CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: June 18, 2004

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

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

Executive Summary

A heat wave in Southern California that began in April peaked on May 3. Temperatures exceeded 100 degrees, causing the system-wide peak load to reach 40,484 megawatts, a level typically not reached until midsummer. While new generation has been sited in California, Mexico, and the Southwest, there is not sufficient transmission available to transport that generation to the load, especially load in the greater Los Angeles area. Due to these conditions the South of Lugo transmission line overloaded on the afternoon of May 3, between 3:00 and 6:00 p.m., requiring ISO operators to redispatch the system in real time to alleviate the congestion. As a result real-time incremental dispatch volume reached 1,800 MW, and the price of incremental balancing energy spiked to $185 per megawatt-hour (MWh).

The management of real-time intrazonal congestion continues to be a problem. Under the current market structure, the ISO must accept schedules in excess of transmission capacity at the Lugo, Sylmar and Miguel Substations and in violation of technical constraints, and then must manage the resultant congestion in real time. That said, intrazonal congestion redispatch costs decreased to $3.7 million in May from $5.7 million in April due largely to a decline in decremental dispatches at Miguel. However, the decline was the result of maintenance work on the Southwest Power Link (SWPL) that brings power in from the Southwest through the Miguel substation, i.e., because SWPL was down, power could not even flow through to Miguel

With respect to system-wide conditions, an early warm spring has depleted snow pack levels in the Sierra Nevada and the Pacific Northwest to less than 50 percent of average. The seasonal hydro runoff began to wane by late April. However, the California Energy Commission reports that enough water has been stored in reservoirs since 2003 to sustain hydro energy production at approximately 85 percent of average.[1]

Ancillary Service (A/S) market prices increased 16.3 percent from April to May, due primarily to higher prices in the regulation markets. Supply during peak periods increased as above-average

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[1] See "California Hydroelectric Energy Outlook," California Energy Commission, June 2004.

energy prices attracted generation that was also able to provide A/S as a by-product. This resulted in a 19 percent decrease in the frequency of bid insufficiency between April and May.

Day ahead interzonal congestion costs totaled $5.6 million in May, a significant increase from the $1.6 million level seen in April. Congestion on the Palo Verde Intertie accounted for more than half of the total, as energy from the Southwest flowed to serve the high loads in Southern California.

I. Fundamental Market Conditions Affecting Electricity Demand and Supply

Loads. A prolonged intermittent heat wave in California and other parts of the West that began in early March lasted through mid-May. On Sunday May 2, unusually high temperatures caused the CAISO system-wide load to reach 34,265 MW, an unusually high weekend load for this time of year. Warm temperatures continued into the workweek, reaching 104 degrees (in Fullerton) on Monday, May 3. This caused load to peak at 40,476 MW,[2] a level not typically seen until July.[3] The unseasonable heat kept loads high through the middle of the month, and then subsided. In the second half of the month, temperatures were considerably lower and loads fell to levels below those in May 2003. On average, loads were 7.3 percent higher in May 2004 than in May 2003. Figure 1 compares May 2004 loads to May 2003 loads. Table 1 shows peak and average loads for May 2004 and May 2003.

Figure 1. ISO Actual Hourly Loads: May 2004 v. May 2003

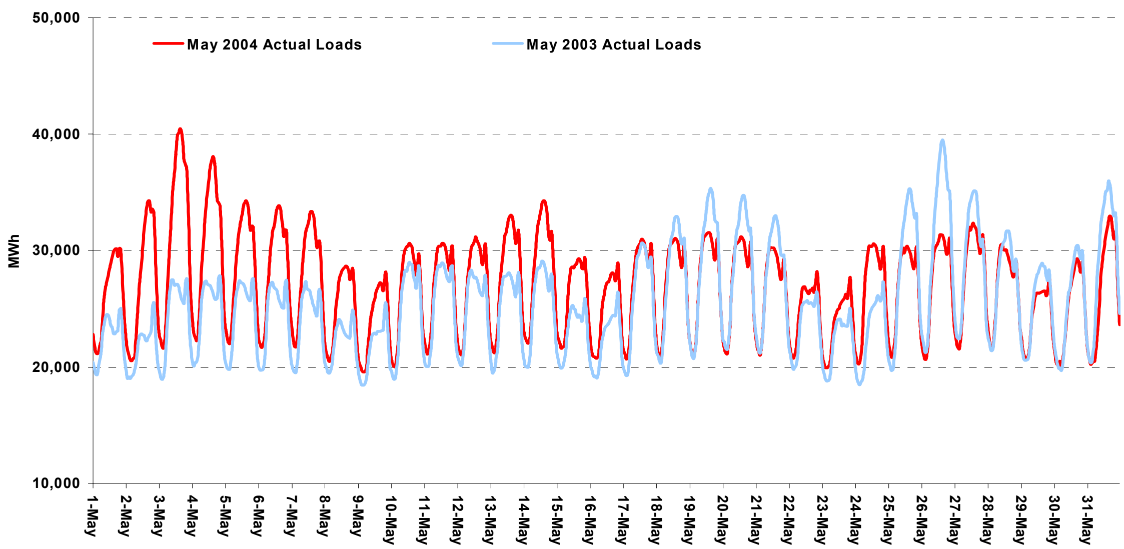

Table 1. Peak and Average Load in May 2003 and May 2004

	2003	2004	Pct. Chg.
Peak Load (MW)	39,502	40,476	2.5%
Avg. Energy (MW)	25,191	27,018	7.3%

[2] All actual loads noted in 2004 are hourly averages. Actual instantaneous peak on May 3 was 40,586 MW.
[3] A spike that occurred on May 28, 2003, was also unseasonably high, peaking at 39,502 MW.

Load Trends. Since July 2003, the ISO has observed a systematic annual growth in load of approximately 4 percent. This is likely due, in part, to weather, particularly during the recent heat wave. But it is also due to economic growth, evidenced by similar increases in monthly average loads, monthly averages of daily peak loads, and monthly averages of daily troughs (minimum loads). The California Energy Commission's (CEC) analysis of recent loads suggest, that after adjusting for weather, demand growth for the last three months has been on average 3.5 percent higher than the 2.6 percent the CEC assumed in its previous forecast.[4] Table 2 shows average loads, average daily peak loads, and monthly peak loads, for the twelve months ending May 2004.[5]

Table 2. Load Growth Rates Compared to Same Months in the Prior Year

	Avg. Hrly. Load	Avg. Daily Peak	Monthly Peak
June-03	-1.6%	-1.1%	3.6%
July-03	4.3%	6.9%	0.5%
August-03	5.4%	8.5%	4.3%
September-03	2.2%	3.3%	0.3%
October-03	5.4%	7.0%	3.7%
November-03	-0.2%	1.0%	0.2%
December-03	2.8%	3.1%	2.7%
January-04	4.3%	3.1%	3.2%
February-04	4.5%	3.9%	4.5%
March-04	4.4%	5.1%	4.5%
April-04	7.1%	8.3%	31.1%
May-04	7.3%	7.7%	2.5%

Note: Load figures are based on unadjusted CAISO control area loads.

Hydroelectric Production. The heat wave continued to melt the Sierra and Pacific Northwest snow packs. They are now below 50 percent of average for this time of year. Since late April, California hydroelectric production has been significantly lower than last year and now appears to be declining further. In comparison, the 2003 season was characterized by heavy precipitation in April, resulting in a robust, late runoff that strengthened in May of that year. Figure 2 compares hydroelectric production in the 2003-04 and 2002-03 hydroelectric seasons.

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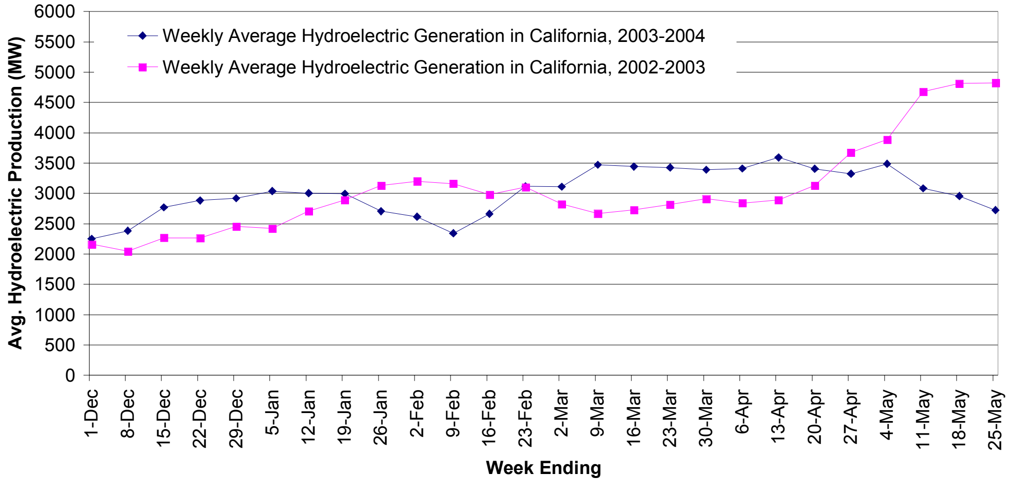
[4] See "California's Summer 2004 Electricity Supply and Demand Outlook," Final Staff Report, June 2004.

[5] A portion of this increase, perhaps 1 percent of the 4 percent average, may be due to increased load visibility associated with improvements in load monitoring tools. This is currently under review by the CAISO.

Figure 2. Approximate Weekly Average Hydroelectric Production in the ISO Control Area: 2003-04 and 2002-03 Hydro Seasons

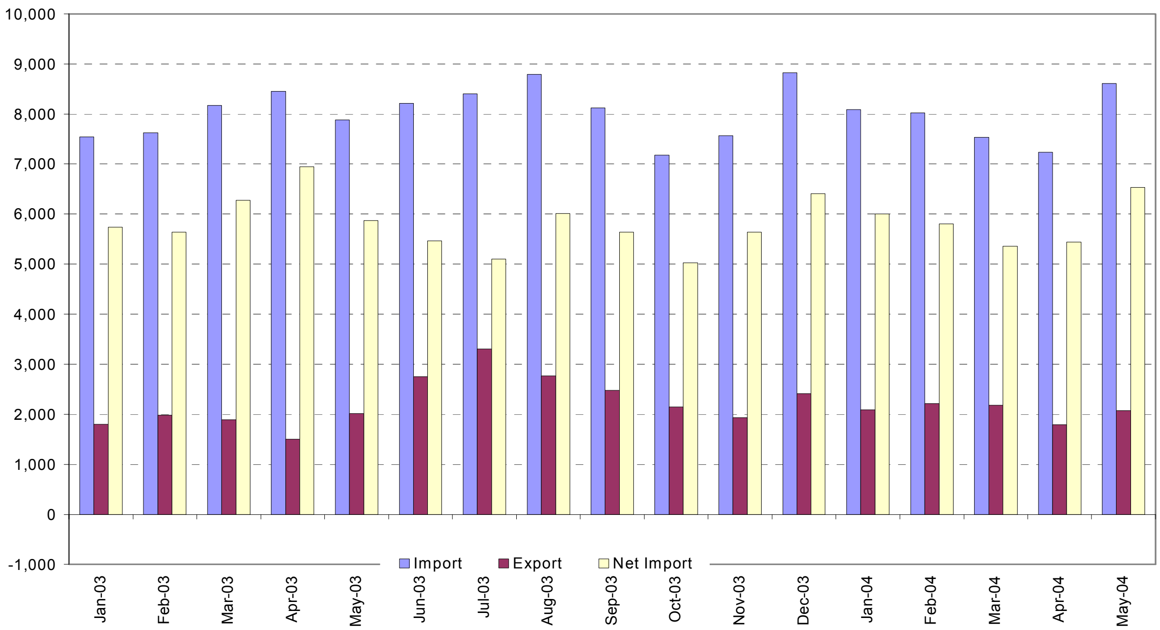


Despite low snow packs, a recent report published by the CEC indicates that the outlook for this year for California's hydro generation is fair to good. This is due to the fact that water stored in reservoirs since 2003 has lasted into 2004, and is likely to sustain hydro energy production at 85 percent of average levels.[6] The CEC estimates that the summer peak dependable capacity for hydro generation during a dry year is only 500 MW lower than average water conditions. The CEC estimates that total in-state hydro capacity will be at 95 percent of average through late summer, as it takes two consecutive dry years to significantly reduce hydro capacity for the summer months of July, August, and September. Water conditions elsewhere in the West are also below average, but are not considered critically dry. In the Northwest, total Columbia River runoff measured at The Dalles is likely to be just 75 percent of average through September. The CEC report states that capacity will be near average in the Pacific Northwest, providing surplus energy that will help to meet the peak load hours this summer in California. However, the total volume of Northwestern energy produced during the year will be below that of 2003. The Pacific Northwest has proportionately much less flexibility in retaining water behind dams across years.

Imports and Exports. Scheduled net imports were 11 percent higher in May 2004 than in May 2003 and 20 percent higher than in April 2004, due to an increase in imports from the Southwest. This shift was due largely to increased generation in the Southwest and modest load in that region as a result of mild temperatures. This increase was offset by lower imports from the Northwest, due, in part, to weather and transmission constraints associated with deratings of the California-Oregon Intertie (COI, also known as the Pacific AC Intertie) and the North-of-Oregon Border Intertie (also known as the Pacific DC Intertie, or PDCI).

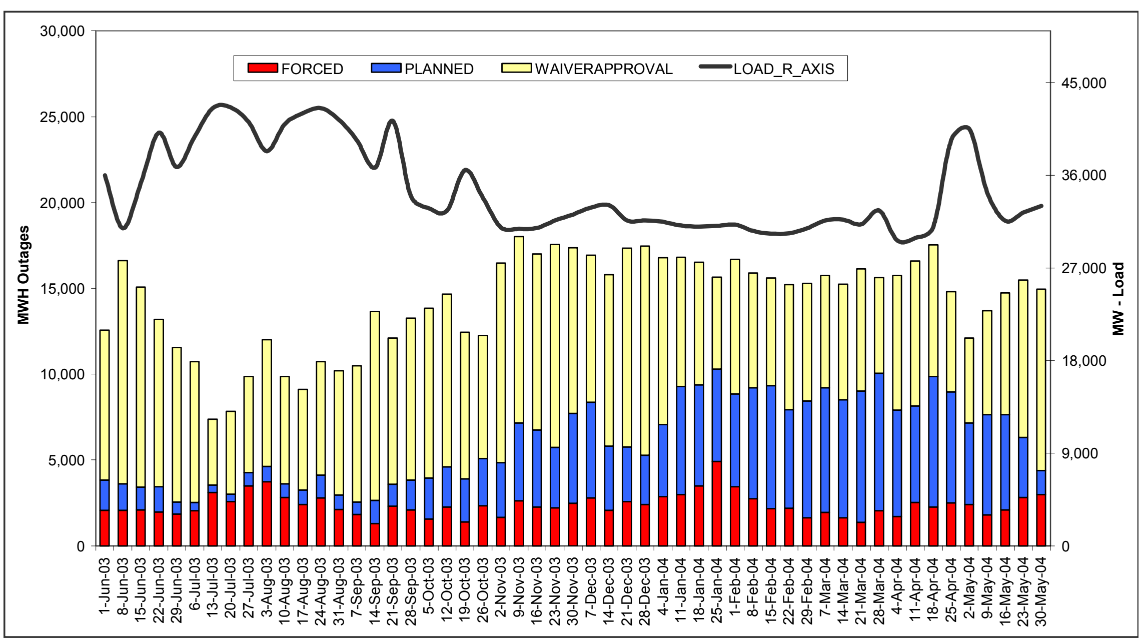
[6] See "California Hydroelectric Energy Outlook," Final Staff Report, June 2004.

Figure 3. Monthly Average Scheduled Imports, Exports, and Net Imports January 2003 through May 2004



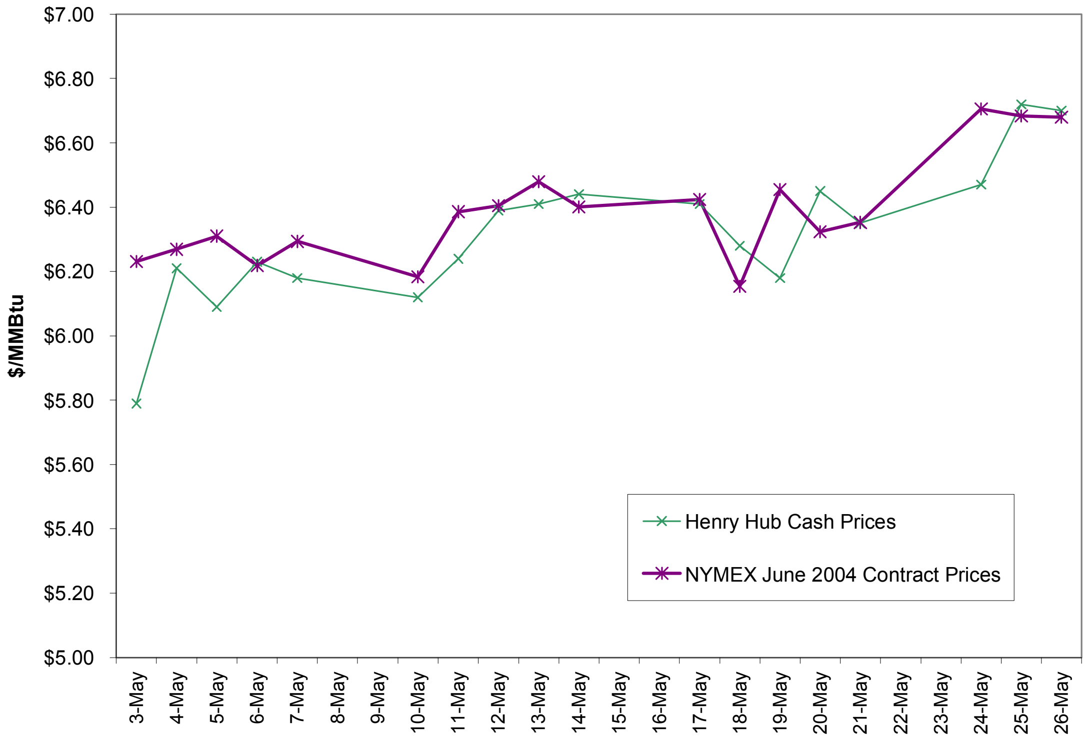
Outages. The level of forced outages in May increased slightly and there were lower levels of planned outages, as the traditional maintenance season ahead of the summer peaks came to an end. Diablo Canyon Unit 1 was out for the entire month for refueling and returned to service on June 13th.

Figure 4. Weekly Average Outage Rates and Peak Load, June 2003 through May 2004



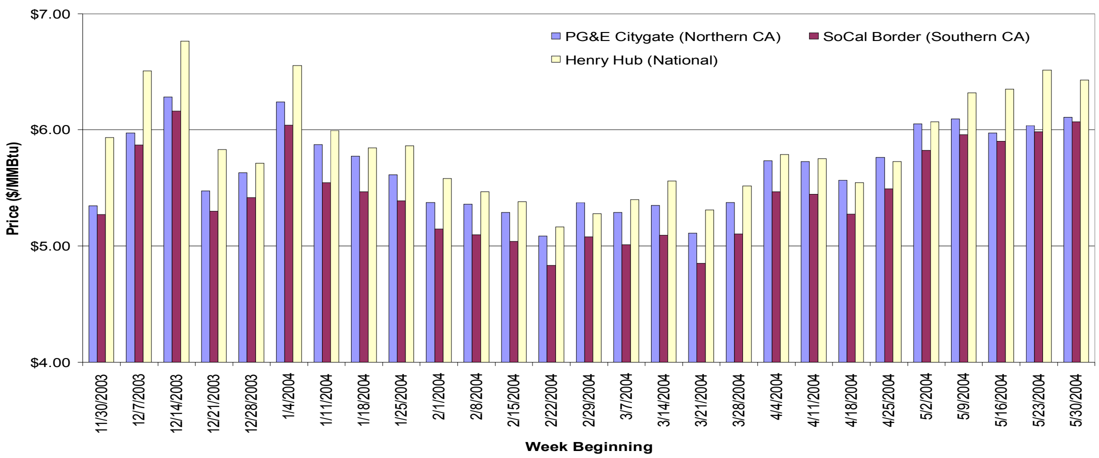
Natural Gas Prices. Expectations of higher NYMEX natural gas futures prices, driven by increasing average peak temperatures and higher cooling demand in May resulted in average prices for natural gas exceeding $6/MMBtu. High correlation between NYMEX June 2004 natural gas contract prices and Henry Hub cash prices (r=0.74) lends support to this view. Correlation was lower for prices at western points, but still positive. Figure 5 compares NYMEX June 2004 Natural Gas Futures Contract Prices to Henry Hub Cash Natural Gas Prices.

Figure 5. NYMEX June 2004 Natural Gas Futures vs. Henry Hub Cash Prices, May 2004



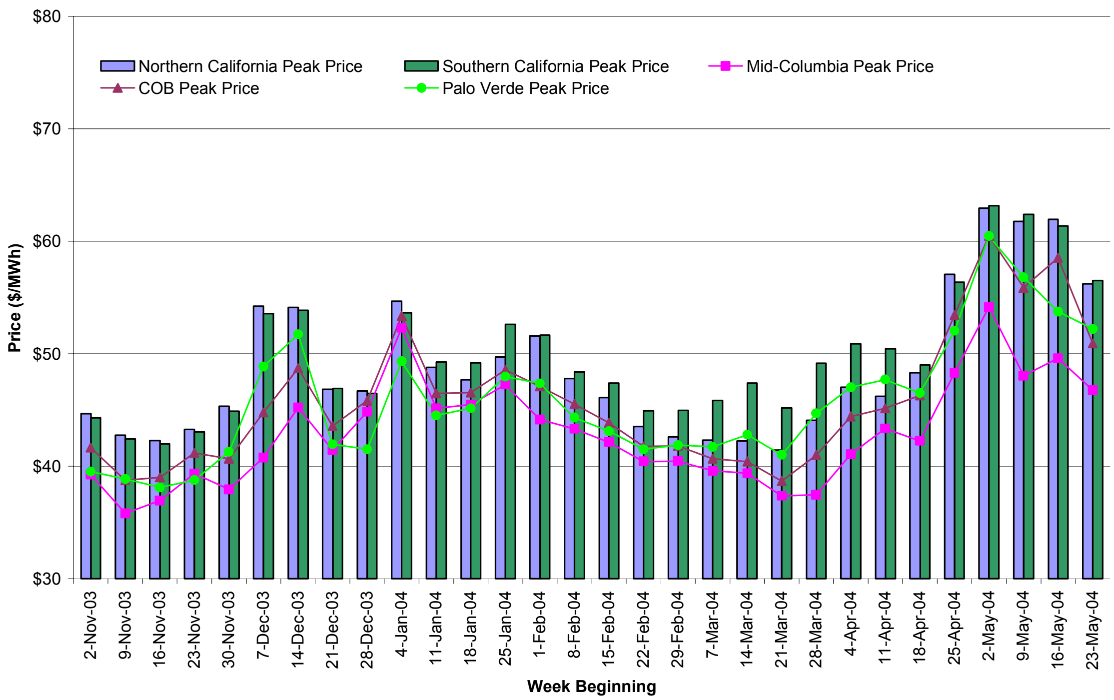
High line pack and, in particular, an Operational Flow Order (OFO) issued on May 14, kept California natural gas prices between $0.10 and $0.40/MMBtu lower than those at Henry Hub. Prices were highest in the last full week of May, with high-line pack OFOs in California lifted and increasing temperatures driving prices upward. Average daily gas prices for May were $6.30/MMBtu at Henry Hub, $5.63/MMBtu at Malin, $6.04/MMBtu at PG&E Citygate, and $5.91/MMBtu at Southern California Border Average. Average bid week prices for June were $6.32, $5.88, and $6.33/MMBtu for SoCal Gas, Malin, and PG&E Citygate, respectively, up 7, 12, and 9 percent from May bid week prices. Figure 6 shows weekly average gas prices at regional delivery points through May.

Figure 6. Weekly Average Natural Gas Price, December 2003 through May 2004



Day-Ahead Bilateral Electricity Prices. Day-ahead electricity prices were highest during the first week of May following the high temperatures the preceding week in April. They gradually descended through May. California prices were still above $60/MWh for the first three weeks of May, likely owing to natural gas prices exceeding $6/MMBtu. On May 12, high temperatures, particularly in southern California, caused northern and southern California prices to diverge by $4/MWh, although that divergence was temporary. Prices at the end of May were around $53/MWh on May 29, and $31/MWh during the Memorial Day holiday. Average May peak weekday regional day-ahead electricity prices were $56.22/MWh at the California-Oregon Border, $49.50/MWh at Mid-Columbia, $55.42/MWh at Palo Verde, $60.36/MWh in Northern California, and $60.48/MWh in Southern California.

Figure 7. Weekly Average Day-Ahead Bilateral Electricity Prices through May 2004



II. Real-Time Market Performance

- ***May 3 SP15 INC price reached $185/MWh***
- ***Intrazonal Congestion continues to be a problem at Lugo, Sylmar, and Miguel Substations, and due to SCIT***

Under-scheduling of load, where actual load is in excess of forward scheduled load, has increased over the past few months to an average of 3.4 percent in May. However, significant amounts of unscheduled energy and energy taken out-of-sequence to mitigate intrazonal congestion in Southern California have continued the decremental bias for imbalance energy. Decremental energy dispatches were 145 percent greater than incremental dispatch volumes in May. Average imbalance energy prices remained stable at $75.27/MWh and $22.77/MWh for incremental and decremental energy respectively, similar to the levels seen in the past few months. Table 3 shows the total real-time imbalance energy market dispatched energy and average prices in May, as well as average loads and percent under-scheduling. Figure 8 shows the monthly average real-time prices for balancing energy, and volumes for energy procured at market and either out of market or out of sequence. Figure 9 shows the increasing trend of average hourly under-scheduled load for the past three months, in most hours of the day.

Table 3. Total Energy and Average Real-Time Energy Prices, Volumes, and Under-Scheduling in May

	Avg. BEEP Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 75.27	$ 28.26	29,322 MW
	110 GWh	339 GWh	2.9%
Off-Peak	$ 61.13	$ 16.26	22,411 MW
	69 GWh	71 GWh	4.7%
All Hours	$ 69.83	$ 26.17	27,018 MW
	179 GWh	410 GWh	3.4%

Figure 8. Daily Average Real-Time Prices and Volumes in May

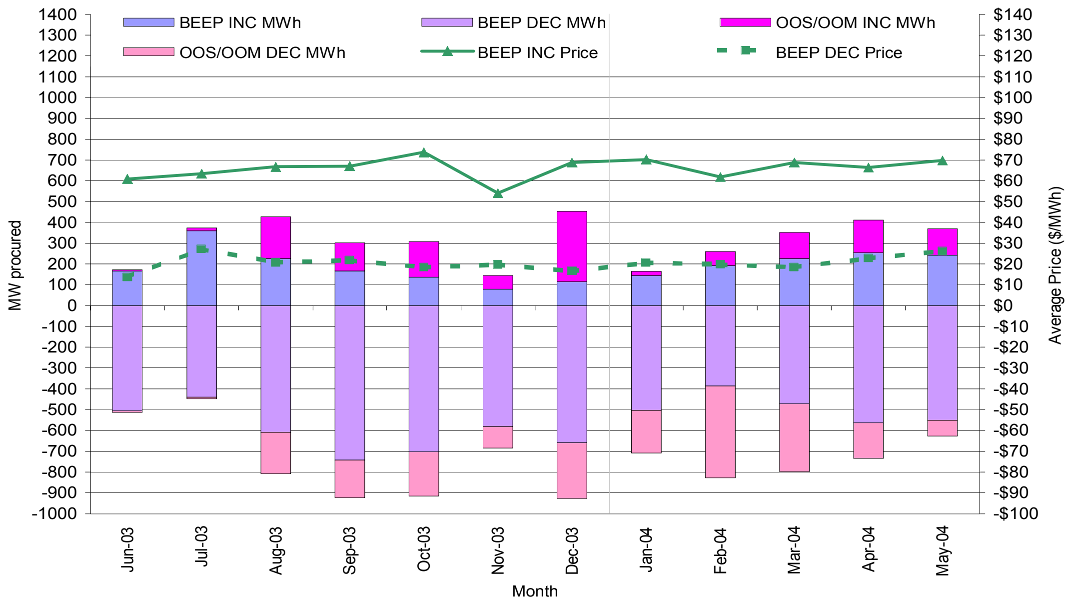
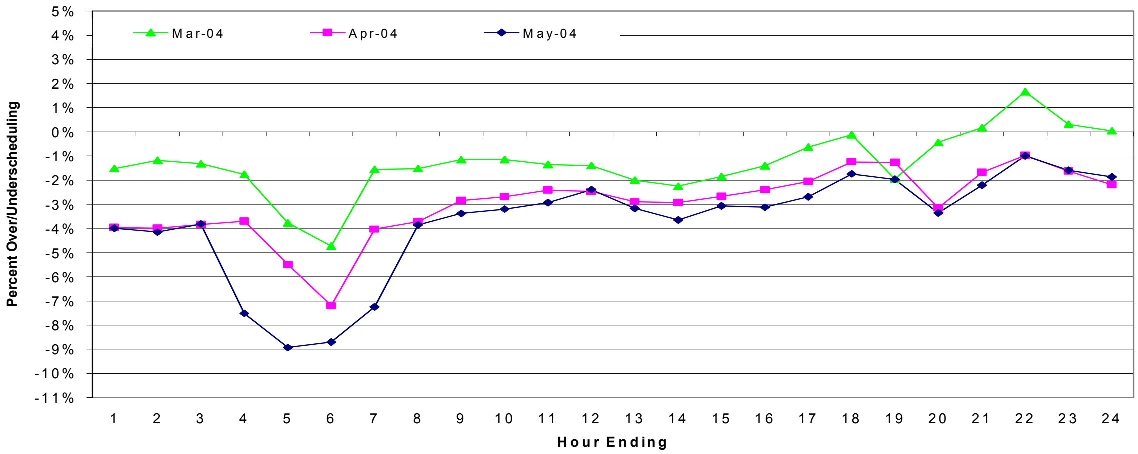


Figure 9. Average Hourly Profile of Underscheduling/Overscheduling, March - May 2004



Price Spikes. On May 3, SP15 hourly average load spiked to 23,384 MW, the highest level since the 2003 zonal peak on September 5. This resulted in the CAISO declaring a transmission emergency in SP15 to mitigate flows on the transmission system south of the Lugo substation between 2:20 and 6:42 p.m. During this period the system-wide hourly average load peaked at 40,484 MW. Technical problems with the CAISO's computerized dispatching system necessitated that operators dispatch units manually for several hours, until approximately 3:30 p.m. The real-time INC price within SP15 between 3:00 and 6:00 p.m. was $185/MWh, set by a combustion turbine unit known to have high operating costs. The CAISO instructed generators within the Los Angeles load pocket to increment energy production by approximately 1,800 MW during this time, and was able to avoid procuring energy out of market for a system emergency condition. At 6:00 p.m., the price retreated to $84/MWh. No unit bid in a manner that would have failed the AMP Conduct Test in these hours. This spike accounted for approximately $257,000 in markup, or between 22 and 27 percent of the monthly total.[7]

On May 5, the SP15 incremental energy price was $125.99/MWh between 4:50 and 5:00 p.m., following a trip of a large steam unit due to a burner problem. The total dispatch during this one interval was 60 MWh, or an average of 360 MW.

On May 6, the SP15 decremental energy price was -$5/MWh between 4:00 and 4:20 a.m., as the decremental bid stack for SP15 was depleted during a low-load period. Approximately -45 MWh were dispatched over the two intervals (average -135 MW), and the price-setting unit was awarded approximately -2 MWh. This anomaly warranted some attention by the Department of Market Analysis (DMA), because the price-setting unit had bid a negative DEC price when it was increasing its schedule. This is unusual because a negative DEC price in this case was a demand for payment to remain at a lower output at which the unit had already contracted to operate voluntarily. After some further monitoring and investigation and a conversation with the scheduling

[7] This was the markup for hours ending 17:00 and 18:00 (between 4:00 and 6:00 p.m.). Because of the manual dispatch through hour ending 16:00 (4:00 p.m.), the quantity of imbalance energy actually instructed, the resultant price-to-cost markup for this period, and AMP analysis were not available at the time of writing.

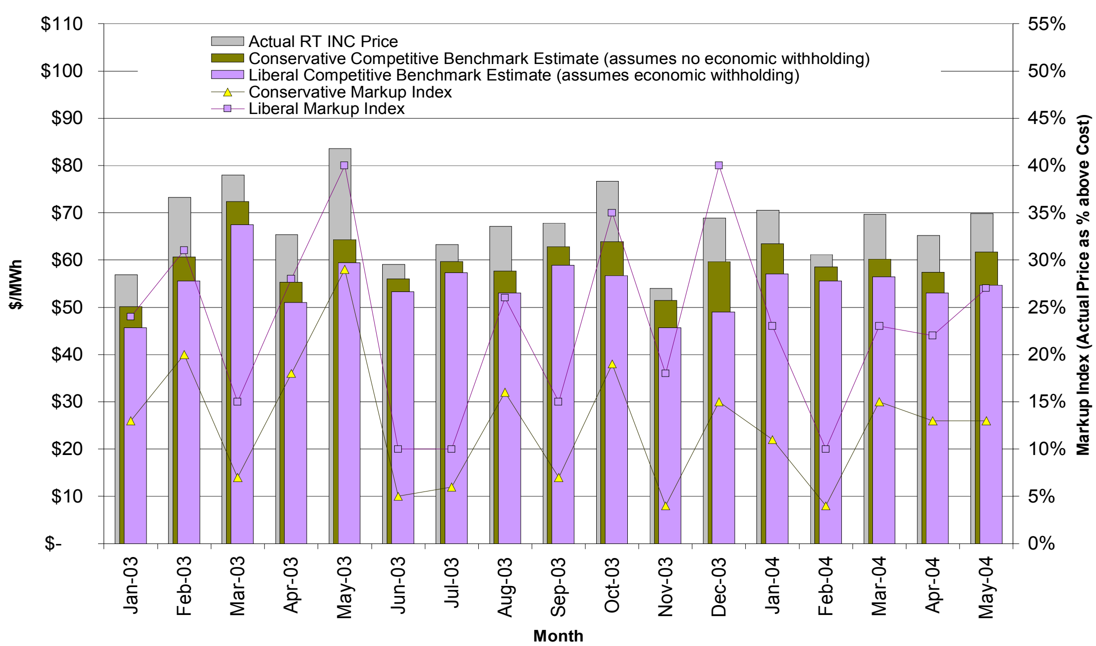
coordinator, DMA noted that the brief nature and minimal market impact of this event warranted continued monitoring but did not require further action.

On May 14, the PDCI was derated, causing the CAISO to dispatch the entire bid stack between 3:50 and 4:10 p.m. The price was set by a hydro resource at $157.70/MWh, one cent below the threshold at which the unit would have failed the Conduct Test, had the hour-ahead predicted price screen exceeded $91.87/MWh.

Real-time Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. This index compares the actual incremental market-clearing price to a competitive benchmark price. As discussed in the Market Analysis Report dated February 19, 2004, the Department of Market Analysis now reports two indices of markup to present a range of the competitiveness of the real-time market. One index assumes no economic withholding; that is, it assumes that high-priced bids in excess of the market clearing price reflect high costs. This produces a higher estimate of the competitive price and results in a conservative (lower) estimate of potential markup. The other index accounts for economic withholding by substituting estimated marginal cost-based bids for dispatched bids. This produces a lower estimate of the competitive price and a more liberal (higher) estimate of potential markup.

The price-to-cost markup in incremental balancing energy was up slightly in May to the range of 13 to 27 percent for the two indices, compared to the range of 13 to 22 percent in April. The eight highest markup hours accounted for over 25 percent of the monthly total markup. Figure 10 compares monthly average prices to the two competitive benchmarks, and shows the two markup indices, through May.

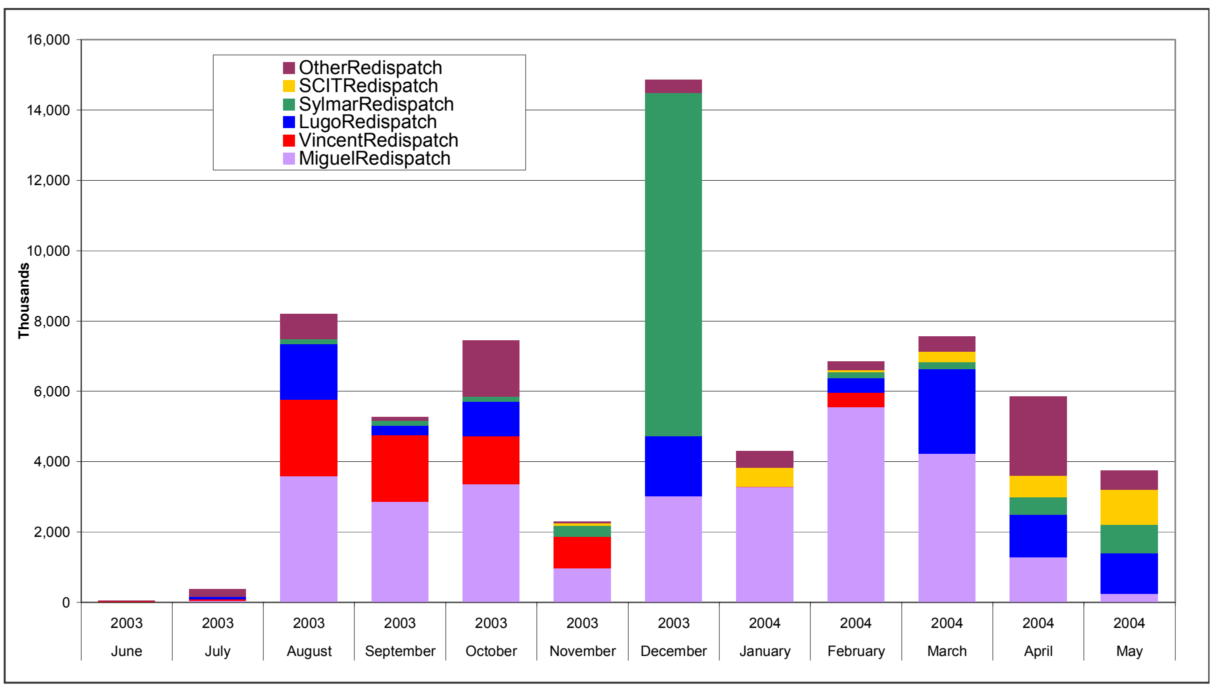
Figure 10. Range of Price-to-Cost Markup in Real-Time Incremental Energy through April



Real-Time Intrazonal Congestion Management. Intrazonal (within zone) congestion decreased between April and May, with significantly smaller volumes of decremental out-of-sequence dispatch energy and slightly less incremental out-of-sequence (OOS) energy. The primary reason for incremental OOS dispatches was constraints on transmission paths into the Los Angeles basin. These constraints occurred at the Lugo and Sylmar substations, used to bring power into the Los Angeles region from the Northwest and Southwest. Transmission was also constrained pursuant to the Southern California Import Transmission nomogram (SCIT), which limits the amount of power that can be simultaneously imported into Southern California. Together, these constraints comprised approximately 88 percent of all incremental out-of-sequence (OOS) re-dispatch costs.

Miguel redispatch costs, which accounted for the majority of the intrazonal congestion costs in February and March were due to the outage of SONGS Unit #2. These costs receded in April when the unit returned to service. They were further reduced in May as a result of maintenance work on the Southwest Power Link (SWPL), which feeds Southwestern power into the Miguel substation. The SWPL line incurred less power flows beginning in early May as capacitor banks on the line were removed from service for a maintenance upgrade which are not expected back in service until the end of November. Figure 11 below shows the intrazonal congestion redispatch costs by month and location.

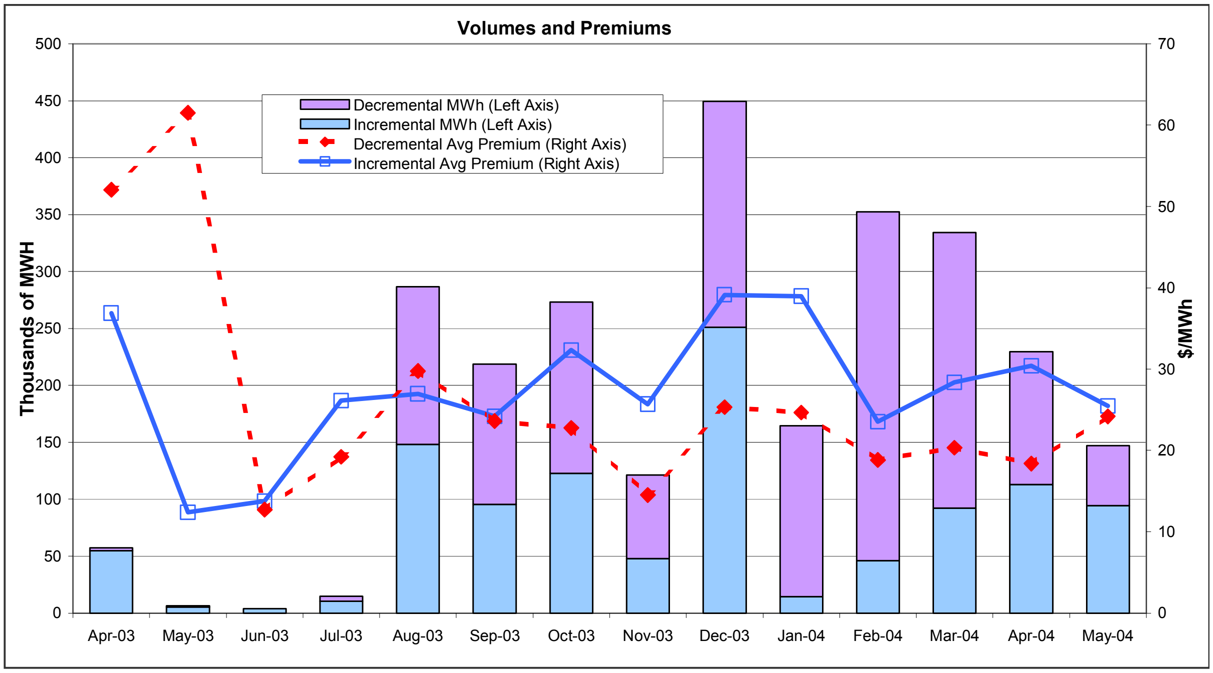
Figure 11. Monthly Total Congestion Costs by Location and/or Cause
Less Congestion at Miguel in May due to SWPL Line Maintenance



The main causes for decremental OOS dispatches were SCIT and congestion at the Lugo and Miguel substations. Congestion at Miguel was dramatically lower in May, continuing a declining trend since February 2004 due to the SONGS outage and line maintenance as discussed above.

Overall May intrazonal congestion OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $3.7 million compared to $5.7 million in April. Total congestion OOS dispatch volume was 146 GWh (INC plus DEC), and the average re-dispatch premium was $25.01/MWh. Overall, Lugo was the most costly constraint (approximately 34 percent of total re-dispatch costs), followed by SCIT (27 percent), Sylmar (22 percent and Miguel (7 percent). The following chart graphs these amounts for recent months.[8]

Figure 12. Intrazonal Congestion Volume and Average Re-dispatch Premium

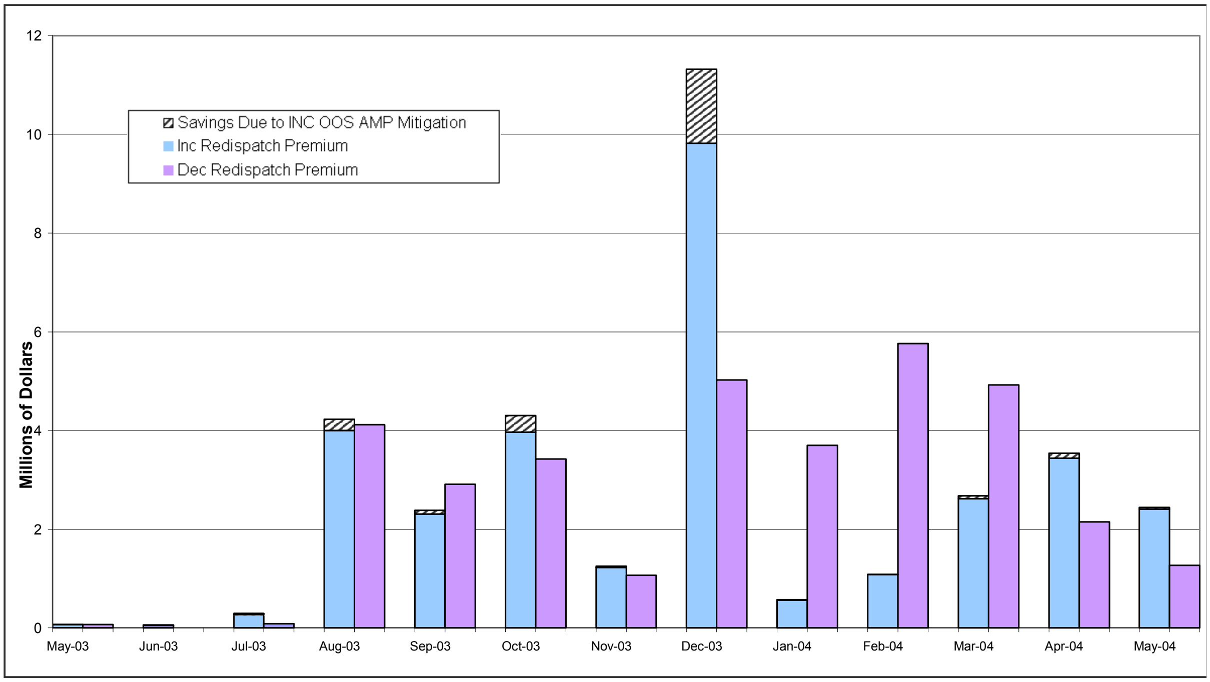


Incremental Congestion Dispatches. CAISO operators dispatched 94 GWh of incremental energy in May to mitigate intrazonal congestion. The average price paid was $68.48/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $2.4 million or $25.48/MWh. The key points of constraint were the Lugo and Sylmar Substations (accounting for approximately 38 and 34 percent of intrazonal congestion costs, respectively), and the SCIT nomogram (16 percent).

All incremental OOS dispatches are subject to mitigation. Figure 13 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 Figure 13 below, very little bid mitigation has taken place due to the large thresholds in AMP for local market power. Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $36,329, or 1.5% of the total re-dispatch premiums in May.

[8] Congestion net cost or re-dispatch 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.

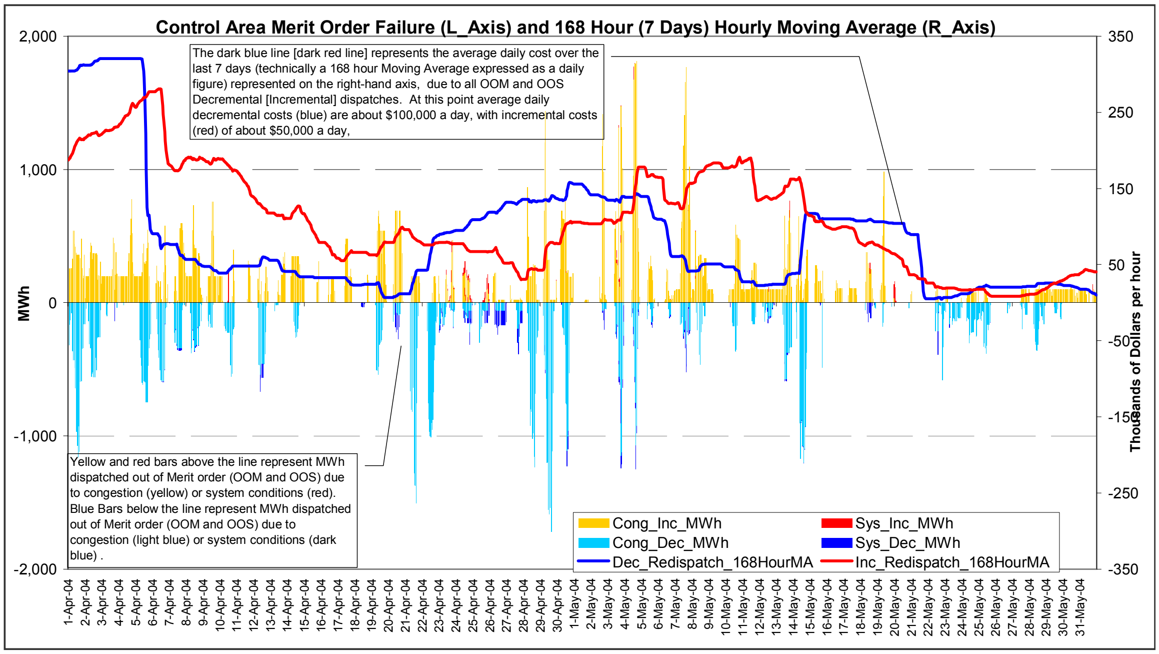
Figure 13. Intrazonal Re-dispatch Premiums and INC OOS Mitigation Savings



Decremental OOS Dispatches. A total of 52 GWh of decremental energy was dispatched out of sequence in May. This energy was settled in accordance with the provisions of the FERC-approved Amendment 50 mitigation measures. The approximate re-dispatch premium in excess of the market clearing price was $1.2 million, or $24.17 MWh. Congestion was a result of the constraints of the SCIT Nomogram (accounting for 49 percent of decremental congestion costs), and the need to manage congestion at the Lugo and Miguel substations (25 and 19 percent of costs, respectively). The following chart shows monthly total congestion costs by the location and/or reason for congestion.

Figure 14 below shows the energy dispatched (bar graph on the left axis) and the seven-day hourly moving average for the intrazonal congestion re-dispatch costs. During May, neither incremental nor decremental re-dispatch costs exceeded $10,000 per hour, and activity declined in the latter part of the month. The vast majority of the dispatches were due to congestion (labeled Cong_Inc_MWh and Cong_Dec_MWh), with incidental dispatches due to grid conditions, typically over-generation, voltage support or something similar (labeled Sys_Inc_MWh, and Sys_Dec_MWh).

Figure 14. Control Area Out-of-Sequence Dispatch Volumes and Costs, April - May 2004



III. Ancillary Services Markets

- ***Overall increase both in supply (5.1 percent) and demand (4.7 percent) in the A/S markets.***
- ***Overall increase in A/S market prices (16.3 percent).***
- ***Overall decrease in bid insufficiency (19 percent). Bid insufficiency shifted from spinning reserves to regulation up and non-spinning reserves***.

Market Prices. Market prices increased in the ancillary services markets from April to May 2004. Overall demand decreased by 4.7 percent in May, while overall supply increased by 5.1 percent. Prices in the regulation up (RU), regulation down (RD) and spinning reserve (SP) markets increased, while non-spinning reserve (NS) prices declined.

Table 4. Average Ancillary Service Requirements and Prices

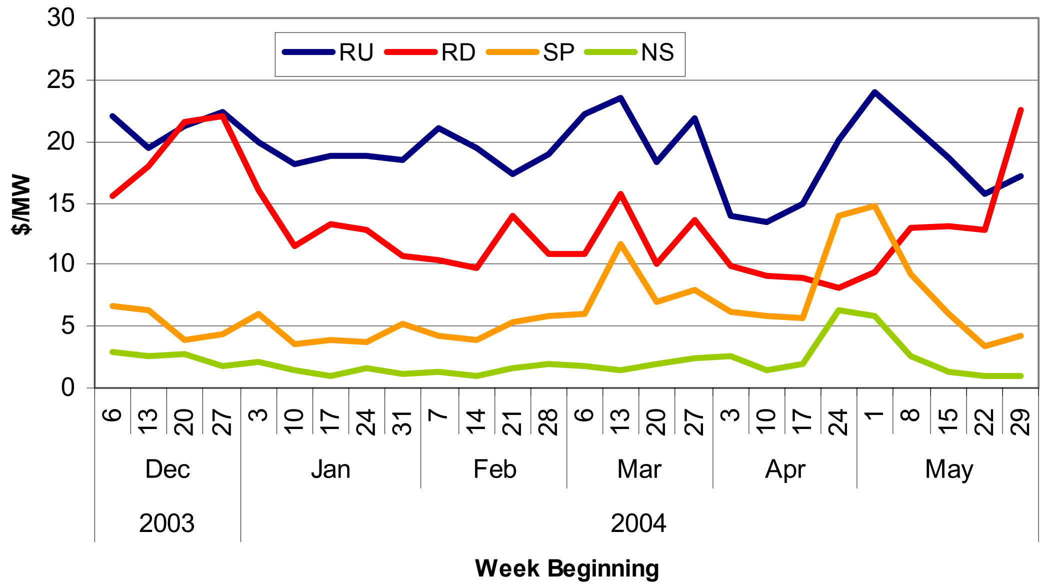
	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Apr 04	363	405	722	699	$ 15.68	$ 9.05	$ 7.89	$ 3.00
May 04	373	402	773	744	$ 19.72	$ 13.09	$ 8.16	$ 2.64

The first week of May was the highest priced in the upward reserve markets (RU, SP, NS). The high-priced days occurred during the week of the transmission emergency of May 3, 2004. High prices in upward reserves were observed on May 3-5, 2004. Day-ahead prices in RU peaked at $69.31/MW during hour 11 on May 4, 2004. Day-ahead prices in SP peaked at $74.31/MW during hours 14-16 on May 4, 2004. Day-ahead prices in NS peaked at $82/MW during hours 14-17 on

May 3, 2004. New resources entered the market to supply the necessary reserves during this period.

The impact of these pricing events is evident when looking at weekly average prices in the ancillary services markets. The week beginning May 1 saw the highest weekly prices in the month of May in RU, SP and NS. Prices in the regulation down (RD) markets increased from their first week lows.

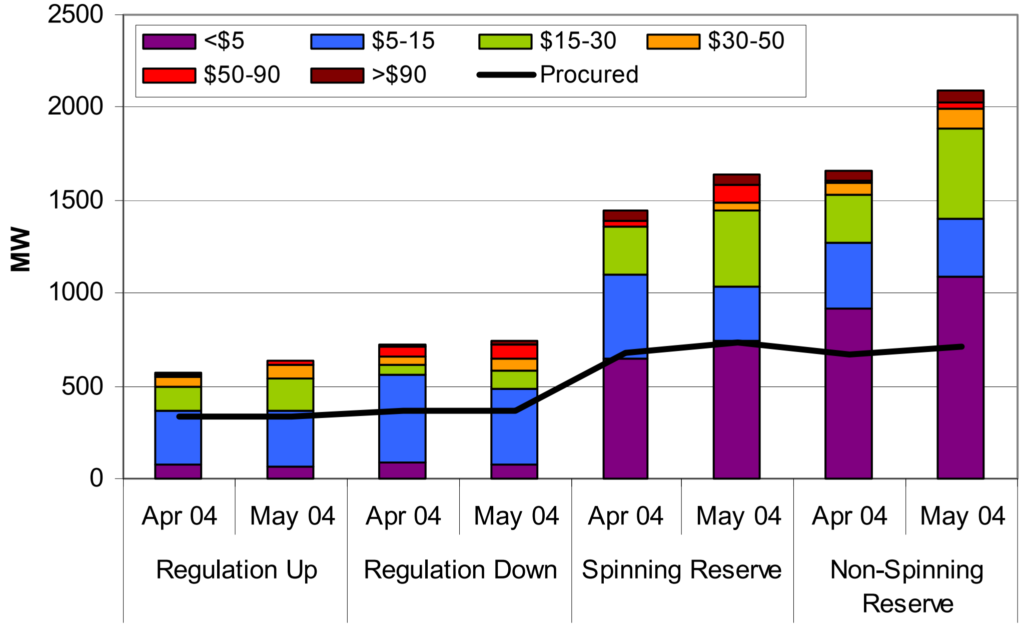
Figure 15. Weekly Weighted Average A/S Prices through Apr-04



Ancillary Service Market Supply. Market supply was characterized by a decrease in the frequency of bid insufficiency for the second consecutive month. Supply during peak periods increased to supply the higher demand for energy due to increasingly warm weather. When the number of resources providing energy increased, the reserves available on peak also increased. Increasing peak demand offset a portion of the increase in supply.

Figure 16 shows the impact of the overall supply composition on ancillary service prices. Bid composition for the RU and RD markets had slightly higher prices than March. The SP markets were skewed toward slightly higher prices, especially given the increase in demand. The NS markets had lower prices. The market results in the SP and NS markets reflect changes in bid composition. The market results in RU and RD – a 26 percent increase in RU price and a 45 percent increase in RD price – are more extreme than the average bid composition suggests. Bid insufficiency and related pricing events increased for both of these services, leading to average price increases greater than indicated by the average bid composition.

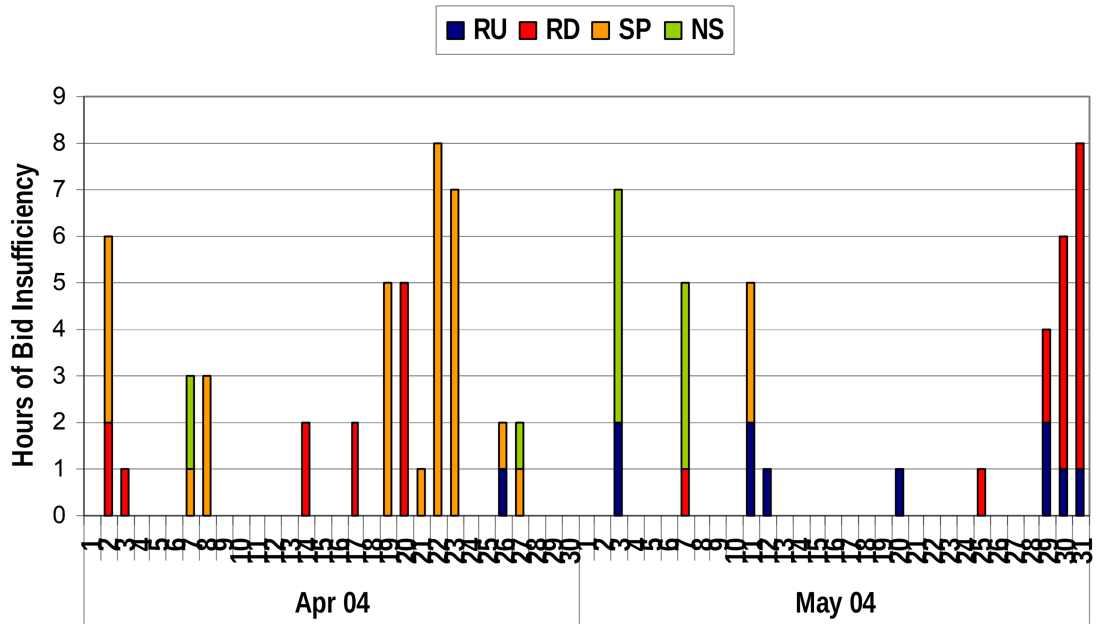
Figure 16. A/S Bid Volume by Price Bin through Apr-04



Bid insufficiency decreased by 19 percent from April to May. Several resources entered the ancillary services markets in May due to increased demand for energy. During the transmission emergency of May 3, 2004, the NS market had insufficient bids for five hours, while the RU market had insufficient bids for two hours.

During the last three days of May (Memorial Day weekend), bid insufficiency in the RD became more frequent. On weekends, the regulation markets tend to receive fewer bids, because regulation-providing thermal resources may shut down for the weekend. Resources that do not shut down usually reduce their schedules. The reduced schedule increases the availability of RU capacity while decreasing the availability of RD capacity. These generalizations held true over the Memorial Day holiday, resulting in mild bid insufficiency in RU and more prevalent bid insufficiency in RD. The following chart shows daily frequencies of bid insufficiency through May.

Figure 17. Daily Frequencies of Bid Insufficiency, April and May 2004



IV. Forward Market Interzonal Congestion Markets

- ***Interzonal Congestion cost $5.6 million in May, due to major line deratings***
- ***Congestion costs high from Southwest into SP15 due largely to Palo Verde derate and high loads in Southern California***

Day-ahead and hour-ahead congestion costs on the major interfaces (Interzonal Congestion) were $5.6 million in May, a significant increase from $1.6 million incurred in April. Among the congested paths, the Palo Verde Intertie accounted for more than half ($2.9 of $5.6 million) of the total congestion costs. Other paths that also had significant positive congestion costs were Blythe, COI, El Dorado, and Path 26.

Throughout May, Palo Verde was frequently congested during peak hours. The path was severely congested in mid-May as a result of a path derating of approximately 1,000 MW. Palo Verde was de-rated from 6:00 a.m. on May 14 to 8:00 p.m. on May 16 due to the clearance of the Imperial Valley-Miguel transmission line. This line outage resulted in congestion prices in excess of $40/MWh for nearly 40 hours after the initial derating. The congestion costs occurred during these three days accounted for the majority of congestion costs in May. Congestion prices were modest for most other congested hours in May. Besides Palo Verde, congestion also occurred in some hours on other paths that connect Southern California to the Southwest, including the El Dorado and Mead Interties.

Significant congestion also occurred in May on the California-Oregon Intertie (COI) in the import direction. COI was congested 46 percent of the time. For the first twenty days of the month, there were consistent peak hour deratings due to service work on the Round Mountain -Table Mountain #1-500kv Line. The increase in congestion frequency and prices in the last few days of May was related to the outage of Pacific DC Intertie. Suppliers had to rely more on COI to import power from the Northwest to California. The import capacity on NOB was 1,300 MW in May, but on several different occasions, the line was completed derated (May 11, 17, 22, 23, and 28-31) due to maintenance and test work. The congestion price was, however, modest.

Path 26 had some unusual congestion patterns in May. For most of year in 2003 and in the earlier months of 2004, the congestion on Path 26 was in the north to south direction. However, in May, some significant congestion occurred in the south to north direction. Starting on May 27, and later on May 28, the path limit in the south to north direction was set at 2,550 MW due to a forced outage of one 230 kV line (Gates CB 272 and Arco 222). Significant congestion occurred from 1:00 a.m. to 6:00 a.m. on May 28 resulting in a congestion price of $75/MW in the day-ahead market. Some high congestion prices (about $90/MW) also occurred in the hour-ahead market during the early morning hours of May 29.

A recurring event in the forward congestion market was the day-ahead congestion on Blythe in the import direction. Similar to April, Blythe was congested during many peak hours from April 26 to 29 with an average congestion price of $87/MW. The operating transfer capability (OTC) of the path was slightly derated during the period and one FTR holder on the path did not adjust its schedule accordingly, causing high congestion prices on the path.

Table 5. Interzonal Congestion Frequencies and Prices, May 2004

	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	4	0	$87		1	0	$43	
CASCADE	16	0	$0		12	0	$1	
COI	46	0	$2		29	0	$8	
ELDORADO	6	0	$9		2	0	$7	
ELVTHRLY	0	0			0	0		$30
LUGOIPPDC	0	0			0	0	$30	
LUGOMKTPC	0	0			0	0	$0	
LUGOTMONA	0	0			0	0	$30	
LUGOWSTWG	1	0	$0		0	0	$1	
MEAD	3	0	$2		5	0	$20	
NOB	19	0	$1		10	0	$13	
PALOVRDE	29	0	$10		10	0	$14	
PARKER	1	0	$1		0	0	$2	
PATH15	5	0	$0		2	0	$6	
PATH26	2	1	$27	$0	3	1	$35	$13
SUMMIT	5	0	$1		4	0	$10	

Table 6. Interzonal Congestion Costs, May 2004

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Day-ahead	Hour-ahead	
BLYTHE	$505,934	$0	$0	$0	$505,934	$0	$505,934
CASCADE	$80	$0	$3	$0	$80	$3	$83
COI	$860,304	$0	$23,190	$0	$860,304	$23,190	$883,494
ELDORADO	$512,640	$0	$4,830	$0	$512,640	$4,830	$517,470
ELVTHRLY	$0	$0	$0	$98	$0	$98	$98
LUGOTMONA	$0	$0	$1	$0	$0	$1	$1
LUGOWSTWG	$1	$0	$9	$0	$1	$9	$10
MEAD	$47,866	$0	$98,332	$0	$47,866	$98,332	$146,198
NOB	$194,200	$0	$7,409	$0	$194,200	$7,409	$201,608
PALOVRDE	$2,870,888	$0	$5,516	$0	$2,870,888	$5,516	$2,876,404
PARKER	$390	$0	$99	$0	$390	$99	$489
PATH15	$0	$0	$42,759	$0	$0	$42,759	$42,759
PATH26	$368,631	$251	$16,775	$27,327	$368,882	$44,102	$412,983
SUMMIT	$477	$0	$7,918	$0	$477	$7,918	$8,395
Total	$5,361,410	$251	$206,839	$27,425	$5,361,661	$234,265	$5,595,926

Firm Transmission Rights (FTR) Market

FTR scheduling. FTRs are used to hedge against congestion prices and establish a scheduling priority in the day-ahead market. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (92 percent on El Dorado, 62 percent on IID-SCE, 93 percent on LOGOIPPDC, 45 percent on LOGOMONA, 53 percent on Palo Verde, 100 percent on Silver Peak in the import direction, and 35 percent on Path 26). Southern California Edison and other municipal utilities own most of the FTRs on these paths.

Table 7. FTR Scheduling Statistics for May, 2004*

Direction	Branch Group	MW FTR Auctioned	Avg. MW FTR Scheduled	Max MW FTR Scheduled	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	COI	617	384	574	574	62%
IMP	BLYTHE	168	73	167	167	43%
IMP	ELDORADO	536	495	536	536	92%
IMP	IID-SCE	600	375	422	402	62%
IMP	LUGOIPPDC **	370	343	370	235	93%
IMP	LUGOTMONA **	160	73	92	52	45%
IMP	LUGOWSTWG **	93	35	46	28	38%
IMP	MEAD	624	23	58	27	4%
IMP	NOB	725	97	193	100	13%
IMP	PALOVRDE	1021	541	688	613	53%
IMP	SILVERPK	10	10	10	10	100%
IMP	VICTVL	921	7	50	50	1%
EXP	LUGOMKTPC **	247	3	3	3	1%
EXP	LUGOTMONA **	543	10	10	10	2%
EXP	NOB	722	4	31	31	1%
N-S	PATH26	1141	394	945	575	35%

*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 CAISO operation and were not released in the primary auction.

FTR Revenue per Megawatt. Table 8 summarizes the FTR revenue for the first two months of this FTR cycle. Due to high congestion frequency and high congestion prices on the Blythe, Palo Verde, and COI branch groups, FTR revenues on these paths were significant: about $2,770/MW, $2,164/MW, and $741/MW on Blythe, Palo Verde, and COI, respectively. The FTR revenues on other paths were modest in comparison.

Table 8. FTR Revenue Per MW ($/MW), May 2004

Direction	Branch Group	Net $/MW FTR Revenue		Cumulative Net $/MW FTR Revenue	Pro Rated NET $/MW FTR Revenue	FTR Auction Price
		Apr	May			
IMPORT	BLYTHE	1,395	2,770	4,165	24,990	8,759
IMPORT	COI	100	741	840	5,041	26,964
IMPORT	ELDORADO	0	408	408	2,446	11,646
IMPORT	LUGOIPPDC*	1	0	1	9	N/A
IMPORT	LUGOTMONA*	0	0	0	0	N/A
IMPORT	LUGOWSTWG*	0	0	0	1	N/A
IMPORT	MEAD	204	195	399	2,392	14,775
IMPORT	NOB	31	165	196	1,174	19,050
IMPORT	PALOVRDE	296	2,164	2,460	14,760	24,346
IMPORT	PARKER	29	4	32	195	240
S-N	PATH15	0	20	20	118	7,035
N-S	PATH26	213	14	227	1,362	19,113

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

V. Issues under Review

Must-Offer Obligation. In efforts to prevent the physical withholding of generation capacity for the purpose of exercising market power, the Federal Energy Regulatory Commission's (FERC) Order of June 19, 2001, upheld in later orders, required that generators must offer any available capacity into the CAISO real-time market (the "Must-Offer" Obligation). The CAISO may waive this obligation at its option if units are not needed. Units whose obligation is not waived are required to remain online and generating at minimum load, and are entitled to compensation for costs incurred. During the past year, DMA has noted several incentive problems that result as a direct or indirect consequence of the Must-Offer Waiver Denial procedure and the resultant level of units that remain on minimum load, including:

- Ancillary Services bid insufficiency;
- Incentives for utilities' inefficient scheduling without regard to local reliability needs, in anticipation of CAISO commitment under the Must-Offer Obligation, and cross-subsidization of costs incurred;
- Resultant balancing in the decremental direction, often to the point of depleting the available bid stack;
- Inability of units to decrement in some hours (due to the generation remaining at minimum load), requiring out-of-market procurement of decremental energy;

In an effort to modify the Must-Offer Waiver procedure to diminish the effects of these problems, the CAISO has petitioned FERC for Amendment 60 to the CAISO Tariff. This amendment would modify the CAISO Tariff provisions related to the implementation of the Commission-imposed must-offer obligation. In particular, Amendment 60 would (1) provide for a more rational and efficient process for granting or denying waivers rather than first in the queue (2) modify certain payment terms and the allocation of must-offer costs in a manner more consistent with cost causation, and (3) set forth clear conditions in which Condition 2 Reliability Must-Run (RMR) Units would be subject to the must offer obligation.