Market Performance Report
September 2009

October 26, 2009

ISO Market Services

CAISO
151 Blue Ravine Road
Folsom, California 95630
(916) 351-4400

Executive Summary

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

- The average energy demand was 1.1 percent higher than one year ago.
- Natural gas prices increased significantly given some indications of improvements in the economy.
- Day-ahead on-peak bilateral contract prices increased by the end of September, mirroring the movement of natural gas prices.
- The day-ahead (IFM) market saw an increasing trend in the energy prices for the three default LAPs in the last three weeks of September, thanks largely to the rising natural gas prices.
- Real-time energy prices were generally stable in September with a few exceptions.
- The cumulative total congestion rent for interties in September was approximately $10.81 million, and the cumulative total branch group congestion rent was approximately $5.39 million.
- Total congestion revenues were in deficit of $5.2 million, to cover all payments to CRR holders and cost of the perfect hedge, a significant increase with respect to Augusts' $0.2 million.
- The monthly ancillary service average cost to load for September decreased to $0.27/MWh, down slightly from $0.28/MWh in July.
- The total RUC procurement cost declined to $3,007 in September from Augusts' $24,888.

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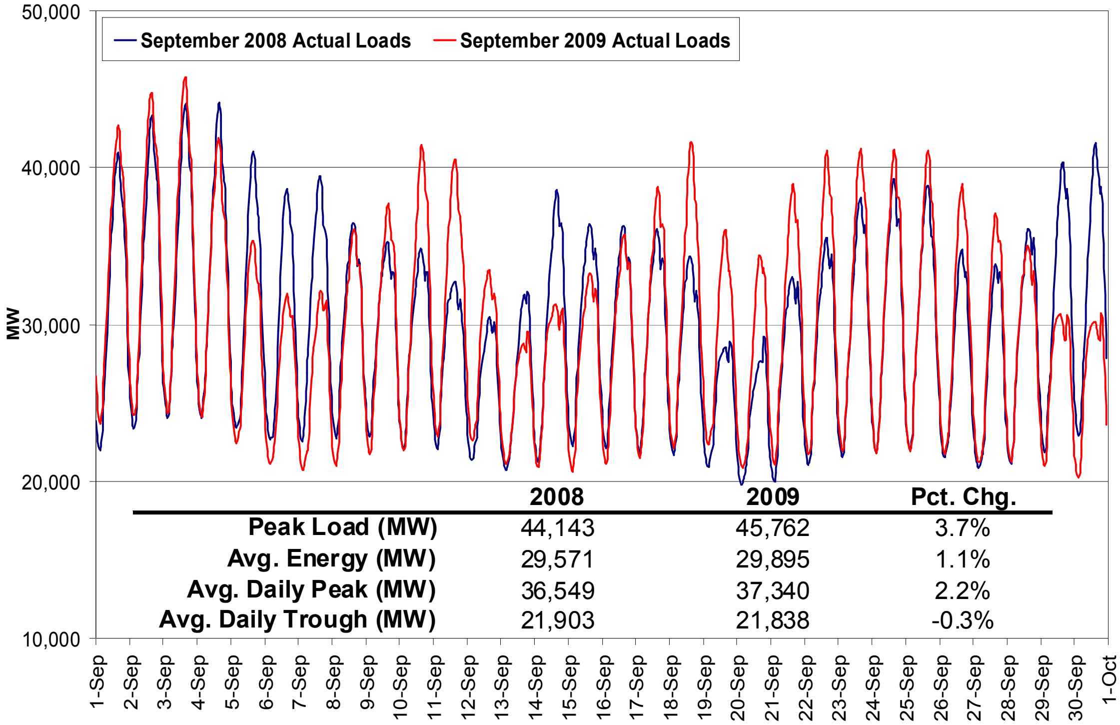
Market Characteristics

Loads

The summer weather prevailed during September 2009 as loads drifted over 40,000 MW on 11 out of 30 days of the month, peaking at 45,762 MW. The average energy demand was 1.1 percent higher than one year ago, and it was 0.45 percent lower than the average demand in August 2009. The loads were significantly higher during the first week of this month due to warmer weather.

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

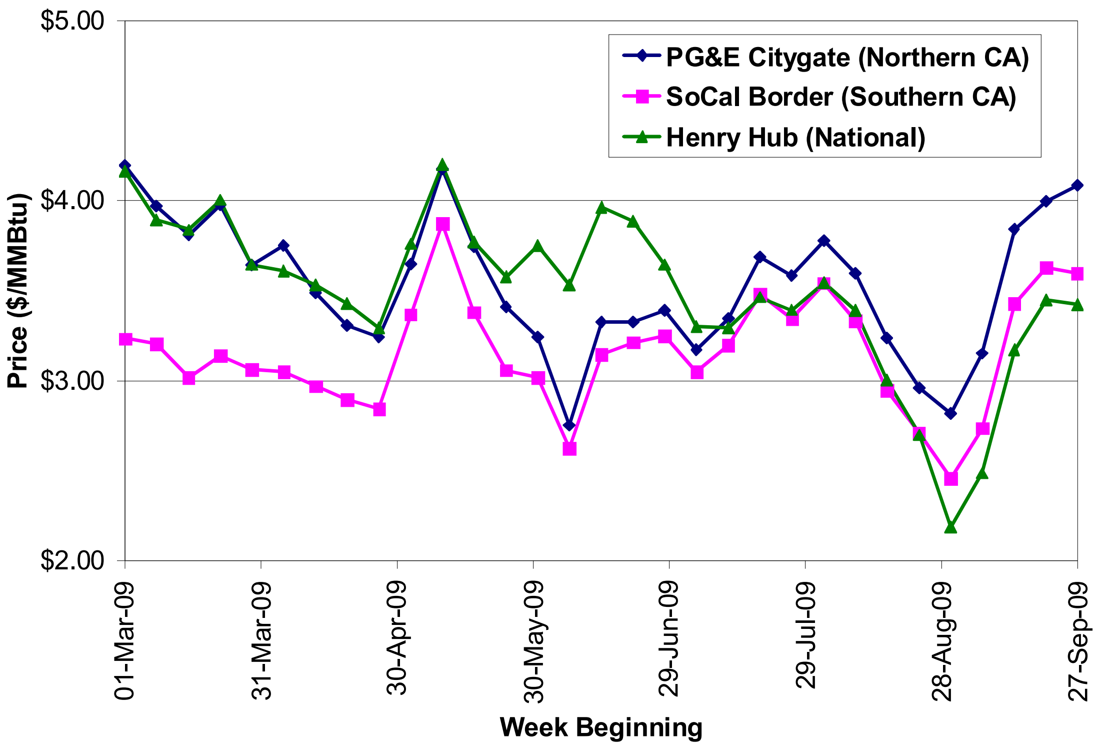


	2008	2009	Pct. Chg.
Peak Load (MW)	44,143	45,762	3.7%
Avg. Energy (MW)	29,571	29,895	1.1%
Avg. Daily Peak (MW)	36,549	37,340	2.2%
Avg. Daily Trough (MW)	21,903	21,838	-0.3%

Natural Gas Prices and Inventories

In September, natural gas prices increased significantly given some indications of improvements in the economy. According to the Energy Information Administration (EIA), significant price increases in this month may suggest that the year-long trend of declining prices may be coming to an end. The California Composite Average gas price posted an increase this month, going up approximately 39 percent to $3.76 per MMBtu on September 30th from $2.7 per MMBtu on August 31st. As of September 25th, the working gas in underground storage in the West increased to 489 Bcf, which is 17 percent above the five-year average.

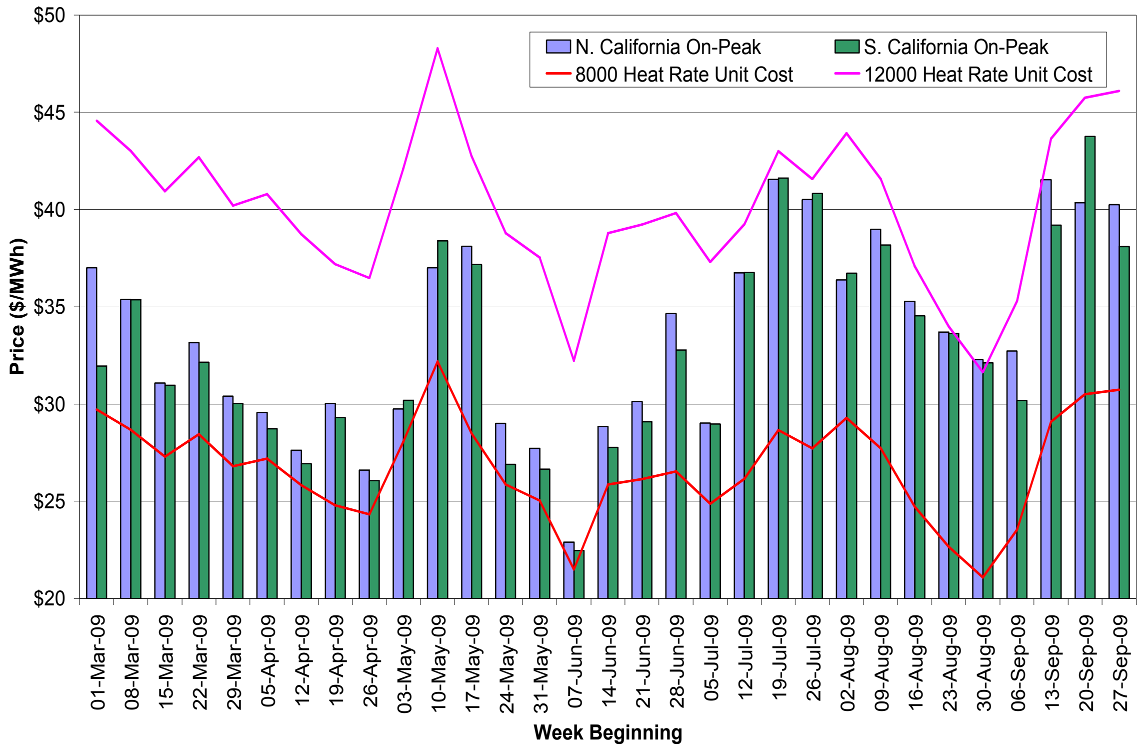
Figure 2: Weekly Average Natural Gas Spot Prices – March 2009 to September 2009



Bilateral Electricity Prices

Mirroring the movement of natural gas prices, day-ahead on-peak power prices increased by the end of September. 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



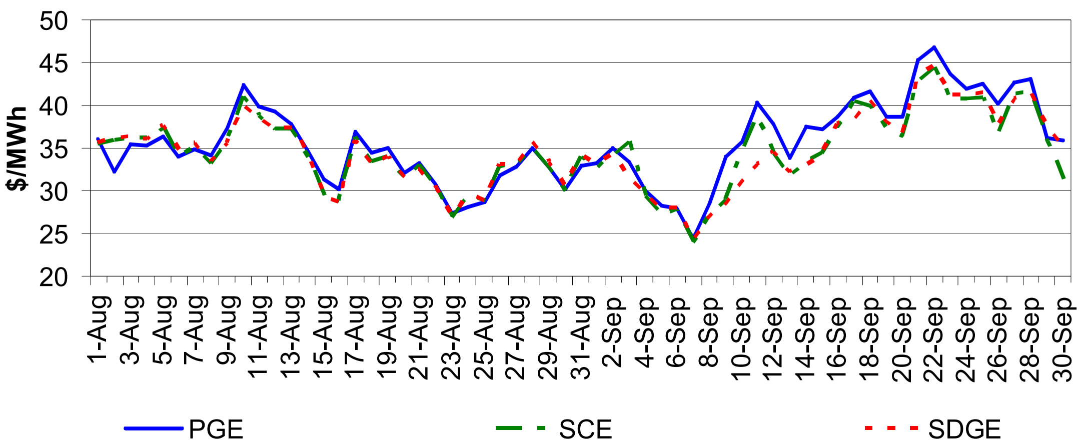
Market Performance Metrics

Energy

Day-Ahead Prices

The day-ahead market saw an increasing trend in the energy prices in the last three weeks of September, thanks largely to the rising natural gas prices. The prices in three default LAPs diverged on several days due to congestions on some transmission facilities. On September 11th, prices in the SDG&E area were depressed by the congestion on a nomogram, which was created to account for a scheduled outage of the San Onofre-Santiago # 2 230 kV line. On September 15th, congestion on the Los Banos North branch group elevated prices in the PG&E area. On September 8th and 9th, also from September 12th to 14th, Gates-Midway 500 kV line was congested, elevating prices in the PG&E area on those days. As shown in Figure 4, the daily average prices were moderate for the month, falling into the range between \$24/MWh and \$47/MWh.

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



Real-Time Prices

Real-time energy prices were generally stable in September with a few exceptions, as shown in Figure 5. On September 3rd, the prices in the SDG&E area were depressed by congestion on a nomogram, where this nomogram was created to account for a scheduled outage of the San Onofre -Santiago # 2 230 kV line. On September 17th, 18th and 20th, congestion on the Los Banos North branch group elevated prices in the PG&E area. On all the other days in the month, the daily average real-time energy prices for three default LAPs fell into the range between \$15/MWh and \$70/MWh.

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

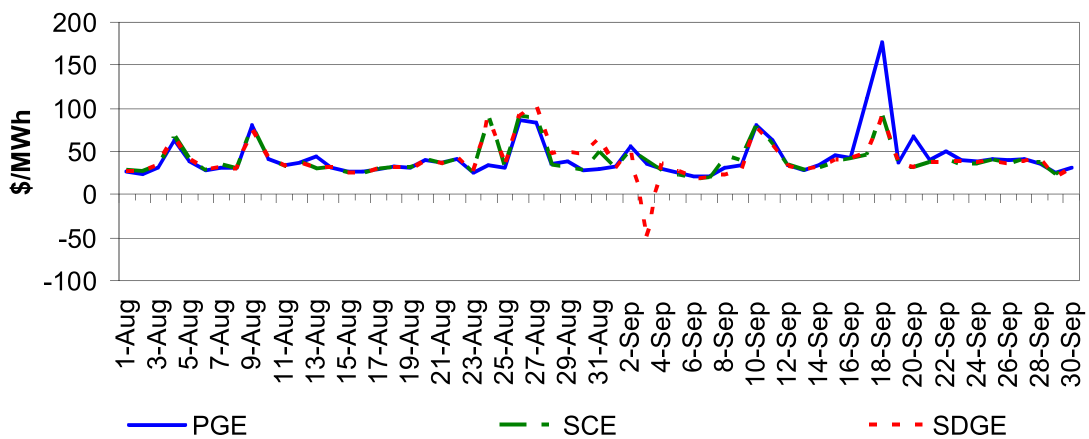
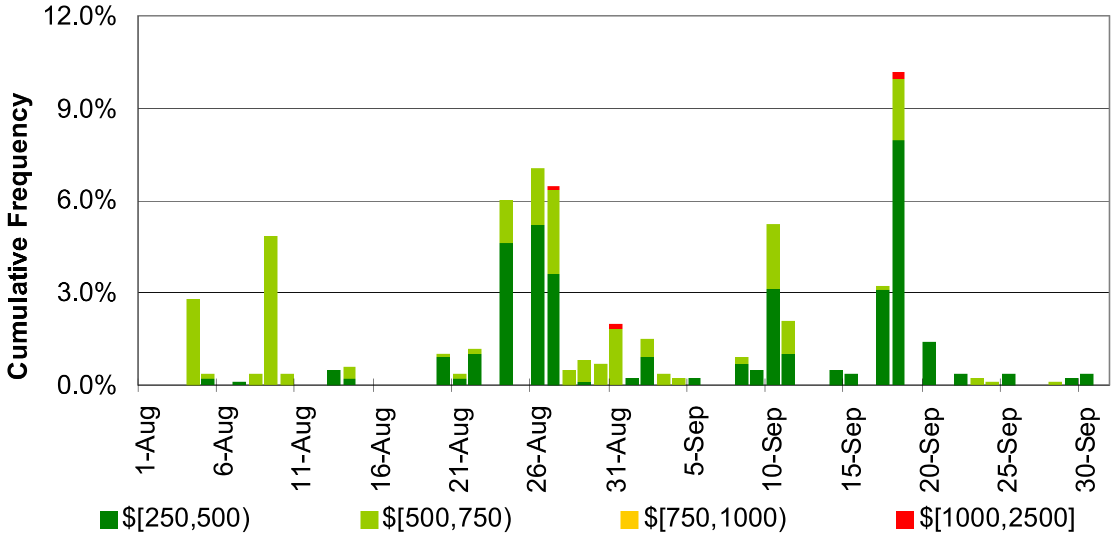


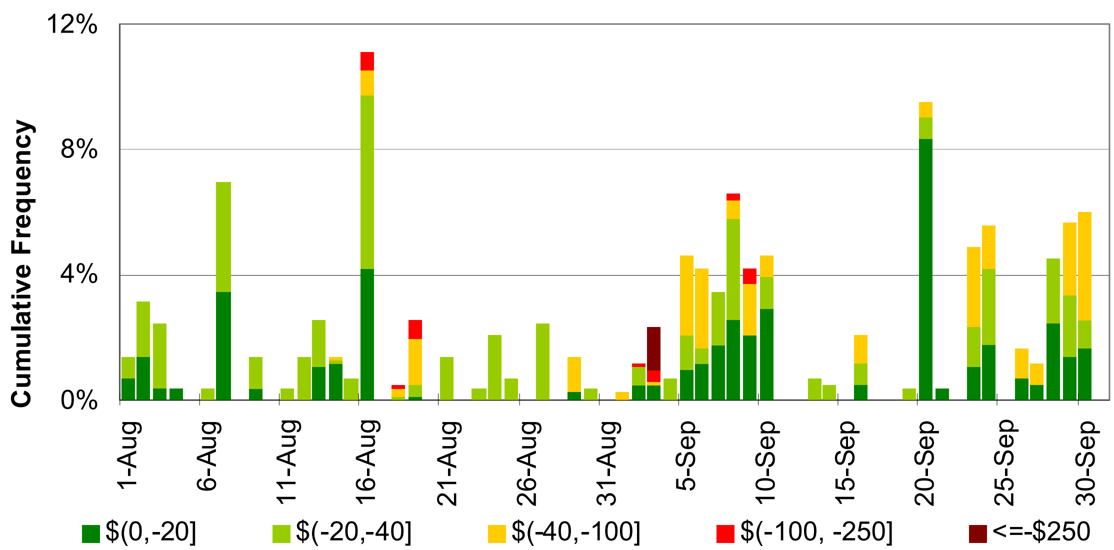
Figure 6 on the next page shows the daily frequency of price spikes by price range for all three default LAPs in the 5-minute Real-Time Dispatch (RTD). In percentage terms, the frequency of prices over \$250/MWh slightly declined from 1.15 percent in August to 0.95 percent in September. Extreme prices (over \$1000/MWh) remained constant, with a frequency of approximately 0.007 percent in both August and September. As shown in Figure 6, the only occurrence of the extreme prices was on September 18th, and it was due to congestion as explained above.

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 were mainly observed as a result of over-generation in the early morning off-peak hours when there were light loads and many units were operating at minimum loads and, thus, the system was more limited to ramp down. Some other instances of negative prices were driven by congestion on different transmission constraints, such as that of September 3rd discussed above. Frequency of negative prices increased from 1.45 percent in August to 2.49 percent in September.

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 August and September 2009. The cumulative total congestion rent for interties in September was approximately $10.81 million, up considerably from $2.56 million in August. Most of the congestion occurred on Palo Verde (79.53 percent), El Dorado (8.13 percent) and NOB (6 percent) interties.

Figure 8: IFM Congestion Rents by Intertie (Import)

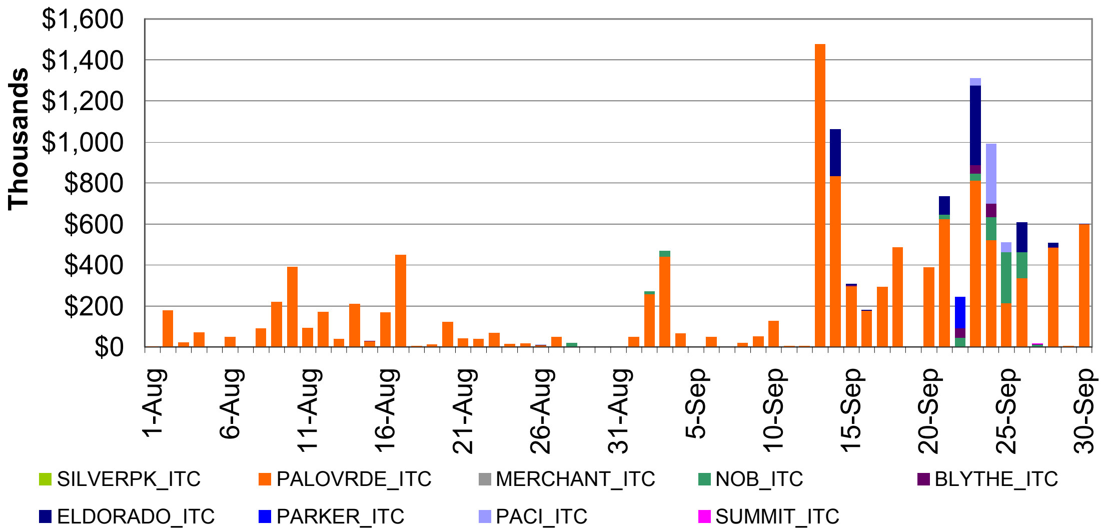


Table 1 shown on the next page provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by intertie. The average shadow price on Palo Verde intertie was $21/MWh in September, which was significantly higher than $4/MWh in August. The congestion on Palo Verde intertie was primarily driven by a forced outage of the Hassayampa-North Gila 500 kV line. Starting from September 13th, the Palo Verde intertie was sharply derated to approximately 50 percent of its nominal capacity due to this forced outage. For the subsequent couple of weeks the capacity on the Palo Verde intertie fluctuated between approximately 1500 MW and 1000 MW due to numerous outages including the forced outage of the Hassayampa-North Gila 500kV line, which was back in service on September 24th. This intertie was again derated in certain hours from September 25th through September 30th due to a combination of other planned and forced outages.

The Eldorado intertie saw significant portions of its congestion rents on September 14th, 23rd and 26th. Congestion rents on these days were primarily driven by path capacity derates motivated by a combination of scheduled and forced outages.

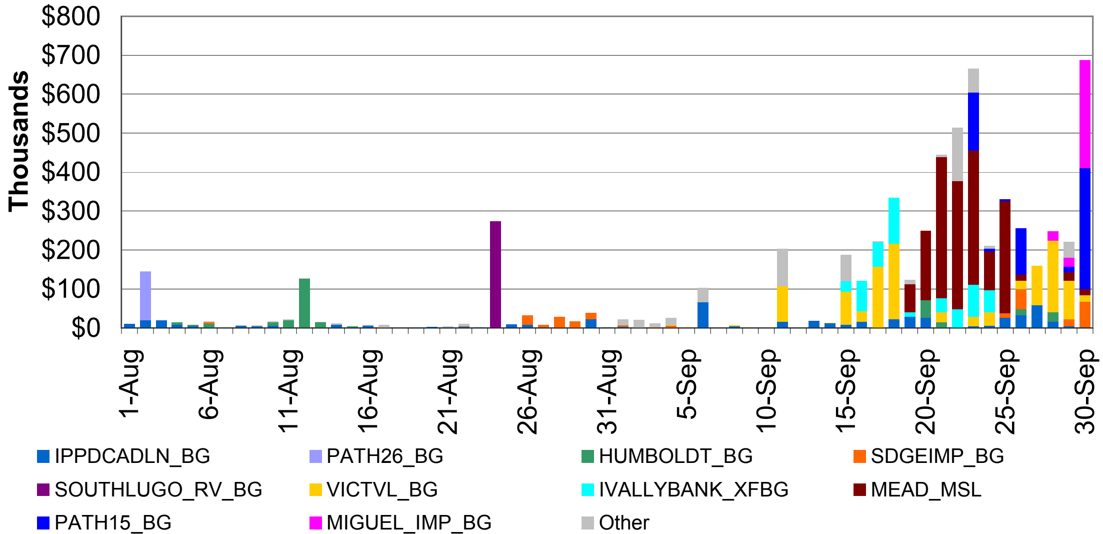
Table 1: IFM Congestion Statistics by Intertie (Import)

Intertie	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
BLYTHE_ITC	160	30	70
ELDORADO_ITC	1252	13	56
NOB_ITC	1099	19	33
PACI_ITC	2492	9	16
PALOVRDE_ITC	1486	21	362
PARKER_ITC	186	35	23
SUMMIT_ITC	43	5	13

Congestion Rents on Branch Groups

Figure 9 illustrates IFM congestion rents on selected branch groups. For the month of September, the total branch group congestion rent was approximately $5.39 million, up significantly from $0.82 million in August. Of the total, the vast majority of rents occurred on the Mead_MSL (32 percent), Victorville branch group (20 percent), Path 15 (11 percent) and Imperial Valley transformer branch group (10 percent).

Figure 9: IFM Daily Congestion Rents by Branch Group



Two significant transmission outages in September were primarily driving congestion rents on branch groups. First, the Adelanto-Toluca 500kV line was forced out of service starting from September 2nd till September 27th due to station fires. Second, as mentioned in the previous section, the Hassayampa-North Gila 500kV line was forced out of service from September 11th till September 24th. These two outages were primarily driving congestion on Victorville branch group. The forced outage of Hassayampa-North Gila 500kV line was also driving congestion at the Imperial Valley transformer branch group.

As mentioned in the previous section the Palo Verde intertie was derated due to a forced outage, so the scheduling coordinators were apparently looking for alternative tie points to import power from Northwest into the CAISO. Scheduling coordinators increased their imports bids on the Mead scheduling point, which motivated congestion on the Mead scheduling limit.

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

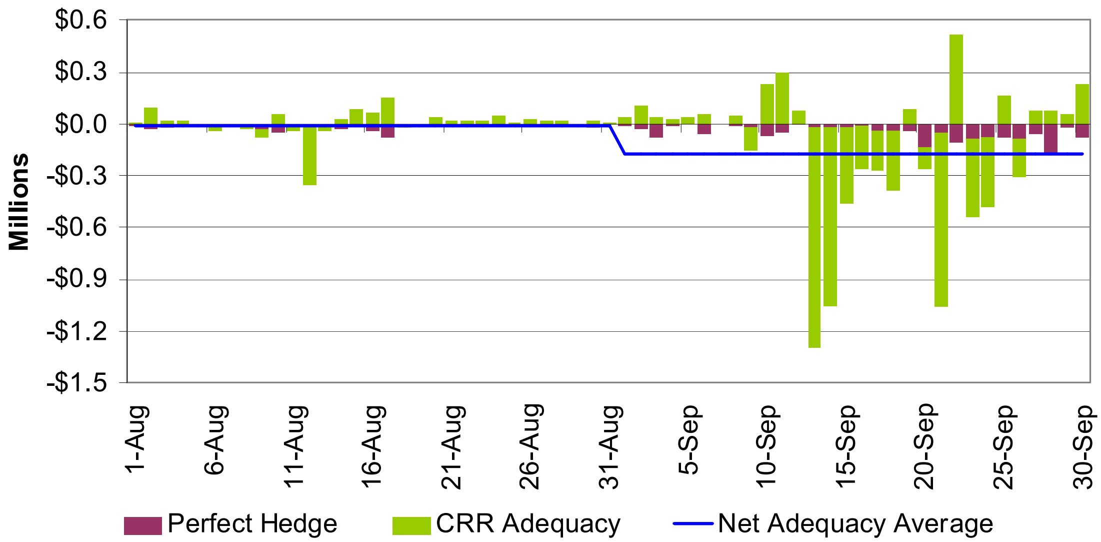
Table 2: IFM Congestion Statistics by Branch Group

Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
ADLANTOSP_MSL	1208	5	29
HUMBOLDT_BG	45	276	8
IPPDCADLN_BG	647	4	142
IVALLYBANK_XFBG	900	7	79
LOSBANOSNORTH_BG	2305	4	20
LUGO_VINCENT_BG	3000	0	3
MEAD_MSL	1460	10	113
MIGUEL_IMP_BG	1900	9	19
MKTPCADLN_MSL	630	9	5
MONAIPPDC_MSL	236	1	5
PATH15_BG	3318	6	34
SDGEIMP_BG	2096	4	25
SDGE_CFEIMP_BG	2260	3	7
VICTVL_BG	2550	6	76
WSTWGMEAD_MSL	186	32	16

Congestion Revenue Rights

Figure 10 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of August and September 2009. In comparison to the daily average deficit of $6,649 for August, September experienced a daily average revenue deficit of $175,246.

Figure 10: Daily Revenue Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in 15 out of 30 days of the month, with the most significant deficiencies observed between September 13th and September 24th. Revenue deficiencies accrued in the latter half of the month due to a significant derate on the Palo Verde intertie, as described above in the section of congestion. Such revenue deficiencies occurred because with the derate on Palo Verde, congestion rents were collected on less transmission capacity, in comparison to the transmission capacity used to release CRRs. It is worth noting that outside the period in which Palo Verde was forcedly derated, the market saw a CRR revenue surplus of $0.34 million, which may suggest that if the outage had not occurred, September would have seen a revenue surplus.

For the month of September, 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 September was of 15 percent. Given the forced outage that affected Palo Verde, the global derating factor was largely insufficient to attain CRR revenue adequacy.

The monthly summary is provided in Table 3 on the next page. Overall, the total dollars collected from the IFM were sufficient to cover approximately 80 percent of the net payments to CRR holders and the cost of the perfect hedge.

Approximately 7.2 percent of the congestion rents were needed to cover the cost of the perfect hedge. On net, total congestion revenues were in deficit of $5.2 million, a significant increase with respect to Augusts' deficit of $0.2 million. The auction revenues credited to the balancing account for September were $1.73 million, and will be fully used to offset the $5.2 million of revenue deficiency, leaving a net deficit of approximately $3.52 million to be allocated to measured demand.

Table 3: CRR Adequacy Statistics for September

Concept	Amount
IFM Congestion Rents	$20,452,204.65
CRR Payments	$24,233,273.82
CRR Adequacy	-$3,781,069.16
Perfect Hedge	-$1,476,300.41
Net Revenue Adequacy	-$5,257,369.57
Revenue Adequacy Ratio	79.55%
Annual Auction Revenues	$1,295,671.68
Monthly Auction Revenues	$438,709.00
Monthly Net Balance	-$3,522,988.89

Ancillary Services

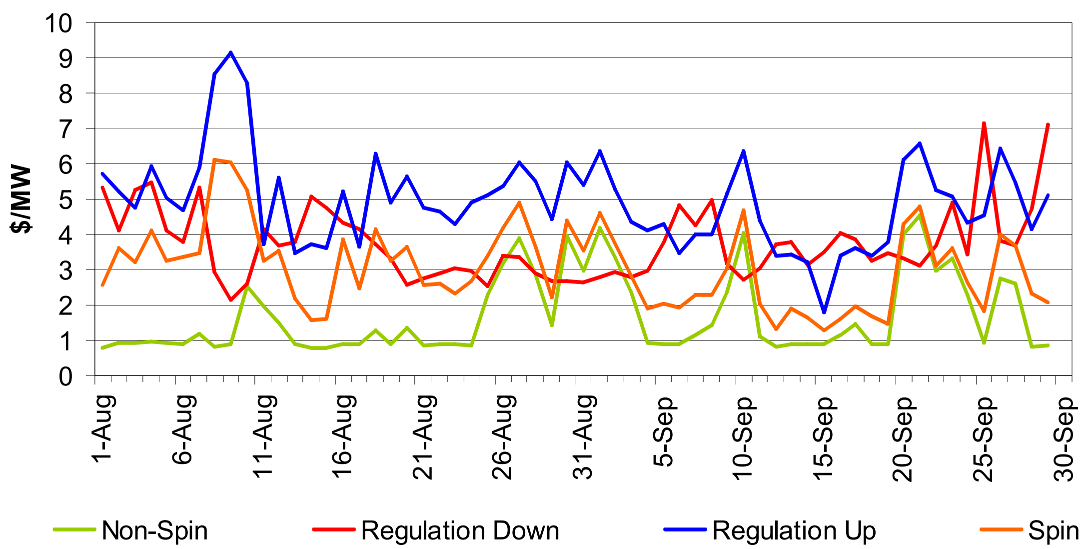
IFM (Day-Ahead) Average Price

Table 4 shows the monthly IFM average ancillary service procurements and prices for August and September 2009. The average procurement quantity for all four types of ancillary services remained relatively unchanged in September compared with the month of August. The average price for both regulation up and spin saw a decline in September, whereas average price for both regulation down and non-spin saw an increase. Among the four types of ancillary services, spin saw the largest decline in the monthly average price, while non-spin saw the largest increase in the monthly average price. Figure 11 below shows the daily IFM average prices for August and September 2009; the daily average prices were moderate on most days in September 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
Sep-09	375.00	375.00	927.04	914.09	$4.54	$3.82	$2.67	$1.95
Aug-09	375.16	375.00	925.39	923.35	$5.29	$3.68	$3.43	$1.42
	-0.04%	0.00%	0.18%	-1.00%	-14.19%	3.83%	-22.28%	37.39%

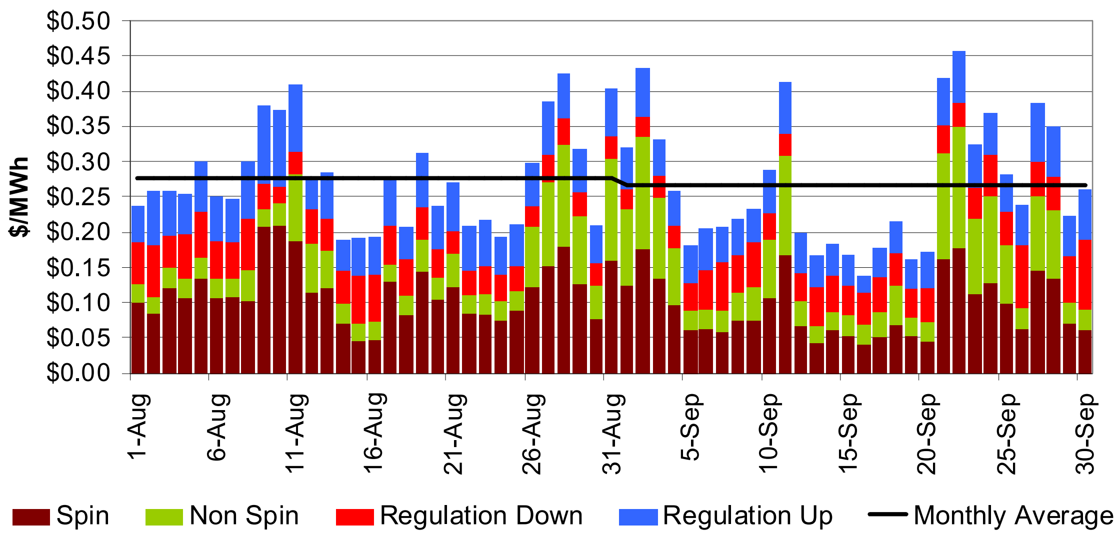
Figure 11: IFM (Day-Ahead) Ancillary Service Average Price



AS Cost to Load

Figure 12 below shows the total system (day-ahead and real-time) average cost to load for ancillary services procured in August and September 2009. The monthly average cost to load for September decreased to $0.27/MWh, down slightly from $0.28/MWh in August.

Figure 12: System (Day-Ahead and Real-Time) Average Cost to Load

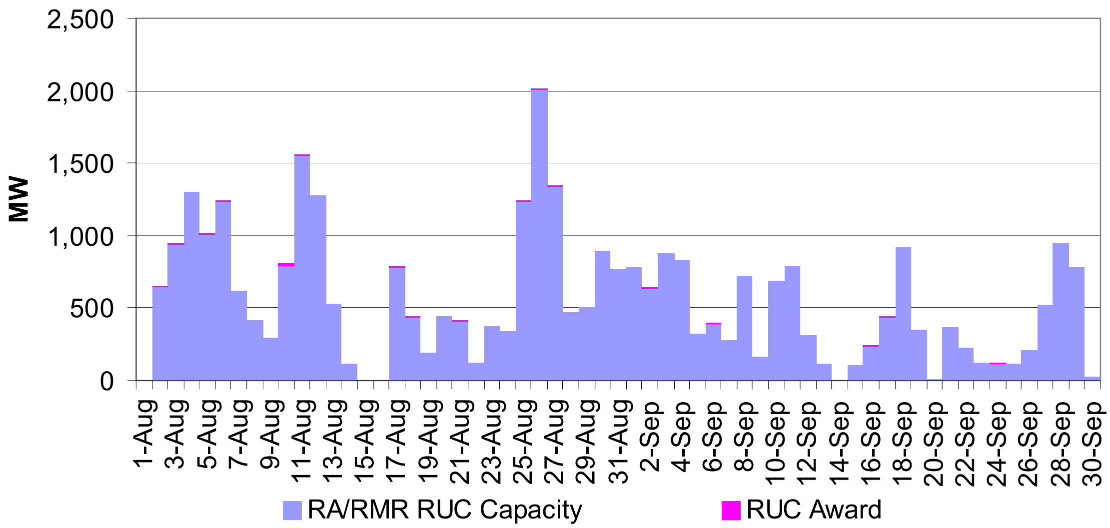


Residual Unit Commitment

RA/RMR RUC Capacity vs. RUC Award

Figure 13 shows the daily average RA/RMR RUC capacity and RUC award for August and September 2009. The monthly average RUC capacity for September fell 41 percent to 400 MW from Augusts' 681 MW. However, the percentage of RUC capacity procured from RA or RMR units remained approximately the same, around 99.4 percent in both September and August.

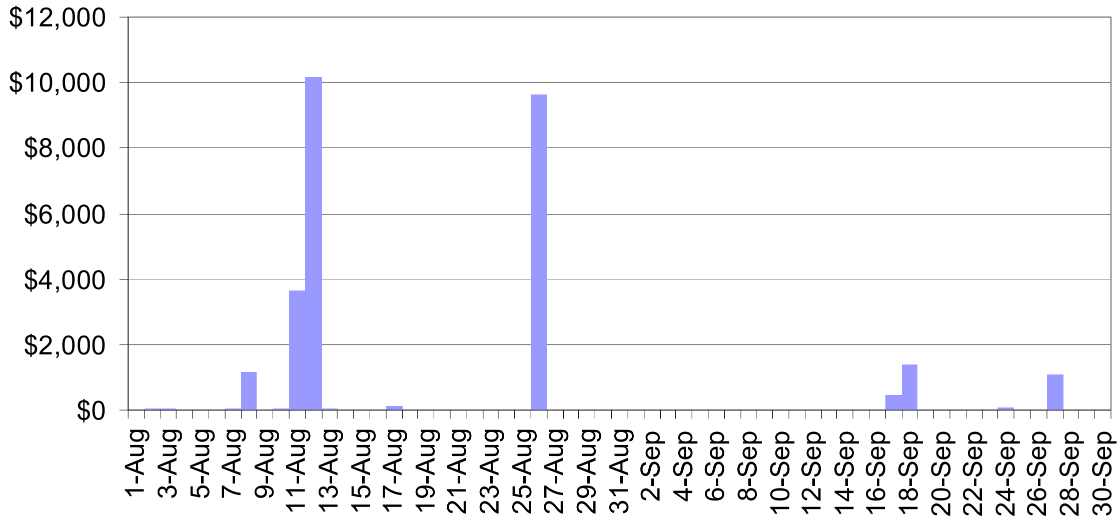
Figure 13: RA/RMR RUC Capacity vs. RUC Award (All Hours)



Total RUC Cost

Figure 14 shows the daily cost of RUC procurement for each trading day in August and September 2009. The total RUC procurement cost declined to $3,007 in September from Augusts' $24,888. This was because less RUC capacity was procured from non-RA/RMR units in September than in August, and it was procured at lower prices. About 80 percent of RUC cost of the month occurred on two days, September 18th and September 27th, while Victorville branch group was binding, driving up the LMPs in that area.

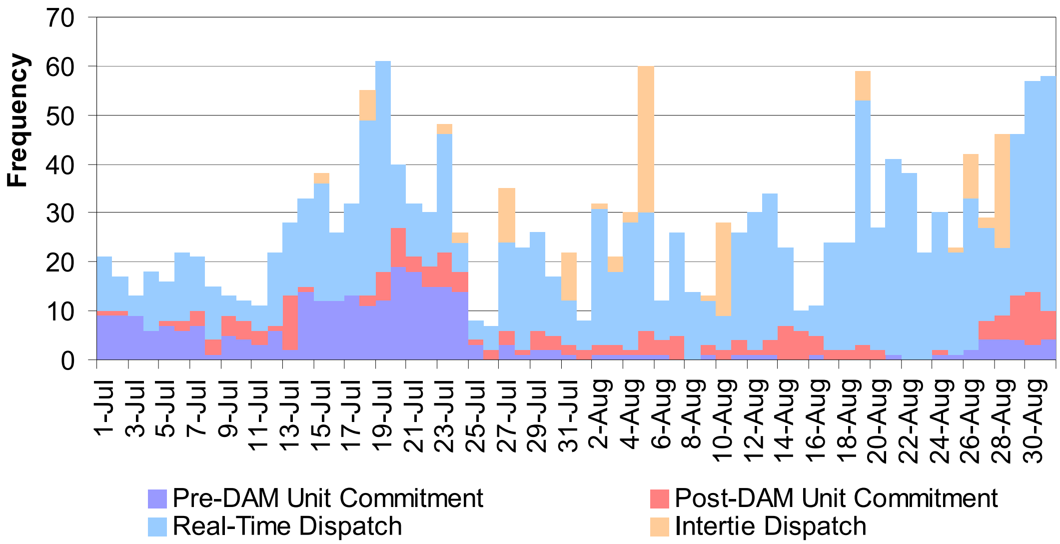
Figure 14: Total RUC Cost



Exceptional Dispatch

For the months of July and August 2009, Figure 15 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).[1] Overall, the number of exceptional dispatches increased by 12 percent to 847 in August from July's total of 755. The CAISO developed two nomograms for generation procedures G-217 and G-219 which were implemented in the RUC market starting on the DAM for July 27th. This drove down the Pre-DAM unit commitment in August. However, the real-time exceptional dispatch instructions saw an increase during the second half of August due to HASP failures and Fresno area mitigation. The additional real-time exceptional dispatch in the Fresno area was necessary because the transmission constraints that are related to Remedial Actions Schemes (RAS) are not fully modeled in the market application.

Figure 15: Exceptional Dispatch Frequency



[1] 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.

Figure 16 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. Even though the occurrences of exceptional dispatch instructions increased in August, the daily exceptional dispatch MWh volume declined sharply by 87 percent in August from July. As mentioned in the previous paragraph, the implementation of nomograms in RUC drove down Pre-DAM exceptional dispatch unit commitments.

Figure 16: Total Exceptional Dispatch MWh Volume

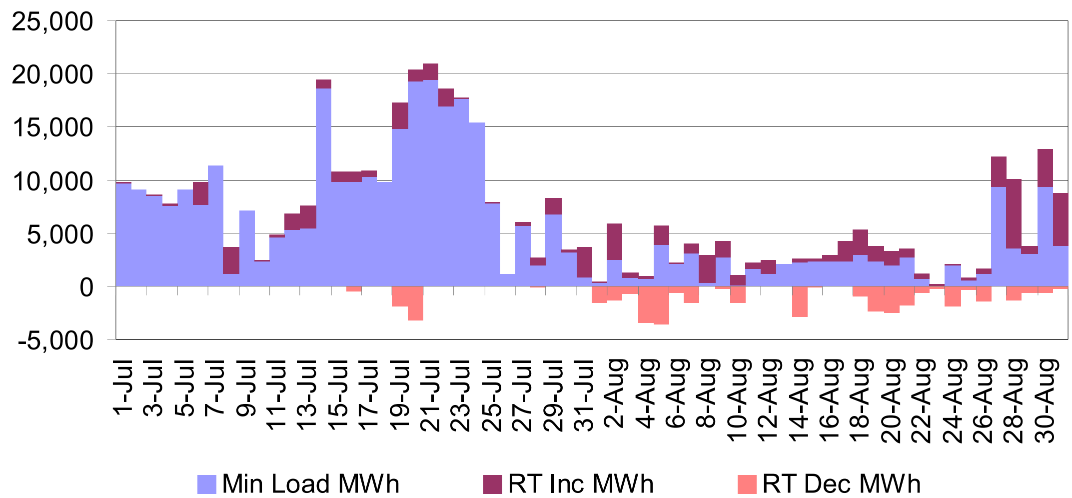


Figure 17 shows the total MWh quantity of exceptional dispatch as a percentage of the total load in the CAISO balancing area, where the total load is equal to internal generation plus imports minus exports. The horizontal lines in the figure identify the monthly averages for each month.

Figure 17: Exceptional Dispatch Percent of Total Load