Market Performance Report
June 2009

July 27, 2009

ISO Market Services

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Executive Summary

This report contains the highlights of the month of May 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 June 2009:

- June 2009 saw lower average energy demand than one year ago.
- Natural gas prices rose generally this month. The increase of the gas prices was mainly driven by rising crude oil prices and warmer temperatures which put upward pressure on cooling demand.
- Daily weighted average Load Aggregation Point (LAP) prices were relatively stable in June, falling into the range of $15 to $40.
- Real-Time energy prices were less variable in June than in May, especially in the SCE and SDGE area.
- The cumulative total congestion rent for inter-ties was approximately $4.6 million, and the total branch group congestion rent was $0.6 million.
- Overall, the total dollars collected from the IFM were sufficient to cover approximately 93 percent of the net payments to CRR holders and holders of the perfect hedge, allocating approximately 17 percent of the congestion rents to honor the perfect hedge. On net, total congestion revenues were deficient by $0.45 million, a sharp decrease of 85 percent with respect to April's deficiency of $3.2 million.
- The monthly average cost to load for June declined to $0.34/MWh, down from $0.44/MWh in May.

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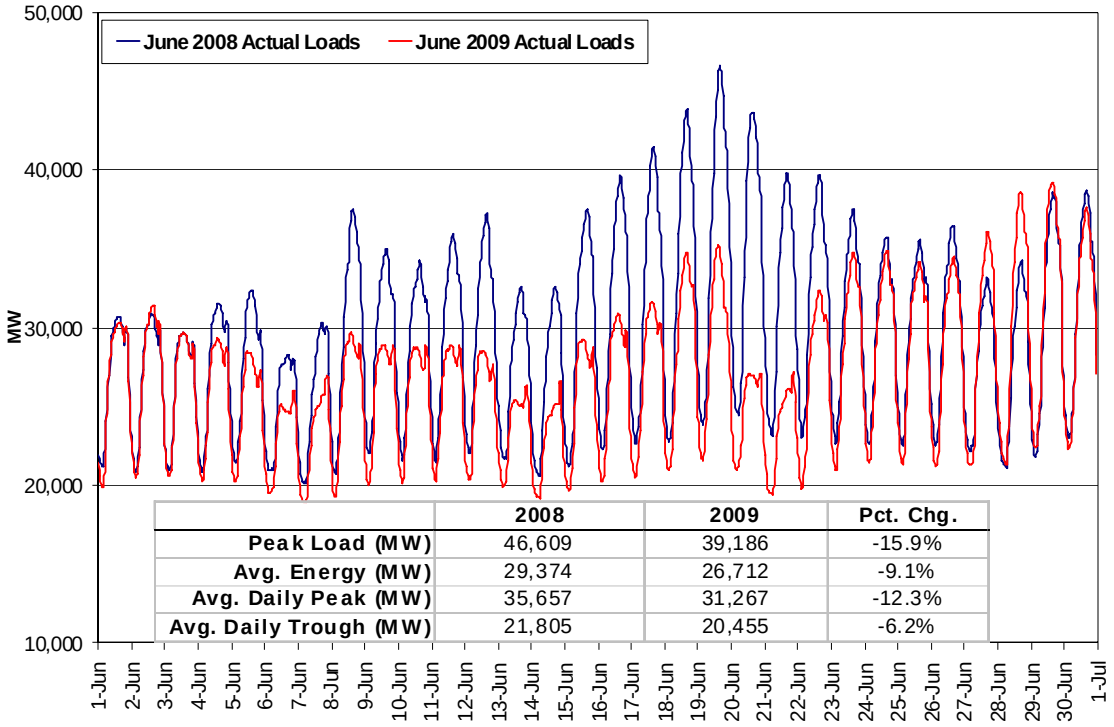
Market Characteristics

Loads

June 2009 saw lower average energy demand than one year ago. Both the average daily peaks and troughs were lower than June one year ago for most days of the month. The average daily peak fell 12.7 percent and the average trough fell 6.3 percent when compared with June 2008. The decline in energy demand can be attributed to a combination of the weakness in the economy and moderate weather. The actual loads increased in the latter half of June due to rising temperatures.

Figure 1: System Load Comparison – June 2009 v. June 2008

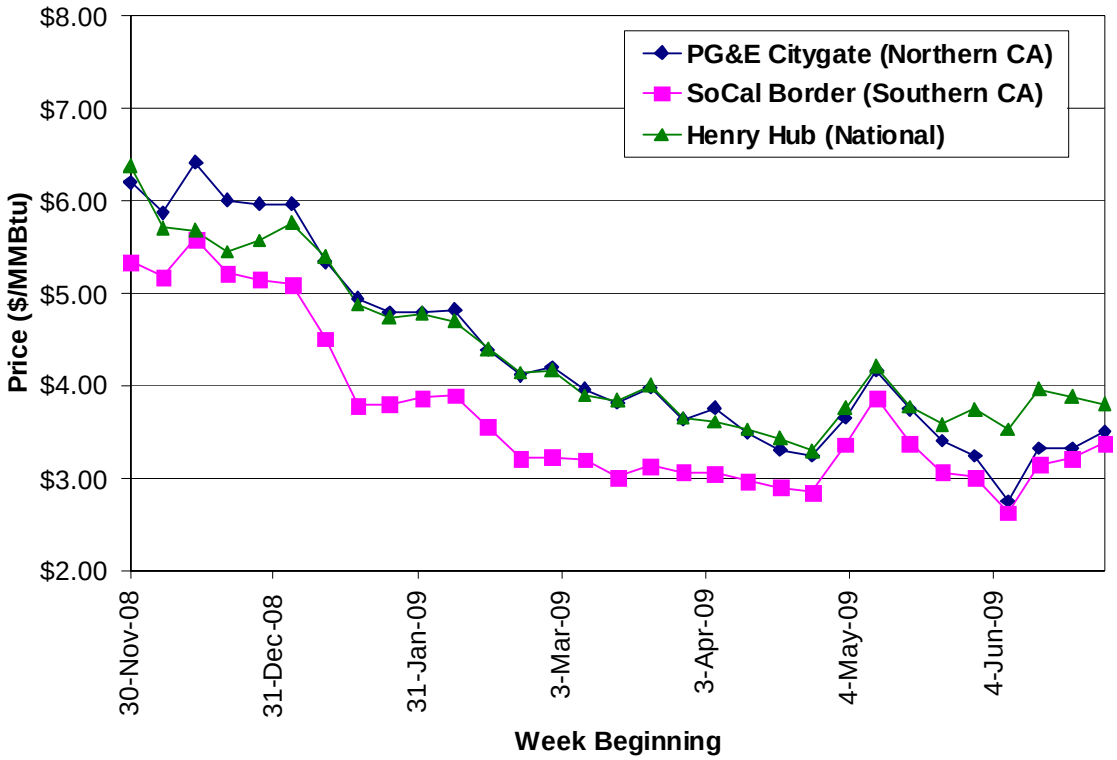


	2008	2009	Pct. Chg.
Peak Load (MW)	46,609	39,186	-15.9%
Avg. Energy (MW)	29,374	26,712	-9.1%
Avg. Daily Peak (MW)	35,657	31,267	-12.3%
Avg. Daily Trough (MW)	21,805	20,455	-6.2%

Natural Gas Prices and Inventories

Natural gas prices rose generally this month. According to EIA, the increase of the gas prices was mainly driven by rising crude oil prices and warmer temperatures which put upward pressure on cooling demand. The California Composite Average gas price inched up two cents to $3.35 per MMBtu on June 30th from $3.33 per MMBtu on June 1st.

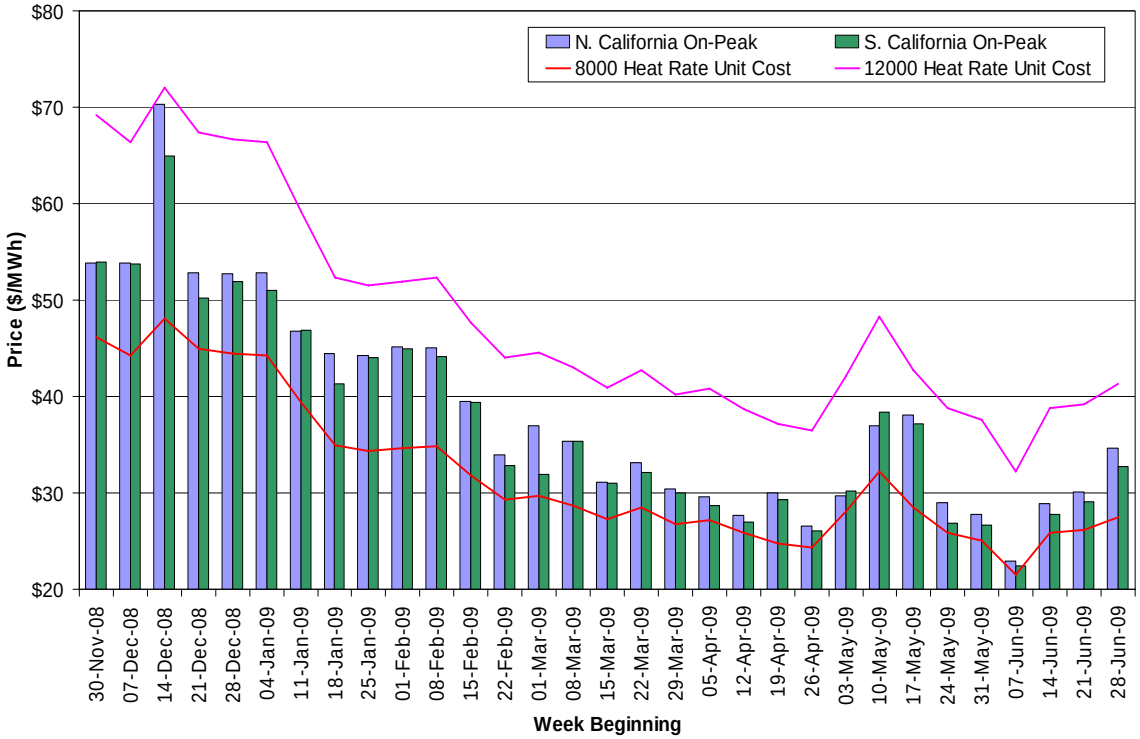
Figure 2: Weekly Average Natural Gas Spot Prices – December 2008 to June 2009



Bilateral Electricity Prices

Day-Ahead, on-peak power prices declined in the week of June 7th and then increased steadily in the rest of this month. Warming weather in the West and rising gas prices contributed to the increased power 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



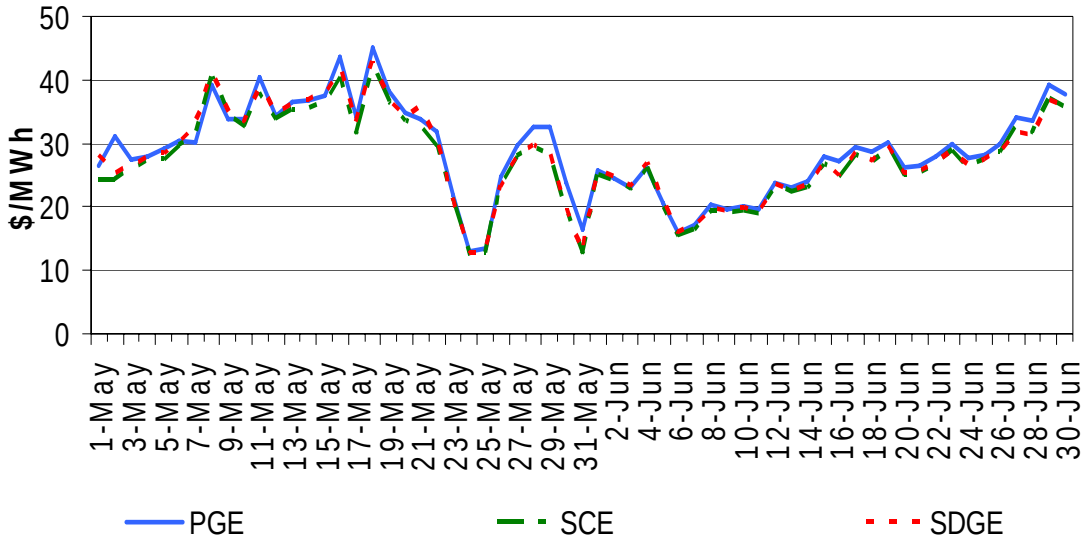
Market Performance Metrics

Energy

Day-Ahead Prices

Daily weighted average Load Aggregation Point (LAP) prices were relatively stable in June, falling into the range of $15 to $40. Figure 4 shows an increasing trend in the average LAP prices thanks largely to the warmer weather and rising natural gas prices.

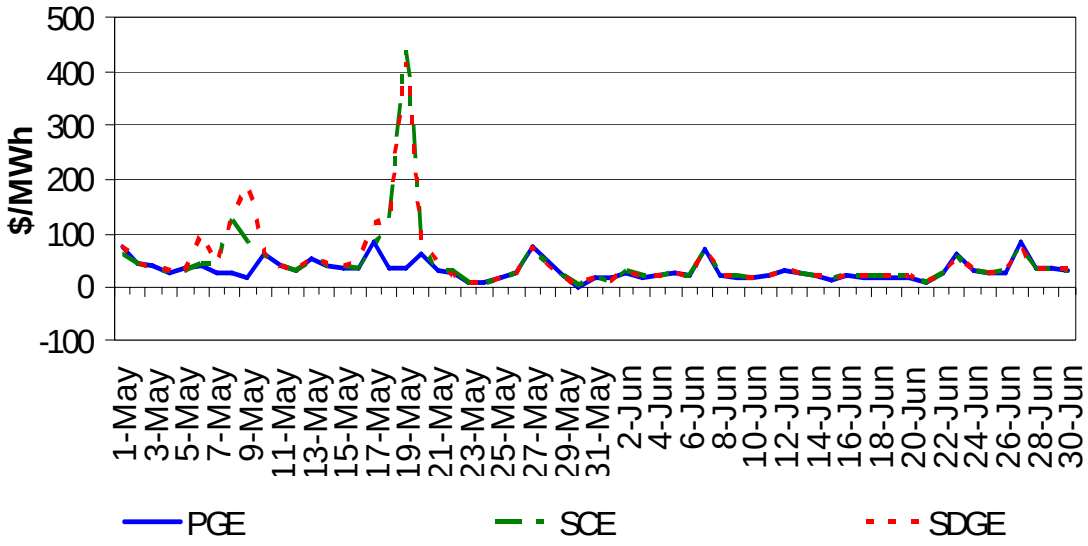
Figure 4: Day-Ahead Weighted Average LAP Prices (All Hours)



Real-Time Prices

Real-Time energy prices were less variable in June than in May, especially in the SCE and SDGE area, as shown in Figure 5. The standard deviations of the prices in these two areas changed from $57.48 and $57.58 in May, to $13.30 and $12.95 in June, respectively. Less maintenance work was scheduled on transmission lines and generation stations in June than in May. This combined with temperate weather contributed to the moderate June prices, ranging from $3 to $67. The Real-Time energy market saw a slightly increasing trend in the last week of June along with the rising temperatures.

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

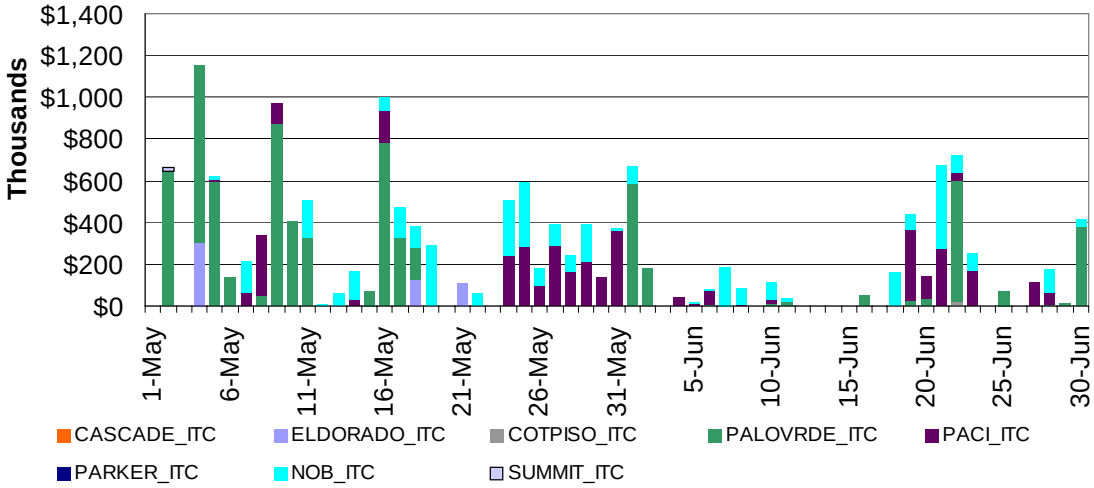


Congestion

Congestion Rents on Interties

Figure 6 below illustrates daily IFM congestion costs by intertie for the months of May and June 2009, while Table 1 provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by intertie. Congestion costs for interties are calculated as the shadow price multiplied by the flow limit. The cumulative total congestion rent for interties in June 2009 was approximately $4.6 million, down from $10.45 million in May. Of the total, the vast majority of costs occurred on three interties: Palo Verde (42 percent), PACI (27 percent) and NOB (30 percent).

Figure 6: IFM Congestion Rents by Intertie (Import)



The Palo Verde intertie incurred most of its congestion rents on June 22nd and June 30th. On June 22nd, the Palo Verde intertie was derated by 846 MW due to scheduled maintenance on Olinda-Tracy 500 kV line, which resulted in significant congestion costs. The CAISO control area experienced a spike in demand on June 30th driven by a heat wave which resulted in over scheduling on the Palo Verde intertie and concomitant non-zero congestion rents.

Most of the congestion rents on the PACI and NOB interties occurred between June 19th and June 21st when the Pacific Northwest was experiencing an abundance of cheap hydropower. This led to over-scheduling on the PACI and the NOB interties which resulted in significant congestion costs.

Table 1: IFM Congestion Statistics by Inter-Tie (Import)

Inter-Tie	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
COTPISO_ITC	24	60	12
NOB_ITC	1489	9	115
PACI_ITC	2698	5	88
PALOVRDE_ITC	2497	11	79

Congestion Rents on Branch Groups

Figure 7 illustrates IFM congestion rents on selected branch groups, while Table 2 provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by branch group. Congestion rents for branch groups are calculated as the shadow price multiplied by the flow limit. For the month of June, the total branch group congestion rent was approximately $0.6 million, down significantly from $3.1 million in May. Of the total, the vast majority of costs occurred on the IPPDC branch group (89 percent) and the Los Banos North branch group (nine percent).

Figure 7: IFM Daily Congestion Rents by Branch Group

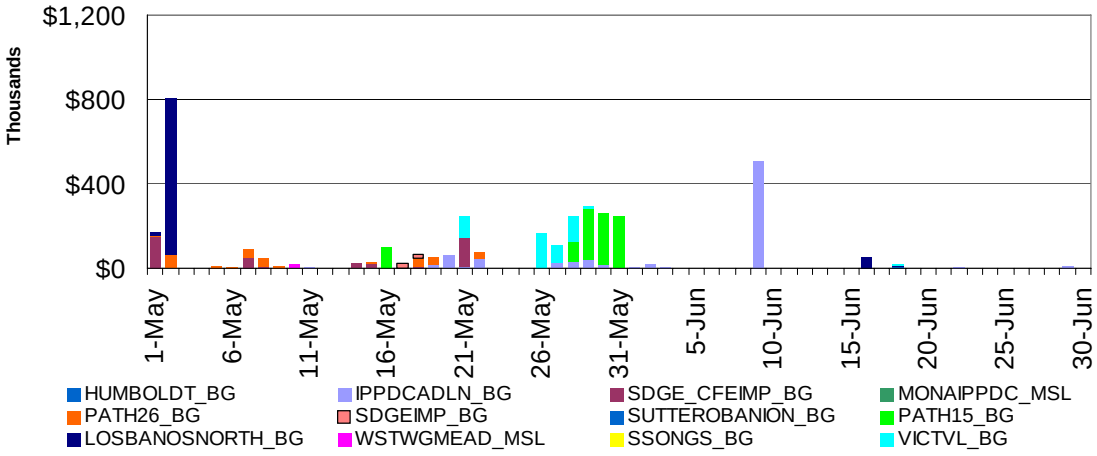


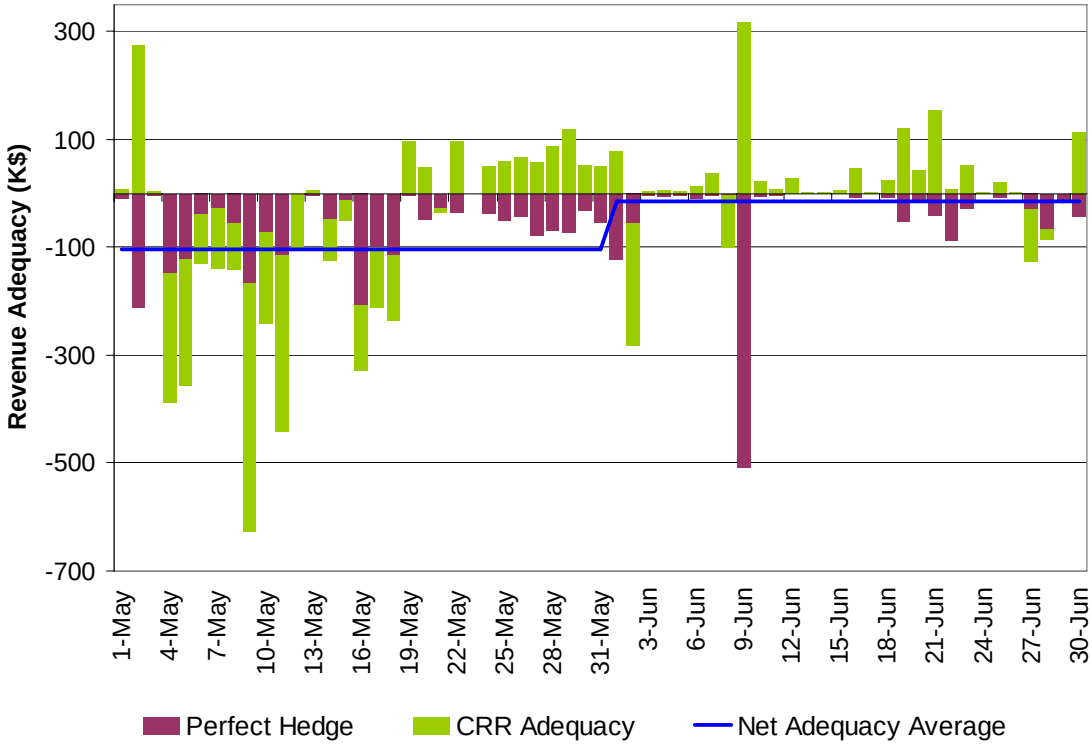
Table 2: IFM Congestion Statistics by Branch Group

Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	43	14	10
IPPDCADLN_BG	549	27	49
LOSBANOSNORTH_BG	1964	3	9
SDGEIMP_BG	2550	0	1
VICTVL_BG	2400	1	1
WSTWGMEAD_MSL	186	1	1

Congestion Revenue Rights

Figure 8 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of May and June 2009. Unlike the month of May, June saw less routine maintenance on transmission facilities, which lessen the impact on revenue adequacy. In comparison to the daily average deficiency of $103,976 for May, CRR revenue deficiency for June sharply diminished to a daily average of $14,970.

Figure 8: Daily Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in 10 out of 30 days of the month, with the major deficiencies occurring on June 2nd, 9th and 27th. The deficiency on June 2nd occurred when the Palo Verde inter-tie was heavily derated to accommodate an outage of the Devers-Palo Verde 500 kV line. On June 9th, there was a deficiency due to the derate of the IPPDCADLN branch group. On June 27th, the outage of the Round Mountain –Table Mountain line led to a derate of the PACI inter-tie, resulting in revenue deficiency.

For the month of June and onwards, 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 June was of 15 percent. These elements in conjunction, however, were marginally insufficient to attain revenue neutrality.

Table 3: June CRR Adequacy Statistics

Concept	Amount
IFM Congestion Rents	$6,442,759.92
CRR Payments	$5,772,604.08
CRR Adequacy	$670,155.84
Perfect Hedge	-$1,119,271.10
Net Revenue Adequacy	-$449,115.26
Revenue Adequacy Ratio	93.48%
Annual Auction Revenues	$2,614,840.36
Monthly Auction Revenues	$955,471.16
Monthly Net Balance	$3,121,196.26

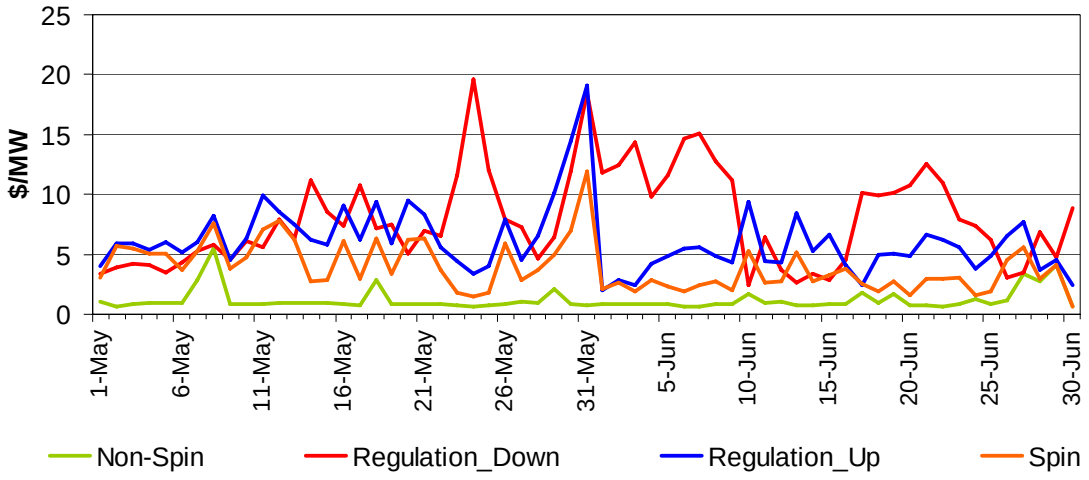
Overall, the total dollars collected from the IFM were sufficient to cover approximately 93 percent of the net payments to CRR holders and holders of the perfect hedge, allocating approximately 17 percent of the congestion rents to honor the perfect hedge. On net, total congestion revenues were deficient by $0.45 million, a sharp decrease of 85 percent with respect to April's deficiency of $3.2 million. The auction revenues credited to the balancing account for June were $3.57 million. Once the revenue deficiency of the month is accounted for, approximately 87 percent of the auction revenues remain as a surplus for allocation to metered demand (see Table 3 above).

Ancillary Services

IFM (Day-Ahead) Average Price

Figure 9 below shows daily IFM average prices for May and June 2009. On numerous days in June, the Regulation Down Ancillary Service saw some elevated prices in the early morning off-peak hours. During those hours, the system was experiencing light loads and most of the units were dispatched at their minimum operating levels, which were also their economic operating levels. In order to provide Regulation Down Ancillary Service, some of the units were dispatched above their economic operating point. Whenever a resource is dispatched above its economic operating point to provide Regulation Down, it loses money in the energy market which is termed the unit's opportunity cost. All resources which are awarded Regulation Down receive a payment equal to or greater than the sum of its Regulation Down bid price and opportunity cost arising from its dispatch in the energy market. The elevated prices for Regulation Down were motivated by the opportunity cost in the energy market.

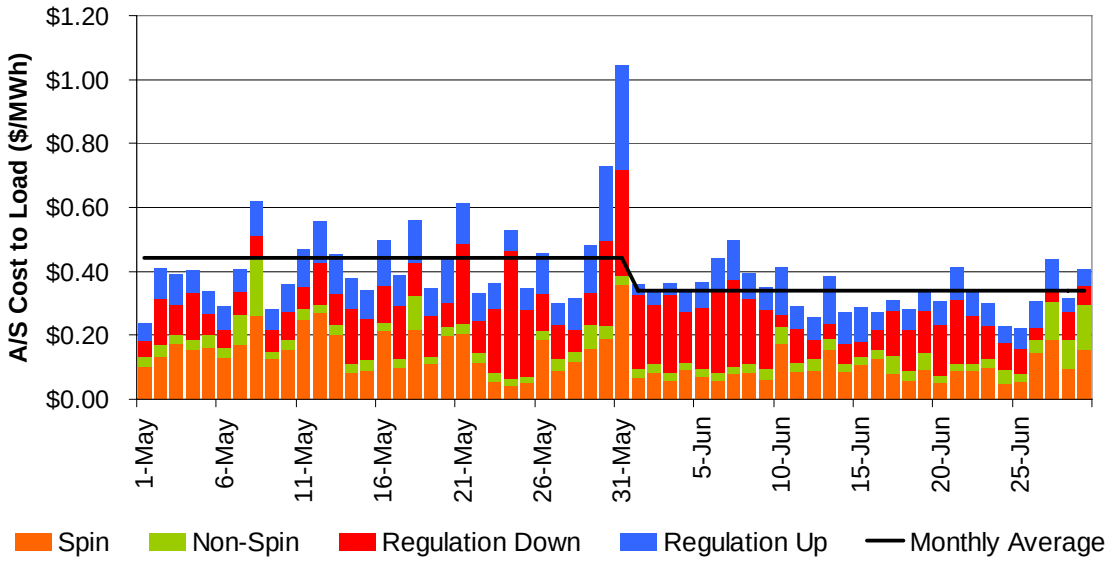
Figure 9: IFM Ancillary Service Average Price



AS Cost to Load

Figure 10 below shows the total system (Day-Ahead and Real-Time) average cost to load for Ancillary Services procured in May and June 2009. The monthly average cost to load for June declined to $0.34/MWh, down from $0.44/MWh in May.

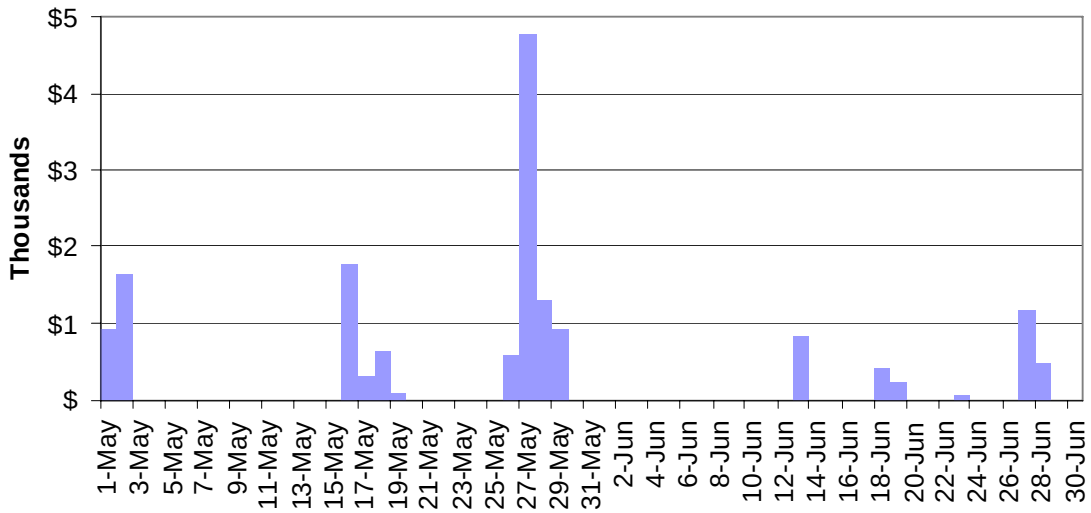
Figure 10: System (Day-Ahead and Real-Time) Average Cost to Load



Residual Unit Commitment

Figure 11 shows the daily cost of RUC procurement for each trading day in May and June 2009. The total RUC procurement cost was $3,236 in June, which is a 75 percent reduction from May's total. This is because less RUC capacity was procured from non-RA/RMR units in June than in May, and the procurement that did occur was at lower prices. The highest daily RUC cost of the month occurred on June 27th when a large amount of RUC capacity from non-RA/RMR units was procured due to the hot weather.

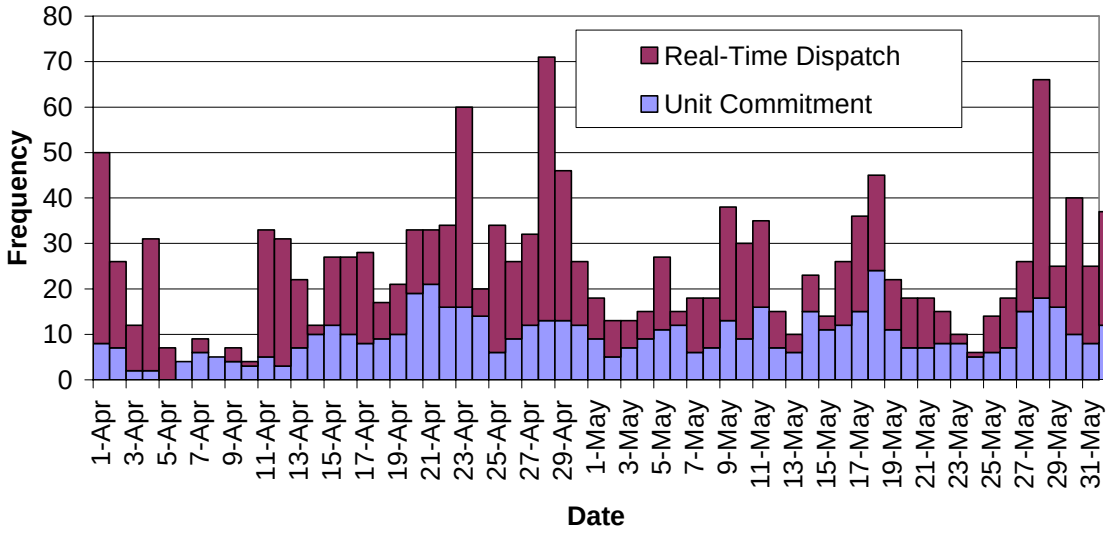
Figure 11: Total RUC Cost



Exceptional Dispatch

Exceptional Dispatch refers generally to a subset of manual commitment or dispatch instructions that are not determined as a result of the market software in either the Day-Ahead or Real-Time markets. Figure 12 shows the frequency of Exceptional Dispatches broken out by Commitment Type for the months of April and May, while Figure 13 displays the daily total MWh volume of unit commitments to minimum load as well as the total volume of incremental and decremental Exceptional Dispatches in Real-Time over the same time horizon.* For May, the average daily frequency of Exceptional Dispatch declined to 12.9 from 21.2 in April. The average daily MWh volume of dispatch however increased over the same time frame, from 587,000 MWh/day in April to 625,000 in May.

Figure 12: Exceptional Dispatch Frequency (Unit Commitment vs. Real-Time Dispatch)



* 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 Market Performance Report will follow the rest of the report with a one month lag.

Figure 13: Total Exceptional Dispatch MWh Volume