California Independent
System Operator

CALIFORNIA ISO

# Memorandum

**To:** ISO Board of Governors

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

**cc:** ISO Officers, ISO Board Assistants

**Date:** September 10, 2004

***Re:*** ***Market Analysis Report for July and August 2004***

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

## Executive Summary

The CAISO control area saw peak load records set on five successive days during two separate heat waves in July and August. However, the heat waves were relatively brief, and temperatures soon returned to normal levels. The approximate four percent system-wide year-over-year energy growth pattern, apparent since the summer of 2003, slowed in July and August. The record peak load of 44,872 megawatts (MW), set on August 11, 2004, was 5.2 percent above the August 2003 peak. However total energy use during August 2004 was only 1.7 percent greater than in August 2003, which had longer periods of heat, especially in the fast-growing areas of Southern California.

Two structural changes implemented during the July-August months have substantially impacted the ancillary services (A/S) markets. Amendment 60 to the CAISO's Tariff, approved with modifications on July 8, impacted the A/S markets by allowing units held online pursuant to the "Must-Offer" Obligation to keep minimum-load cost compensation, even if they are awarded ancillary services. However, to facilitate participation by these units in the day-ahead A/S markets, the must offer timeline must be moved forward prior to the deadline for submitting day-ahead A/S bids. Until this change is implemented, generators committed by the CAISO under the must offer obligation have not fully been able to utilize opportunities to bid into ancillary service markets. This change to CAISO operating procedure, to inform units whether they will be committed in the Must-Offer process prior to final day-ahead A/S procurement, was implemented on September 3. Meanwhile, on August 7, the CAISO began procuring ancillary services zonally, when projected capacity on the internal paths is expected to render system procurement of reserves undeliverable and the initial system distribution of reserves differs significantly from the distribution of load. Since July, price spikes in the A/S markets have been nearly a daily occurrence. These price spikes may be somewhat alleviated by the September changes.

Intra-zonal congestion continues to be a significant problem, as redispatch premium costs totaled $10.3 and $15.3 million in July and August, respectively.

## I. Trends Affecting Electricity Market Demand and Supply

- ***New all-time peak of 44,872 MW set August 11 was the fifth record set between July and August***
- ***Load growth that began Summer 2003 may be beginning to slow***

**Loads.** Hot summer weather, coupled with load growth, contributed to five successive all-time peak load records between July 19 and August 11, 2004, with the monthly peaks in July and August 2004 respectively 4.0 and 5.2 percent above July and August 2003 peaks. However, overall average energy use in July and August 2004 respectively were 0.7 and 1.0 percent above that in July and August 2003. Prolonged heat spells largely resulted in high energy use during summer 2003. In comparison, the summer of 2004 experienced only brief heat waves, particularly within the eastern portion of Southern California, where population growth has put upward pressure on load. For example, Ontario experienced ten days with peak temperatures at or above 100 degrees in August 2003, but had only three such days in August 2004. With the exception of those days with very hot temperatures, daily loads remained near the levels seen in the summer of 2003. Figures 1 and 2 compare hourly average loads in July and August 2004 to those months in 2003.

**Figure 1. Comparison of Actual Loads in July: 2004 v. 2003**

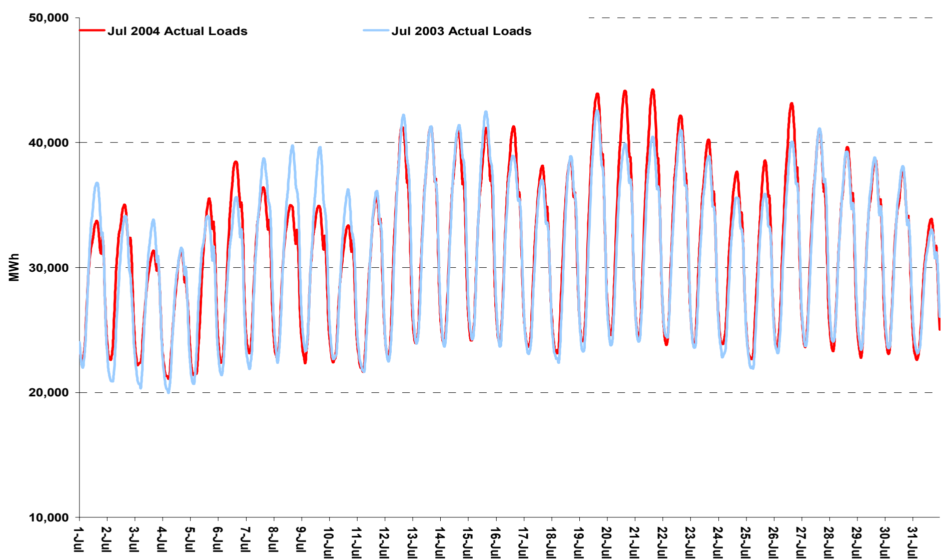
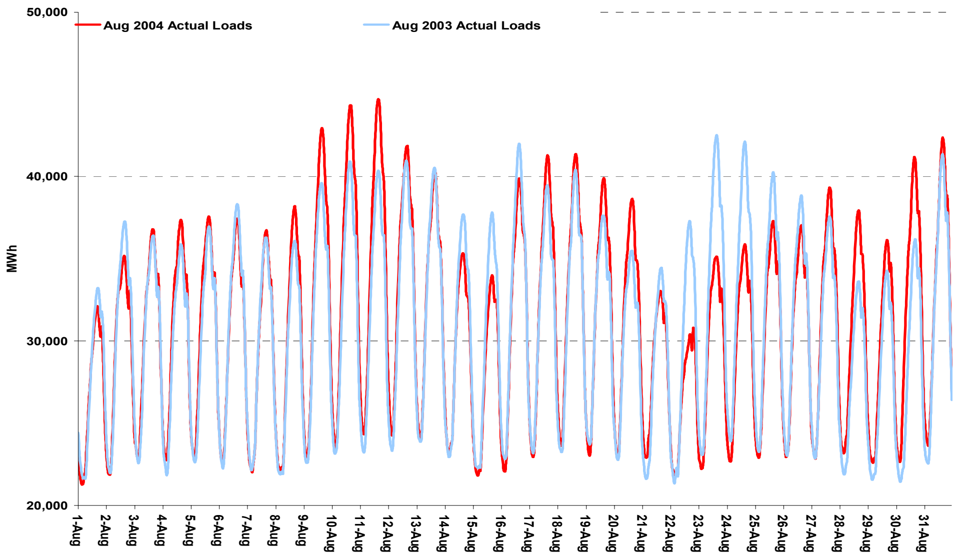


**Figure 2. Comparison of Actual Loads in August: 2004 v. 2003**




There has been a clear trend toward higher loads since the summer of 2003. Between January and June 2003, loads were moderate, at or below the same-month levels of the previous year. Between July and September 2003, hot weather had an increasing impact on loads. Since approximately October 2003, the CAISO has experienced load growth in excess of what can be explained by weather alone. Whether this non-weather-related growth trend will be permanent should become clearer in the fall of 2004. The following table shows same-month year-to-year changes in average hourly load, average daily peak load, average daily trough (minimum) load for each month, and monthly peak loads for each month. The average daily trough serves as an indicator of non-weather related load growth, as loads tend to vary minimally with weather during off-peak nighttime hours.

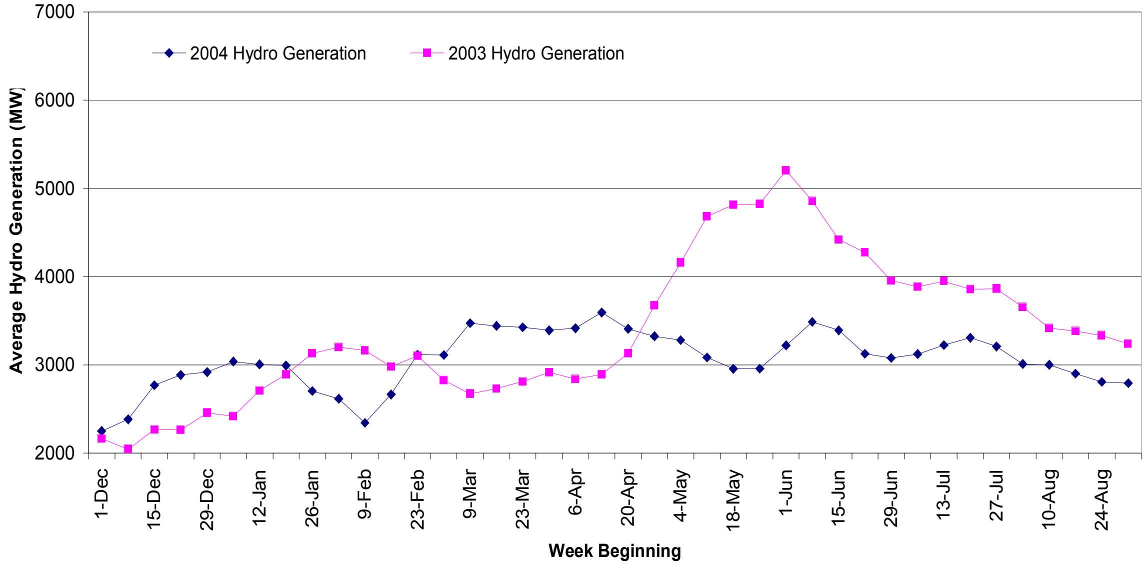
**Table 1. Year-to-Year Growth in Load: Monthly Indices through August 2004**

| | Avg. Hrly. Load | Avg. Daily Peak | Avg. Daily Trough | Monthly Peak |
|---|---|---|---|---|
| January-03 | -2.7% | -2.3% | -3.6% | -4.1% |
| February-03 | -2.6% | -1.9% | -5.0% | -1.4% |
| March-03 | 0.7% | 1.6% | -2.7% | 4.7% |
| April-03 | -2.7% | -2.2% | -5.3% | 0.2% |
| May-03 | -0.8% | 0.7% | -2.8% | 10.5% |
| June-03 | -1.6% | -1.1% | -3.7% | 3.6% |
| July-03 | 4.3% | 6.9% | 0.1% | 0.5% |
| August-03 | 5.4% | 8.5% | 1.5% | 4.3% |
| September-03 | 2.2% | 3.3% | 0.2% | 0.3% |
| October-03 | 5.4% | 7.0% | 2.6% | 3.7% |
| 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% |

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

**Hydroelectric Production and Imports.** 2004's hydro production has been significantly less than that of 2003. Overall, California hydroelectric production averaged approximately 2,952 MW in mid-August, compared to 3,402 MW the same week of the previous year as hydro producers reduced energy production to retain water for peak load periods. In 2003, hydro production declined significantly in September as was seasonally expected. Similarly, hydro production is likely to drop off in the fall shoulder months in 2004. The following chart shows weekly average hydroelectric production through August 2004 compared to the same period in 2003.

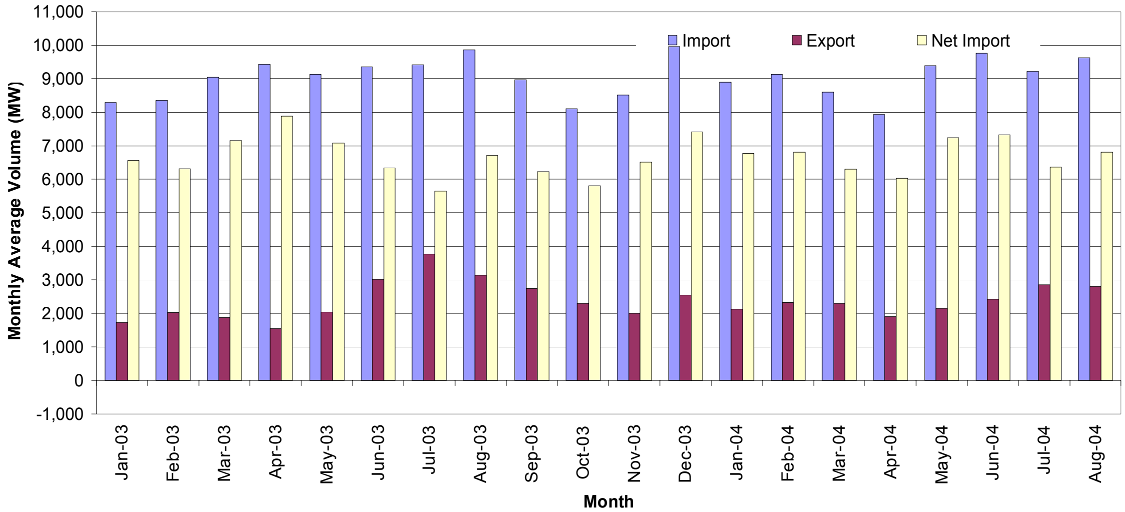
**Figure 3. Approximate Weekly Average Hydro Generation Within the ISO Control Area, 2003 and 2004 Seasons**[1]




Although the Pacific Northwest has had limited excess energy due to below-average hydro conditions and outages of major thermal units in the region, significant generation in the Southwest has resulted in high levels of imports during peak hours in July and August. Figure 4 shows monthly average import schedules through August.

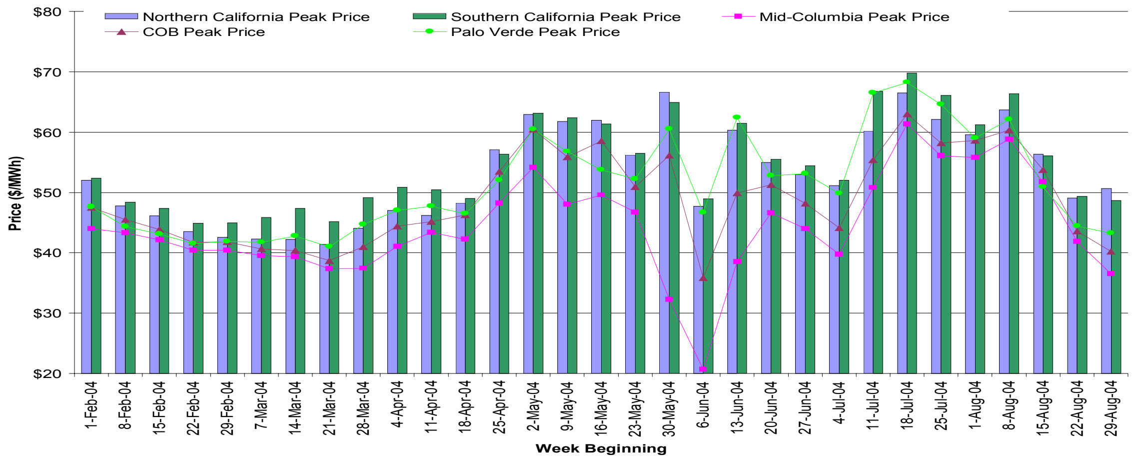
[1] Generation shown represents weekly averages. This does not show hydro generation available during peaks.

## Figure 4. Monthly Average Imports, Exports, and Net Imports in Peak Hours through August



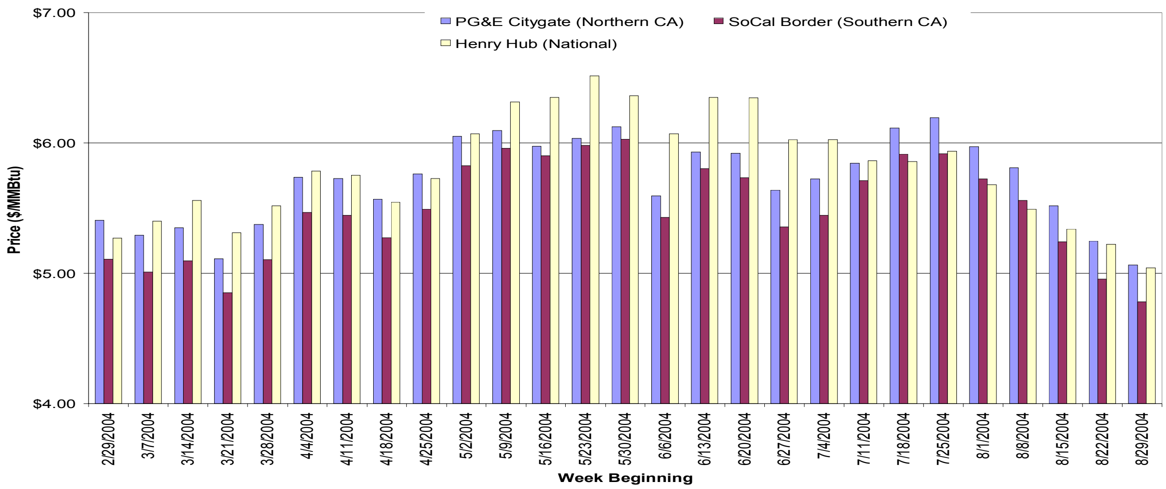

**Spot Bilateral Electric Markets.** Day-ahead bilateral contract prices for electric power increased rapidly during the first week in July, peaking around the record-setting July load spike the week of July 18-23. During this time, tight hydroelectric supply in the Pacific Northwest resulted in prices reaching levels typical for thermal units in California and the Southwest at the California-Oregon Border ("COB") and Mid Columbia. Meanwhile, an outage of a Palo Verde nuclear unit, a fire at the West Wing substation near Phoenix, and extraordinary temperatures near 110 degrees across Arizona and Nevada kept Palo Verde hub prices at or above California levels. Region-wide prices retreated slightly, but increased in anticipation of the next record-setting heat wave and load spike during the week of August 8-15. Several outages in the Northwest at this time, including the Columbia nuclear unit, contributed to high prices, reaching into the unusually high range of $60/MWh and above at Mid-Columbia and the COB delivery points. A forecast, calling for an excess of 46,000 megawatts in the CAISO control area (though not realized; see details below), resulted in day-ahead prices reaching the low $70/MWh range. Southwest prices reached California levels, despite frequent westbound congestion on the Palo Verde branch group due to regional temperatures in excess of 110 degrees. By late August, heat subsided across the region and prices retreated accordingly. Figure 5 shows weekly average day-ahead bilateral contract prices for peak-hour energy delivered to regional trading points through August.

**Figure 5. Day-Ahead Bilateral Trade Prices for Power Delivered to Regional Hubs: Weekly Averages through August**




**Natural Gas Market.** Since mid-July, western prices for natural gas have exceeded the benchmark price for delivery at Henry Hub, a national trading location located in Louisiana. The PG&E Citygate (NP15) price moved from the mid-$5/MMBtu range in late June, to the low-$6 range by mid-July, and returned to the mid-$5 range by late August, driven largely by the electricity markets. The Southern California Border (SP15) price has moved approximately 25 cents below the PG&E Citygate price over the same period. The Energy Information Administration (EIA), a unit of the U.S. Department of Energy, reports that soft demand from electricity production due to cool weather has put downward pressure on natural gas prices nationwide. As of Friday, August 13, gas storage increased to 2,530 billion cubic feet (Bcf), or 5.7 percent above the average for that week in the last five years. While tropical storm Bonnie and Hurricane Charley passed through areas of natural gas production, they had minimal effect on operations. The EIA reports that the NYMEX futures contract price for September delivery of natural gas was $5.382/MMBtu on August 13. Figure 7 shows regional weekly average prices for natural gas through August.

**Figure 6. Weekly Average Natural Gas Prices, through August**




## II. Real-Time Energy Market

- ***Real-time intra-zonal congestion costs totaled $10.3 million and $15.3 million in July and August, respectively, due largely to Sylmar congestion***
- ***Out-of-sequence dispatches for intra-zonal congestion management represented more than half of the real-time incremental market for the first time***

The real-time market has largely been composed of dispatches to manage locational real-time (intra-zonal) congestion. This has been a trend since July 2003. At that time, generators in Mexicali, Mexico began to supply the CAISO control area, creating unprecedented intra-zonal congestion at the Miguel Substation, east of San Diego. Since that time, congestion has increased in other regions within Southern California, notably south of the Lugo Substation ("South-of-Lugo"), at the Sylmar Substation, and others.

The CAISO resolves intrazonal congestion in two ways: the "Must-Offer Waiver Process"[2] and out-of-sequence (OOS) calls to available resources (market, Must-Offer and/or RMR). Pursuant to the Federal Energy Regulatory Commission's (FERC) Order of June 19, 2001, available generation must offer energy to the CAISO's markets (the "Must-Offer Obligation"). To ensure units that are potentially needed will be available, the CAISO can call upon slow-start units a day ahead of the time they are needed, to run at minimum load, for which they are reimbursed their costs. Generators can apply for waivers to the Must-Offer Obligation, which the CAISO can grant at its

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[2] Pursuant to the FERC 6/19/2001 Order, all public and non-public utilities selling into CAISO markets or using FERC-jurisdictional transmission, who own or control generation in California, must offer their unused non-hydroelectric capacity into the CAISO's ancillary services or real-time markets. Suppliers outside the CAISO control area must offer unused capacity in a spot market of their choice. FERC*, Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference,* Docket Nos. EL00-95-031 et al. (95 FERC 61,418) .

discretion when those units are not needed. The waiver application, granting, and denial/rescission process is often referred to as the "Must-Offer Waiver" (or MOW) process.

The CAISO then manages intra-zonal congestion in real time by issuing out-of-sequence ("OOS") dispatches to those units within Southern California – usually committed under the MOW process, but not exclusively -- that are most cost-effective in resolving the congestion.[3] In the last several months these dispatches have been to Must-Offer committed units in the Los Angeles Basin in the incremental direction, to manage congestion primarily at the Sylmar substation. As a result, most in-sequence dispatches have been in the decremental direction, to offset energy from OOS dispatches, as well as unscheduled energy from Must-Offer units generating at minimum load.

Overall, July's and August's out-of-sequence incremental energy prices have been slightly higher than in-sequence prices during the summer.[4] However, intra-zonal congestion OOS dispatches have increased substantially in volume. Incremental and decremental prices overall, respectively averaged $67.94 and $30.95 in July, and $68.55 and $26.19 in August, compared to $61.81 and $26.72 in June. The ratio of out-of sequence to in-sequence incremental energy was 1.8 to 1 in July and 2.4 to 1 in August, a significant increase from the June level of 0.3 to 1. The equivalent ratio for decremental energy was 0.4 to 1 in July and 0.3 to 1 in August, compared to 0.1 to 1 in June.

**Note:** The Department of Market Analysis will now report average prices and volumes for all out-of market and out-of-sequence energy, going forward. The following tables show incremental ("Inc") and decremental ("Dec") for in-sequence market prices procured through the California ISO's Balancing Energy Ex-Post Price ("BEEP") auction market, as well as total out-of-sequence and out-of-market costs ("OOS/OOM"), and weighted averages of the two categories. **Because these tables report OOS energy, they are not comparable to similar tables shown in previous reports, which excluded OOS energy.**

[3] The out-of-sequence dispatch protocol weights the effectiveness factor for resolving intra-zonal congestion by the price the unit has bid to be dispatched.

[4] At any given moment, an incremental out-of-sequence price paid as bid will necessarily be higher than an in-sequence market price. However, volume-weighted averages of incremental in-sequence market prices across multiple hours are not necessarily lower than out-of-sequence prices, since they are almost always taken in different hours of the day. For example, the in-sequence market weighted average price during peak hours in July of $71.51/MWh was less than the out-of-sequence price of $68.88/MWh. Similarly, weighted average decremental in-sequence market prices are not necessarily lower than average out-of-sequence prices.

## Table 2. Real-Time Prices and Volumes in July 2004

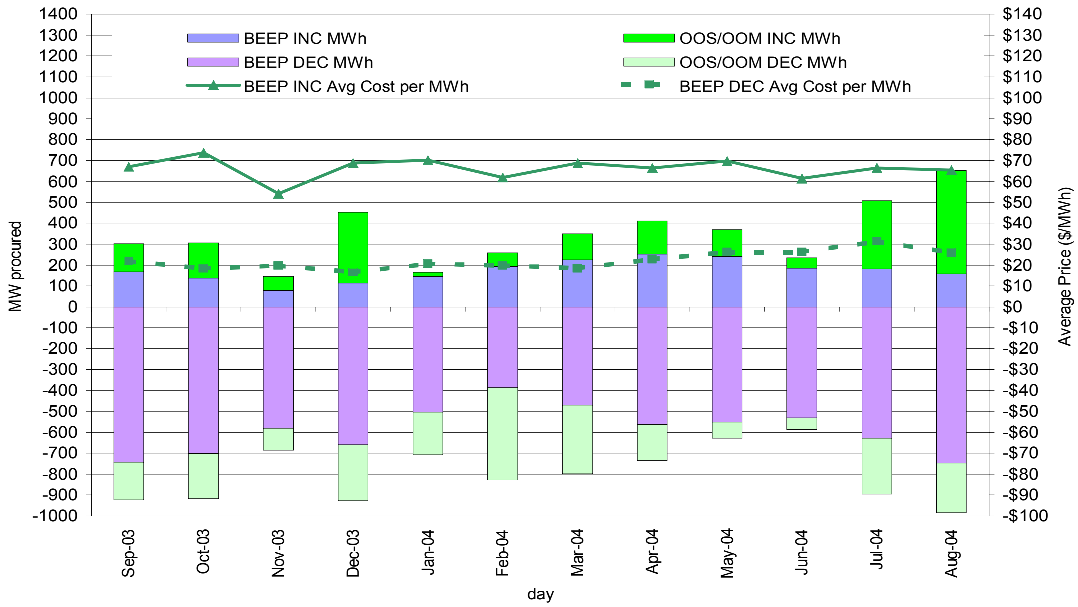
| | Avg. BEEP Price and Total Volume | | Avg. OOS/OOM Price and Total Volume | | Overall Avg. Real-Time Price and Total Volume | | Avg. System Loads (MW) and Pct. Underscheduling |
|---|---|---|---|---|---|---|---|
| | Inc | Dec | Inc | Dec | Inc | Dec | |
| Peak | $ 71.51 | $ 34.67 | $ 68.88 | $ 30.89 | $ 69.83 | $ 33.42 | 34,269 MW |
| | 98 GWh | 357 GWh | 173 GWh | 177 GWh | 271 GWh | 535 GWh | 2.2% |
| Off-Peak | $ 53.00 | $ 20.36 | $ 68.36 | $ 22.32 | $ 63.22 | $ 20.62 | 25,002 MW |
| | 36 GWh | 110 GWh | 72 GWh | 17 GWh | 109 GWh | 128 GWh | 3.0% |
| All Hours | $ 66.49 | $ 31.29 | $ 68.73 | $ 30.13 | $ 67.94 | $ 30.95 | 31,180 MW |
| | 134 GWh | 468 GWh | 245 GWh | 194 GWh | 380 GWh | 662 GWh | 2.4% |

## Table 3. Real-Time Prices and Volumes in August 2004

| | Avg. BEEP Price and Total Volume | | Avg. OOS/OOM Price and Total Volume | | Overall Avg. Real-Time Price and Total Volume | | Avg. System Loads (MW) and Pct. Underscheduling |
|---|---|---|---|---|---|---|---|
| | Inc | Dec | Inc | Dec | Inc | Dec | |
| Peak | $ 62.92 | $ 29.97 | $ 69.89 | $ 28.85 | $ 68.48 | $ 29.66 | 34,004 MW |
| | 69 GWh | 409 GWh | 272 GWh | 157 GWh | 341 GWh | 565 GWh | 1.7% |
| Off-Peak | $ 69.09 | $ 14.90 | $ 68.53 | $ 11.50 | $ 68.72 | $ 14.48 | 24,686 MW |
| | 48 GWh | 147 GWh | 93 GWh | 21 GWh | 142 GWh | 168 GWh | 2.0% |
| All Hours | $ 65.47 | $ 25.98 | $ 69.54 | $ 26.81 | $ 68.55 | $ 26.19 | 30,898 MW |
| | 117 GWh | 555 GWh | 365 GWh | 178 GWh | 483 GWh | 733 GWh | 1.8% |

The following chart shows monthly average volumes for in-sequence BEEP, and OOS/OOM incremental and decremental energy, as well as average in-sequence BEEP prices, through August.

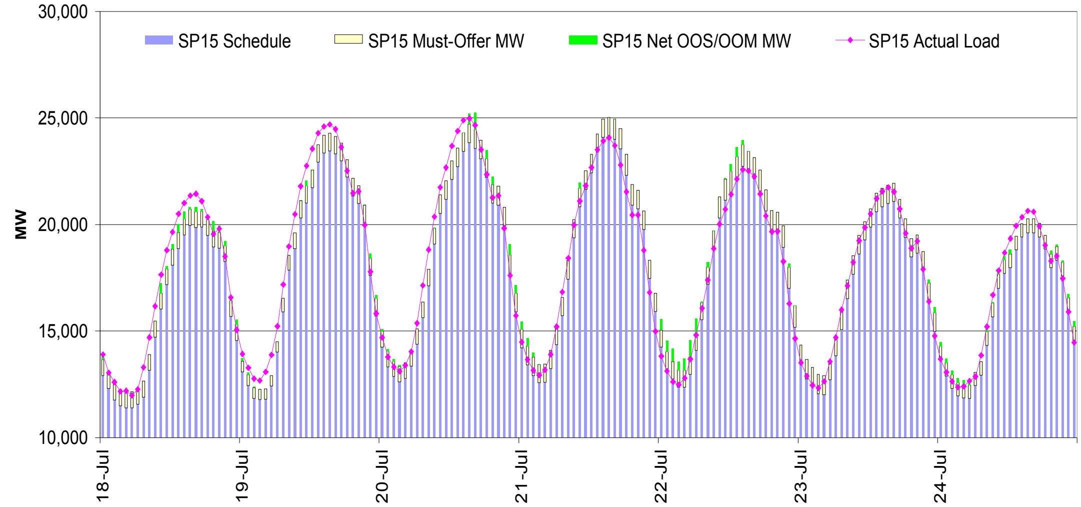
**Figure 7. Monthly Average Real-Time In-Sequence and OOS/OOM Volumes, and In-Sequence Market Clearing Prices, through August**



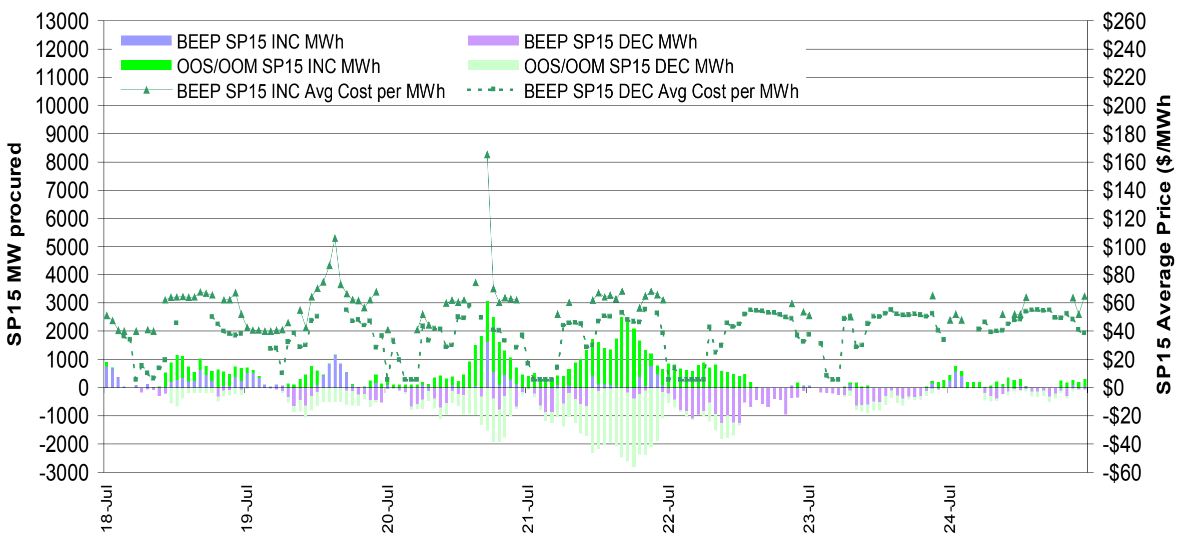

**Energy Schedules during Peaks.** Scheduling coordinators submitted schedules that substantially met the high expected loads resulting in minimal average underscheduling of 2.4 percent in July and 1.8 percent in August. At the same time, the CAISO held approximately 800 to 900 megawatts online at minimum load, pursuant to the "Must-Offer" Obligation,[5] largely to manage intra-zonal congestion within SP15. Consequently, on most peak days, the real-time generation supply was more than sufficient to meet load causing the CAISO to primarily decrement energy in real time on a market merit-order basis, particularly within SP15. On the first day of the heat wave, July 18, an imbalance within NP15 and real-time south-to-north congestion on Path 15 necessitated some incremental calls within that zone, but did not result in prices higher than those typically seen in afternoons. On July 19 and 20, imbalances within SP15 with north-to-south congestion on Path 26 required the CAISO to dispatch real-time incremental energy, resulting in two modest price spikes within SP15. For the remainder of this heat wave, and for the entire duration of the heat wave of August 10-15, bilateral schedules and Must-Offer commitments were more than sufficient to meet load. In all of these cases, however, intra-zonal congestion continued to require resolution in real time through out-of-sequence calls. Figure 8 shows actual load within SP15 for the week of July 18 through 24, and compares it to energy schedules, Must-Offer commitments, and out-of-sequence procurement to manage real-time intra-zonal congestion, on an hourly basis. The chart that follows shows real-time incremental and decremental energy procured at market-clearing prices (balancing energy at ex-post prices, or "BEEP"), out-of-sequence and out-of-market energy, and average market-clearing prices, on an hourly basis, for the same time period.

[5] FERC 6/19/01 Order, upheld in later Orders.

## Figure 8. Actual Load v. Hour-Ahead, Must-Offer, And Net Real-Time Out-of-Sequence Energy within SP15, July 18-24[6]



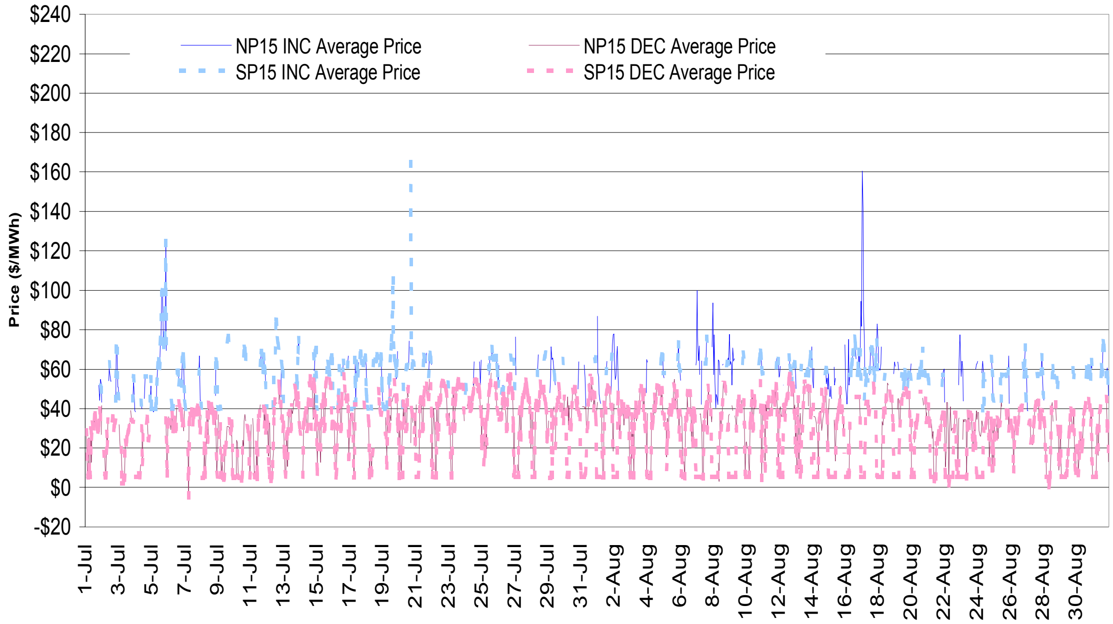

## Figure 9. Real-Time Procurement within SP15, July 18-24




**Price Spikes.** Because the market has been largely decremental, and incremental dispatches have been paid out of sequence as bid, there have been few incremental market-clearing price spikes this summer. Figure 10 shows ten-minute market-clearing prices in July and August. The discussion that follows describes the few notable spikes in July and August.

[6] Net OOS only shown when greater than zero.

**Figure 10. Hourly Average Real-Time Prices by Zone, July-August 2004**




On Monday, July 5, a holiday, the system-wide real-time incremental price was $100/MWh between 3:10 and 5:00 p.m. The price was set by a thermal peaking unit in NP15 that bid within its AMP Conduct Test threshold (reference price was $106.21). During this spike 4,916 MWh were dispatched over 11 intervals (average of 2,681 MW), with a price-to-cost markup of approximately $159,000, or 12 percent of the July total of $1.4 million. The weather on this day was hot, reaching as high as 106 degrees (in Redding), and schedules were approximately 9.6 percent short of load. The CAISO did not use real-time bids from ancillary services at this time to conserve operating reserves.[7]

Later on the evening of July 5, between 9:00 and 10:00 p.m., a municipal thermal unit within SP15 set the systemwide price at $125/MWh. This unit bid within its AMP Conduct Test threshold (reference level of $75.83/MWh). During this hour, 2,673 MWh were dispatched, with an approximate price-to-cost markup of $65,000, or 5 percent of the July total. In addition to a late import schedule cut, Huntington Beach Unit 3 (225 MW) was not able to return from an outage as planned at this hour.

On July 19, between 2:50 and 3:50 p.m., the SP15 incremental price spiked to $110.86/MWh. This price was set by a unit that has repeatedly bid and set this price since September 2004 but has been unable to respond to its dispatch instructions. (For details, please see the section below on "Issues under Review".) Load peaked during this hour, an all-time record up to that date, at 44,042 MW, with 20,888 MW within Southern California. At 2:54 p.m., the Gila River generation plant in Arizona tripped, causing a brief frequency disturbance. The market impact of this spike was approximately $53,000. Earlier that day, a fire at the West Wing substation near Phoenix caused

[7] ISO Operating Procedure M-430, "Splitting Operating Reserve Energy from Imbalance Energy."

disturbances to the western grid, including some rolling blackouts within the APS service territory. Price-to-cost markup during this spike was approximately $41,000, or 3 percent of the July total.

On July 20, between 5:00 and 6:00 p.m., the SP15 incremental price spiked to $165.25/MWh, set by a thermal peaking plant in Southern California. This unit has a reference level of $165.25/MWh. Many bids from units within SP15 were skipped in this hour due to transmission and/or ramping constraints and forced outages. Several transmission lines across the control area were de-energized due to fire, and several units tripped within the Los Angeles and San Diego areas, causing losses of approximately 400 MW. In this hour, 1,630 MWh were dispatched, incurring a total price-to-cost markup of approximately $152,000, or 11 percent of the July total.

On August 17, for 110 of 120 minutes between 1:00 and 3:00 a.m., a peaking unit set the price at $165.01/MWh within NP15. During this spike 2,571 MWh were dispatched (average of 1,286 MW), with a price-to-cost markup of approximately $165,000, or 39 percent of August's otherwise modest total of approximately $420,000. The unit that bid and set the price of $165.01/MWh had an AMP reference level of $62.30/MWh at its level of output, and thus had bid in excess of its AMP Conduct Test threshold of $162.30. However, because this unit was taken immediately following the trip of Moss Landing Unit 7 (756 MW), the hour-ahead predicted price in both of these hours was not in excess of the AMP prices screen of $91.87/MWh, so AMP was not applied. The price-setting unit also was metered to have delivered 17.5 MW of the 27.2 MW that was expected of it between 1:00 and 2:00 a.m. Between 2:00 and 3:00 a.m., the unit was metered at 14.8 MW, compared to 15.3 expected MW. The scheduling coordinator will be charged the uninstructed price for the unmet schedule between 1:00 and 2:00 p.m., but remains eligible to set the market-clearing price.

**Real-Time Intra-zonal Congestion Management:**[8] Intrazonal (within zone) congestion was substantial in the months of July and August. The primary reason for incremental OOS dispatches was constraints at the Sylmar substation due to ongoing maintenance work (78% and 93% of incremental costs in July and August respectively). The balance of the incremental costs was due to both system reliability and fires within Southern California in July.

Decremental congestion costs were significantly less than incremental congestion costs, incurred primarily due to congestion at Miguel (28% and 42% of decremental costs in July and August respectively) and Sylmar (17% and 13% of decremental costs in July and August respectively), with the balance due largely to system reliability reasons. The following chart shows monthly total congestion costs by location and/or cause through August.

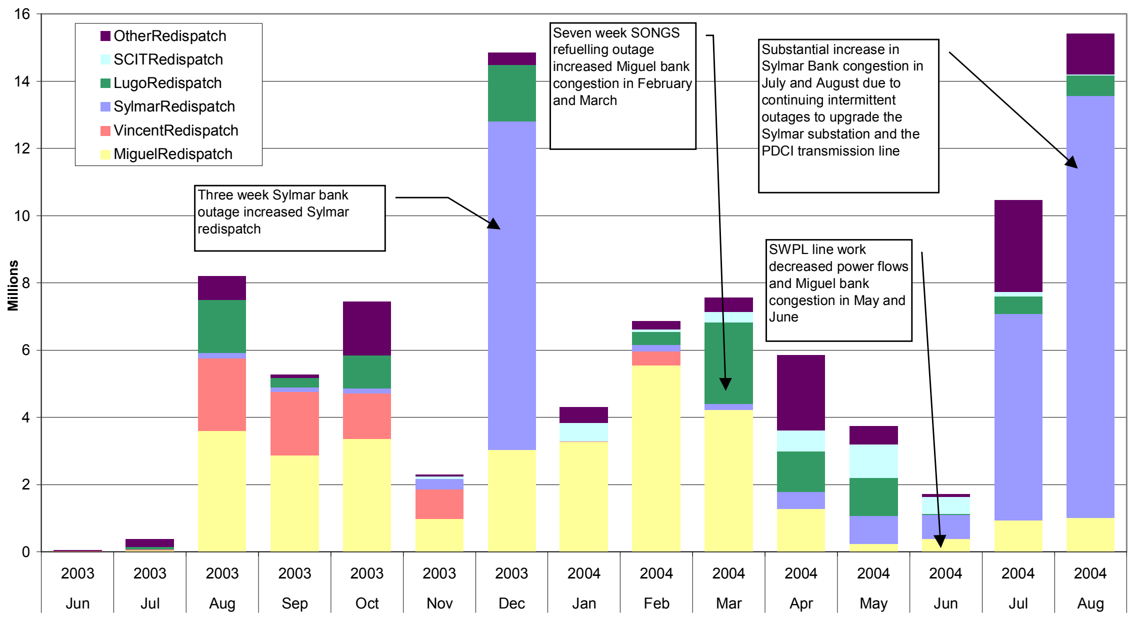
[8] Congestion costs generally have three components, listed below in approximate order of magnitude;

1. MLCC costs due to constraining on in-state generators (about 60% of total congestion costs)
2. Real-time Out-of-Sequence costs (about 25% of total congestion costs), and
3. Real-time RMR dispatches (about 15% of total congestion costs)

Out-of-sequence congestion net cost, or *re-dispatch premium,* is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent in-sequence dispatch cost at zonal MCP. The premium reflects the increased cost of redispatch and any potential mark-up above the zonal marginal cost. Whenever there are no in-sequence dispatches within the zone, the entire out-of-sequence dispatch cost is included as out-of-sequence re-dispatch premium.

This document concentrates on the real-time OOS costs and the MLCC costs. Due to settlement and billing delays RMR costs need to be estimated and this will be done in subsequent reports.

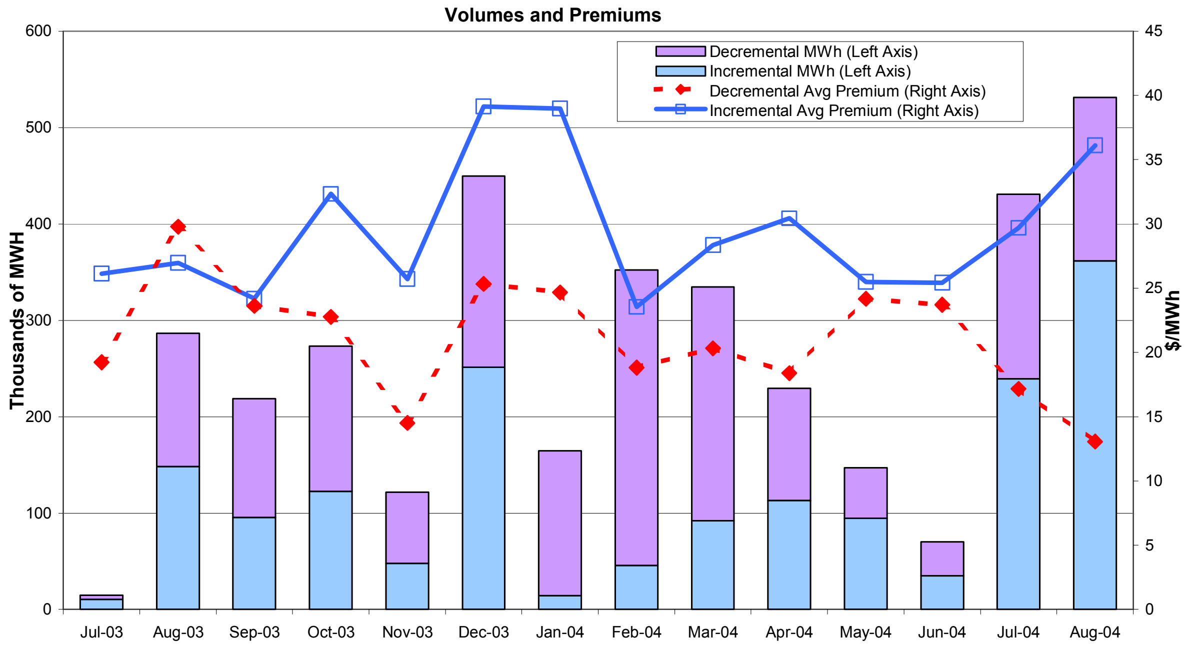
**Figure 11. Monthly Total Congestion Costs by Location and/or Cause through August 2004**




Overall, July and August intrazonal congestion dispatches respectively resulted in net costs (re-dispatch premium) of approximately $10.3 million and $15.3 million, compared to $1.7 million in June. Total congestion OOS dispatch volumes were 430 GWh and 531 GWh respectively (INC plus DEC), and the average re-dispatch premium costs were $24.13/MWh in July and $28.76 in August. In both July and August, Sylmar was the most costly constraint (approximately 59 and 82 percent of total re-dispatch costs, respectively)[9]. The following chart shows these quantities for recent months.

[9] The Sylmar substation and the PDCI transmission line are both undergoing significant maintenance as part of a 30 year program. Congestion as a result of this outage has been anticipated and is likely to become even more expensive in the fourth quarter when the intermittent outages become more sustained. The upgrade project is due to be completed early in the first quarter of 2005, after which point Sylmar bank congestion should disappear.

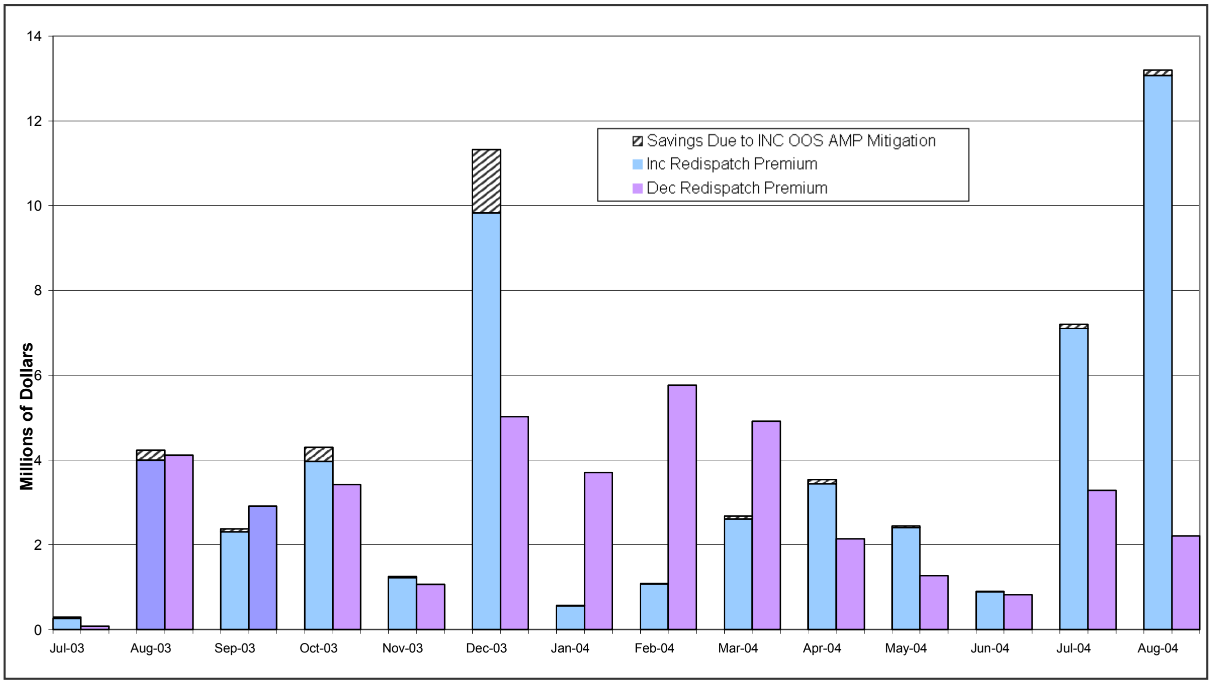
**Figure 12. Intra-zonal Congestion Volume and Average Re-dispatch Premium through August 2004**




**Incremental Congestion Dispatches.** CAISO operators dispatched 239 GWh of OOS incremental energy in July, and 361GWh in August to mitigate intrazonal congestion. The average price paid was $69.23/MWh and $69.73/MWh respectively, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $7.1 million or $29.69/MWh in July and $13 million or $36.12/MWh in August. The key point of constraint was Sylmar.

All incremental OOS dispatches are subject to mitigation. Figure 14 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 chart below, minimal bid mitigation has taken place, given the existing thresholds for local market power mitigation (LMPM) of incremental dispatches. Mitigation in July and August respectively resulted in savings of $92,868 (1.3% of the total re-dispatch premium) and $130,343 (1.0% of the total re-dispatch premium).

**Figure 13. Intrazonal Re-dispatch Premiums and Incremental OOS Mitigation Savings through August 2004**

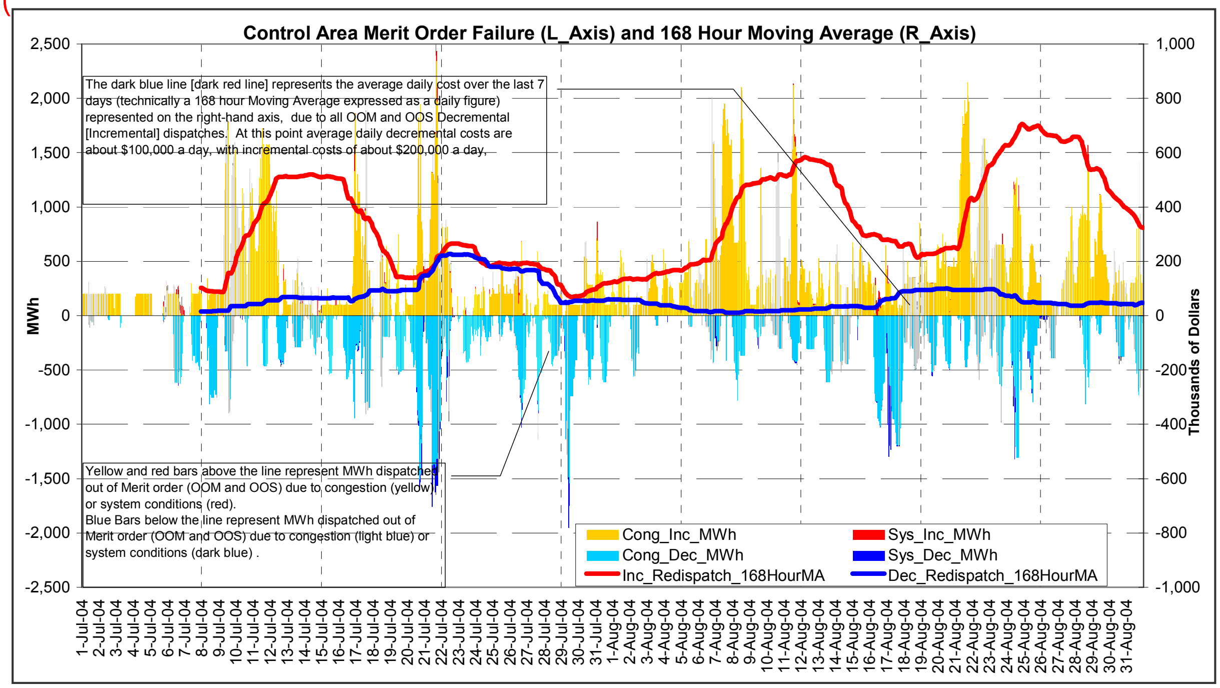



**Decremental OOS Dispatches.** A total of 191 GWh and 161 GWh of decremental energy respectively were dispatched out of sequence in July and August. This energy was settled in accordance with the provisions of the FERC-approved Amendment 50 mitigation measures. The approximate re-dispatch premium in excess of the market clearing price was $3.2 million, or $17.16/MWh in July; and $2.2 million, or $13.06/MWh in August. Congestion was primarily a consequence of the Miguel Bank constraint (accounting for 28% and 42% of decremental congestion costs in July and August respectively).

The chart below shows the energy dispatched (bar graph on the left axis) and the seven-day daily moving average for the intrazonal congestion re-dispatch costs. Congestion increased after the first week of July, especially on the incremental side.

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 through August 2004**




**MLCC Costs.** Costs for constraining on in-state generators in both July and August were higher than June, and were in excess of $30 million for each month. This was largely due to increased SCIT and System costs in July and substantially increased Lugo costs in August, which compensated for the decreased SCIT costs in that month. Substation and Transmission line maintenance costs decreased substantially in June, July and August compared to the preceding "Spring Maintenance" months of March, April and May. The chart below shows the monthly MLCC costs by constraint for the past 18 months.

**Figure 15. MLCC Costs by Constraint**

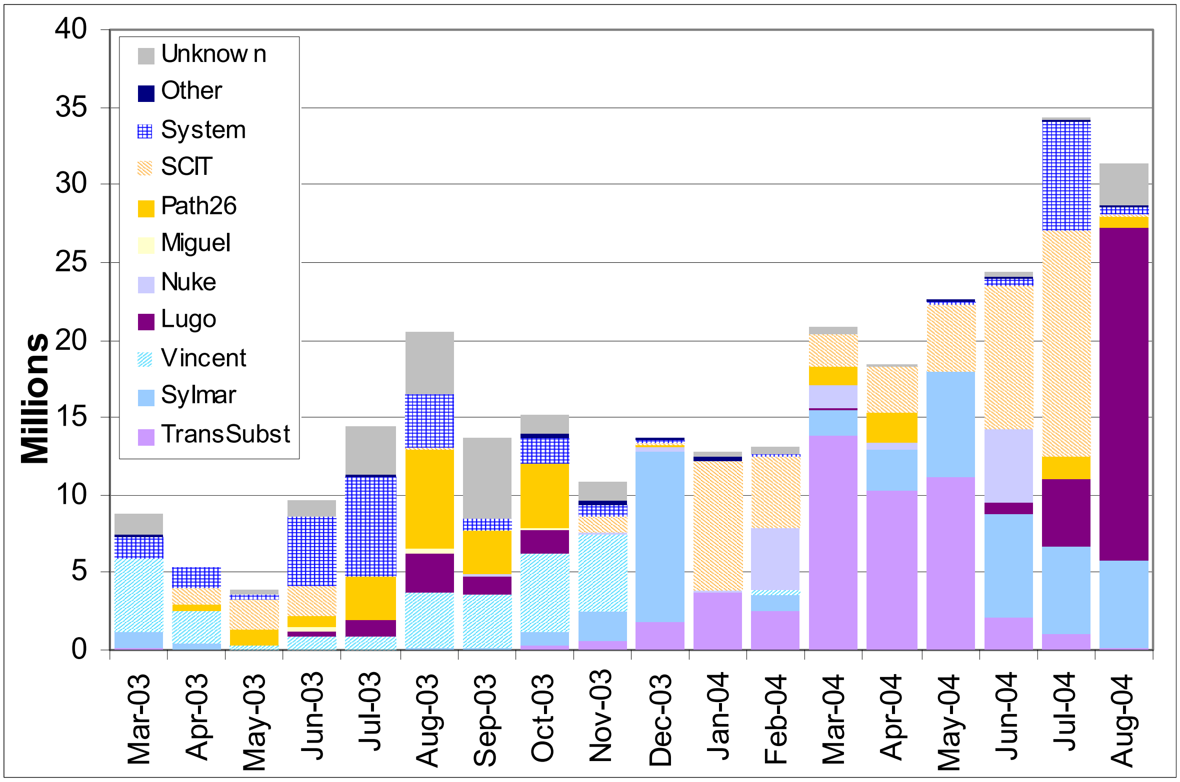



**Table 4. Explanation of MLCC Constraints**

| Constraint | Description |
|---|---|
| Miguel | Anticipated congestion at the Miguel Bank feeding into SDG&E service territory |
| Lugo | South-of-Lugo constraint, between 4800-5100 depending on load |
| Sylmar | Anticipated congestion at the Sylmar bank, generally due to planned upgrade work |
| TransSubst | Anticipated congestion due to planned transmission line or substation maintenance |
| Vincent | Anticipated congestion at the Vincent substation |
| Nuke | Energy needed due to the absence of one of the four in-state nuclear reactors |
| Path 26 | Congestion on Path 26 |
| SCIT | Import limitations due to the Southern California Import Transmission nomogram |
| System | Energy needed for system needs |
| Other | Other occasional constraints |
| Unknown | Reasons not captured |

## III. Ancillary Services Markets Performance

- ***Amendment 60 yet to significantly increase day-ahead A/S market supply***
- ***Zonal procurement results in bid insufficiency within SP15***

**Amendment 60**. The CAISO ancillary service (A/S) markets went through significant changes in the July/August period. On July 8, the FERC issued an order accepting, subject to modification, Amendment 60 to the CAISO's Open Access Transmission Tariff. Amendment 60 impacts the A/S markets by no longer rescinding the minimum load costs payment to must offer generation units awarded ancillary services. The CAISO requested this change to increase the amount of supply offered into the A/S markets. This provision was implemented on July 11. However, to allow units committed by denying waivers to the "Must-Offer" Obligation (MOW-D) to participate in the day-ahead A/S markets, the must offer timeline must be moved forward prior to the deadline for submitting day-ahead A/S bids. This change is not scheduled to occur until September 2. Therefore, to date, the increase in offers from MOW-D units has been primarily contained to the hour-ahead markets, as shown in the following charts. These depict the spinning reserve offer volume from MOW-D and Non-MOW-D units in the day-ahead and hour-ahead markets, from July 1 through August 31, respectively.

**Figure 16. Daily Average Day-Ahead Spinning Reserve Bid Volumes**

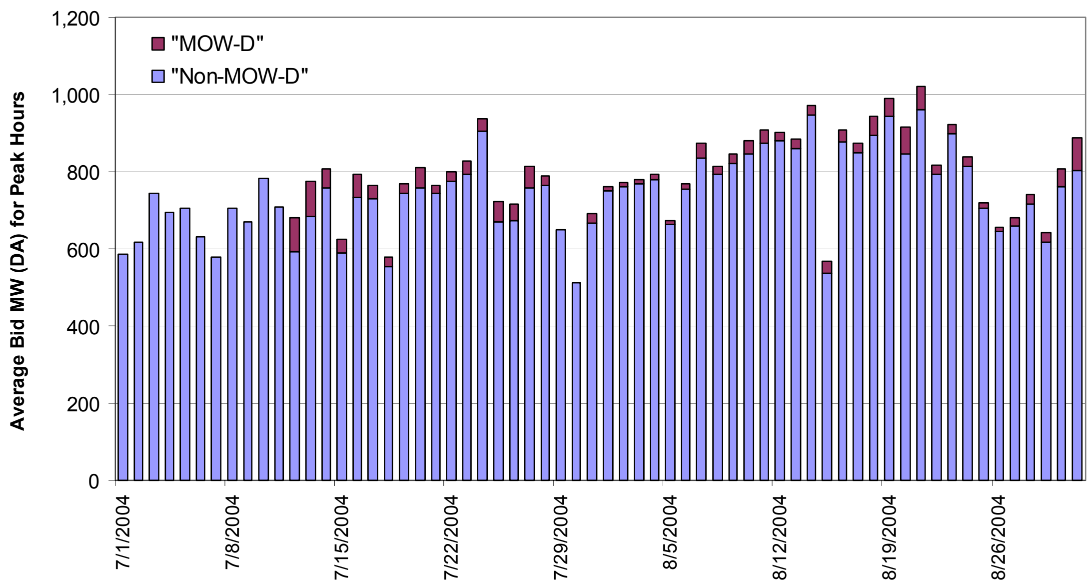
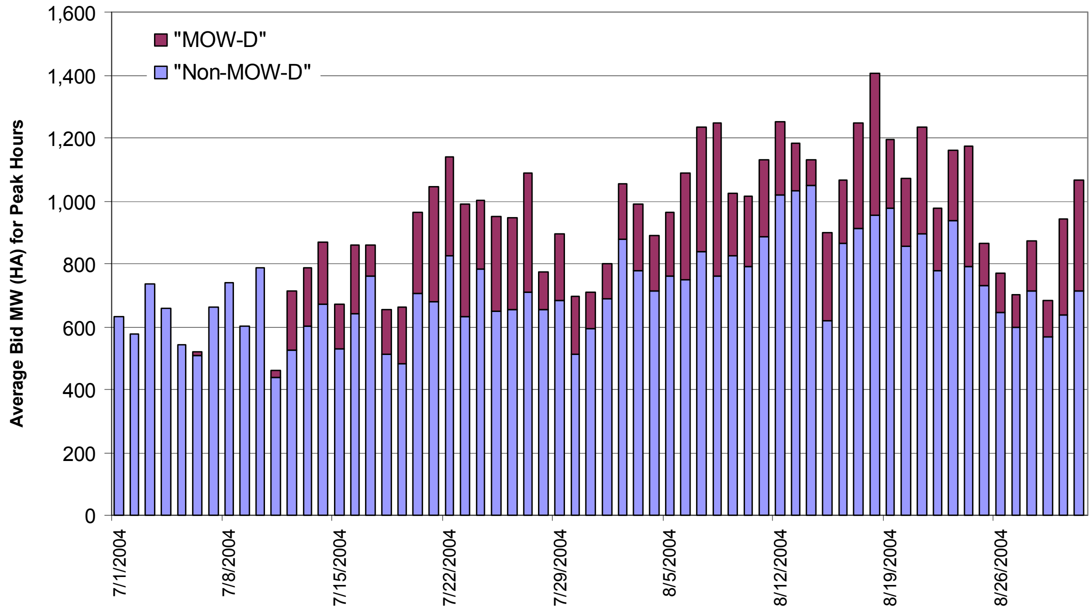


**Figure 17. Daily Average Hour-Ahead Spinning Reserve Bid Volumes**




## Market Prices

**Locational Procurement.** On August 7, the CAISO implemented zonal procurement of ancillary services during periods when transfer capability is limited between northern and southern California. During times of zonal procurement, the CAISO will split the ancillary services markets by zone, by selecting offers on a zonal basis to satisfy A/S obligations in each zone. Each zone then has a distinct market-clearing price for each service type. High loads in mid-August resulted in the CAISO splitting the ancillary service markets on several occasions during peak hours. Prior to locational procurement of A/S, approximately 80 percent of the CAISO's A/S requirements were provided by resources located in NP15. During times of locational procurement, the CAISO must now purchase significantly more A/S from SP15 resources, which has put stress on the market and has resulted in frequent price spikes. Between July and August, average A/S prices rose 153 percent in SP15, while prices decreased 47 percent in NP15. The following tables show the average requirements of each A/S and the weighted average prices for July and August for SP15 and NP15.

**Table 5. SP15 Average A/S Requirements and Prices**

| | Average Required (MW) | | | | Weighted Average Price ($/MW) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | RU | RD | SP | NS | RU | RD | SP | NS | All Svcs. |
| Jul 04 | 162 | 89 | 292 | 206 | $ 14.97 | $ 9.91 | $ 4.96 | $ 8.87 | $ 8.79 |
| Aug 04 | 207 | 89 | 273 | 250 | $ 23.83 | $ 8.58 | $ 17.14 | $ 31.23 | $ 22.20 |
| | 27.6% | 0.0% | -6.4% | 20.9% | 59.2% | -13.4% | 245.4% | 251.9% | 152.6% |

**Table 6. NP15 Average A/S Requirements and Prices**

| | Average Required (MW) | | | | Weighted Average Price ($/MW) | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | RU | RD | SP | NS | RU | RD | SP | NS | All Svcs. |
| Jul 04 | 239 | 248 | 752 | 682 | $ 18.27 | $ 15.51 | $ 7.67 | $ 7.31 | $ 9.87 |
| Aug 04 | 241 | 264 | 730 | 661 | $ 10.29 | $ 9.22 | $ 4.16 | $ 2.97 | $ 5.23 |
| Chg. | 0.7% | 6.4% | -3.0% | -3.1% | -43.7% | -40.5% | -45.7% | -59.4% | -47.0% |

Locational procurement of A/S has had the largest impact on SP15 peak hour prices as these are the times when the A/S markets are most frequently split. SP15 on-peak operating reserve prices have increased dramatically since July with spinning and non-spinning reserve prices increasing 264 percent and 236 percent respectively. Average SP15 monthly regulation up peak prices have also increased 91 percent since July. Conversely, on-peak prices in NP15 have dropped dramatically falling over 50 percent in both on peak and off peak hours. The following tables show the average amount procured and price by time of day for each ancillary service for both SP15 and NP15.

**Table 7. SP15 Time of Day A/S Demand and Pricing**

| | | Average AS Procured (MW) | | | Weighted Average Price ($/MW) | | |
|---|---|---|---|---|---|---|---|
| | | On-Peak | Off-Peak | All Hours | On-Peak | Off-Peak | All Hours |
| Jul 04 | RU | 180 | 125 | 162 | $ 13.86 | $ 18.17 | $ 14.97 |
| | RD | 97 | 73 | 89 | $ 7.49 | $ 16.36 | $ 9.91 |
| | SP | 315 | 245 | 292 | $ 6.14 | $ 1.93 | $ 4.96 |
| | NS | 222 | 176 | 206 | $ 11.73 | $ 1.64 | $ 8.87 |
| | Total | 814 | 618 | 749 | $ 9.54 | $ 6.82 | $ 8.79 |
| Aug 04 | RU | 248 | 123 | 207 | $ 26.54 | $ 12.92 | $ 23.83 |
| | RD | 100 | 66 | 89 | $ 7.61 | $ 11.50 | $ 8.58 |
| | SP | 306 | 208 | 273 | $ 22.32 | $ 1.90 | $ 17.14 |
| | NS | 293 | 164 | 250 | $ 39.36 | $ 2.19 | $ 31.23 |
| | Total | 946 | 562 | 818 | $ 27.14 | $ 5.54 | $ 22.20 |
| Difference | RU | 68 | -1 | 45 | $ 12.68 | $ (5.25) | $ 8.86 |
| | RD | 3 | -6 | 0 | $ 0.12 | $ (4.86) | $ (1.33) |
| | SP | -9 | -37 | -19 | $ 16.18 | $ (0.03) | $ 12.18 |
| | NS | 71 | -12 | 43 | $ 27.62 | $ 0.55 | $ 22.36 |
| | Total | 132 | -56 | 69 | $ 17.61 | $ (1.28) | $ 13.41 |

**Table 8. NP15 Time of Day A/S Demand and Pricing**

| | | Average AS Procured (MW) | | | Weighted Average Price ($/MW) | | |
|---|---|---|---|---|---|---|---|
| | | On-Peak | Off-Peak | All Hours | On-Peak | Off-Peak | All Hours |
| Jul 04 | RU | 230 | 256 | 239 | $ 15.88 | $ 22.54 | $ 18.27 |
| | RD | 241 | 262 | 248 | $ 10.42 | $ 24.88 | $ 15.51 |
| | SP | 797 | 663 | 752 | $ 9.83 | $ 2.46 | $ 7.67 |
| | NS | 715 | 617 | 682 | $ 9.95 | $ 1.17 | $ 7.31 |
| | Total | 1983 | 1798 | 1922 | $ 10.56 | $ 8.07 | $ 9.78 |
| Aug 04 | RU | 230 | 263 | 241 | $ 9.51 | $ 11.64 | $ 10.29 |
| | RD | 265 | 262 | 264 | $ 7.63 | $ 12.44 | $ 9.22 |
| | SP | 742 | 705 | 730 | $ 5.47 | $ 1.41 | $ 4.16 |
| | NS | 679 | 624 | 661 | $ 4.01 | $ 0.69 | $ 2.97 |
| | Total | 1916 | 1854 | 1895 | $ 5.67 | $ 4.14 | $ 5.17 |
| Difference | RU | -1 | 6 | 2 | $ (6.37) | $ (10.90) | $ (7.98) |
| | RD | 24 | 0 | 16 | $ (2.79) | $ (12.44) | $ (6.28) |
| | SP | -55 | 42 | -23 | $ (4.36) | $ (1.05) | $ (3.50) |
| | NS | -36 | 7 | -21 | $ (5.94) | $ (0.49) | $ (4.34) |
| | Total | -68 | 56 | -26 | $ (4.88) | $ (3.93) | $ (4.61) |

High loads and increased bid insufficiency sent average prices sharply higher in SP15 for regulation up and spinning and non spinning operating reserves. At the same time, prices dropped in NP15 as A/S market splits during peak hours resulted in lower prices for the A/S supply rich region. The large increase in prices in SP15 receded near the end of August due to lower load levels. The following charts show the weekly average A/S prices for SP15 and NP15.

**Figure 18. SP15 Weekly Weighted Average Ancillary Service Prices**

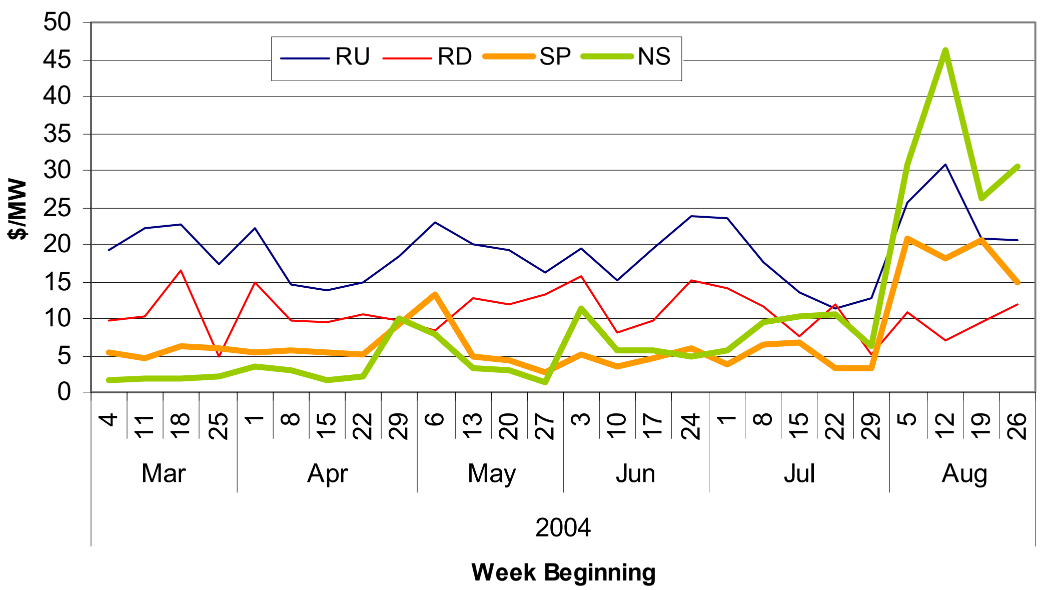
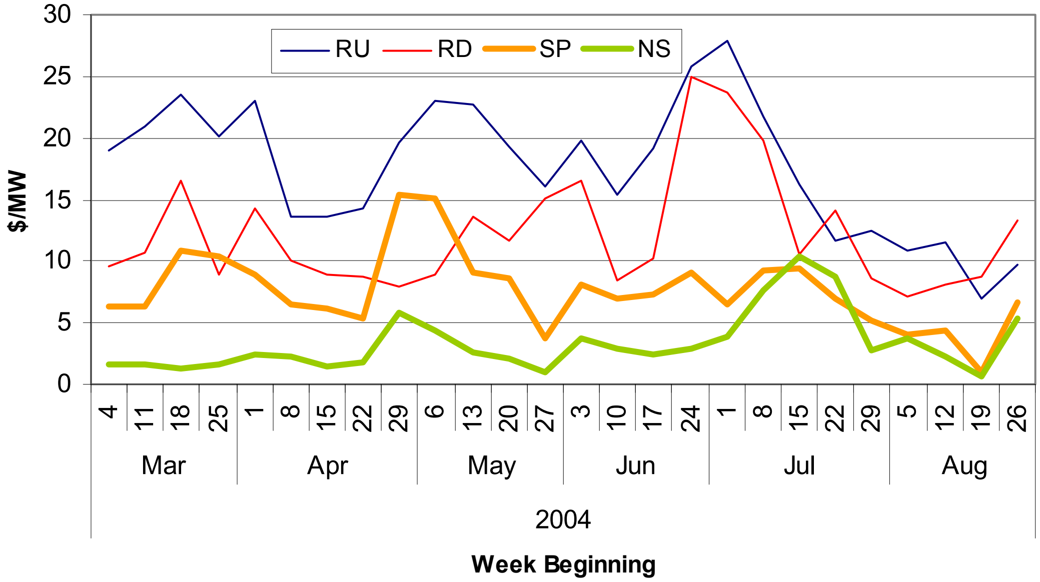


**Figure 19. NP15 Weekly Weighted Average Ancillary Service Prices**




**Ancillary Service Market Supply.** Market supply was characterized by a substantial increase in the frequency of bid insufficiency in SP15 primarily as a result of locational procurement in August. Bid quantities increased modestly in the day ahead market in both SP15 and NP15 shown in the charts below.

However, as noted above, significant increases in SP15 bid quantities in the day-ahead market are not expected until early September, when Amendment 60 is fully implemented and Must-Offer Waiver Process timelines are adjusted to allow MOW-D units to bid into the day ahead A/S markets. Specifically, generators will learn whether or not they will be waived from the Must-Offer Obligation before the closing of the Day-Ahead Market. If a generator is not waived (i.e. it is committed to run at minimum load), it can then bid into the A/S market without risk. Currently, the generator must bid before being committed, thus facing the risk of either buying back its day-ahead A/S sales in the market, or running without minimum-load cost compensation. Due likely to this risk, bid insufficiency in SP15 increased to the highest levels of the year to date in July and August.

**Figure 20. SP15 Day Ahead Average Bid Quantities by Price Bin**

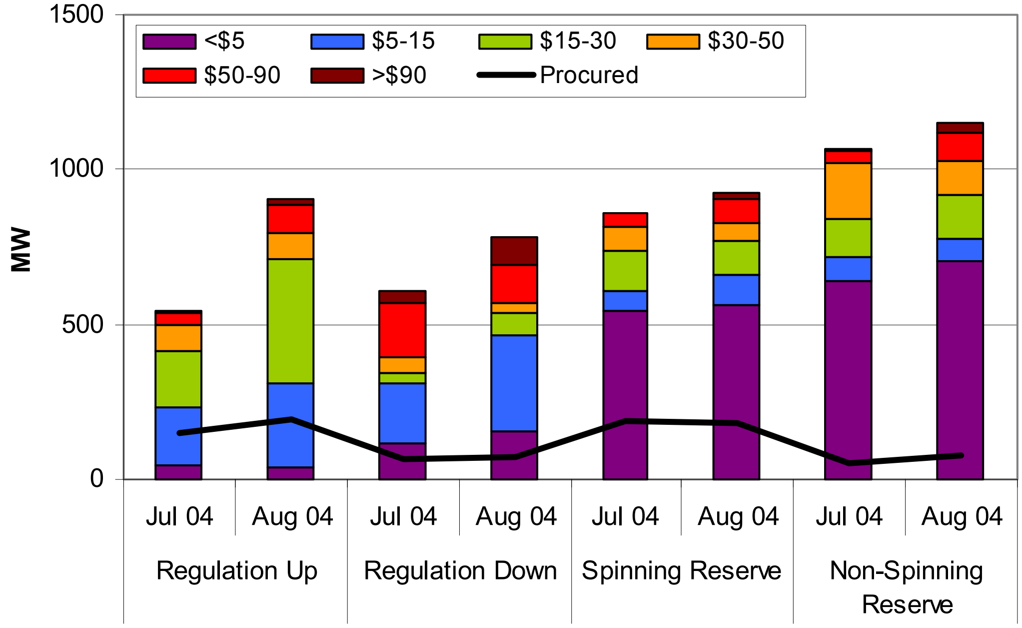



**Figure 21. NP15 Day Ahead Average Bid Quantities by Price Bin**

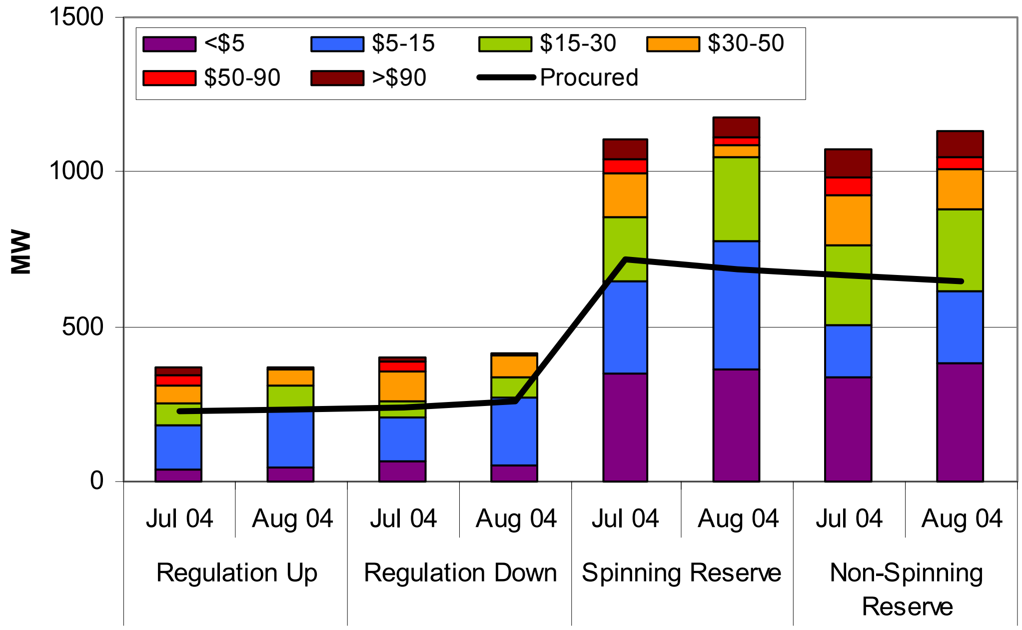
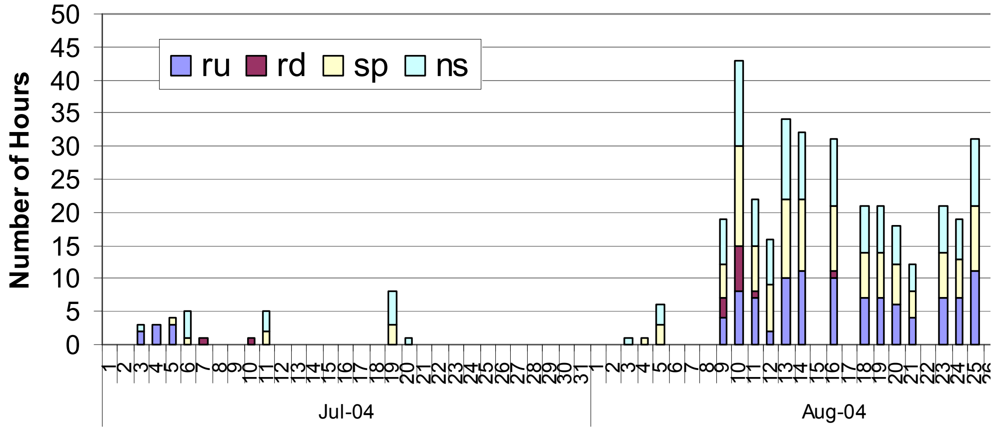


**Figure 22. Frequency of Bid Insufficiency, July 1 through August 25, 2004**




## III. Inter-zonal Congestion

- ***Congestion totaled $4.4 million and $4 million in July and August, respectively, due largely to transmission constraints on Palo Verde***
- ***Day-ahead congestion costs in the South-to-North direction on Path 15 due to a change in bidding practice by a utility***

**High Congestion Cost on Palo Verde in July and August.** Inter-zonal congestion costs totaled $4.4 million and $4 million in July and August, respectively. Among all congested paths, the Palo Verde branch group accounted for the bulk of congestion costs incurred, totaling $2.7 million in July and $2.4 million in August, about 60 percent of total congestion costs in each month. Other paths that incurred significant positive congestion costs were the California-Oregon Intertie (COI), the Pacific DC Intertie (also referred to as the North-of-Oregon Border Intertie, or NOB), and Path 26, all in the south to north direction into NP15. Also, significant day-ahead congestion on Path 15 emerged in the second half of August.

Most congestion costs on Palo Verde occurred during peak hours on a few days in these two summer months; namely, on July 7, 11, 12, and 19, and on August 8, 11, and 18. The congestion prices in the day-ahead market ranged from $20/MWh to $35/MWh. No line derates were reported on these dates. The significant demand for power from the southwest region led to a large import schedule, which exceeded the import limit of the line and caused significant congestion costs. The only derate on Palo Verde was reported from 2,823 MW to 1,063 MW, between 11:00 p.m. on July 28 and 5:00 a.m. on July 29, due to an outage of the Devers-Palo Verde and Devers-Valley 500kv Lines.

**Day-ahead Congestion Costs on Path 15.** Beginning August 22, Path 15 started to show positive congestion prices in the day-ahead market. The total day-ahead congestion cost in August was approximately $0.8 million, with congestion prices ranging between $4/MWh and $8/MWh. In the past few years, Path 15 had frequently experienced some day-ahead congestion in the off-peak hours in the south to north direction, but typically the day-ahead congestion price was zero. As a result, the total congestion costs were also zero. Pursuant to its tariff, the CAISO must withhold the entire Existing Transfer Capacity (ETC) regardless of the day-ahead ETC schedule. One utility in the region often provided the zero load adjustment bids on account of the fact that the day-ahead congestion was largely due to this practice of capacity withholding, and in the real-time congestion should not exist. While this is true for most times during the year, real-time congestion recently appeared on Path 15, in the south-north direction. When Path 15 is congested in real time, this utility would then be penalized due to the differences in prices on two sides of Path 15. To avoid these real-time congestion costs, the utility ceased submitting zero adjustment bids that had minimized day-ahead congestion prices.

**Congestion on other Major Branch Groups**. The frequency of congestion on COI was lower in July than in June. COI was congested in 14 and 26 percent of hours in July and August, with the average day-ahead congestion price of $4/MWh and $1/MWh respectively. The importing capacity of COI fluctuated between 3,000 MW and 4,600 MW during July, whereas the capacity had largely stayed above 4,000 MW in August. The congestion on COI usually occurred during peak hours, during which the submitted initial schedules exceeded the import limit of the path. Most congestion costs can be attributed to deratings due to scheduled maintenance. On July 6, congestion price spikes were reported in approximately two hours in the hour-ahead market as a result of line deratings.

The Pacific DC Intertie (also referred to as the North-of-Oregon Border Intertie, or NOB) experienced many complete and partial outages in July and August. The Path was out of service July 9 to July 12, and in many hours on August 6, 17, 21,22, and 28, due to several maintenance projects. These include a fix for a problem with the Sylmar 220/230kV Bus 1, Pole3 Metallic return configuration, clearance of Sylmar Converter 3 DC/Neutral bus, and others. Most congestion costs in July on NOB occurred between 1:00 and 7:00 p.m. on July 13, when the import capacity was derated to 400 MW. Congestion prices ranged between $62/MWh to $78/MWh.In August, the congestion prices, however, were below $5/MWh for most hours.

Path 26 had day-ahead congestion during many peak hours throughout July and some peak hours in the first half of August. In July, for most hours, the north-south capacity of line had been 3,400 MW. The congestion prices were modest and below $10/MWh. On July 19, from HE1300 to HE2000, the hour-ahead prices on Path 26 exceeded $50/MWh. The total congestion costs were $768,100 and $162,098 in July and August, respectively.

**Table 9. Inter-zonal Congestion Frequencies and Prices, July 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 |
| **CASCADE** | 3 | 0 | $0 | | 3 | 0 | $0 | |
| **COI** | 14 | 0 | $4 | | 11 | 0 | $9 | |
| **LUGO-WEST WING** | 0 | 0 | | | 1 | 0 | $0 | |
| **MEAD** | 0 | 0 | $30 | | 2 | 0 | $16 | |
| **NOB** | 9 | 0 | $8 | | 2 | 1 | $8 | $7 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **PALO VERDE** | 14 | 0 | $13 | | 5 | 0 | $10 | |
| **PARKER** | 0 | 0 | | | 0 | 0 | $3 | |
| **PATH 15** | 7 | 0 | $0 | | 4 | 0 | $14 | |
| **PATH 26** | 0 | 18 | | $2 | 0 | 6 | | $13 |
| **SILVER PEAK** | 0 | 0 | | | 0 | 0 | | $30 |
| **SUMMIT** | 2 | 0 | $1 | | 1 | 0 | $2 | |

## Table 10. Inter-zonal Congestion Costs, July 2004

**Congestion Cost by Branch Group: 01-Jul-04 to 31-Jul-04**

| Branch Group | Day-ahead | | Hour-ahead | | Total Congestion Cost | | Total Congestion Cost | | Total Congestion Cost |
|---|---|---|---|---|---|---|---|---|---|
| | Import | Export | Import | Export | Import | Export | Day-ahead | Hour-ahead | |
| **COI** | $526,645 | $0 | $319 | $0 | $526,964 | $0 | $526,645 | $319 | $526,964 |
| **LAUGHLIN** | $0 | $22 | $2 | $0 | $2 | $22 | $22 | $2 | $23 |
| **LUGO-WEST WING** | $0 | $0 | $3 | $0 | $3 | $0 | $0 | $3 | $3 |
| **MEAD** | $25,349 | $0 | $31,592 | $0 | $56,940 | $0 | $25,349 | $31,592 | $56,940 |
| **NOB** | $294,342 | $0 | -$925 | $48,440 | $293,416 | $48,440 | $294,342 | $47,514 | $341,856 |
| **PALO VERDE** | $2,688,845 | $0 | $17,284 | $0 | $2,706,130 | $0 | $2,688,845 | $17,284 | $2,706,130 |
| **PARKER** | $0 | $2,876 | $172 | $0 | $172 | $2,876 | $2,876 | $172 | $3,048 |
| **PATH 15** | $0 | $0 | $12,372 | $0 | $12,372 | $0 | $0 | $12,372 | $12,372 |
| **PATH 26** | $0 | $761,774 | $0 | $6,327 | $0 | $768,100 | $761,774 | $6,327 | $768,100 |
| **SUMMIT** | $563 | $0 | $410 | $0 | $973 | $0 | $563 | $410 | $973 |
| **Total** | $3,535,744 | $764,671 | $61,228 | $54,766 | $3,596,973 | $819,438 | $4,300,416 | $115,995 | $4,416,410 |

## Table 11. Interzonal Congestion Frequencies and Prices, August 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** | 0 | 0 | $1 | | 0 | 0 | | |
| **CASCADE** | 17 | 0 | $0 | | 6 | 0 | $0 | |
| **COI** | 26 | 0 | $1 | | 16 | 0 | $14 | |
| **ELDORADO** | 0 | 0 | $0 | | 0 | 0 | | |
| **LUGO-MARKETPLACE** | 0 | 0 | $1 | | 0 | 0 | | |
| **LUGO-WEST WING** | 0 | 0 | | | 1 | 0 | $1 | |
| **MEAD** | 8 | 0 | $0 | | 1 | 0 | $15 | |
| **NOB** | 4 | 0 | $3 | | 5 | 2 | $6 | $11 |
| **PALO VERDE** | 25 | 0 | $6 | | 3 | 0 | $14 | |
| **PARKER** | 0 | 0 | $1 | | 0 | 0 | | |
| **PATH 15** | 31 | 0 | $1 | | 13 | 0 | $24 | |
| **PATH 26** | 0 | 12 | | $1 | 0 | 3 | | $2 |
| **SILVER PEAK** | 0 | 1 | | $30 | 0 | 1 | $5 | $0 |
| **SUMMIT** | 8 | 1 | $0 | $3 | 3 | 0 | $6 | |

## Table 12. Inter-zonal Congestion Costs, August 2004

| Branch Group | Day-ahead | | Hour-ahead | | Total Congestion Cost | | Total Congestion Cost | | Total Congestion Cost |
|---|---|---|---|---|---|---|---|---|---|
| | Import | Export | Import | Export | Import | Export | Day-ahead | Hour-ahead | |
| **BLYTHE** | $651 | $0 | $0 | $0 | $651 | $0 | $651 | $0 | $651 |
| **COI** | $437,503 | $0 | -$4,713 | $0 | $432,790 | $0 | $437,503 | -$4,713 | $432,790 |
| **ELDORADO** | $30 | $0 | $0 | $0 | $30 | $0 | $30 | $0 | $30 |
| **ELVERTA-HURLEY** | $0 | $1 | $0 | $12 | $0 | $13 | $1 | $12 | $13 |
| **LUGO-MARKETPLACE** | $247 | $0 | $0 | $0 | $247 | $0 | $247 | $0 | $247 |
| **LUGO-WEST WING** | $0 | $0 | $320 | $0 | $320 | $0 | $0 | $320 | $320 |
| **MEAD** | $12,791 | $0 | $17,971 | $0 | $30,762 | $0 | $12,791 | $17,971 | $30,762 |
| **NOB** | $84,964 | $0 | $11,001 | $27,200 | $95,965 | $27,200 | $84,964 | $38,201 | $123,165 |
| **PALO VERDE** | $2,421,864 | $0 | $226 | $0 | $2,422,090 | $0 | $2,421,864 | $226 | $2,422,090 |
| **PARKER** | $183 | $0 | $0 | $0 | $183 | $0 | $183 | $0 | $183 |
| **PATH 15** | $798,476 | $0 | $18,781 | $0 | $817,257 | $0 | $798,476 | $18,781 | $817,257 |
| **PATH 26** | $0 | $161,490 | $0 | $609 | $0 | $162,098 | $161,490 | $609 | $162,098 |
| **SILVER PEAK** | $0 | $4,087 | $78 | $0 | $78 | $4,087 | $4,087 | $78 | $4,165 |
| **SUMMIT** | $130 | $1,954 | $6,039 | $0 | $6,169 | $1,954 | $2,084 | $6,039 | $8,123 |
| **Total** | $3,756,840 | $167,532 | $49,702 | $27,820 | $3,806,542 | $195,352 | $3,924,371 | $77,523 | $4,001,894 |

## IV. Firm Transmission Rights Market

**FTR scheduling.** FTRs can be used to hedge against high congestion prices, and to establish scheduling priority in the day-ahead market. Tables 9 shows a high percentage of FTRs was scheduled on some paths (in July: 100 percent on El Dorado, 77 percent on IID-SCE, 94 percent on Lugo-IPP (DC), 65 percent on Lugo-Mona, 60 percent on Palo Verde, 100 percent on Silver Peak in the import direction, and 54 percent on Path 26; in August: 100% on El Dorado, 76% on IID-SCE, 97% on Lugo-IPP (DC), 66% on Lugo-Mona, 63% on Palo Verde, 100% on Silver Peak in the import direction, and 47% on Path 26). FTRs of those paths are mainly owned by Southern California Edison Company (SCE1) and other municipal utilities.

## Table 13. FTR Scheduling Statistics for July, 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 | 88 | 167 | 167 | 53% |
| IMP | ELDORADO | 536 | 536 | 536 | 536 | 100% |
| IMP | IID-SCE | 600 | 463 | 470 | 450 | 77% |
| IMP | LUGO-IPP (DC) ** | 370 | 347 | 370 | 235 | 94% |
| IMP | LUGO-MARKETPLACE ** | 247 | 20 | 50 | 50 | 8% |
| IMP | LUGO-MONA ** | 160 | 104 | 117 | 65 | 65% |
| IMP | LUGO-WEST WING ** | 93 | 28 | 43 | 27 | 30% |
| IMP | MEAD | 624 | 10 | 52 | 27 | 2% |
| IMP | NOB | 725 | 47 | 148 | 100 | 6% |
| IMP | PALO VERDE | 1021 | 611 | 775 | 600 | 60% |
| IMP | SILVER PEAK | 10 | 10 | 10 | 10 | 100% |
| EXP | LUGO-MARKETPLACE ** | 247 | 3 | 3 | 3 | 1% |
| EXP | LUGO-MONA ** | 543 | 31 | 177 | 177 | 6% |
| EXP | NOB | 722 | 12 | 83 | 83 | 2% |
| EXP | PATH 26 | 1141 | 610 | 945 | 575 | 54% |

## Table 14. FTR Scheduling Statistics for July, 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 | 69 | 167 | 167 | 41% |
| IMP | ELDORADO | 536 | 536 | 536 | 536 | 100% |
| IMP | IID-SCE | 600 | 454 | 465 | 445 | 76% |
| IMP | LUGO-IPP (DC) ** | 370 | 357 | 370 | 235 | 97% |
| IMP | LUGO-MARKETPLACE ** | 247 | 25 | 50 | 50 | 10% |
| IMP | LUGO-MONA ** | 160 | 106 | 117 | 65 | 66% |
| IMP | LUGO-WEST WING ** | 93 | 28 | 42 | 28 | 30% |
| IMP | MEAD | 624 | 10 | 55 | 27 | 2% |
| IMP | NOB | 725 | 40 | 148 | 100 | 6% |
| IMP | PALO VERDE | 1021 | 647 | 775 | 600 | 63% |
| IMP | SILVER PEAK | 10 | 10 | 10 | 10 | 100% |
| IMP | VICTORVILLE | 921 | 5 | 50 | 50 | 1% |
| EXP | CFE | 100 | 11 | 32 | 32 | 11% |
| EXP | LUGO-MARKETPLACE ** | 247 | 3 | 3 | 3 | 1% |
| EXP | LUGO-MONA ** | 543 | 14 | 60 | 60 | 3% |
| EXP | NOB | 722 | 15 | 83 | 83 | 2% |
| S-N | PATH 26 | 1141 | 533 | 945 | 575 | 47% |

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

**FTR Revenue per Megawatt.** Due to high congestion frequency and high congestion prices on Palo Verde, NOB and COI, the FTR revenues on these Paths were significant; about $9,505/MWh, $3,725/MWh, and $828/MWh, respectively in July, and about $8,173/MWh, $1,013/MWh, and $521/MWh in August. The FTR revenues on other paths are modest. The following table summarizes FTR revenues during July and August.

**Table 15. FTR Revenue Per MW ($/MW), 2004 FTR Cycle**

| Direction | Branch Group | Net $/MW FTR Rev | | | | | Cumm Net $/MW FTRREV | Pro Rated NET $/MW FTRREV | FTR Auction Price |
|---|---|---|---|---|---|---|---|---|---|
| | | Apr | May | Jun | Jul | Aug | | | |
| IMPORT | BLYTHE | 2,791 | 5,540 | 433 | 0 | 7 | 8,770 | 21,047 | 8,759 |
| IMPORT | COI | 199 | 1,481 | 4,853 | 822 | 521 | 7,876 | 18,902 | 26,964 |
| IMPORT | ELDORADO | 0 | 408 | 10 | 0 | 0 | 417 | 1,002 | 45,169 |
| IMPORT | LUGO-IPP (DC)* | 3 | 0 | 0 | 0 | 0 | 3 | 7 | 63,374 |
| IMPORT | LUGO-MARKETPLACE* | 0 | 0 | 0 | 0 | 5 | 5 | 12 | 81,579 |
| IMPORT | LUGO-MONA* | 0 | 0 | 192 | 0 | 0 | 192 | 461 | 99,784 |
| IMPORT | LUGO-WEST WING* | 0 | 1 | 0 | 0 | 17 | 18 | 43 | 117,989 |
| IMPORT | MEAD | 1,223 | 1,168 | 634 | 464 | 238 | 3,728 | 4,473 | 136,194 |
| IMPORT | NOB | 336 | 1,816 | 19,123 | 3,725 | 1,013 | 26,013 | 31,215 | 154,399 |
| IMPORT | PALO VERDE | 2,074 | 15,146 | 2,457 | 9,505 | 8,173 | 37,355 | 44,826 | 172,604 |
| IMPORT | PARKER | 115 | 15 | 0 | 5 | 6 | 141 | 338 | 190,809 |
| S-N | PATH 15 | 0 | 20 | 20 | 5 | 287 | 332 | 796 | 209,014 |
| IMPORT | SILVER PEAK | 0 | 0 | 0 | 0 | 5 | 5 | 11 | 227,219 |
| EXPORT | NOB | 0 | 0 | 0 | 910 | 522 | 1,433 | 1,719 | 245,424 |
| N-S | PATH 26 | 427 | 27 | 357 | 573 | 139 | 1,523 | 3,655 | 263,629 |
| EXPORT | SILVER PEAK | 0 | 0 | 0 | 0 | 480 | 480 | 1,152 | 281,834 |
| EXPORT | SUMMIT | 0 | 0 | 608 | 0 | 39 | 647 | 1,553 | 300,039 |

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

## V. Issues under Review

**Ancillary Service Market Performance under Amendment 60 and Locational Procurement.** DMA is conducting an analysis of the impacts of the recent market changes on the ancillary service markets. In particular, DMA is looking into whether all available capacity is being bid into the SP15 A/S markets, A/S market concentrations in SP15, and market participant bidding behavior during times of locational procurement. The DMA will provide the results of the analysis to FERC for further review.

**Infeasible Production of Real-Time Energy by Price Setter.** Over the past several months, DMA found that a particular resource that repeatedly set the CAISO's real-time incremental price for balancing energy at $110.86/MWh did so without ever responding to its real-time dispatch. Under current market rules, a unit need not adhere to dispatch instructions, or even be capable of doing so, in order to set the market-clearing price. This will remain the case with the implementation of Phase 1B of the Market Redesign and Technology Upgrade (formerly MD02), although the resource will face uninstructed deviation penalties for its withheld instructed output.

Since September 2003, this small peaking resource has had a standing bid of approximately 7 megawatts, always at $110.86/MWh or higher (approximately $40 to $50 above market average prices for the same time period). It was called and set the price in at least 79 pricing intervals, for an added cost to the market of approximately $250,000. This apparently was a consequence of a discrepancy regarding the unit's operating capability between the resource's owner and its scheduling coordinator. The resource was only able to deliver 17.5 MW but had an hour-ahead schedule when it was to operate to deliver 17 MW. Meanwhile, the scheduling coordinator evidently was under the impression that the resource was able to generate up to 24.6 MW and thus would bid the difference of 7.1 MW into the real-time market. After the CAISO contacted the scheduling coordinator regarding the discrepancy, requiring several follow-ups, the scheduling coordinator resolved the discrepancy, effective July 20. This unit has bid only its actual real-time feasible capacity of 0.5 MW into the real-time market since July 21, still at the price of $110.86/MWh.