



California ISO
Your Link to Power

Market Performance Report May 2009

June 25, 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 May 2009:

- The average energy demand in May 2009 was lower than one year ago, reflecting milder weather across the state and reduced demand for heating and cooling.
- Natural gas prices rallied in the first half of May, but prices declined in the second half of this month with the arrival of more moderate weather and continued weakness in the economy.
- Day-Ahead (IFM) average prices in May were generally moderate varying between \$11 and \$43.
- The monthly average IFM Ancillary Service cost-to-load for May was \$0.42/MWh.
- The Real-Time prices had less variation in May than in April. Congestion on Path-26 caused some price excursions.
- The cumulative total congestion cost for inter-ties was approximately \$10.5 million, and the total branch group congestion cost was \$3.1 million.
- Overall, the total dollars collected from the Integrated Forward Market (IFM) were only sufficient to cover approximately 83 percent of the net CRR payments and perfect hedge costs. IFM congestion revenues were deficient by \$3.2 million

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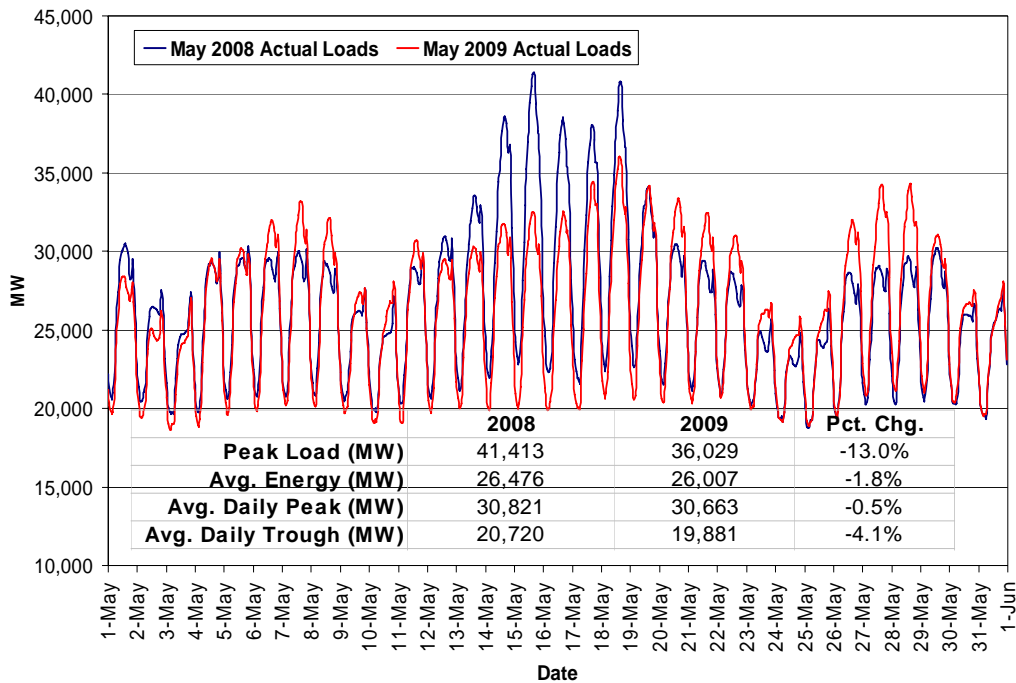
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Market Characteristics

Loads

The average energy demand in May 2009 was lower than one year ago, reflecting milder weather across the state and reduced demand for heating and cooling. The average daily peak fell 0.5 percent while the average trough fell 4.1 percent when compared with May 2008. The actual loads were higher on average in the middle of this month due to higher than average temperatures.

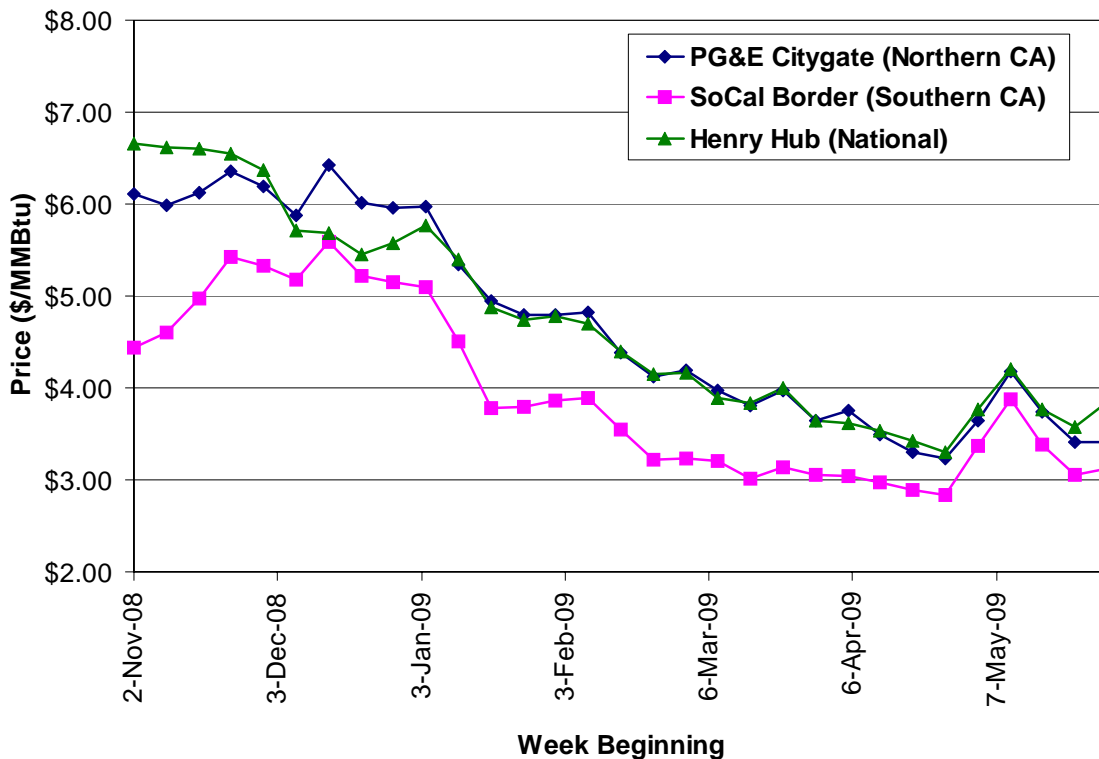
Figure 1: System Load Comparison – May 2009 v. May 2008



Natural Gas Prices and Inventories

Natural gas prices rallied in the first half of May. As EIA cited, this can be attributed to increased cooling demand, rising crude oil prices, and a weaker U.S. dollar. Natural gas prices declined in the second half of this month with the arrival of more moderate weather and continued weakness in the economy. The California Composite Average gas price increased 14.5 percent to \$3.40 per MMBtu on May 29th from \$2.97 per MMBtu on April 30th.

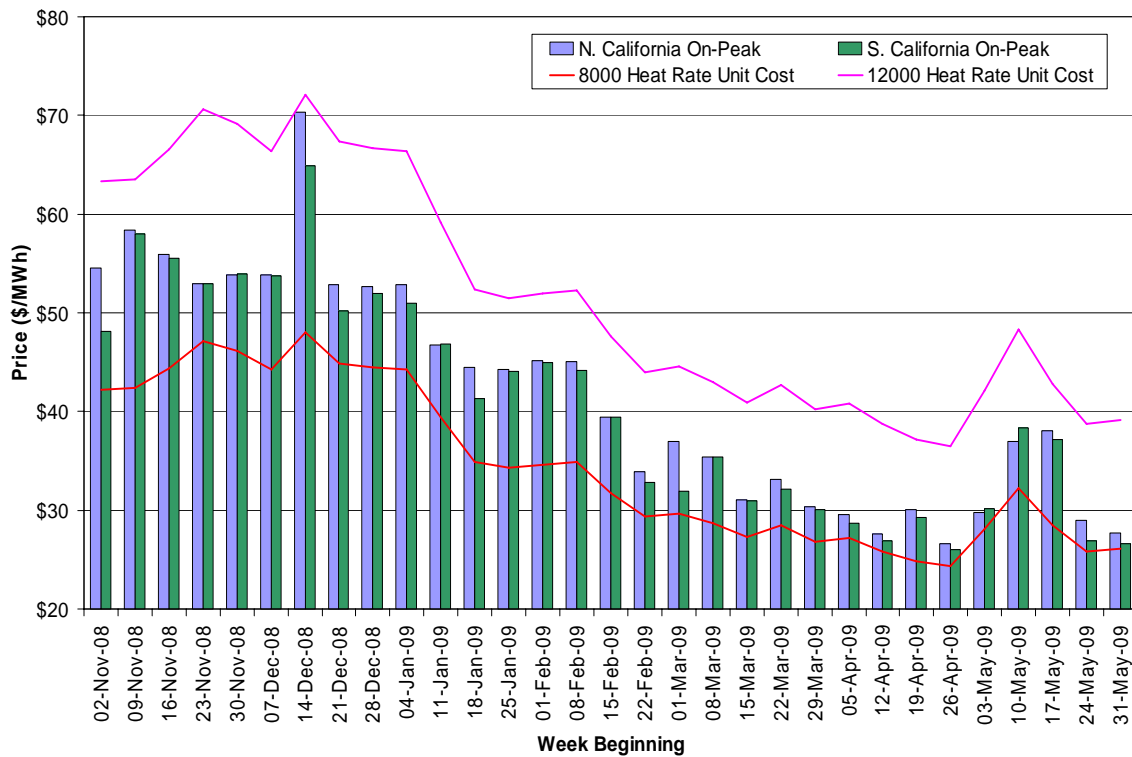
**Figure 2: Weekly Average Natural Gas Spot Prices
– November 2008 to May 2009**



Bilateral Electricity Prices

Day-Ahead, on-peak power prices jumped in the beginning of this month and then fell from the week of May 24th, roughly following the trend in natural gas prices. The increase in electricity prices was driven by high temperatures across the West. 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



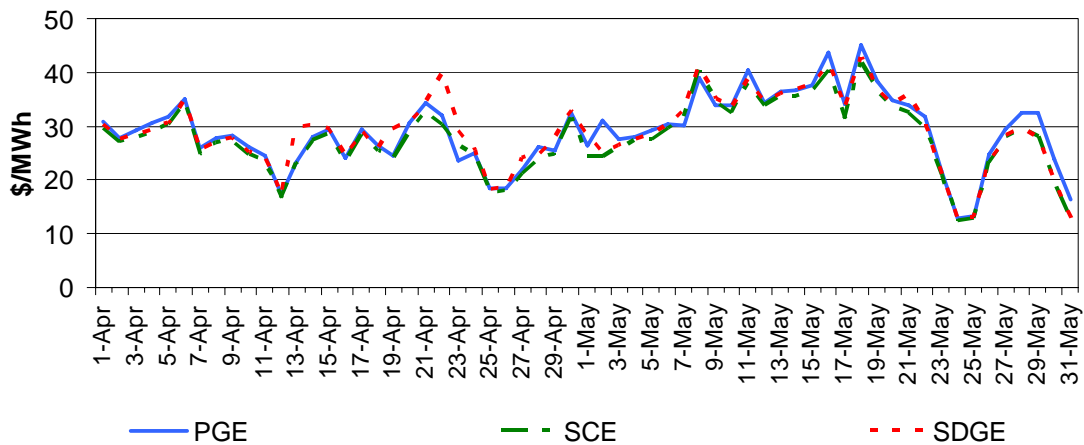
Market Performance Metrics

Day-Ahead Markets

Prices

Figure 4 shows the daily weighted average Load Aggregation Point (LAP) prices for all hours (on-peak and off-peak hours). The Day-Ahead Market saw an increasing trend in prices in the first three weeks of May due to warm weather and rising natural gas prices. Slack electricity demand for Memorial Day, temperate weather, and slipping gas prices contributed to the slump of average prices from May 23rd to May 25th. On May 2nd, congestion on Los Banos North branch group increased PG&E’s daily average price. From May 28th to May 31st, Path 15 was congested, resulting in market separation with higher prices in the PG&E area.

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



Residual Unit Commitments

Daily average deviations of the Residual Unit Commitment (RUC) schedule from the Integrated Forward Market (IFM) schedule in May were relatively small, as shown in Figure 5. The deviation peaked at approximately 2 percent on two days when relatively large amount of RUC capacity were procured. In contrast, on May 24th, the daily deviation reached minimum at -3.5 percent, when no RUC capacity was procured.

Figure 6 presents average hourly deviations between the RUC schedule and the IFM schedule for May where a clear trend is apparent. In the morning ramping hours, RUC schedules are usually below IFM schedules with the deviation peaking in Hour Ending (HE) 7. However, in the late night ramping down hours, RUC schedule was usually above IFM schedules, peaking in HE 23. This positive deviation in the late evening hours/early morning hours reflects hours during which RUC capacity was most frequently procured in May.

Figure 5: Daily Deviation of RUC Schedule from IFM Schedule

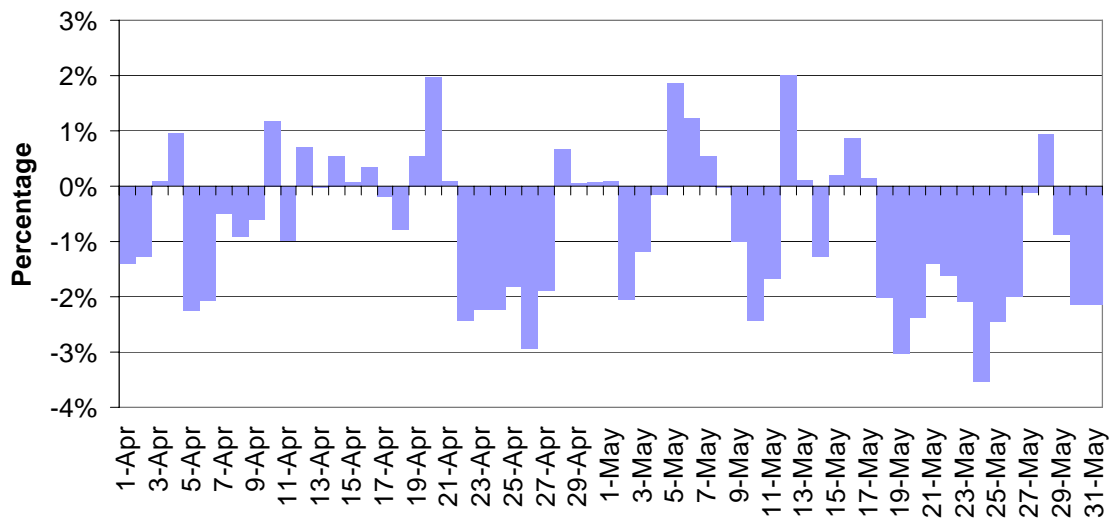


Figure 6: Hourly Deviation of RUC Schedule from IFM Schedule – May 2009

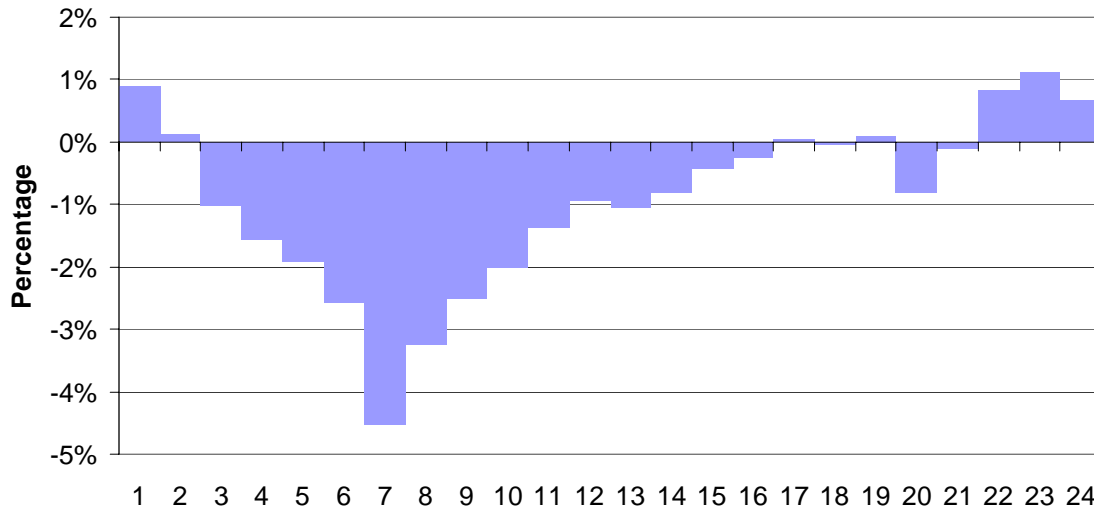
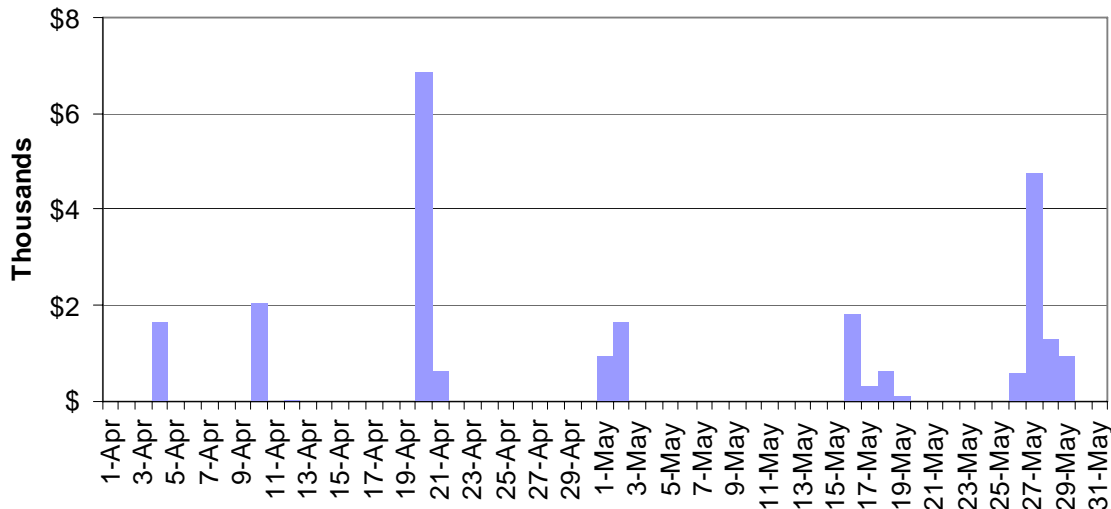


Figure 7 shows the daily cost of RUC procurement for each trading day in April and May 2009. The total RUC procurement cost was \$12,297 in May, which is a 16 percent increase over April’s total. This is partly because there were more days with non-zero RUC costs in May than in April. However, similarly to April, the RUC cost was zero for most days in May. The highest daily cost in May occurred on May 27th while there was congestion on the Victorville-Lugo branch group which drove up LPMs in that area.

Figure 7: Total RUC Cost

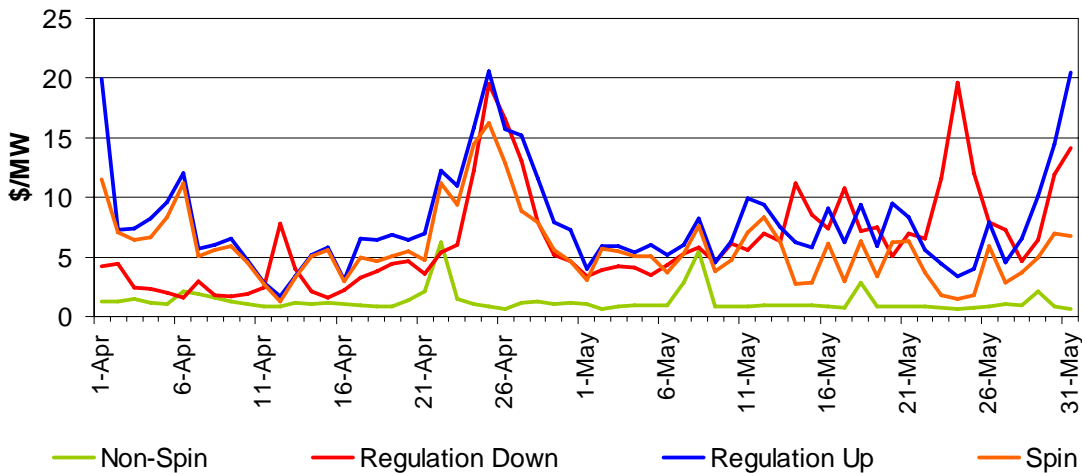


Ancillary Service Markets

IFM (Day-Ahead) Ancillary Service

Figure 8 below shows the Daily IFM average prices for April and May 2009. Regulation Down Ancillary Service saw some elevated prices in the early morning off-peak hours during the last two weeks of May. 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 as the unit's opportunity cost. All resources which are awarded Regulation Down receive a payment equal to or greater than 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.

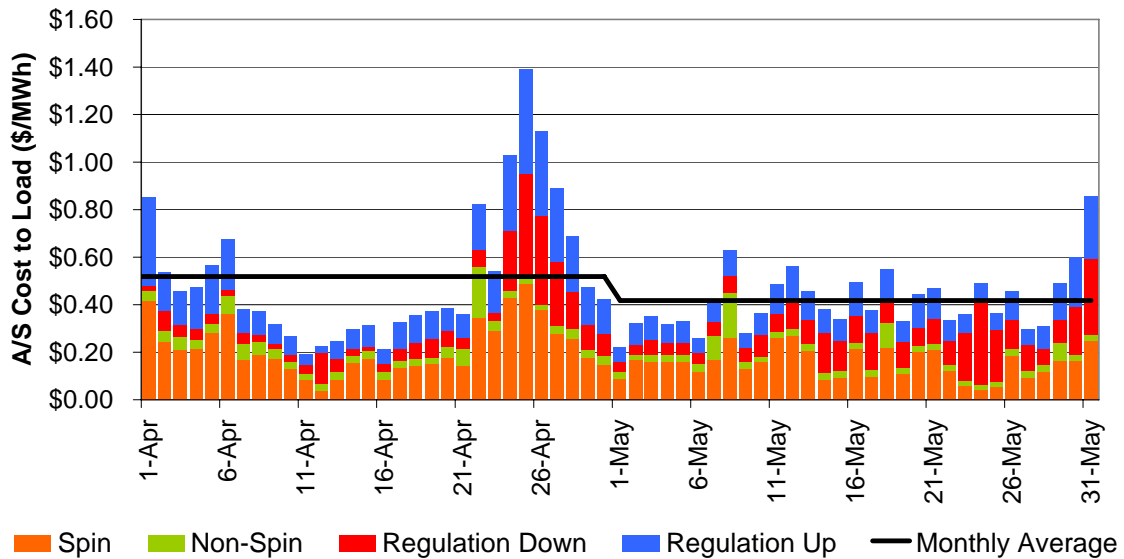
Figure 8: IFM Ancillary Service Average Price



AS Cost to Load in the IFM

The daily total costs of Ancillary Services per MWh of load for the IFM market are presented in Figure 9 for the month of April and May 2009. The monthly average cost to load for May declined to \$0.42/MWh down from \$0.52/MWh in April.

Figure 9: Average AS Cost to Load in IFM



Real Time Ancillary Services

The CAISO procures 100 percent of its Ancillary Services requirements in the IFM (Day-Ahead) market based on the Day-Ahead load forecast. Incremental procurements in the Real-Time market are driven by two scenarios. First, Ancillary Services requirements could change in the Real-Time market due to forecast deviation. Second, if a unit which is unable to provide its Day-Ahead Ancillary Service award in Real-Time; the market will automatically procure additional services to replace that service. Figure 10 displays the Real-Time Ancillary Services Average price and Figure 11 displays the proportion of Real-Time procurement as percentage of Day-Ahead procurement for all four types of Ancillary Service.

Figure 10 Real Time Ancillary Service Average Price

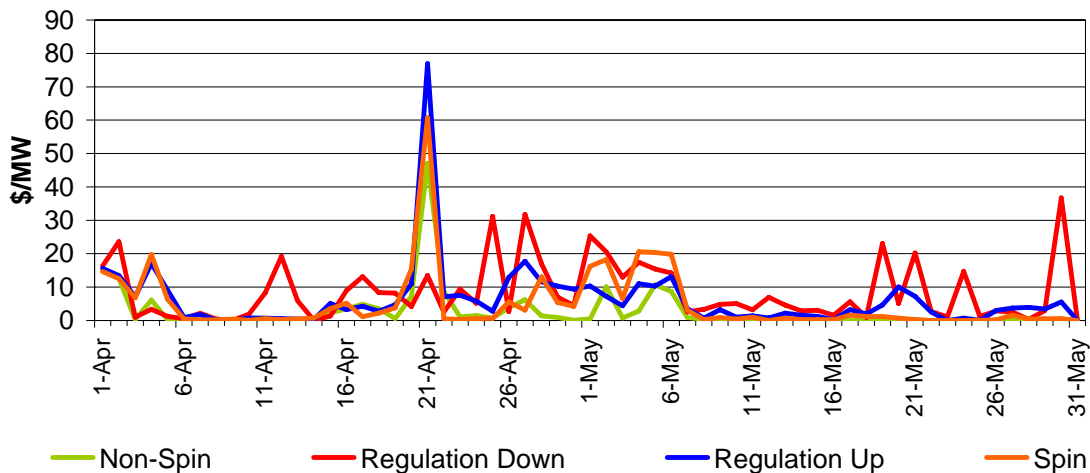
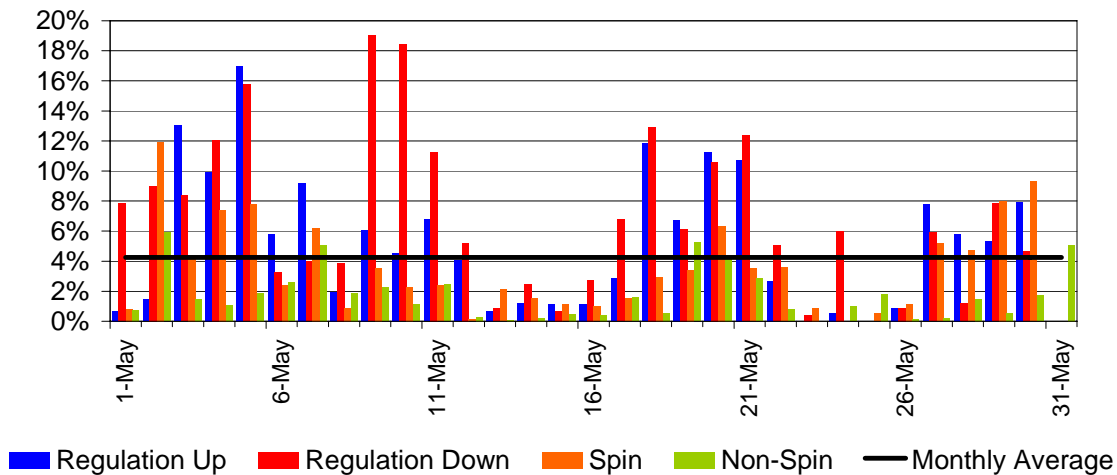


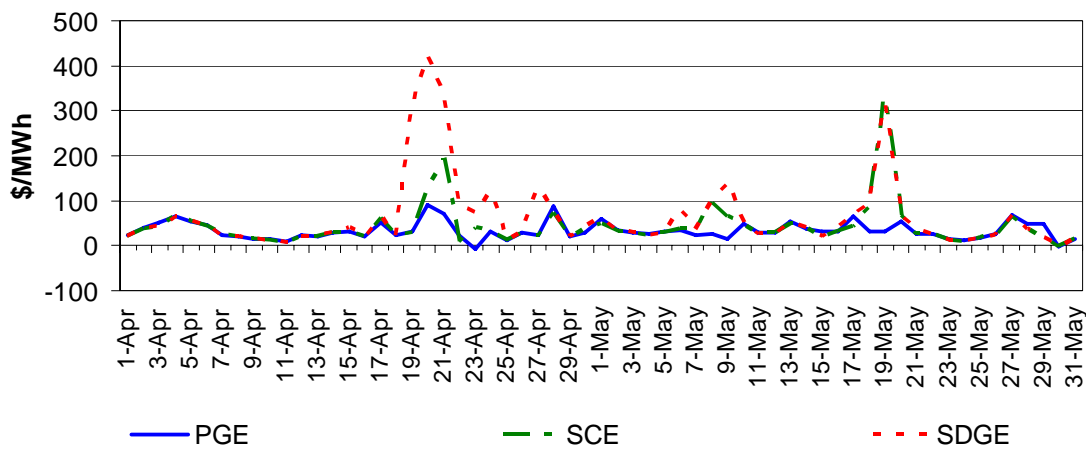
Figure 11: Proportion of Real-Time procurements as Percentage of Day-Ahead procurement



Real-Time Markets

Real-Time prices had less variation in May than in April, especially in the SDGE area, as shown in Figure 12. Prices were generally stable in May with a few exceptions. From May 7th to May 9th, and also from May 18th to May 19th, prices in SCE and SDGE were lifted by congestion on Path 26, while on May 9th, congestion on the SDGE-CFE import branch group further lifted prices in the SDGE area. On May 29th, Path 15 was congested due to a scheduled outage, elevating prices in the PG&E area.

Figure 12: RTD Weighted Average LAP Prices (All Hours)

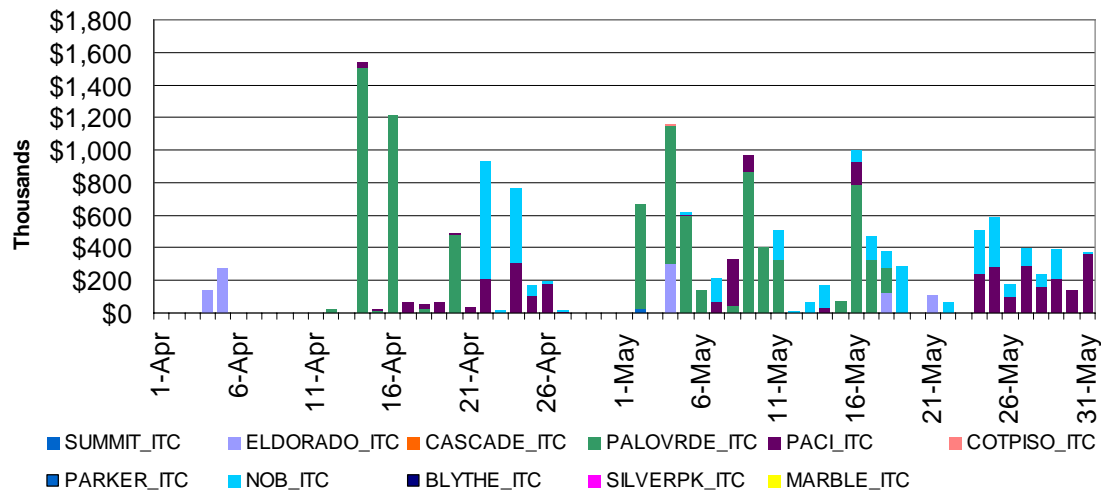


IFM (Day-Ahead) Congestion

Congestion on Inter-ties in IFM

Figure 13 below illustrates daily IFM congestion costs by inter-tie for the months of April and May 2009, while Table 1 provides a breakout of the IFM cleared value (MW), average shadow price (\$/MWh) and number of congested hours by inter-tie. Congestion costs for interties are calculated as the shadow price multiplied by the flow limit. The cumulative total congestion cost for inter-ties in May 2009 was approximately \$10.45 million. Of the total, the vast majority of costs occurred on three interties: Palo Verde (50 percent), PACI (23 percent) and NOB (21 percent).

Figure 13: IFM Congestion Costs by Intertie (Import)



During spring months (mid March through May) loads are relatively light which makes this an opportune time for maintenance. In May, numerous transmission and generation owners had scheduled outages which motivated congestion on various interties and branch groups. Scheduled maintenance on the Devers-Palo Verde 500 kV Line, the Imperial Valley- North Gila 500 kV line and the Eldorado-Moenkopi 500 kV Line during the first half of the month resulted in path capacity derates on the Palo-Verde inter-tie which resulted in congestion.

The PACI and NOB interties saw significant congestion during the second half of the month. Congestion costs were driven by path capacity derates motivated by scheduled maintenance on various transmission lines and over-scheduling in the IFM market. An availability of cheap hydro power in Pacific Northwest contributed to over-scheduling on the PACI and NOB interties.

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

Inter-Tie	Month	Average Cleared Value (MW)	Average Shadow Price (\$/MWh)	Number of Congested Hours
CASCADE_ITC	May-09	80	16	1
COTPISO_ITC	May-09	24	54	3
ELDORADO_ITC	May-09	913	16	36
MARBLE_ITC	May-09	0	65	24
NOB_ITC	May-09	1530	10	152
PACI_ITC	May-09	2444	8	120
PALOVRDE_ITC	May-09	1695	19	167
SUMMIT_ITC	May-09	45	457	1

Congestion on Branch Groups in IFM

Figure 14 illustrates IFM congestion costs 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 costs for branch groups are calculated as the shadow price multiplied by the flow limit.

For the month of May, the total branch group congestion cost was approximately \$3.1 million. A majority of costs occurred on the Path15 branch group (29 percent) and the Los Banos-North branch group (25 percent). All of the congestion costs on the Los Banos-North branch group occurred on May 1st and May 2nd, driven by scheduled maintenance of the Moss Landing-Los Banos 500 kV line. Most of the congestion on Path-15 occurred from May 28th through May 31st, driven by path capacity derates motivated by scheduled maintenance of the Diablo-Gates 500 kV line.

Figure 14: IFM Congestion Costs by Branch Group

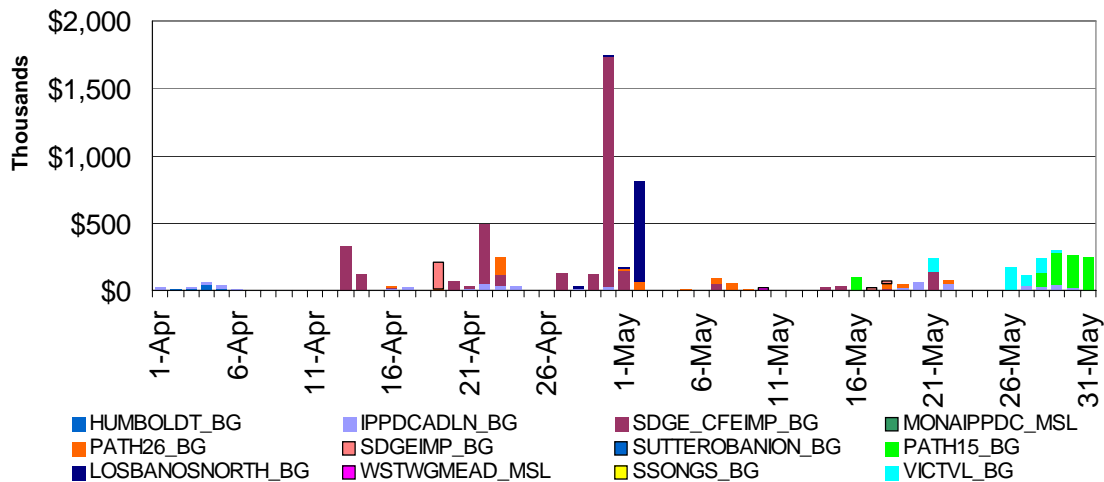


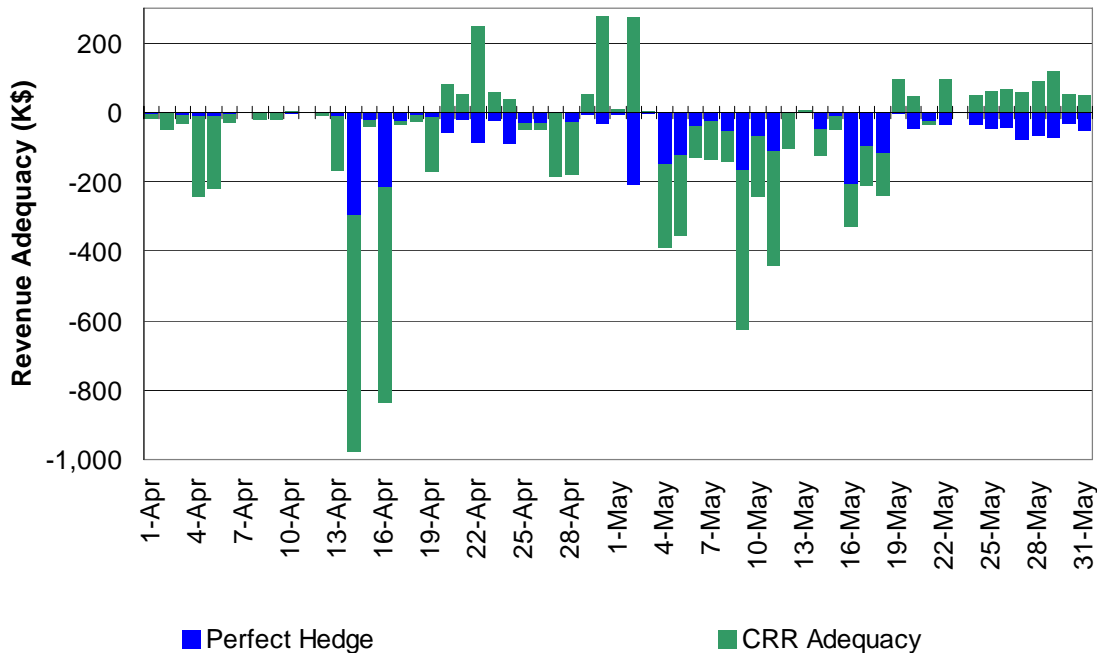
Table 2: IFM Congestion Statistics by Branch Group

Branch Group	Month	Average Cleared Value (MW)	Average Shadow Price (\$/MWh)	Number of Congested Hours
HUMBOLDT_BG	May-09	43	23	1
IPPDCADLN_BG	May-09	644	4	100
LOSBANOSNORTH_BG	May-09	2218	31	11
MONAIPPDC_MSL	May-09	236	11	1
PATH15_BG	May-09	2528	9	43
PATH26_BG	May-09	1391	6	39
SDGE_CFEIMP_BG	May-09	2164	5	34
SDGEIMP_BG	May-09	1231	3	11
SSONGS_BG	May-09	1520	0	3
SUTTEROBANION_BG	May-09	525	2	1
VICTVL_BG	May-09	2400	6	36
WSTWGMEAD_MSL	May-09	116	15	10

Congestion Revenue Rights

Figure 15 illustrates the revenue adequacy for Congestion Revenue Rights (CRRs) for the months of April and May 2009. Similar to April, May saw routine maintenance on transmission facilities. The significant volume of scheduled outages drove capacity derates on some major interfaces, such as Palo Verde, NOB, PACI and Path 26. This was reflected as a persistent net revenue deficiency throughout the first 20 days in May. In contrast, with fewer outages towards the end of the month, the last 10 days of May saw a net revenue surplus of \$17,000 on a daily average.

Figure 15: Daily Adequacy of Congestion Revenue Rights



As per the tariff, PTOs are required to report scheduled outages at least 30 days prior to the date of the outage. This 30-day rule provides a critical mechanism for the CAISO to account for significant transmission outages when determining the network capacity available for each monthly CRR release process. Starting with the May process, the CAISO was able to utilize information provided by the 30 day-rule to improve the modeling of outages. For May, only outages with a duration of 10 days or longer were removed from the network model used for the monthly CRR release process. With actual operational data available, the CAISO has subsequently identified the need to also remove outages of transmission facilities with durations of less than 10 days, as short duration outages on major interfaces were driving significant revenue deficiencies.

Effectively for June and onwards, outages with duration of less than 10 days are modeled with pro-rata derates.

In addition to this modeling approach, the monthly CRR process employs a global derating factor to account for the likelihood of unscheduled outages. To preserve revenue adequacy, this factor reduces the system-wide transmission capacity available in the release process and thereby indirectly limits the amount of CRRs released. For the month of May, the global derating factor was partially increased to 10 percent. This factor, however, was only applied to Tier 2 and the auction. Tier 1 was still processed with a derating factor of 2.5 percent. However this was a grossly insufficient percentage to preserve revenue adequacy.

Table 3: May CRR Adequacy Statistics

Concept	Amount
IFM Congestion Rents	\$15,906,574.35
CRR Payments	\$17,134,245.13
CRR Adequacy	-\$1,227,670.78
Perfect Hedge	-\$1,995,591.52
Net Revenue Adequacy	-\$3,223,262.30
Revenue Adequacy Ratio	83.15%
Annual Auction Revenues	\$2,638,701.29
Monthly Auction Revenues	\$847,172.89
Monthly Net Balance	\$262,611.88

Overall, the total dollars collected from the IFM were sufficient to cover approximately 83 percent of the net payments to CRR holders and of the perfect hedge, allocating approximately 12 percent of the congestion rents to honor the perfect hedge. On net, total congestion revenues were deficient by \$3.2 million, a 10 percent increase with respect to April's deficiency of \$2.9 million. The auction revenues credited to the balancing account for May were approximately \$3.48 million, an increase of approximately five percent in comparison to April's revenues. Overall there was slightly more than \$0.26 million as a final surplus in the CRR balancing account for May (see Table 3 above).