Market Performance Report
July 2009

August 24, 2009

ISO Market Services

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Executive Summary

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

- System demand was moderate in July due to relatively mild weather and a slow economy.
- Natural gas prices trended upward slightly in July mainly due to increase in demand for electricity which was driven by warmer temperature.
- Day-ahead on-peak power prices rose in July commensurate with higher natural gas prices.
- Day-ahead (IFM) prices were moderate on almost all days, and the weighted average default LAP price was $37.26/MWh for the month.
- Real-time energy prices were more volatile in July than in June, especially in the SDGE area.
- The cumulative total congestion rent for interties was approximately $3.98million, and the total branch group congestion rent was $1.12 million.
- Total CRR revenue adequacy was in excess of $0.63 million, a fair improvement with respect to June's deficiency of $0.45 million.
- The monthly Ancillary Service average cost to load for July increased to $0.43/MWh, up from $0.33/MWh in June.
- In July, only 0.3 percent of RUC capacity was procured from non-RA/RMR units, and it was procured at a price of $0/MW.

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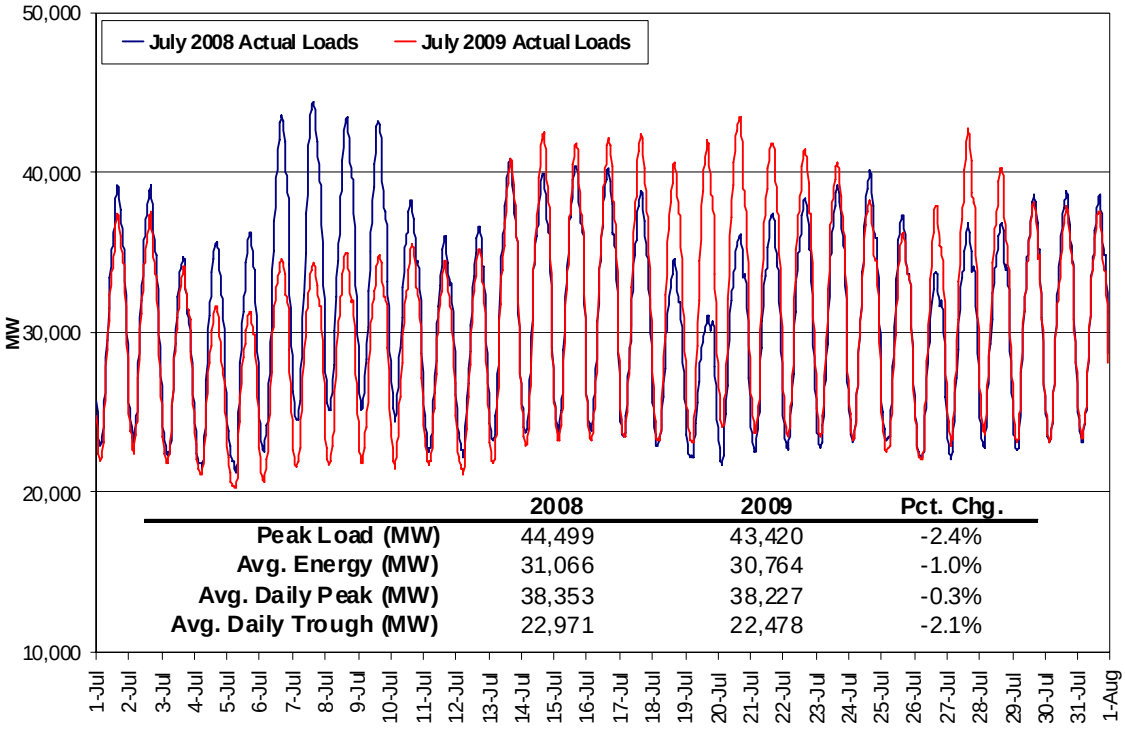
Market Characteristics

Loads

System demand was moderate in July due to relatively mild weather and a slow economy. The summer-time loads occasionally drifted over 40,000 MW, mostly in the middle of this month when temperatures were high. Both the average energy demand and the peak load were lower than in July 2008 as loads did not reach 44,000 MW this month.

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

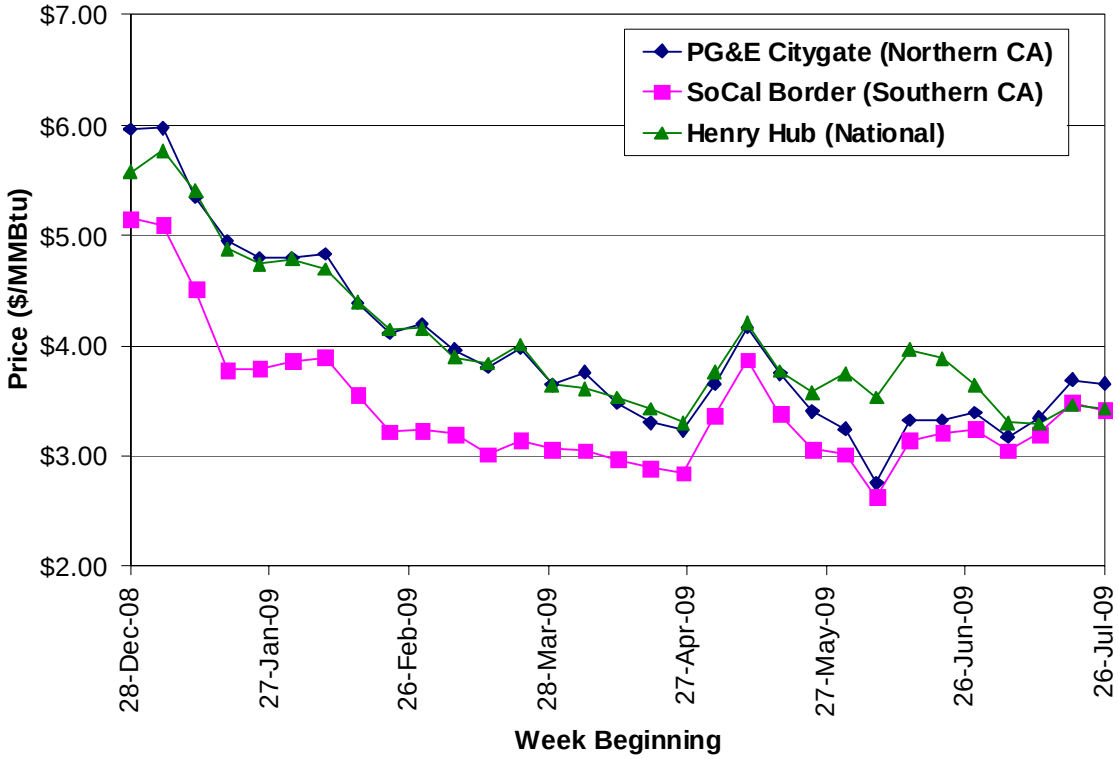


	2008	2009	Pct. Chg.
Peak Load (MW)	44,499	43,420	-2.4%
Avg. Energy (MW)	31,066	30,764	-1.0%
Avg. Daily Peak (MW)	38,353	38,227	-0.3%
Avg. Daily Trough (MW)	22,971	22,478	-2.1%

Natural Gas Prices and Inventories

Natural gas prices trended upward slightly in July. As cited by the Energy Information Administration (EIA), the higher prices seen in Figure 2 can be attributed to increased demand due to warmer temperatures. At the same time, a slack economy and plentiful supplies kept the gas prices lower than they would have been otherwise. The California Composite Average gas price ended at $3.27 per MMBtu on July 31st, relatively unchanged from $3.29 per MMBtu on July 1st. As of July 31st, the working gas in underground storage rose to 442 Bcf in the West, which is approximately 21 percent above the five-year average.

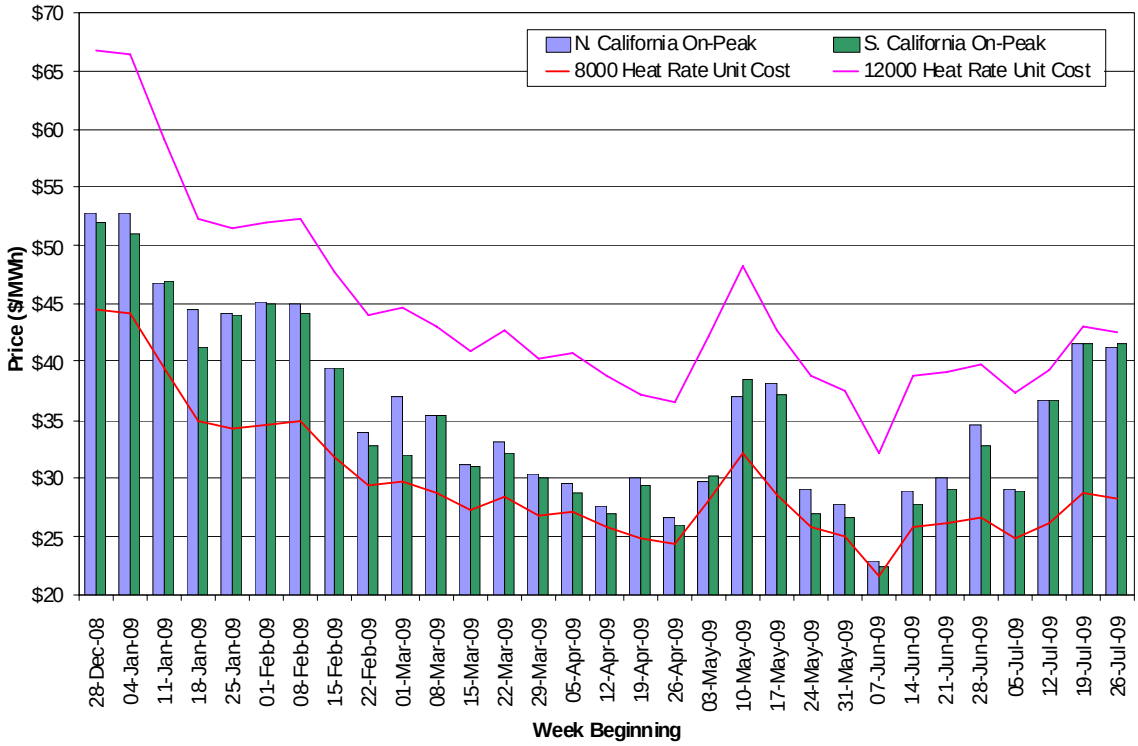
Figure 2: Weekly Average Natural Gas Spot Prices – January 2009 to July 2009



Bilateral Electricity Prices

Day-ahead, on-peak power prices rose in July commensurate with higher natural gas prices. Higher loads in July also put upward pressure on day-ahead prices as more expensive units were required to come online to meet demand. This can be seen in Figure 3 where the On-Peak prices trend closer to the 12,000 Heat Rate Unit Cost curve, although electricity prices in this month were much lower than in July 2008 when the electricity prices were generally above $80. 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



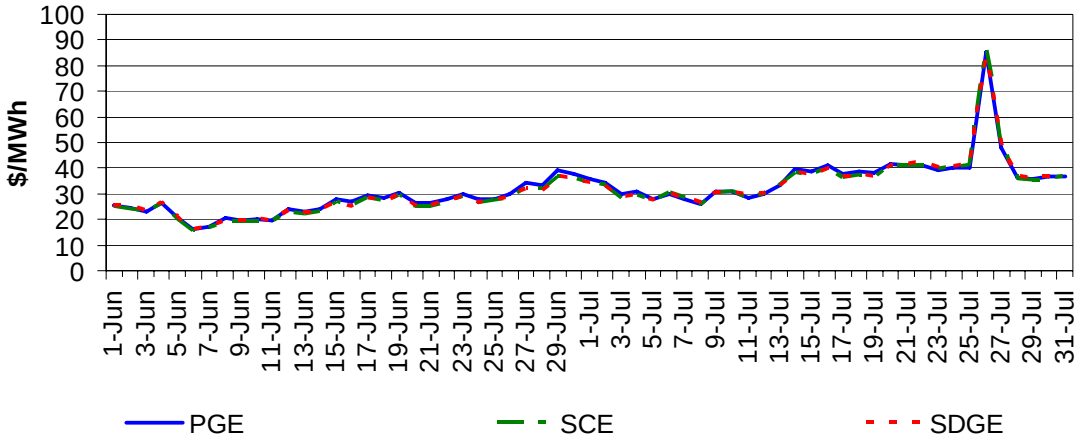
Market Performance Metrics

Energy

Day-Ahead Prices

In July, daily weighted average prices on almost all days were moderate for the three default Load Aggregation Points (LAPs), as shown in Figure 4. The exception was July 26 when LAP prices spiked above $420 for two hours due to a limited availability of resources in the IFM. This limitation was due to a specific design feature of the DAM. Prior to the IFM the Market Power Mitigation (MPM) run clears forecast CAISO demand against all bid-in generation, and then generates a mitigated bid set. This mitigated bid set contains only those units which were used to meet the day-ahead load forecast and only these bids from these particular units are considered by the IFM. On July 26 in hours ending 17 and 18, the cleared demand in IFM was significantly above the day-ahead load forecast used in the MPM run and this required the IFM to clear higher priced resources in the mitigated bid-set to meet this demand. Due to these unusual circumstances, prices were higher than they might otherwise have been because some resources which were bid into the DAM were excluded from the mitigated bid set in the IFM because they were not picked up in the preceding MPM run.

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

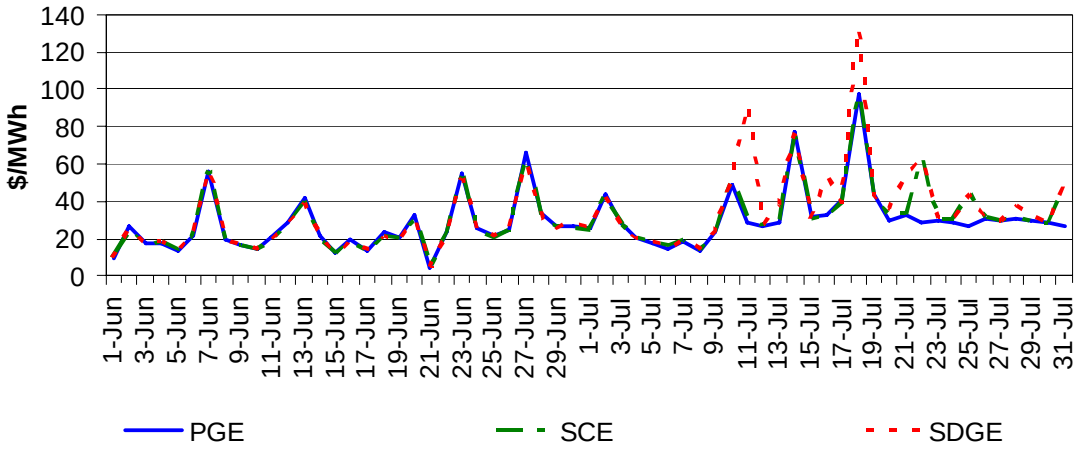


Real-Time Prices

Real-time energy prices were more volatile in July than in June, especially in the SDGE area, as shown in Figure 5. Load demand rose in mid-July due to higher temperatures, which contributed to the increased price volatility on several days. On July 14th, one generation unit tripped offline and another generation unit deviated from its day-ahead schedule causing a loss of 700MW. This combined with high load demand resulted in high prices in all default LAPs on that day, with daily average prices around $76/MWh. On July 18th, the peak load pull and limited ramp capability, plus loss of 325 MW due to a trip of a generation unit, resulted in elevated energy prices in all default LAPs, with daily average prices above $97/MWh.

Prices in the SDGE area were elevated by congestion on the SDGE_CFE import branch group on several days. On July 11th and 16th, SDGE prices were further elevated by congestion on the SDGE import branch group. On July 22nd, 25th and 31st, Path 26 congestion contributed to high prices in the SCE and SDGE area.

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



Congestion

Congestion Rents on Interties

Figure 6 below illustrates daily IFM congestion rents by intertie for the months of June and July 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 July 2009 was approximately $3.98 million, down from $4.64 million in June. Of the total, the vast majority of rents occurred on two interties: Palo Verde (49 percent), and NOB, (29 percent).

Figure 6: IFM Congestion Rents by Intertie (Import)

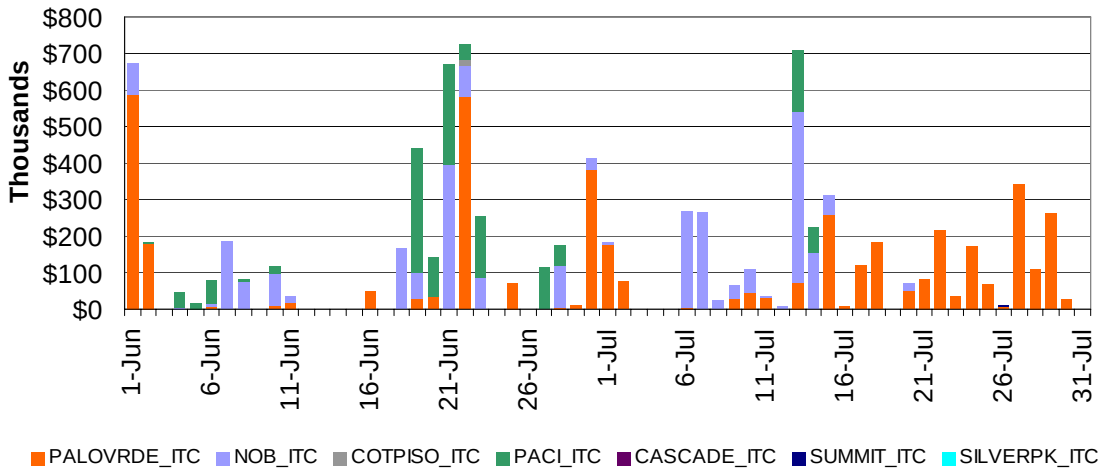


Table 1: IFM Congestion Statistics by Inter-Tie (Import)

Intertie	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

The Palo Verde intertie was congested on most days during the second half of July, and this congestion was primarily driven by over scheduling. The average shadow price on the Palo Verde branch group was $11/MWh. The majority of the congestion rents on the NOB branch group were incurred during the first half of July at a monthly average shadow price of $9/MWh. During this timeframe, congestion was driven by price differential between the Pacific Northwest Trading Hub prices and the California Trading Hub prices. In the second half of July, loads picked up significantly in the Pacific Northwest due to an increase in temperatures and congestion on NOB reduced significantly.

Congestion Rents on Branch Groups

Figure 7 illustrates IFM congestion rents on selected branch groups. For the month of July, the total branch group congestion rent was approximately $1.12 million, up from $0.6 million in June. Of the total, the vast majority of rents occurred on the IPPDC branch group (37 percent), the SDGEIMP branch group (17 percent), and the IPP-IPPGEN_MSL (11 percent).

Figure 7: IFM Daily Congestion Rents by Branch Group

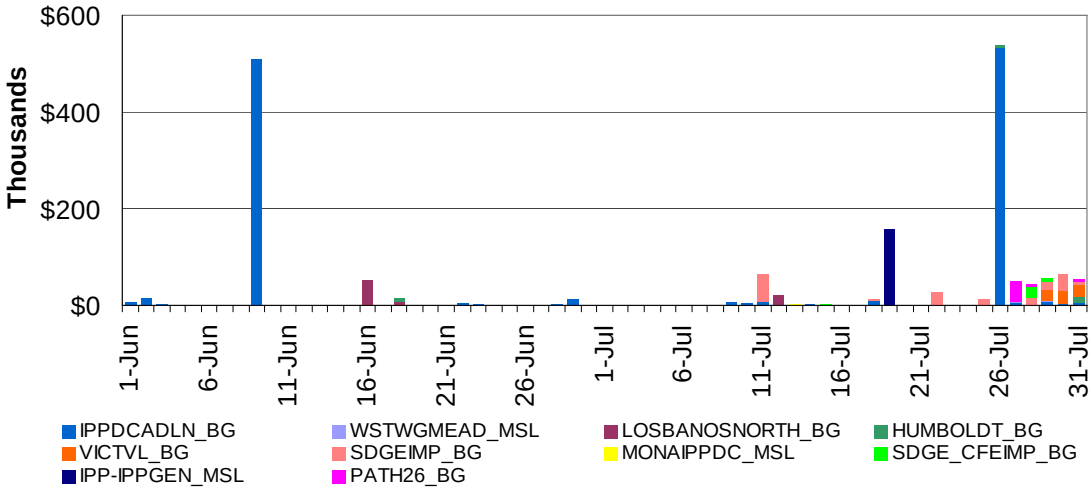


Table 2: IFM Congestion Statistics by Branch Group

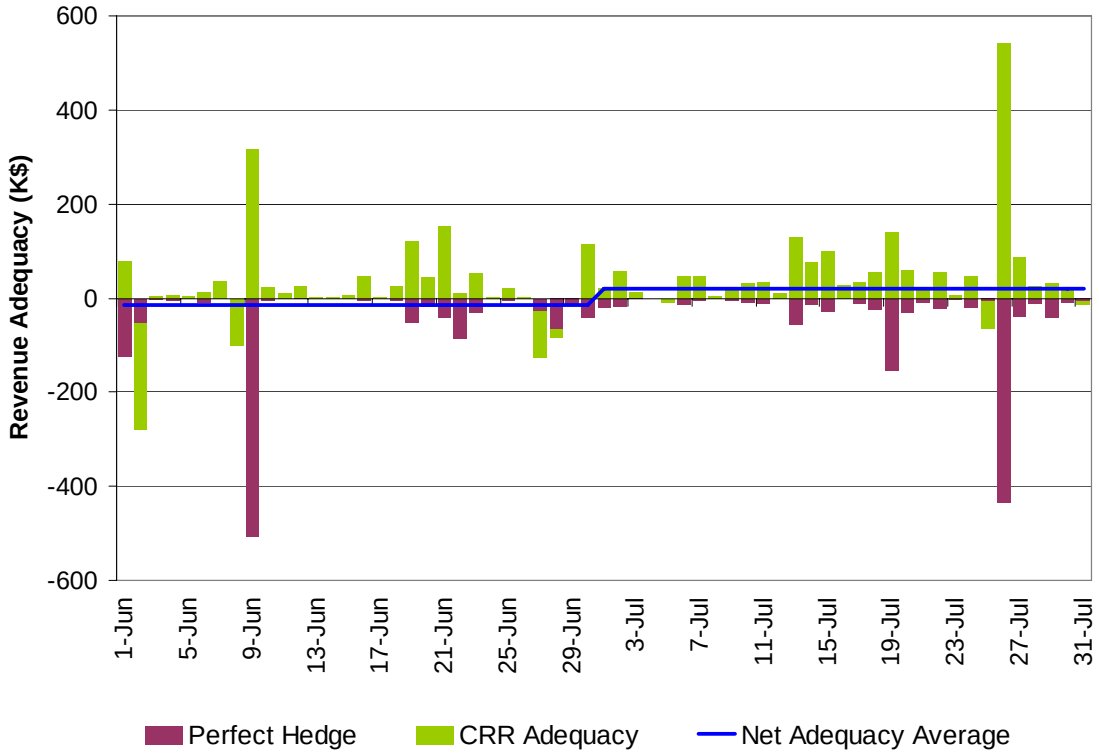
Branch Group	Average Cleared Value (MW)	Shadow Price ($/MWh)	Number of Congested Hours
HUMBOLDT_BG	43	14	10
IPPDCADLN_BG	549	27	49
LOSBANOSNORTH_BG	1964	3	9
SDGEIMP_BG	2550	0	1
VICTVL_BG	2400	1	1
WSTWGMEAD_MSL	186	1	1

Table 2 provides a breakout of the IFM cleared value (MW), average shadow price ($/MWh) and number of congested hours by branch group. More than 80 percent of July's congestion on the IPPDC branch group occurred on July 26 in hours ending 17 and 18. The shadow price on a radial branch group is the difference between LMPs at the two price nodes at each end of the branch group. The IPPDC branch group is a radial branch group which connects the Adelanto pricing node to the Inter-Mountain Power Project . During those hours most of the CAISO system, including the Adelanto pricing node, saw LMPs greater than $450/MWh which was driven by an unusual event. As explained on Page 7 of this report, day-ahead LAP prices were driven up when bid-in demand was significantly higher than the day-ahead load forecast. As the software was trying to dispatch all possible generation including imports, this resulted in flows reaching the capacity of the IPPDC branch group. With cheap generation stranded at the other end of IPPDC branch group, significantly high shadow prices resulted.

Congestion Revenue Rights

Figure 8 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of June and July 2009. In comparison to the daily average deficiency of $14,970 for June, July saw daily average revenue surplus of $20,587.

Figure 8: Daily Adequacy of Congestion Revenue Rights



Revenue deficiencies were observed in six out of 31 days of the month, with the most significant deficiency occurring on July 25th. On this day, the NOB inter-tie was out of service to accommodate the outage of the Celilo-Sylmar 1000 kV line.

For the month of July, 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 July was of 15 percent. These elements in conjunction were sufficient to attain CRR revenue adequacy.

Table 3: July CRR Adequacy Statistics

Concept	Amount
IFM Congestion Rents	$6,750,872.85
CRR Payments	$5,098,371.85
CRR Adequacy	$1,652,500.99
Perfect Hedge	-$1,014,300.48
Net Revenue Adequacy	$638,200.51
Revenue Adequacy Ratio	110.44%
Annual Auction Revenues	$1,344,248.42
Monthly Auction Revenues	$808,482.31
Monthly Net Balance	$2,790,931.24

Overall, the total dollars collected from the Integrated Forward Market (IFM) were in excess of 10 percent of net payments to CRR holders and holders of the perfect hedge, allocating approximately 15 percent of congestion rents to honor the perfect hedge. On net, total congestion revenues were in excess of $0.63 million, a fair improvement with respect to June's deficiency of $0.45 million. The auction revenues credited to the balancing account for July were $2.15 million. Once the revenue surplus of the month is accounted for, a total surplus of approximately $2.79 million will be allocated to measured demand (see Table 3 above).

Ancillary Services

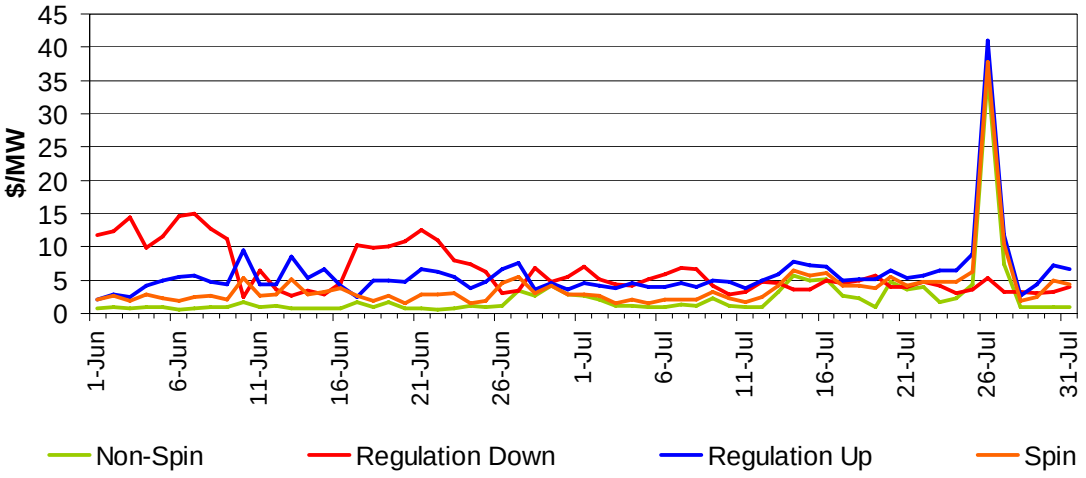
IFM (Day-Ahead) Average Price

Table 4 shows the average Ancillary Service procurements and prices for June and July 2009, and Figure 9 below shows daily IFM average prices for June and July 2009. The operating reserve requirements increased in July from June as loads picked up primarily due to increased temperatures. The increase in requirements drove up procurements of both the Spin and Non-Spin Ancillary Services. The Regulation Up and Regulation Down procurement declined in July commensurate with a decrease in requirements. The hourly Regulation Up and Regulation Down requirement was reduced from 425 MW to 375 MW on June 16.

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

	Average Procured				Average Price			
	Reg Dn	Reg Up	Spin	Non-Spin	Reg Dn	RegUp	Spin	Non-Spin
Jun-2009	400	416.34	825.31	821.07	$ 8.30	$ 4.98	$ 2.93	$ 1.26
Jul-2009	375	375.46	962.63	930.10	$ 4.45	$ 6.71	$ 4.93	$ 4.93
	-6%	-10%	17%	13%	-46%	35%	69%	292%

Figure 9: IFM Ancillary Service Average Price



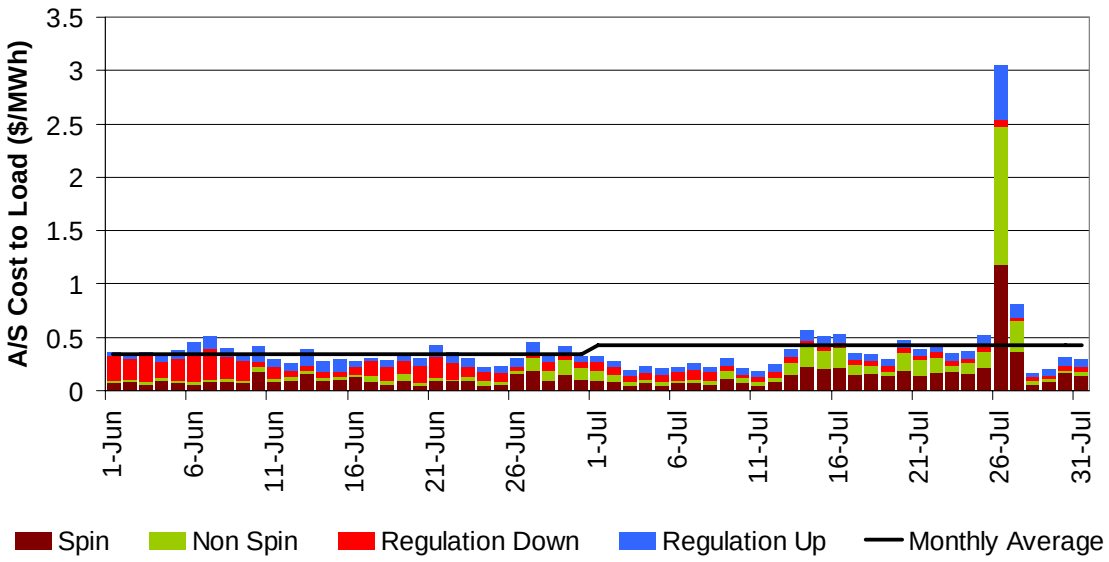
The monthly average Ancillary Service price increased for the Regulation Up, Spin and Non-Spin Ancillary Service, whereas the Regulation Down saw a decline. As loads picked up during the off-peak hours in July, the opportunity costs for resources providing Regulation Down declined, because there is a strong correlation between load levels and opportunity costs.[1] This decline in opportunity costs coupled with the decline in Regulation Down requirement drove down prices.

As mentioned previously, the increase in Spin and Non-Spin requirements exerted upward pressure on average prices. Also, higher loads in July resulted in higher opportunity costs for Regulation Up, Spin and Non-Spin Ancillary Services, mostly in those hours when the hourly cleared demand was above 37,000 MW in the IFM. On July 26, 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. These high prices for Ancillary Services were driven by the opportunity cost of resources providing Ancillary Services.

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 June and July 2009. The monthly average cost to load for July increased to $0.43/MWh, up from $0.33/MWh in June. As mentioned in the previous paragraph, the increase in Ancillary Service cost to load was primarily driven by higher average prices on July 26.

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



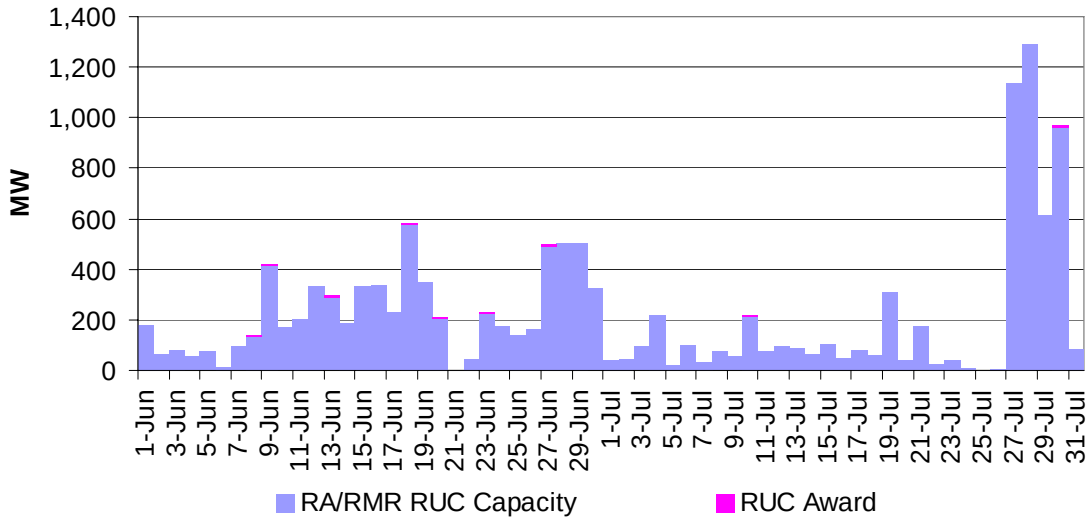
[1] The concept of Opportunity Cost is explained in detail in Section 4.3 of the Market Operations Business Practice Manual.

Residual Unit Commitment

RA/RMR RUC Capacity vs. RUC Award

Figure 11 shows the daily average RA/RMR RUC capacity and RUC award for June and July 2009. Approximately 99.7 percent of RUC capacity was procured from RA or RMR units in July. On July 27th, in an attempt to reduce the overall frequency of Exceptional Dispatch, the CAISO began implementing Generation Procedures G-217 and G-219 in RUC on a trial basis. This resulted in a significant increase in the amount of RUC capacity procured after that date.

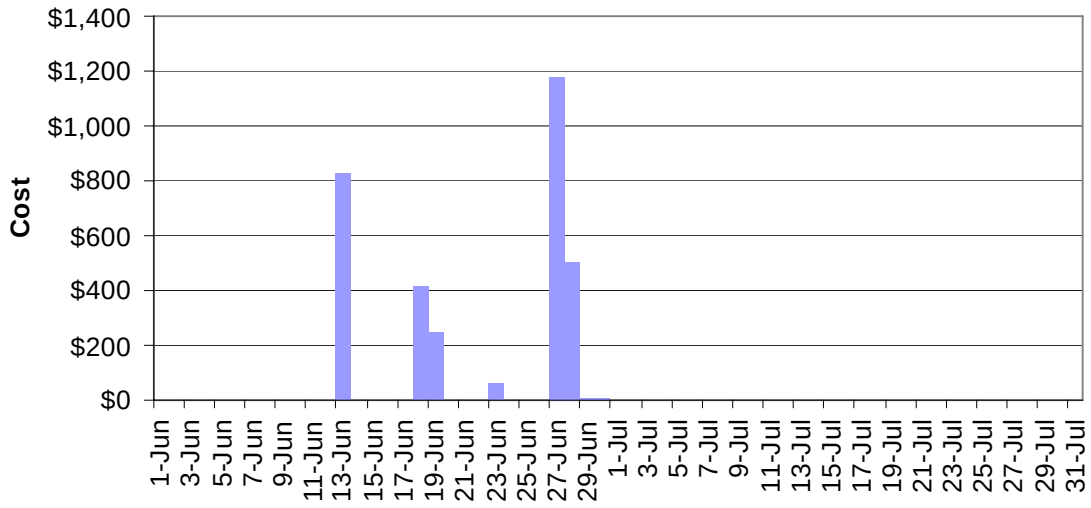
Figure 11: RA/RMR RUC Capacity vs. RUC Award (All Hours)



Total RUC Cost

Figure 12 shows the daily cost of RUC procurement for each trading day in June and July 2009. In July, only 0.3 percent of RUC capacity was procured from non-RA/RMR units, and it was procured at a price of $0/MW. As a result, the total RUC cost declined to $0 in July from June's $3,236.

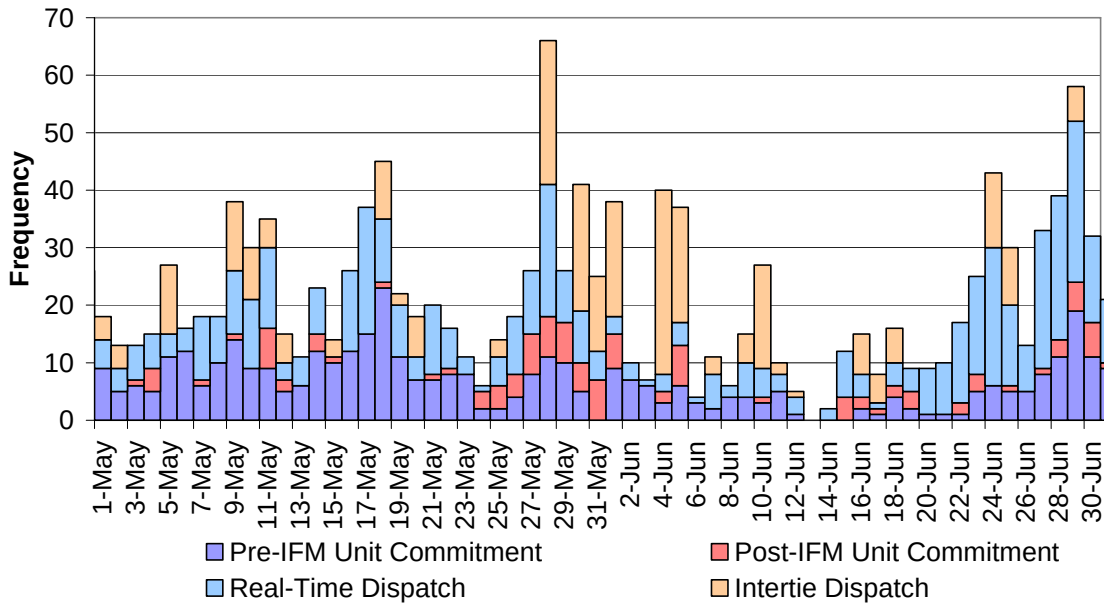
Figure 12: Total RUC Cost



Exceptional Dispatch

Fort the months of May and June 2009, Figure 13 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).[2] Alternatively, Figure 14 summarizes Exceptional Dispatch frequency by general reason where System includes System Energy on interties and other System Capacity requirements in the ISO Balancing Area Authority, and Market Disruption includes HASP failures. Overall, the number of Exceptional Dispatches declined 20 percent to 581 in June from May's total of 721. This decline was due in part to a decline in the occurrence of HASP failures which often necessitates additional intertie Exceptional Dispatches.

Figure 13: Exceptional Dispatch Frequency



[2] 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.

The decline in the average frequency of Exceptional Dispatch is also attributable to a decline in Exceptional Dispatches for transmission outages as the spring maintenance season came to an end by mid-June. After a brief lull, instances of Exceptional Dispatch increased in late June with the onset of higher summer system loads and increased reliability requirements for transmission procedures and system energy as seen in Figure 14.

Figure 14: Summary of Exceptional Dispatch Frequency by Reason

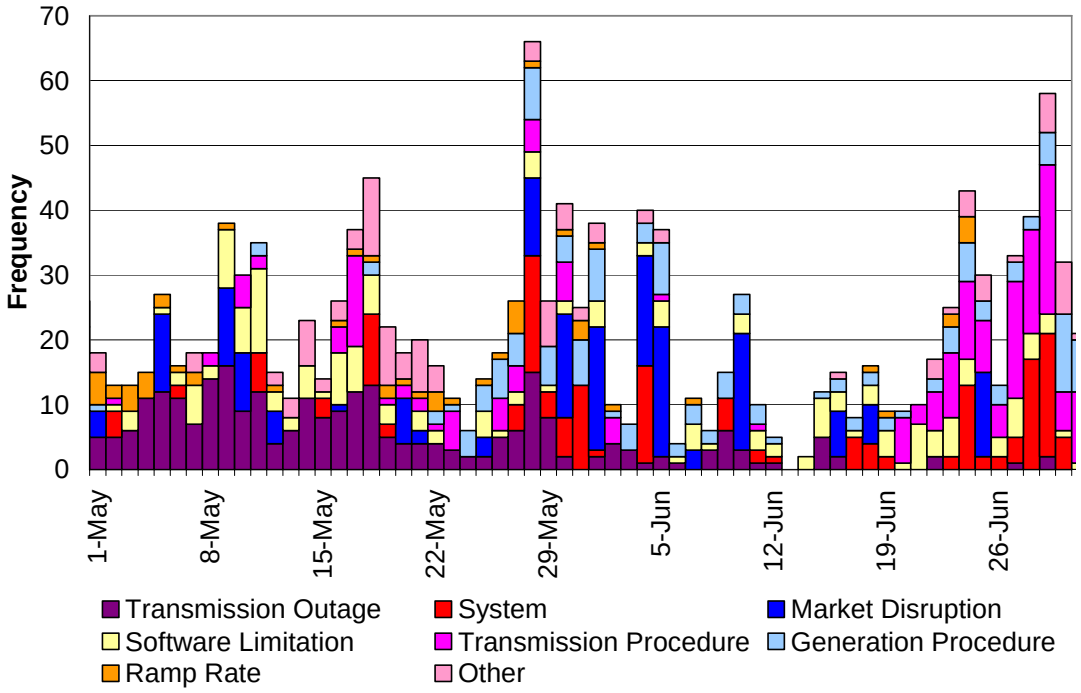


Figure 15 shows the total MW volume of Exceptional Dispatches per trade date broken out by min-load MW volumes for day-ahead unit commitments, and by incremental and decremental real-time imbalance energy. Average daily Exceptional Dispatch MWh volumes declined by 50 percent between May and June 2009.

Figure 15: Total Exceptional Dispatch MWh Volume

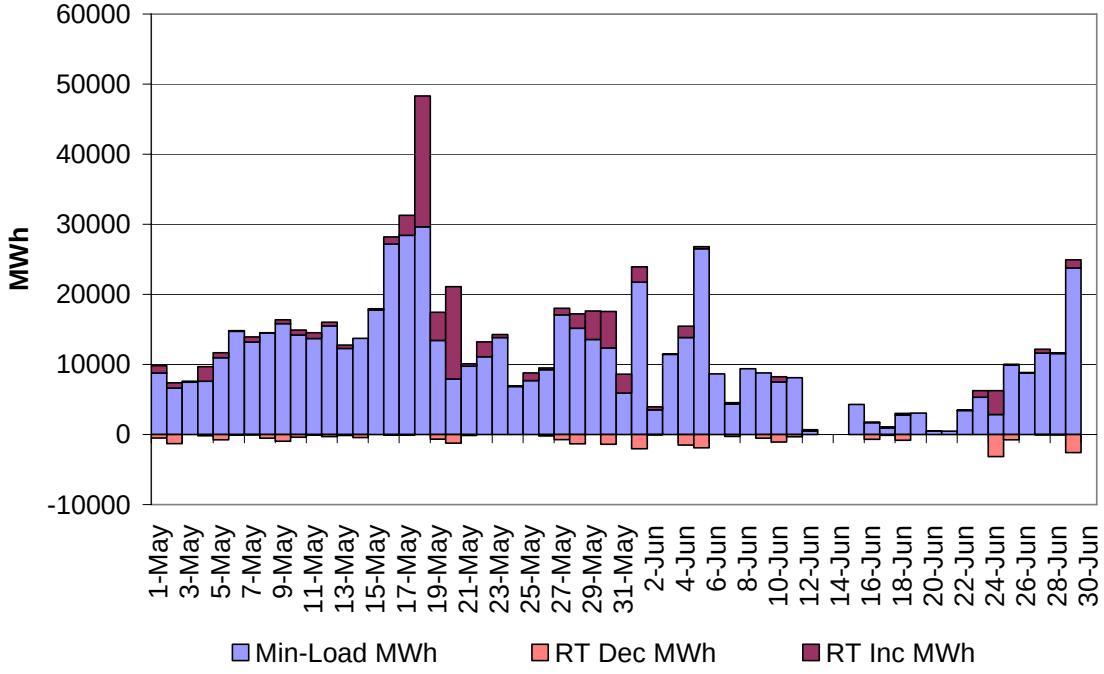


Figure 16 shows the total MWh quantity of Exceptional Dispatch as a percentage of the total load in the CAISO Balancing Area, where total load is equal to internal generation plus imports minus exports. The horizontal lines in the Figure identify the monthly averages for each month.

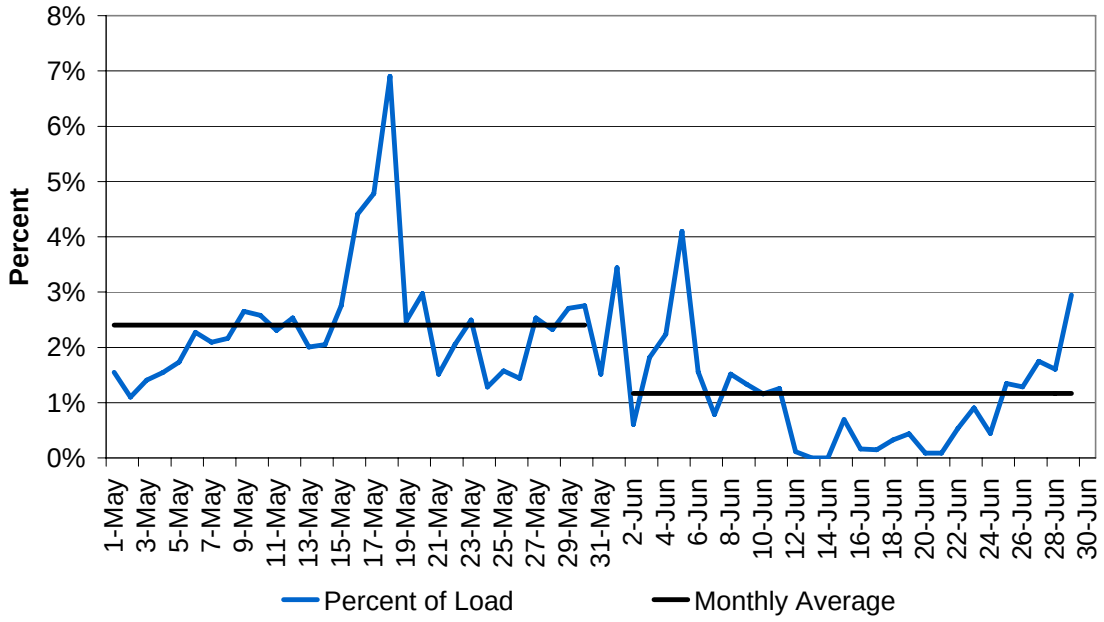



Figure 16: Exceptional Dispatch Percent of Total Load