CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Ph.D., Director of Market Analysis

cc: ISO Officers, ISO Board Assistants

Date: November 23, 2004

Re: ***Market Analysis Report for October 2004***

This is a status report only. No Board Action is required.

Executive Summary

The CAISO implemented Phase 1b of its Market Redesign and Technology Upgrade (MRTU) on October 1. The Real-Time Market Application (RTMA) replaced the previous Balancing Energy Ex-Post Price auction (BEEP) system used to balance generation with load in real time. Initially, the CAISO experienced volatile prices, due in part to low ramp rates input into the software and the lack of sufficient feedback of generation deviation information to the software.

Two outages substantially affecting Southern California also were planned to begin in October, concurrent with the deployment of RTMA: the San Onofre Nuclear Generating Station Unit 3 (SONGS), and the Pacific DC intertie, a key transmission path connecting southern California directly to the Pacific Northwest. Both went out of service on planned outages. These outages also contributed significantly to the increase in real-time price volatility. Both outages are expected to continue through the end of the year. In addition to limiting supply within SP15, the outages have had the compounding effect of lowering the technical limit on energy that instantaneously can be imported into the region from neighboring areas. This resulted in a sharp increase in the frequency that the CAISO split real-time market dispatch between SP15 and NP15 during the first two weeks of October. This exacerbated the increase in price volatility and real-time market costs, particularly in Southern California.

After several days of tuning and lower loads, real-time market prices stabilized and price volatility decreased. Recently, there have been brief price spikes predominantly occurring during rapid ramp periods, which tend to last for a single five-minute dispatch interval. RTMA ramps units quickly to manage steep imbalances, but then is able to replace the more expensive units after lower cost units have ramped to higher generation levels. This occurred most frequently during the morning, afternoon, and evening load ramp periods, and also around the top of the hour schedule changes, and can also occur at other times, usually due to contingency events.

Ancillary services markets have been influenced by the start of the planned generation maintenance season in fall months. This maintenance has significantly reduced the amount of online capacity and has resulted in bid insufficiency and associated price spikes in the regulation and operating reserve markets early in the month. The operating reserve price spikes decreased later in the month as loads declined. Meanwhile, regulation prices increased significantly throughout October as a result of increased CAISO procurement and lower available supply. Overall, average ancillary services prices in October increased 61 percent from September levels.

I. Trends Affecting Market Supply and Demand

- *Moderate loads, but signs of year-to-year load growth persist*
- *San Onofre 3 and Pacific DC Intertie both out of service*

Mild weather resulted in moderate loads in October. Loads averaged 26,057 megawatts (MW), or 1.4 percent below the October 2003 average, when there was unseasonably warm weather throughout the state. The October 2004 monthly peak of 34,320 MW was 5.9 percent lower than the October 2003 peak. However, the average daily trough (the observed daily minimum load) for October 2004 was 1.5 percent above the October 2003 trough. As daily minimum load is less sensitive to weather than peaks, this indicates that potential load growth is being driven by economic and demographic factors. Figure 1 shows daily peak loads for October 2004 and October 2003. Table 1 shows year-to-year load growth trends in average hourly load, average daily peak and trough, and monthly peak load, for each month through October 2004.

Figure 1. Actual Loads: October 2004 v. October 2003

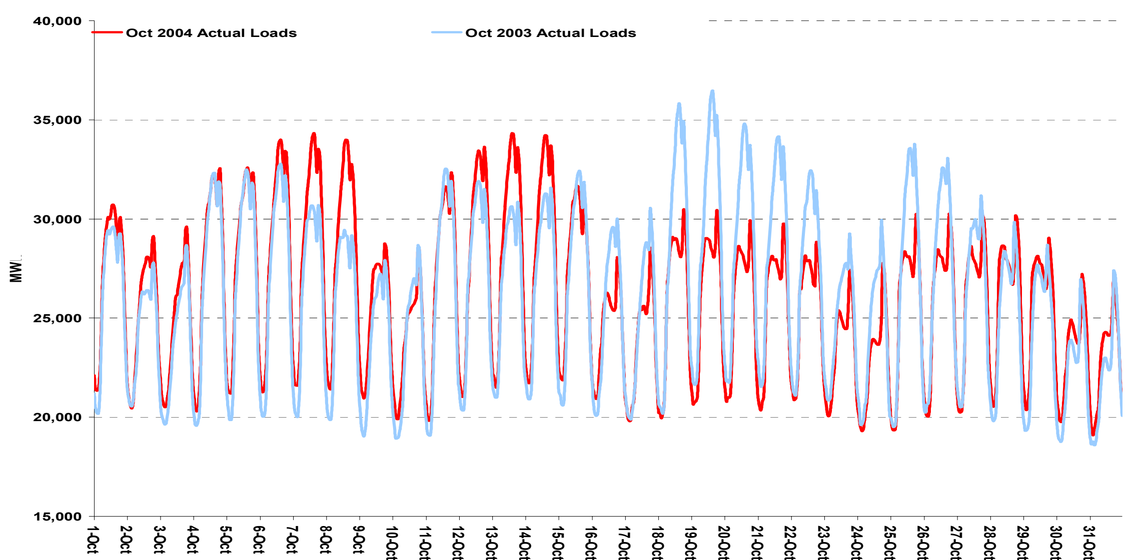


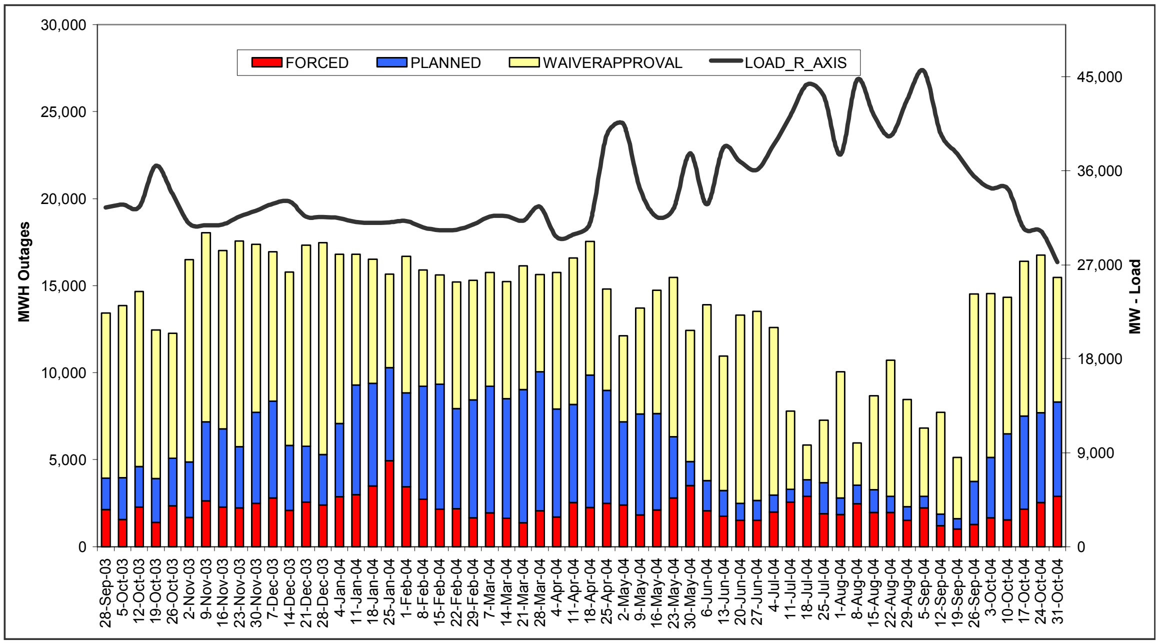
Table 1. Load Growth Rates Compared to Same Month in the Prior Year, Through October 2004

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
November-03	-0.2%	1.0%	-0.8%	0.2%
December-03	2.8%	3.1%	1.5%	2.7%
January-04	4.3%	3.1%	5.1%	3.2%
February-04	4.5%	3.9%	5.4%	4.5%
March-04	4.4%	5.1%	2.5%	4.5%
April-04	7.1%	8.3%	4.8%	31.1%
May-04	7.3%	7.7%	5.5%	2.5%
June-04	6.6%	6.9%	6.1%	-4.7%
July-04	0.7%	0.3%	1.9%	4.0%
August-04	1.0%	0.6%	0.6%	5.2%
September-04	3.4%	3.5%	3.4%	10.1%
October-04	-1.4%	-2.8%	1.5%	-5.9%

Notes: Through 7/10/03: Actual loads at top of hour. Since 7/11/03: Hourly average loads.

Outages. In late September and October, loads moderated substantially resulting in an increase in Must Offer waiver approvals. Additionally, planned outages increased substantially as the post-summer maintenance season began in earnest. In particular, the San Onofre Nuclear Generation Station (SONGS) Unit 3 (1,109 MW) has been down for refueling since September 27. In addition, the Pacific DC Intertie, a key transmission path that connects SP15 directly to the Pacific Northwest, also went out on October 1 for a maintenance upgrade. It is expected to return in January 2005. Finally, a nuclear unit at the Palo Verde Station (1,270 MW), located in the APS Control Area in Arizona also went out on October 2. Figure 2 shows weekly average outages by type through October.

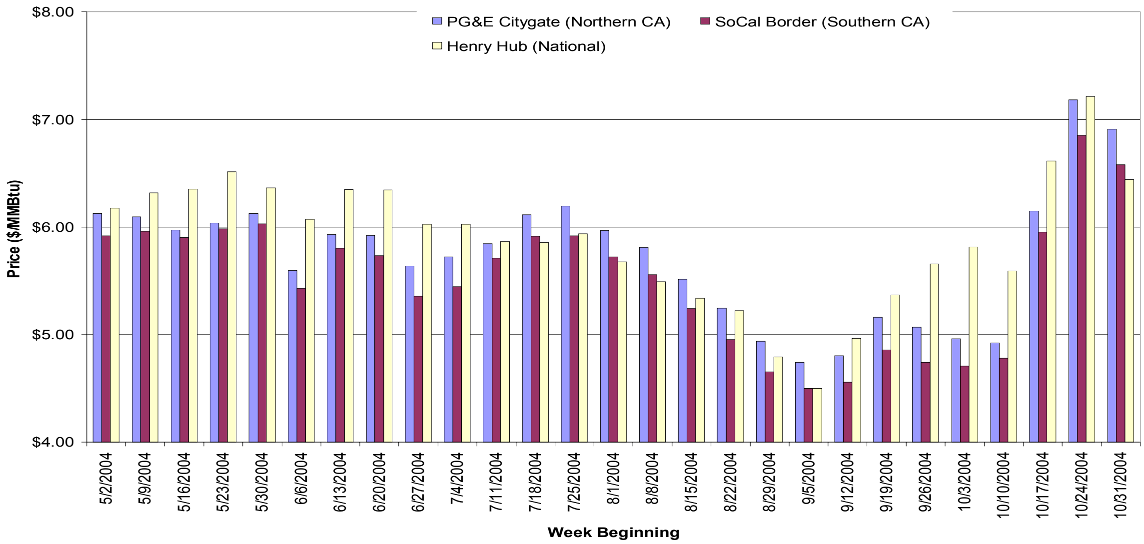
Figure 2. Weekly Average Outages through October



Natural Gas Markets. Average prices for natural gas were higher at all points during October compared to average prices in September, by an average of $1.23 per million British Thermal Units (MMBtu). NYMEX natural gas prices were driven by expectations of colder weather that spiked up prices during the first week of October, with prices reaching highs for that week of $6.21/MMBtu on October 7 at Henry Hub and averaging $5.34/MMBtu across California points on October 6.

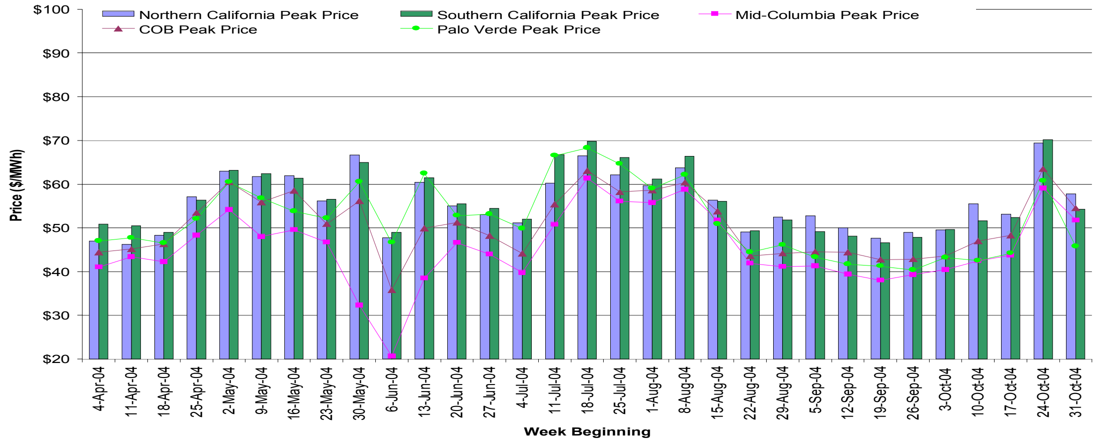
Substantial price increases occurred during the third week of October, when NYMEX futures prices spiked and drove California prices from $4.76-$5.08/MMBtu on October 17 to $6.54-$6.76/MMBtu on October 22. Cash prices peaked on 27 October with Henry Hub prices at $8.12/MMBtu and California prices averaging $7.64/MMBtu. Prices declined after this point sharply in line with drops in the NYMEX futures prices. Average daily gas prices for October were $6.26/MMBtu at Henry Hub, $5.44/MMBtu at Malin, $5.76/MMBtu at PG&E Citygate, and $5.52/MMBtu at Southern California Border Average. Figure 3 shows weekly average prices for natural gas through October.

Figure 3. Regional Weekly Average Natural Gas Prices through October



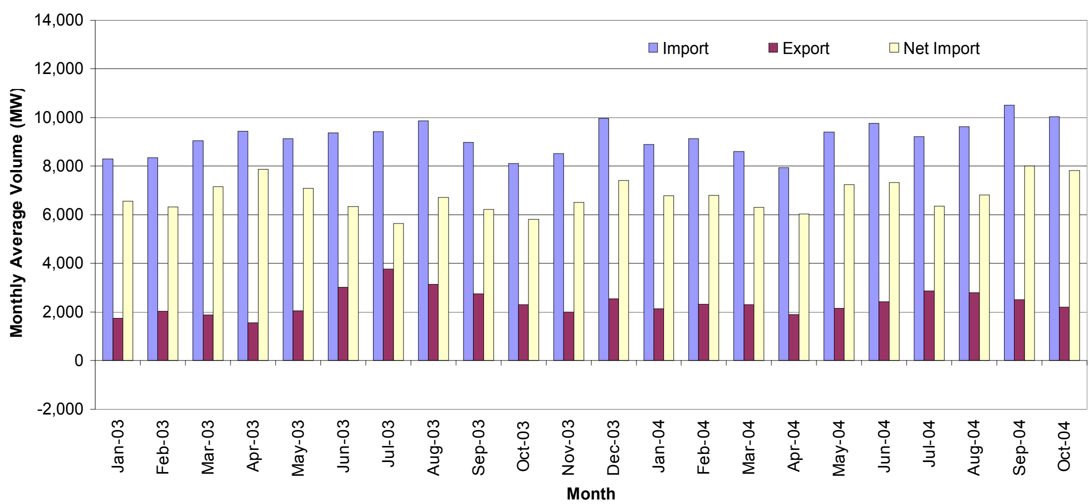
Regional Electric Bilateral Day Ahead Markets. Day-Ahead electricity prices increased concurrent with natural gas prices. Prices remained in the $50-55/MWh range during the first week of October. In general, prices within California were approximately $10/MWh above those at Palo Verde. Specifically, prices in northern California diverged substantially from southern California prices between October 12 and 16, with a $9.25/MWh difference between them on October 16. Electricity prices reflected the sharp increase in natural gas prices on October 22, when prices increased by more than $10/MWh to yield prices above $62/MWh. Prices peaked on October 29 at over $75/MWh, still due to high natural gas prices. Average October peak weekday regional day-ahead electricity prices were $51.38/MWh at the California-Oregon Border, $46.88/MWh at Mid-Columbia, $49.22/MWh at Palo Verde, $58.38/MWh in northern California, and $57.92/MWh in southern California. Figure 4 shows bilateral day ahead spot prices through October.

Figure 4. Electric Bilateral Day Ahead Market Prices
Weekly average prices through October



Imports and Exports. Despite the outage of the Pacific DC Intertie, net imports were substantial, averaging approximately 6,765 MW in October, or 34.4 percent more than the October 2003 level. Imports from the Southwest averaged 3,268 MW, or 17 percent greater than the October 2003 level. This was due in large part to mild weather and excess power in that region. Similarly, imports from the Lower Colorado region (southwest) were also strong, averaging 993 MW, or 30.3 percent above the October 2003 level. Much of this power was destined for northern California, to exploit the $10/MWh price difference between Palo Verde and northern California shown in Figure 4, and periodically resulted in south-to-north congestion on Path 15. Figure 5 shows monthly average scheduled peak-hour imports, exports, and net imports, through October 2004.

Figure 5. Monthly Average Imports and Exports through October 2004



II. Real-Time Energy Market[1]

- *RTMA software in service and operational*
- *Short price spikes during ramp periods are a result of RTMA dispatch*
- *SCIT and Miguel mitigation related to outages caused long price spikes and intra-zonal congestion*

Immediately following the deployment of the new RTMA systems at midnight on October 1, real-time market prices experienced large price swings as the CAISO corrected some of the initial problems with the RTMA software. By October 3, the market had begun to stabilize and its behavior became fairly predictable. The CAISO now determines a single market-clearing price for both incremental and decremental energy procured. Prices may still be split between SP15 and NP15 in the case of real-time congestion on either Path 15 (northbound) or Path 26 (southbound). Nonetheless, average market-clearing prices were similar to those seen prior to implementation although OOS/OOM INC prices are slightly lower, and in-sequence DEC prices are slightly higher than seen previously. Figure 6 shows monthly average real-time prices through October. As expected, dispatch volumes are considerably larger due to the efficient clearing capability of RTMA. Table 2 shows average real-time prices and net real-time energy dispatched for peak, off-peak, and all hours, grouped by in-sequence, out-of-sequence, and total energy types, in addition to average loads and underscheduling, for October. The figures that follow show average dispatch volumes and prices paid for incremental energy and received for decremental energy, for both in-sequence and out-of-sequence/out-of-market energy, through October. Figure 6 shows monthly averages through October; Figure 7 shows daily averages for September and October.

Table 2. Average Real-Time Prices, Net Real-Time Energy, Average Loads, And Underscheduling, for October

	In-Seq. RT Dispatch	OOS/OOM Dispatch	Total Dispatch	Average Loads and % Underscheduling
PEAK	$ 57.75 /MWh	$ 36.96 /MWh	$ 50.36 /MWh	28,479 MW
	(122.0) GWh	(66.8) GWh	(188.8) GWh	1.1%
OFFPEAK	$ 41.30 /MWh	$ 44.23 /MWh	$ 41.74 /MWh	22,053 MW
	0.6 GWh	29.1 GWh	29.7 GWh	2.4%
ALL	$ 52.63 /MWh	$ 37.89 /MWh	$ 48.16 /MWh	25,651 MW
	(121.4) GWh	(37.7) GWh	(159.1) GWh	1.7%

[1] **Note:** All of the real-time data used in this Report reflect the best and most accurate information available at the time of publication. As RTMA represents a fundamental change in the ISO's systems, the data are undergoing reviews for accuracy and may be subject to change.

Figure 6. CAISO Monthly Average Real-Time Prices and Volumes through October 2004

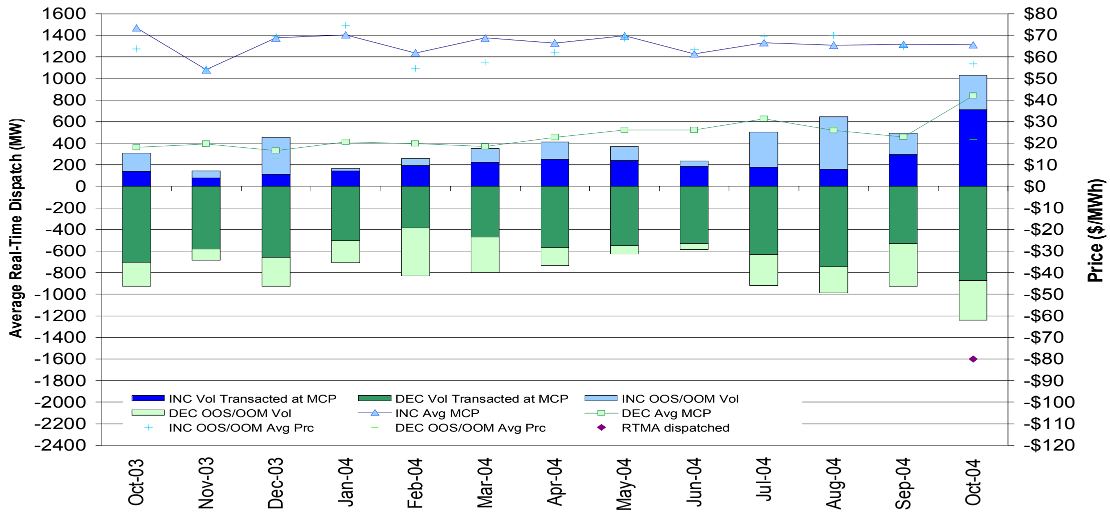
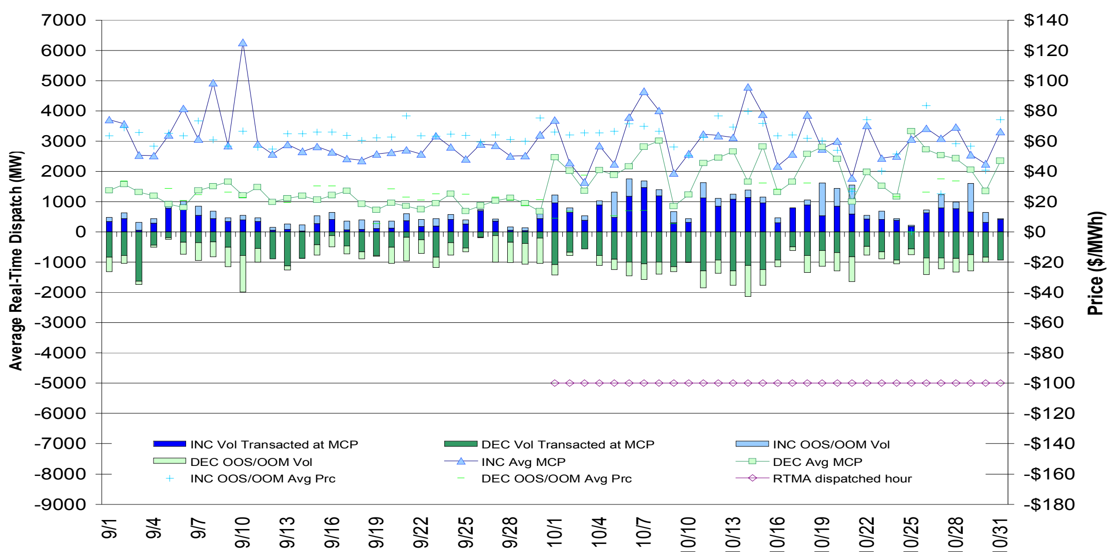
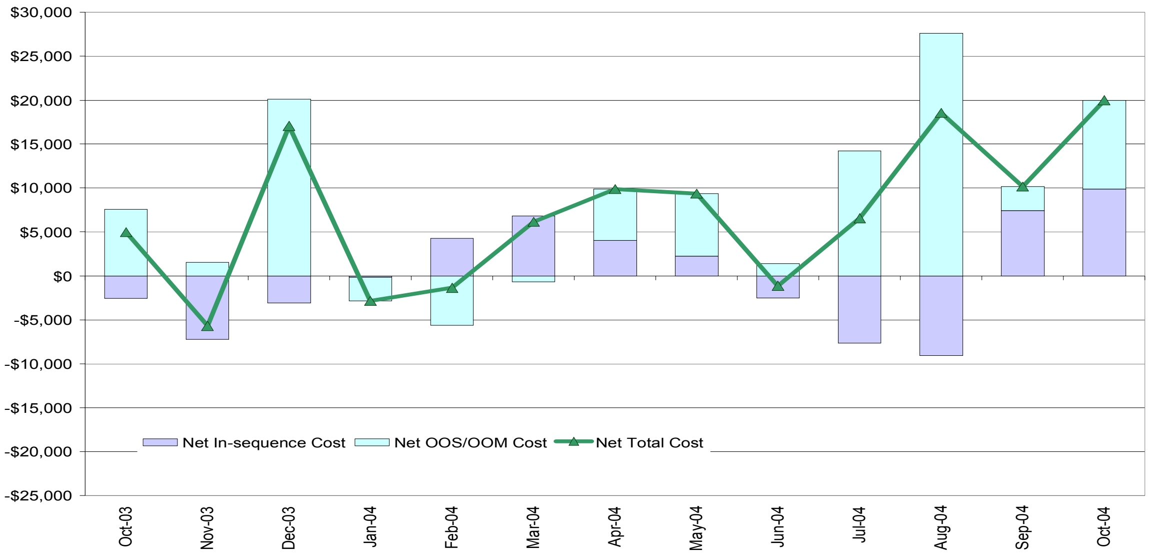


Figure 7. Daily Average Real-Time Prices and Volumes, September and October 2004



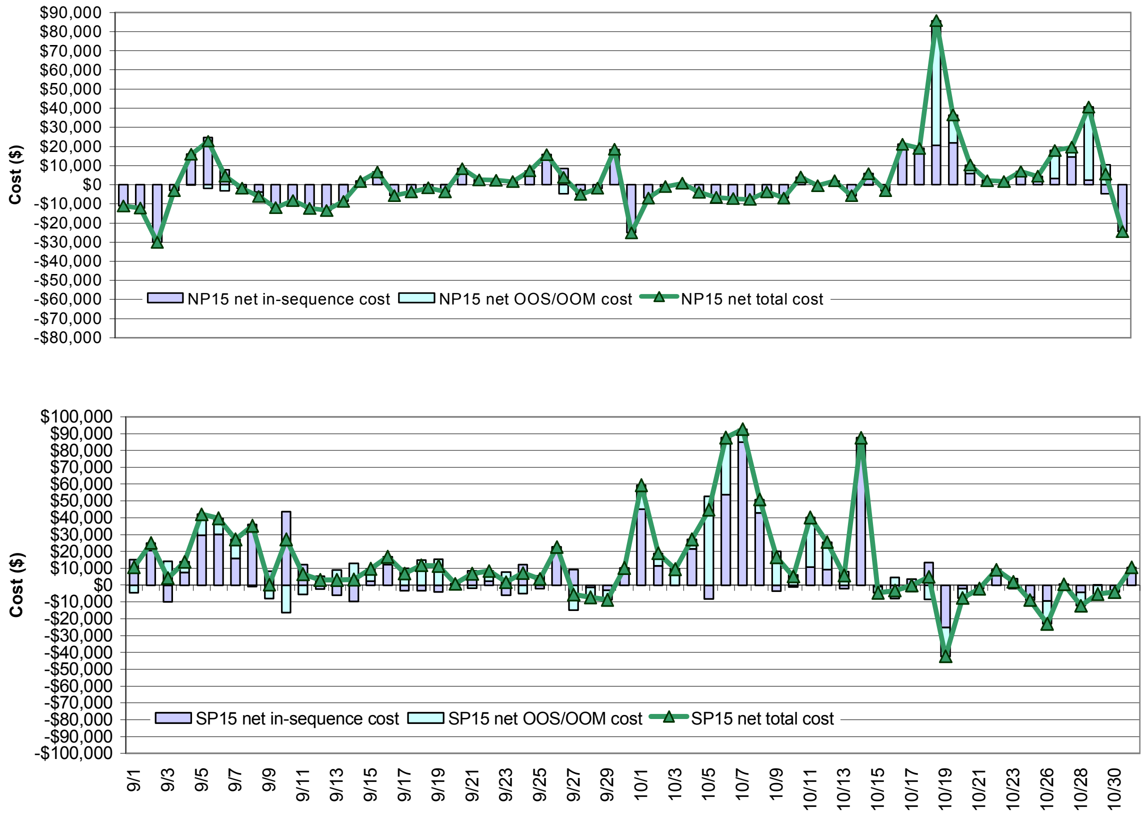
Real-Time Market Cost Trends. Real-time costs increased from September levels due to several factors. These included resource outages, more frequent real-time market splits, and higher natural gas prices. Given the difficultly in isolating the effects of these factors, we believe it premature at this time to state the impacts of RTMA on real-time market costs. Figure 8 shows weekly average in-sequence and out-of-sequence balancing energy costs through October.

Figure 8. CAISO Monthly Average Hourly Real-Time Costs through October 2004



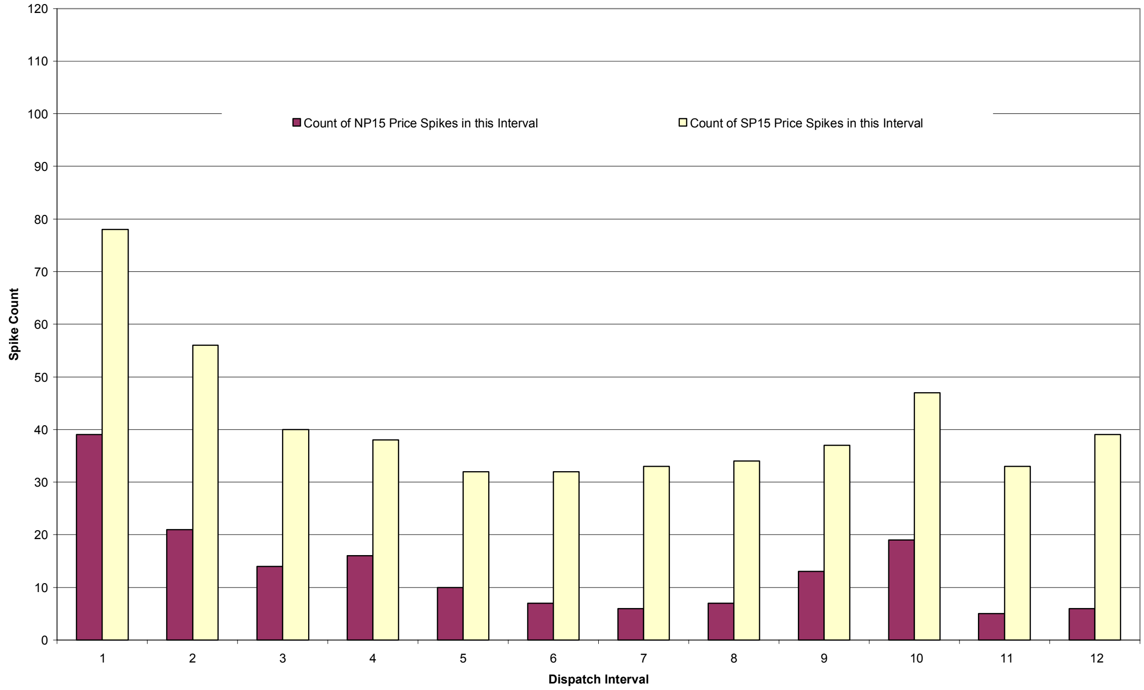
Market splits between SP15 and NP15 occurred regularly in early October, due in large part to the SONGS and PDCI outages that were concurrent with RTMA deployment and the resultant increase in the stringency of constraints on imports into southern California. This resulted in higher real-time energy costs in SP15 during the first two weeks of October. Moderating loads reduced real-time market split frequency later in the month resulting in lower costs in SP15. Figure 9 shows the daily average hourly cost of real-time energy in NP15 and SP15 since the beginning of September.

Figure 9. CAISO Daily Average Hourly Real-Time Costs through October 2004
NP15 Top, SP15 Bottom



Price Spikes. One notable feature of the market since the implementation of the RTMA software has been price spikes. While they have become more frequent, they have also largely become more predictable. Price spikes most often have been one or two five-minute dispatch intervals in duration. These spikes tend to occur in the first interval in each hour, and occasionally last into the second interval. This is especially the case during the morning and evening load pulls when generators are ramping between hourly schedules. To cover the rapidly changing imbalance between the generation and load, RTMA often calls upon numerous real-time energy bids. In that case, the highest dispatched bid sets the market clearing price for that interval. However, the efficient-clearing feature of RTMA enables it to back down these high-bidding units as the lower-bidding units continue to ramp upward to a level that enables them to cover the imbalance. (Under the old BEEP system, units would be ramped as needed, without exchanging high-priced bids for low-priced bids, so that the highest-priced dispatched bid would set the price for the remainder of the period of imbalance, resulting in a prolonged price spike. At the end of the imbalance period, BEEP would have backed down all units concurrently.) Figure 10 shows the frequency that price spikes occur by five-minute pricing interval within NP15 and SP15 between October 3 and 31.

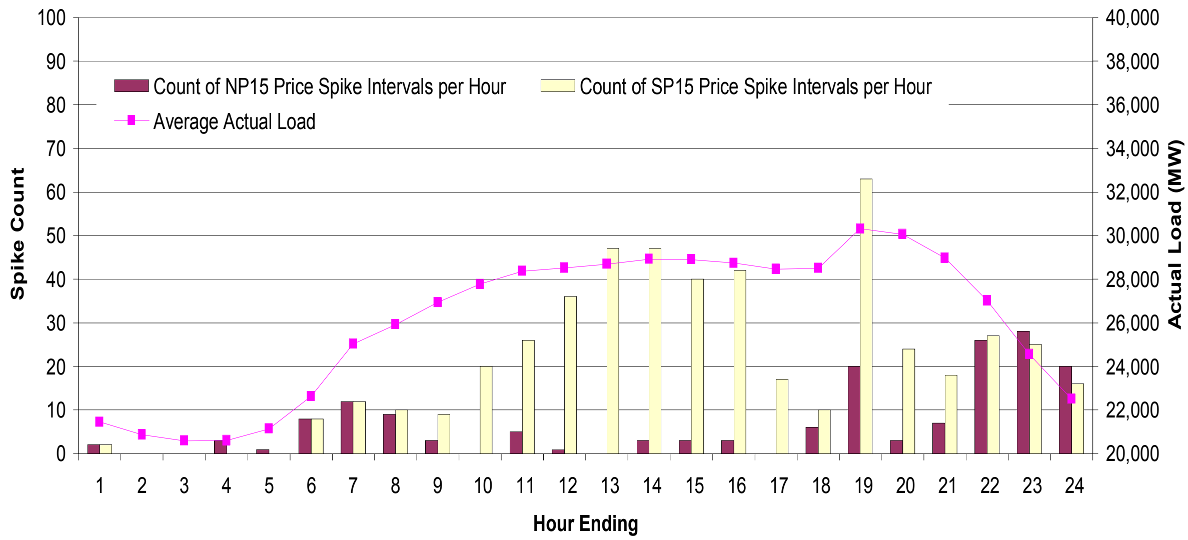
Figure 10. Number of Price Spikes within NP15 and SP15 by Five-Minute Dispatch Interval: Oct. 3-31[2]



On some days, notably October 6, 7, and 14, spikes within SP15 persisted across many intervals, for several hours, due to intra-zonal congestion mitigation. RTMA dispatched units within SP15 to manage generation subject to congestion at the Miguel Substation, near San Diego, and the Southern California Import Transmission Nomogram (SCIT), a technical constraint on the quantity of power that can instantaneously be imported into the region. To manage Miguel congestion, RTMA issues out-of-sequence decremental dispatch instructions to reduce the flow of power into the substation. This decrease in generation must be offset by incrementing other units within SP15. This raises the market-clearing price. To manage SCIT, RTMA calls upon units only within SP15. This limits supply and causes a high zonal price. As a result, SP15 zonal hourly average prices above $100/MWh lasted for 4 hours on each of the afternoons of October 6, 7, and 14, and account for the bulk of SP15 mid- and late-hour spikes in Figure 10 and mid-day spikes in Figure 11. Figure 11 compares hourly NP15 and SP15 price spikes to average actual load between October 3 and 31.

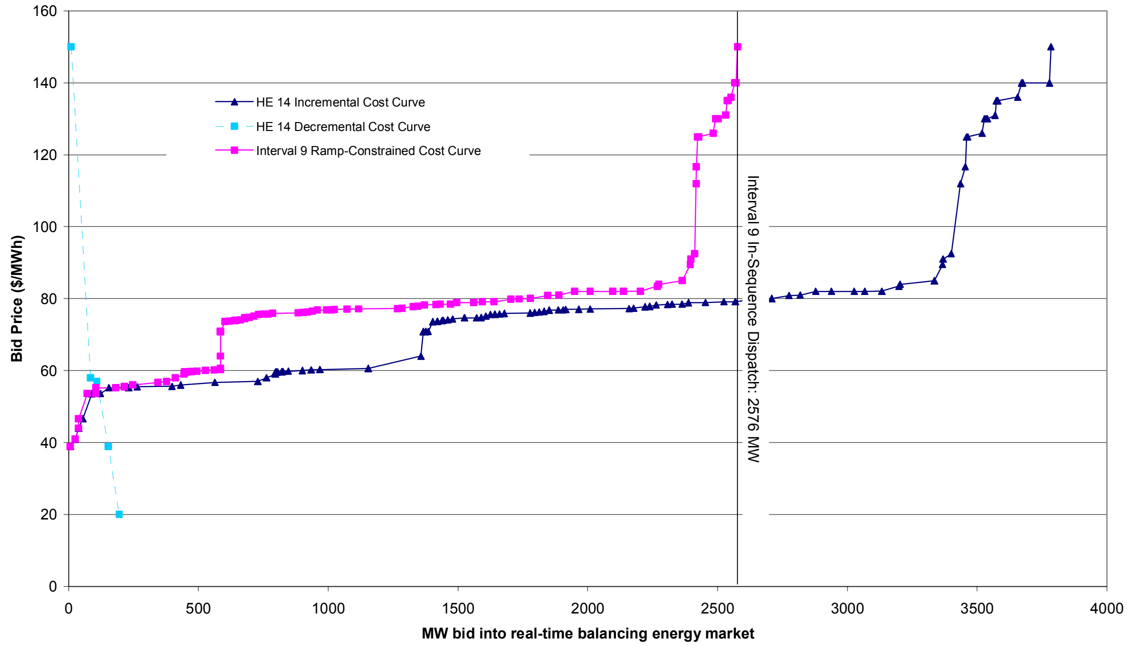
[2] October 1 and 2 are excluded because dispatches immediately following the "Go-Live" event remained under revision at the time of writing.

Figure 11. Number of Price Spikes within NP15 and SP15 by Hour of Day: Oct. 3-31



During several of these hours, the RTMA software nearly or fully dispatched the entire bid stack. For example, on October 7, hour ending 14:00 (between 1:00 and 2:00 p.m.), the very last bid was marginal, setting the price at $150/MWh, as the entire bid stack was called upon to offset congestion management for Miguel and SCIT. During this hour, the CAISO called upon reliability must-run (RMR) units to supply additional energy. Because several units were already ramping upward at maximum capability, some of the highest bid segments from lower priced units were not yet dispatchable. RTMA must wait for low priced units to ramp to the upper levels of their capabilities before it can replace higher-priced units in the bid stack with those lower priced units. Thus, the ramp-constrained bid curve for interval 9 is considerably steeper than the hourly bid curve. Once those units ramp up and can provide energy to replace more costly energy, the bid curve effectively flattens out. Figure 12 shows the real-time balancing energy bid curve for October 7, HE 14:00, and the ramp-constrained bid curve for interval 9 of that hour.

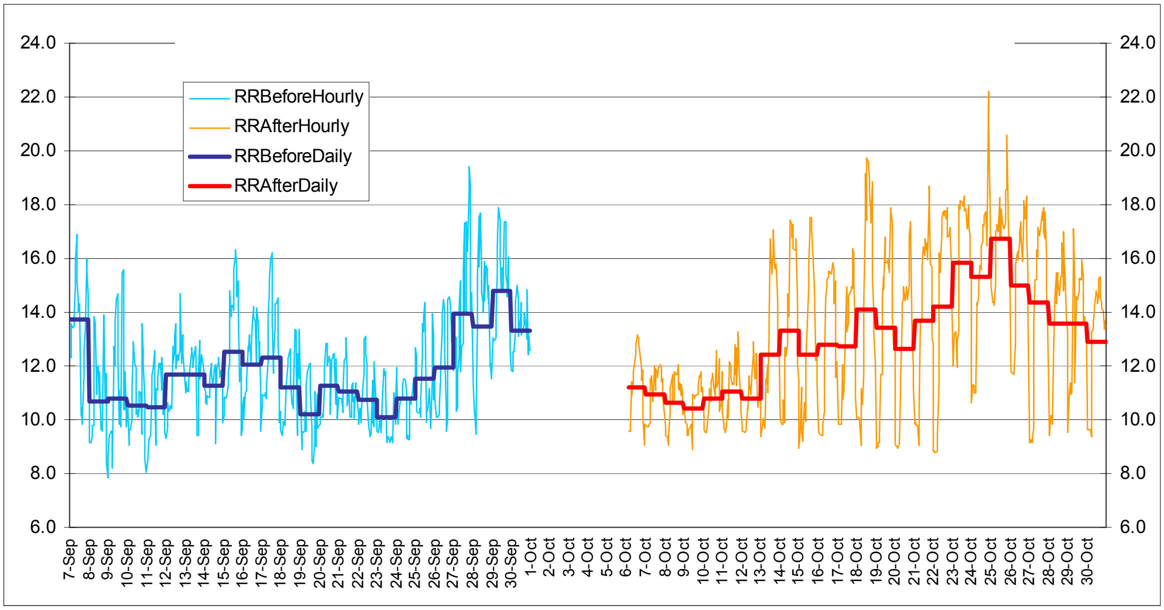
Figure 12. SP15 Supplemental Real-Time Energy Bid Curve for Oct. 7, HE 14:00; And Interval 9 Constrained Bid Curve and In-Sequence Dispatch



Comparison of Submitted Ramp Rates Pre and Post RTMA Implementation. Prior to the implementation of the new RTMA software, market participants could only submit a single ramp rate with their bid segments. That changed with the implementation of Phase 1B. Market participants now submit up to 10 bid segments, each with its own ramp rate. Initially, the new market design called for default ramp rates to be set at a unit's minimum ramp rate. However, during system testing the CAISO found the default ramp rates to cause a problem. RTMA would have to dispatch several units to meet small load imbalances due to the tight ramp rate restrictions. The CAISO filed Amendment 54 which, in part, called for the default ramp rate to be set at a unit's maximum ramp rate. This provision was approved by FERC and implemented on October 2. This helped to settle down some of the volatile market outcomes observed during the first two days of RTMA market operation. System ramping capability remained below that of September contributing to pricing volatility in early October. Submitted ramp rates increased later in the month leading to more price stability.

The monthly weighted average ramp rate for September was 11.63 MW/min compared to 12.82 MW/min for October after RTMA implementation. This indicates that ramp rates have actually increased during October. However, the standard deviation around the mean has also increased from 2.00 in September to 2.94 in October. This result was expected, as market participants were able to take advantage of the greater flexibility embodied in the ten ramp rate segments. Figure 13 compares system average ramp rates for September and October, pre- and post-RTMA implementation. This chart shows that for the first two weeks of RTMA operation (up until about the 13th of October) the system-wide ramp rate was usually lower than prior to RTMA implementation. Since that time, the ramp rate issue appears to have subsided.

Figure 13. System Ramp Rate Comparison, Pre and Post RTMA Implementation



Real-Time Intra-Zonal Congestion Management.[3] Total CAISO total intrazonal congestion costs are the sum of three cost components:

- Minimum-Load Compensation Costs (MLCC) are incurred day-ahead as units are retained on-line, pursuant to the Must-Offer Obligation, to be available to provide energy if called upon for reliability.
- Reliability Must-Run (RMR) Costs are incurred in real-time as RMR units are the first to be dispatched to relieve intra-zonal congestion.
- Redispatch Costs, or costs of out-of-sequence energy in excess of real-time market costs, are also incurred if the RMR dispatches are not sufficient to alleviate the constraint.

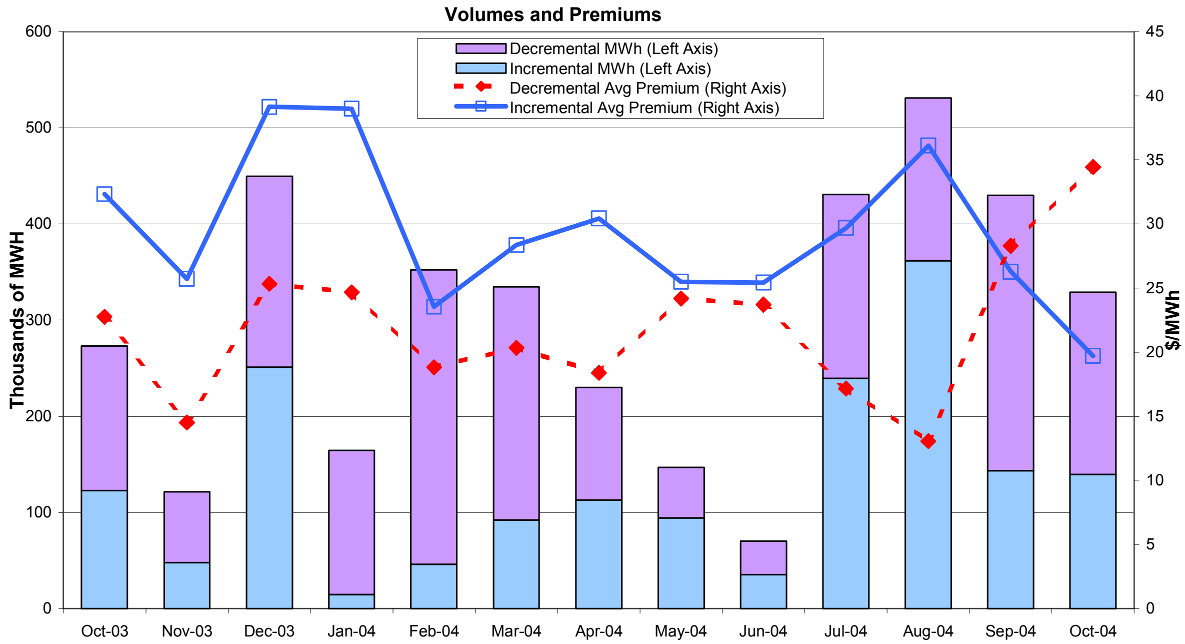
Due to lags in the settlements system, October MLCC and RMR costs were not available at the writing of this report. The following focuses on redispatch costs only.

Between September and October, incremental congestion redispatch volumes remained relatively constant, while decremental redispatch volumes decreased slightly, resulting in a net decrease in overall redispatch volume. The majority of the incremental dispatches were due to Sylmar bank congestion exacerbated by the outage of the Pacific DC Intertie, as units within the Los Angeles basin were incremented out-of-sequence (OOS) to alleviate this constraint. The majority of the decremental dispatches were related to Miguel Bank congestion. October OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $9.3 million. Total OOS dispatch volume was

[3] Real-time dispatches due to intra-zonal congestion management remain under review. This discussion reflects the best information available to date.

328 GWh (INC plus DEC) and the average redispatch premium was $28.18/MWh. Figure 14 presents these results graphically for recent months.[4]

Figure 14. Out-of-Sequence Volume and Average Redispatch Premium

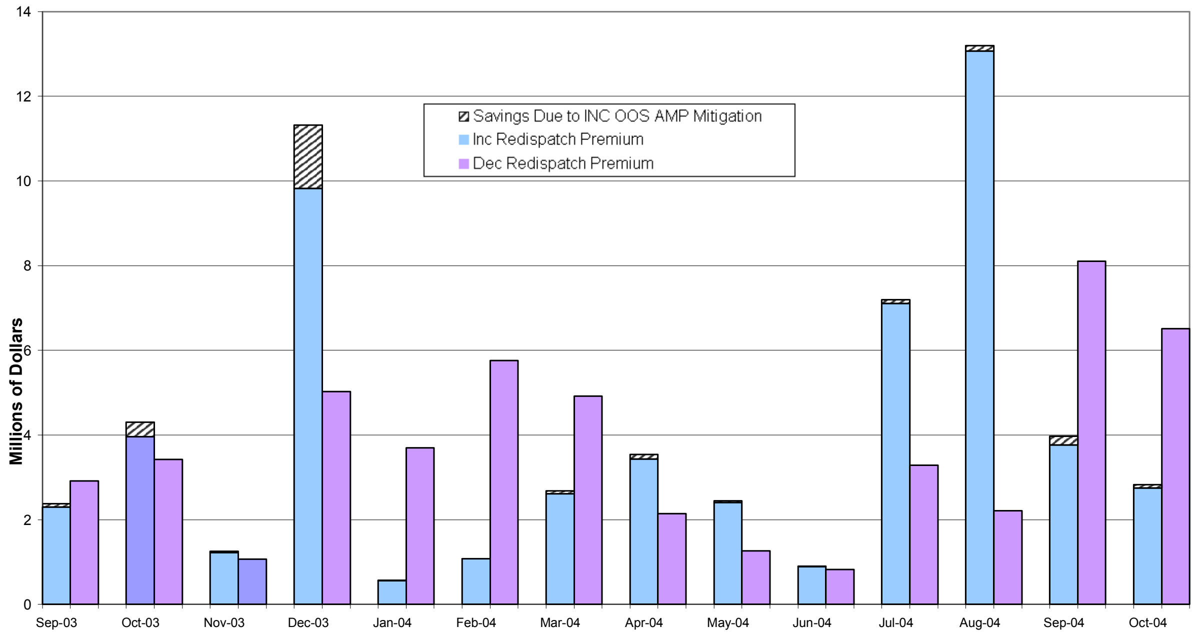


Incremental OOS Dispatches. A total of 139,500 MWh of incremental energy was called out-of-sequence (OOS) by CAISO operators to manage intra-zonal congestion in October. The average price paid was $63.95/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $2.7 million, or $19.69/MWh. The vast majority of the incremental OOS calls were for Sylmar bank congestion. There were also incidental OOS calls due to SCIT and transmission line and substation maintenance.

The Automated Mitigation Procedures' Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $78,022 or approximately 2.8 percent of the incremental redispatch premium in October. All incremental OOS dispatches are subject to mitigation. Figure 15 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. As shown in the figure, very little bid mitigation has taken place, given the current thresholds in AMP for local market power.

[4] OOS net cost or redispatch premium is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent dispatch cost at zonal MCP. The premium reflects the increased cost of redispatch and any potential mark-up above marginal cost.

Figure 15. Re-dispatch Premiums and INC OOS Mitigation Savings



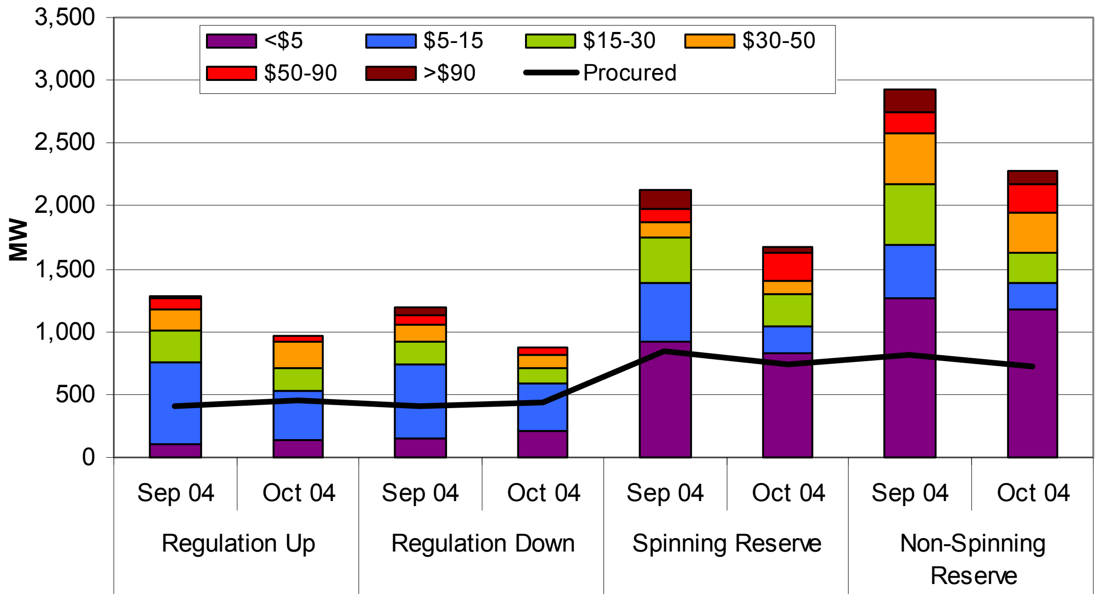
Decremental OOS Dispatches. A total decremental 189 GWh was dispatched out of sequence in October. The average price paid was $13.42/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $6.5 million or $34.44/MWh. This energy is settled according to the provisions of the Amendment 50 mitigation measures approved by FERC. As in previous months, almost all of the decremental activity was due to intra-zonal congestion in the San Diego region caused either by the new generation units located in northern Mexico or the increased generation in the Southwest.

III. Ancillary Services (A/S) Markets

The start of the planned generation maintenance season significantly reduced the volume of online capacity, and resulted in bid insufficiency and associated price spikes in the regulation and operating reserve (spinning and non-spinning reserve) markets early in the month. The operating reserve price spikes dissipated later in the month as loads decreased. Regulation prices increased significantly throughout October as a result of increased CAISO procurement and lower supply. Overall, average ancillary services prices in October increased 61 percent over September levels.

Market Supply. Supply of capacity to the A/S markets decreased between September and October, as expected due to the beginning of the planned maintenance season. Planned maintenance and Must-Offer Waiver Approvals trimmed A/S bid volumes by 20 to 25 percent. Figure 16 shows bid volumes by price bin in September and October.

Figure 16. Ancillary Service Day Ahead Average Bid Volume by Price Bin



Market Prices. While supply decreased rather sharply, requirements for operating reserves decreased relatively moderately. An increase in requirements for regulation reserves[5] (see below) was resulted in a substantial increase in the price of upward regulation. Table 3 shows product requirements and average prices for September and October.

Table 3. Average Ancillary Services Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)				
	RU	RD	SP	NS	RU	RD	SP	NS	All Services
Sep 04	407	424	910	869	$ 10.69	$ 9.14	$ 6.24	$ 4.50	$6.82
Oct 04	455	443	792	767	$ 18.88	$ 9.08	$ 10.61	$ 7.80	$10.99
Change	11.9%	4.4%	-13.0%	-11.8%	76.7%	-0.6%	70.1%	73.4%	61.1%

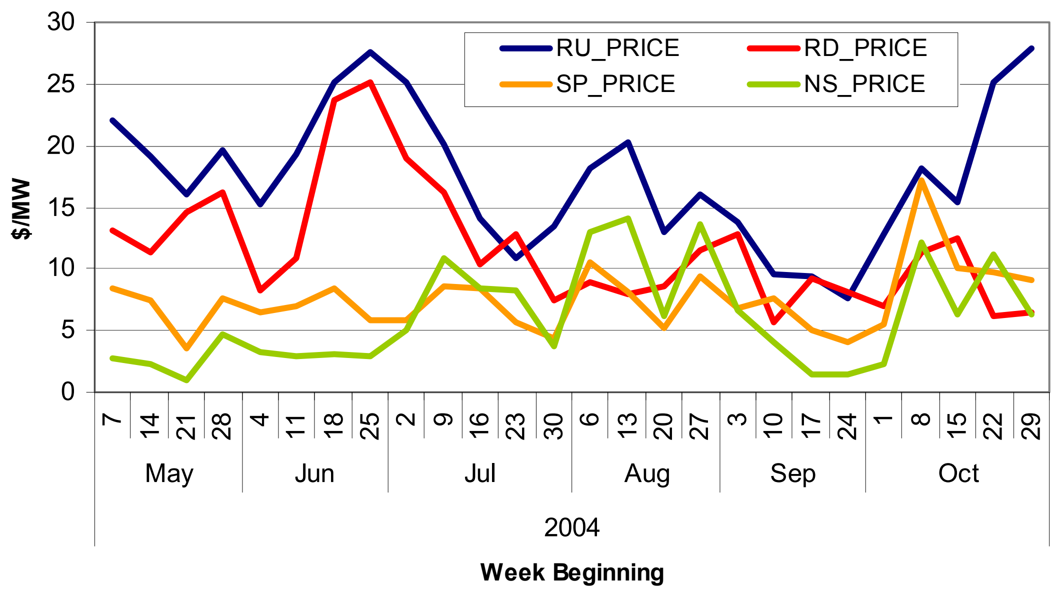
Lower loads resulted in a 6 percent decrease in overall A/S procurement. This was met by a 61 percent increase in overall prices. However, with the average price for all services at $11, the markets have not been excessively costly. Table 4 summarizes A/S procurement, and Figure 17 captures price trends over the past six months. The Department of Market Analysis (DMA) will continue to monitor the trend in Regulation Up pricing.

[5] A 50-MW increase in Regulation Up requirements was a temporary administrative change in procurement policy, to cushion against instability following RTMA deployment. This temporary change was implemented in the first week of October and remained in place throughout the month.

Table 4. Time of Day Ancillary Service Demand Pricing

		Average AS Procured (MW)			Weighted Average Price ($/MW)		
		On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours
Sep 04	RU	420	381	407	$ 11.66	$ 8.55	$ 10.69
	RD	435	403	424	$ 6.83	$ 14.12	$ 9.14
	SP	980	772	910	$ 7.86	$ 2.10	$ 6.24
	NS	922	763	869	$ 6.03	$ 0.78	$ 4.50
	Total	2757	2319	2611	$ 7.61	$ 4.78	$ 6.77
Oct 04	RU	469	429	455	$ 20.67	$ 14.99	$ 18.88
	RD	451	427	443	$ 6.94	$ 13.59	$ 9.08
	SP	852	671	792	$ 13.84	$ 2.44	$ 10.61
	NS	822	657	767	$ 10.61	$ 0.78	$ 7.80
	Total	2594	2185	2457	$ 12.73	$ 6.53	$ 10.89
Difference	RU	11.5%	12.8%	11.9%	77.3%	75.4%	76.7%
	RD	3.7%	6.0%	4.4%	1.6%	-3.8%	-0.6%
	SP	-13.0%	-13.0%	-13.0%	75.9%	15.9%	70.1%
	NS	-10.9%	-13.9%	-11.8%	75.9%	-0.9%	73.4%
	Total	-5.9%	-5.8%	-5.9%	67.3%	36.8%	60.9%

Figure 17. Weekly Weighted Average Ancillary Service Prices



IV. Interzonal Congestion Markets

- *Inter-zonal congestion costs totaled $9.9 million, due in large part to wheeling energy from the Southwest to northern California, where day-ahead bilateral prices were higher*

Inter-zonal costs in October totaled $9.9 million. The vast majority of all congestion was on three paths, namely Path 15 (57 percent of total cost), the Palo Verde branch group (23 percent), and the California-Oregon Intertie (COI) (13 percent).

Path 15 was congested in the south-to-north direction for 23 percent of all hours in the Day-Ahead (DA) market at an average congestion price of $21/MW, and 12 percent of all hours in the Hour-Ahead (HA), at an average price of $15/MW. Path 15 experienced almost daily derates between the 4th and the 26th of the month due to line work on the Tracy-Los Banos transmission line. As noted previously, much of this congestion was due to wheeling from the Southwest to arbitrage the wholesale power price premium in northern California.

The Palo Verde branch group was congested for 32 percent of hours in the DA import direction at an average price of $5/MW, and 11 percent of hours in the HA import direction, at an average congestion price of $20/MW. The Palo Verde branch group was derated intermittently throughout the month for maintenance, as well as for upgrades to the Miguel bank, which were completed at the end of October.

COI was congested for 27 percent of all hours in the DA import direction at an average price of $5/MW, and 20 percent of all hours in the HA import direction at an average price of $12/MW. COI was affected by the same transmission line work at Tracy-Los Banos as Path 15, but was congested slightly less often. Tables 5 and 6 detail inter-zonal congestion costs, and congestion prices and frequencies of congestion, by branch group, in October.

Table 5. Inter-Zonal Congestion Costs in October

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
BLYTHE	$29,092	$0	$0	$0	$29,092	$0	$29,092	$0	$29,092	0%
CASCADE	$0	$0	$7	$0	$7	$0	$0	$7	$7	0%
COI	$1,298,943	$0	$29,696	$0	$1,328,639	$0	$1,298,943	$29,696	$1,328,639	13%
ELDORADO	$117,244	$0	$42,754	$0	$159,998	$0	$117,244	$42,754	$159,998	2%
ELVTHRLY	$0	$14	$0	$5	$0	$18	$14	$5	$18	0%
LUGOMKTPC	$26,185	$0	$779	$0	$26,964	$0	$26,185	$779	$26,964	0%
LUGOMONAI	$48,233	$0	$8,984	$0	$57,217	$0	$48,233	$8,984	$57,217	1%
LUGOWSWGI	$7,024	$0	$829	$0	$7,852	$0	$7,024	$829	$7,852	0%
MEAD	$170,665	$0	$9,347	$0	$180,012	$0	$170,665	$9,347	$180,012	2%
NOB	$2	$0	$7	$1	$9	$1	$2	$8	$10	0%
PALOVRDE	$2,233,815	$0	$13,672	$0	$2,247,487	$0	$2,233,815	$13,672	$2,247,487	23%
PATH15	$5,648,600	$0	$26,697	$0	$5,675,296	$0	$5,648,600	$26,697	$5,675,296	57%
PATH26	$0	$196,041	$0	$12,918	$0	$208,958	$196,041	$12,918	$208,958	2%
SUMMIT	$11,459	$0	$12,103	$0	$23,562	$0	$11,459	$12,103	$23,562	0%
Total	$9,591,261	$196,054	$144,875	$12,923	$9,736,137	$208,977	$9,787,316	$157,799	$9,945,114	100%

Table 6. Inter-Zonal Congestion Prices and Frequencies in October

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
	Import	Export	Import	Export	Import	Export	Import	Export
BLYTHE	0	0	$102		1	0	$12	
CASCADE	9	0	$0		3	0	$0	
COI	27	0	$5		20	0	$12	
ELDORADO	12	0	$1		17	0	$5	
LUGOMKTPC	3	0	$4		1	0	$21	
LUGOMONAI	1	0	$13		3	0	$34	
LUGOWSWGI	3	0	$3		0	0	$23	
MEAD	7	0	$3		8	0	$26	
PALOVRDE	32	0	$5		11	0	$20	
PARKER	0	0			1	0	$0	
PATH15	23	0	$21		12	0	$15	
PATH26	0	7		$2	0	2		$13
SUMMIT	13	0	$1		5	0	$9	

V. Firm Transmission Rights Market

FTR Scheduling. FTRs can be used to hedge against high congestion prices and to provide scheduling priority in the day-ahead market. Many of the FTRs are owned by Southern California Edison and municipal utilities. Table 7 shows the extent to which FTRs were scheduled on the various paths connecting to the CAISO control area.

Table 7. FTR Scheduling Statistics - October 2004*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE	168	106	167	167	63%
IMP	ELDORADO	536	513	536	536	96%
IMP	IID-SCE	600	453	466	446	76%
IMP	LUGOMKTPC	247	26	41	25	10%
IMP	MEAD	624	21	61	30	3%
IMP	PALOVRDE	1021	386	475	450	38%
IMP	SILVERPK	10	9	10	10	90%
IMP	VICTVL	921	19	50	50	2%
EXP	CFE	100	10	30	30	10%
EXP	LUGOMKTPC	247	3	5	5	1%
EXP	PATH26	1141	411	885	515	36%

*only those paths on which 1% or more of FTRs were attached are listed.
** The FTRs on these paths were awarded to municipal utilities that converted their lines under the ISO operation and there were not released in the primary auction.

FTR Revenue per Megawatt. FTR revenues in October decreased for almost all branch groups. The most congested branch groups, Palo Verde and Path 15, accounted for most of the revenues. Table 8 shows the FTR revenue per MW for each branch group in 2004.

Table 8. FTR Revenue Per MW ($/MW) - October 2004

Direction	Branch Group	Net $/MW FTR Rev Apr	May	Jun	Jul	Aug	Sep	Oct	Cumm Net $/MW FTRREV	Pro Rated NET $/MW FTRREV	FTR Auction Price
IMPORT	BLYTHE	2,791	5,540	433	0	7	736	332	9,838	16,865	8,759
IMPORT	COI	199	1,481	4,853	822	521	2,554	1,872	12,302	21,088	26,964
IMPORT	ELDORADO	0	408	10	0	0	400	136	954	1,635	45,169
IMPORT	LUGOIPPDC	3	0	0	0	0	0	0	3	5	63,374
IMPORT	LUGOMKTPC	0	0	0	0	5	160	546	711	1,218	81,579
IMPORT	LUGOTMONA	0	0	192	0	0	8	0	200	343	99,784
IMPORT	LUGOWSTWG	0	1	0	0	17	679	0	697	1,194	117,989
IMPORT	MEAD	1,223	1,168	634	464	238	930	1,114	5,771	4,947	136,194
IMPORT	NOB	336	1,816	19,123	3,725	1,013	1,272	0	27,285	23,387	154,399
IMPORT	PALOVRDE	2,074	15,146	2,457	9,505	8,173	16,719	8,805	62,879	53,896	172,604
IMPORT	PARKER	115	15	0	5	6	178	0	319	547	190,809
S-N	PATH15	0	20	20	5	287	597	3,105	4,033	6,914	209,014
IMPORT	SILVERPK	0	0	0	0	5	0	0	5	8	227,219
EXPORT	NOB	0	0	0	910	522	0	0	1,433	1,228	245,424
N-S	PATH26	427	27	357	573	139	22	226	1,771	3,037	263,629
EXPORT	SILVERPK	0	0	0	0	480	0	0	480	823	281,834
EXPORT	SUMMIT	0	0	608	0	39	0	0	647	1,109	300,039

* FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and there were not released in the primary auction.

VI. Issues Under Review

The CAISO implemented locational procurement of ancillary services in early August of this year to ensure that reserves would be deliverable if awarded in the A/S markets. Ancillary service market performance while implementing locational procurement remains a current focus of DMA. We have been assessing market participant bidding behavior encompassing the change to locational procurement and have provided analysis to FERC that displays marked bidding behavior changes of certain market participants corresponding with the move to locational procurement. Figure 18 shows the maximum and average daily bid levels for one market participant that was able to become a price setter during times of A/S market splits. DMA will continue to expand its analysis of this type of behavior and report to the Federal Energy Regulatory Commission accordingly.

Figure 18. Daily Average and Maximum Day Ahead Non-Spin Bid Price Histories