auction, on average the bid-in MW volume has steadily increased by approximately 20,000 MW, however because the quantity of awarded CRRs is limited by the simultaneous feasibility test in the auction process, the MW volume for awards has increased at a lower average rate of 3000 MW. As a result, the proportion of cleared MW volume with respect to bid-in MW volume has steadily decreased from 27.5 percent in April to 20 percent in September. Unlike CRRs from allocation processes, participants can bid any valid path in the CRR auctions and, thus, the volume of CRRs awarded has also depended on the level of counter-flows that bids have provided to each other in the auction-clearing processes.

**Figure 11: Volumes of Monthly CRR Auctions**



## Ancillary Services

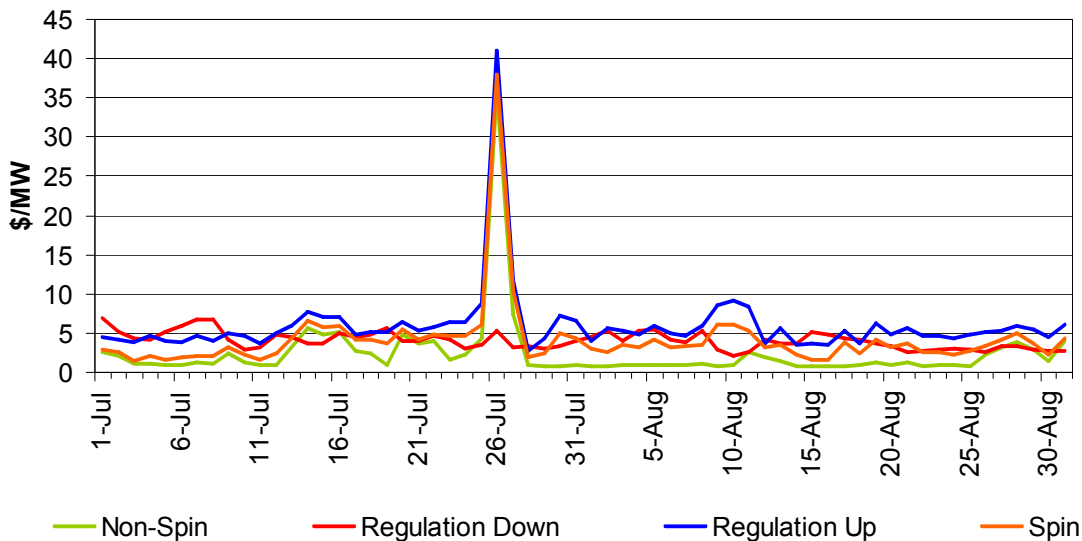
### IFM (Day-Ahead) Average Price

Table 4 shows the average ancillary service procurements and prices for July and August 2009, and Figure 12 below shows daily IFM average prices for July and August 2009. The hourly regulation up and regulation down procurements were relatively unchanged in August from the month of July, whereas the spin and non-spin ancillary services procurement fell slightly by less than 5 percent. As compared with July 2009, all four types of ancillary services saw declines in average prices in August. In the previous month, regulation up, spin and non-spin saw significantly higher average ancillary service prices than August due to an event on July 26<sup>th</sup>.<sup>1</sup>

**Table 4: Average Ancillary Service Procurements and Price – July and August 2009**

|         | Average Procured |        |        |          | Average Price |        |        |          |
|---------|------------------|--------|--------|----------|---------------|--------|--------|----------|
|         | Reg Up           | Reg Dn | Spin   | Non-Spin | Reg Up        | Reg Dn | Spin   | Non-Spin |
| AUG2009 | 375.16           | 375.00 | 923.65 | 916.53   | \$5.29        | \$3.68 | \$3.43 | \$1.42   |
| JUL2009 | 375.46           | 375.00 | 963.66 | 937.75   | \$6.71        | \$4.45 | \$4.93 | \$3.54   |

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

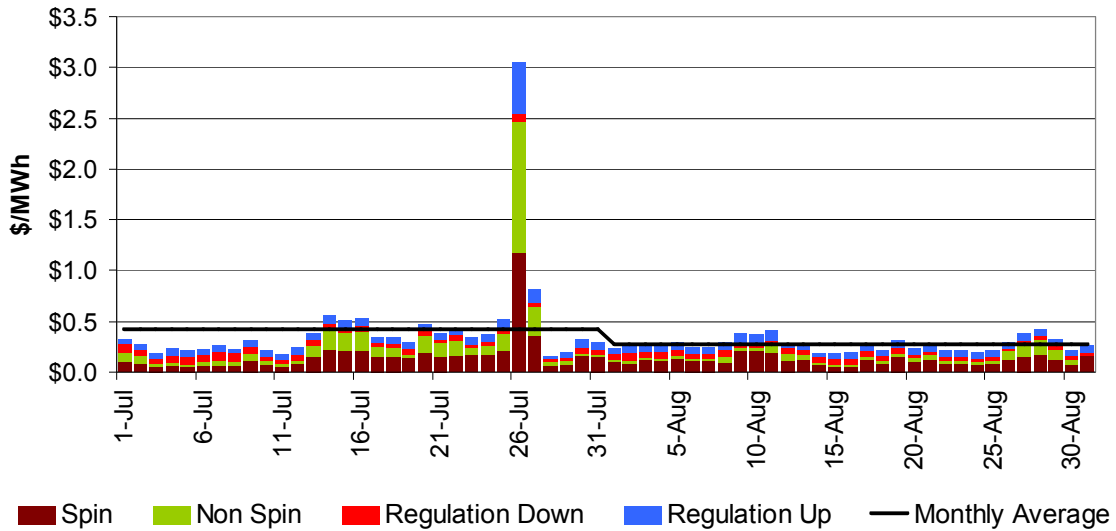


<sup>1</sup> On July 26<sup>th</sup>, in Hour Ending 17 and 18, all three default LAPs saw LMPs greater than \$450/MWh which drove hourly prices for regulation up, spin and non-spin above \$350/MWh. For details please refer to the Market Performance report for July 2009.

### 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 July and August 2009. The monthly average cost to load for August decreased to \$0.28/MWh, down from \$0.43/MWh in July.

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

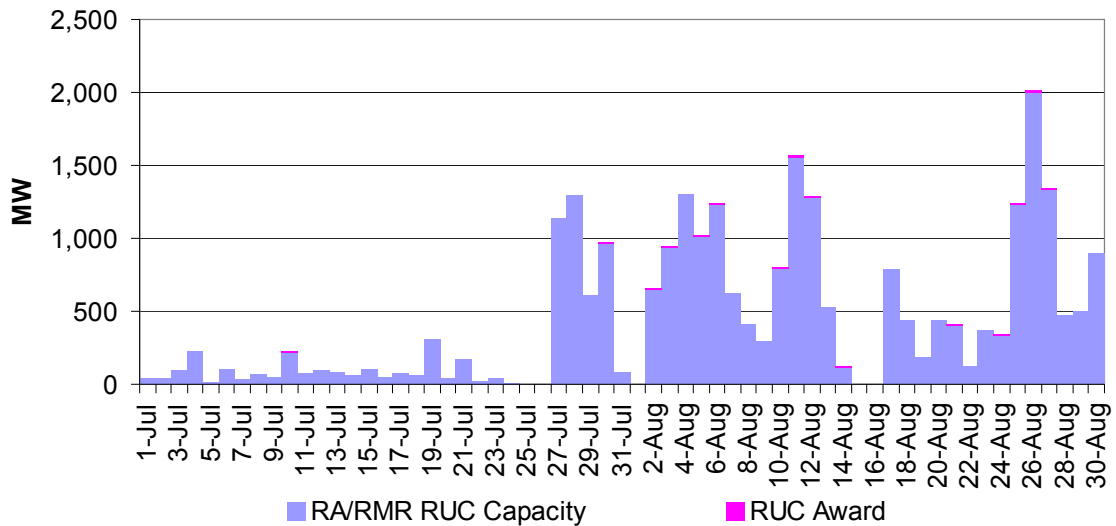


## Residual Unit Commitment

### RA/RMR RUC Capacity vs. RUC Award

Figure 14 shows the daily average RA/RMR RUC capacity and RUC award for July and August 2009. Approximately 99.4 percent of RUC capacity was procured from RA or RMR units in August. The monthly average RUC capacity for August was 681 MW, which was more than triple of July’s 200 MW. This was due to the implementation of Generation Procedures G-217 and G-219 in RUC since July 27<sup>th</sup>. Previously such commitments would have occurred via exceptional dispatch.

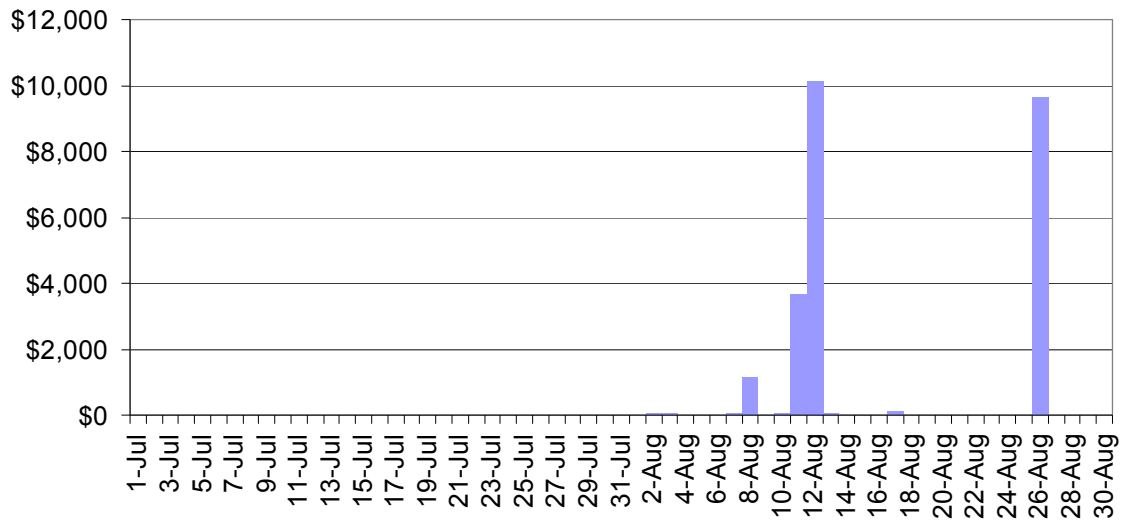
**Figure 14: RA/RMR RUC Capacity vs. RUC Award (All Hours)**



**Total RUC Cost**

Figure 15 shows the daily cost of RUC procurement for each trading day in July and August 2009. The total RUC procurement cost increased to \$24,888 in August from July's \$0. This was because more RUC capacity was procured from non-RA/RMR units in August than in July, and some of them were procured at high prices. About 80 percent of RUC cost of the month occurred on two days, August 12<sup>th</sup> and August 26<sup>th</sup>, while G-217 was binding, driving up the LMPs in that area.

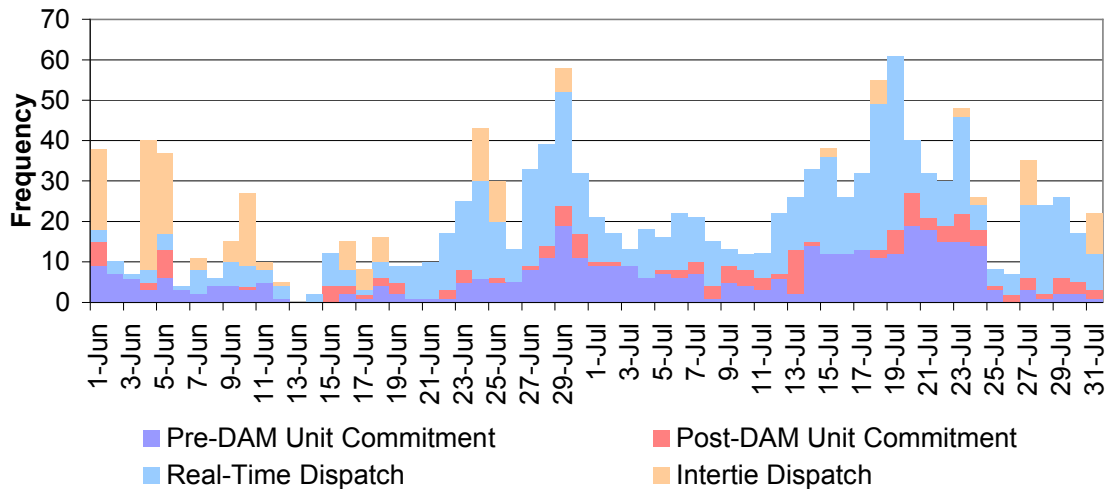
**Figure 15: Total RUC Cost**



### Exceptional Dispatch

For the months of June and July 2009, Figure 16 shows the frequency of exceptional dispatch broken out by: (1) unit commitments made prior to the Day-Ahead Market (DAM); (2) unit commitments made after the close of the DAM; (3) Instructed Imbalance Energy Dispatches made in real-time (dispatches above a units minimum operating level); and (4) real-time dispatches on interties (including HASP dispatches).<sup>2</sup> Alternatively, Figure 17 summarizes exceptional dispatch frequency by general reason where system includes system energy on interties and other system capacity requirements in the ISO balancing authority area, and market disruption includes HASP failures. Overall, the number of exceptional dispatches increased by 36 percent to 788 in July from June’s total of 581. The increase in occurrence of exceptional dispatch was primarily driven by higher loads, mostly in the middle of the month when the summer time loads occasionally drifted above 40,000 MW. The CAISO developed two nomograms for generation procedures G-217 and G-219 which were implemented in the RUC market starting on the day-ahead market for July 27<sup>th</sup>. This significantly reduced the pre-DAM commitments from that date.

**Figure 16: Exceptional Dispatch Frequency**



<sup>2</sup> The process of incorporating exceptional dispatch instruction into downstream CAISO databases is largely a manual process and runs on approximately a T + 38 settlements time-line. As a result, it is not possible to provide accurate MWh values for the time frame of this report. In the interest of providing reasonably accurate data, the time frame of this section of the report will follow the rest of the report with a one month lag.

The increase in exceptional dispatch was mainly due to reliability requirements for both transmission procedures and generation procedures. In July, the occurrence (frequency) of exceptional dispatch due to the transmission procedures and the generation procedures increased by more than 100 percent from the prior month. The intra-zonal congestion in the Fresno area and the Sierra area primarily drove up the transmission reliability requirements.

**Figure 17: Summary of Exceptional Dispatch Frequency by Reason**

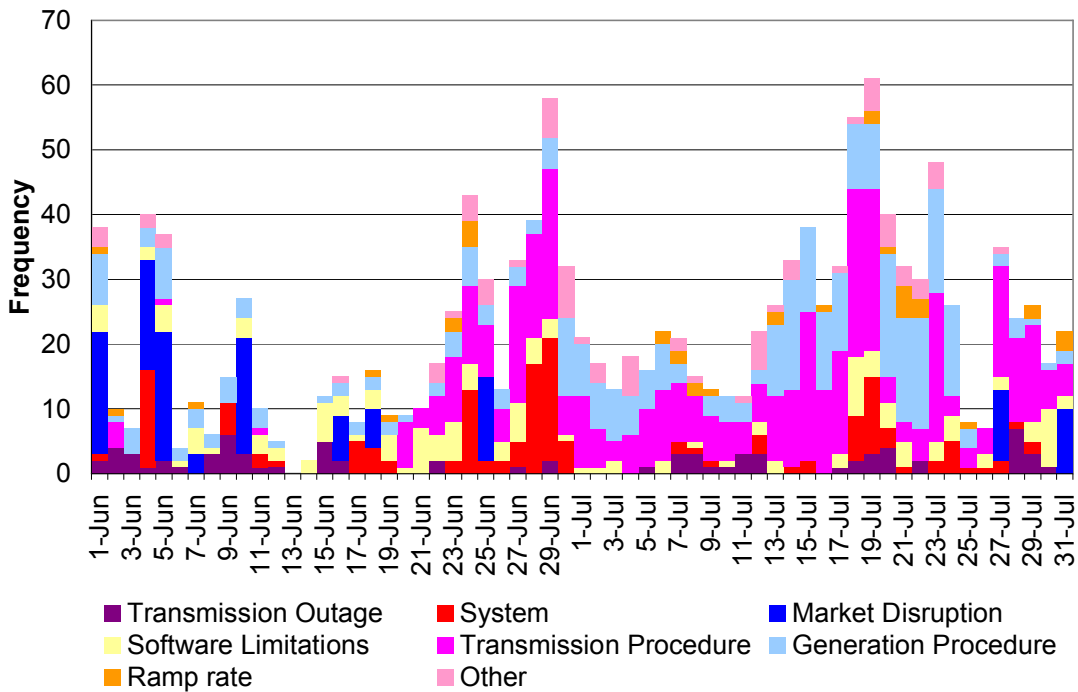


Figure 18 shows the total MWh volume of exceptional dispatches per trade date broken out by min-load MWh volumes for day-ahead unit commitments, and by incremental and decremental real-time imbalance energy. The average daily exceptional dispatch MWh volumes increased by 3 percent in July from June.

**Figure 18: Total Exceptional Dispatch MWh Volume**

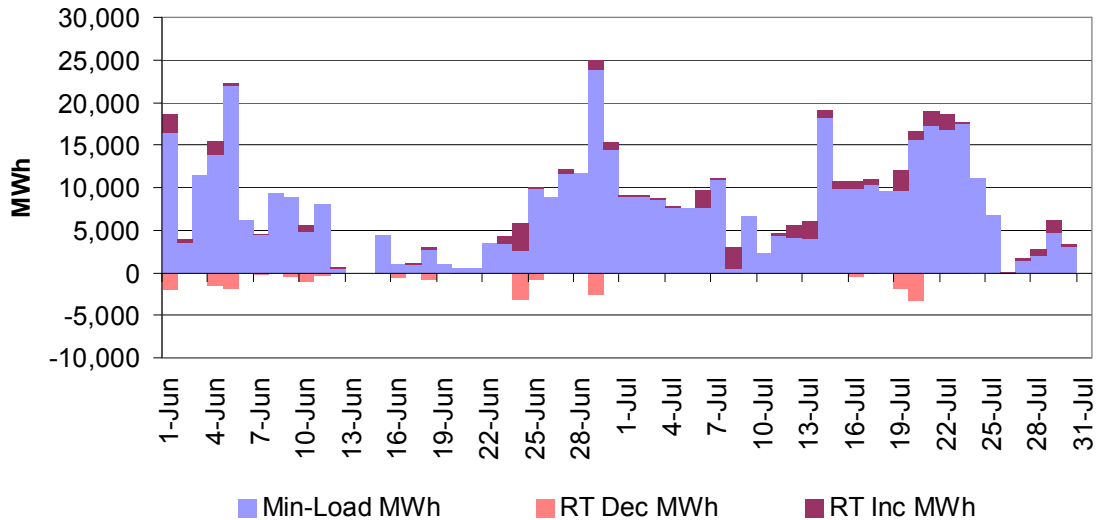


Figure 19 shows the total MWh quantity of exceptional dispatch as a percentage of the total load in the CAISO balancing area, where the total load is equal to internal generation plus imports minus exports. The horizontal lines in the figure identify the monthly averages for each month.

**Figure 19: Exceptional Dispatch Percent of Total Load**

