California ISO
Your Link to Power

2005 Annual Report

Market Issues and Performance

Department of Market Monitoring
California Independent System Operator

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Executive Summary

Overview

Each year the Department of Market Monitoring (DMM)[1] publishes an annual report on the performance of markets administered by the California Independent System Operator (CAISO). This report covers the period of January 1, 2005, through December 31, 2005.

California's spot wholesale energy markets in 2005 were generally stable and competitive, similar to the past several years (2002-2004), however, as discussed below, the slow pace of new generation investment in California remains a growing concern. One of the primary metrics that the DMM uses to gauge overall market competitiveness is a 12-month Market Competitive Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated "competitive" prices derived from cost-based simulations). The DMM considers MCI values in the range of $5-$10/MWh to be reflective of a workably competitive market. The monthly MCI values estimated for 2005 were well within this range for all months of the year.

The average "all-in" cost of wholesale energy in 2005 was $56.71/MWh of load compared to $53.93 in 2004. All-in costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net RMR costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The increase in the all-in costs in 2005 was primarily due to higher natural gas prices, particularly in the September-December period when there was a sharp increase in natural gas prices due to the supply interruptions from the Gulf Coast hurricanes.

One of the major success stories in 2005 is the sharp reduction in intra-zonal congestion costs. In 2005, intra-zonal congestion costs totaled $203 million, compared to $426 million in 2004, representing a 52 percent decrease. Intra-zonal congestion cost is comprised of three components 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) RMR Costs, and 3) real-time redispatch costs. The main contributors to this decrease were a decline in MLCC costs from $274 million in 2004 to $114 million in 2005 and a decline in real-time redispatch costs from $103 million in 2004 to $36 million in 2005. RMR costs for intra-zonal congestion increased slightly in 2005 ($53 million in 2005, $49 million in 2004). However, total RMR costs, which includes annual fixed option payments and total dispatched energy costs, declined substantially from approximately $644 million in 2004 to $455 million in 2005, a reduction of approximately $189 million. The sharp decline in total RMR costs is due primarily to changes in contract elections relating to the level of fixed option payments for RMR units, reductions in local reliability requirements, and a higher percentage of RMR energy being provided through the market as opposed to the contract.

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2005, the moderate pace of new generation investment in Southern California coupled with unit retirements and significant load growth has created reliability challenges for this region during the peak summer season. In the 2005 summer season, the CAISO declared two Stage 2 Emergencies in Southern California (July 21 and 22). Though a significant amount

[1] As a result of a corporate reorganization in July 2005, the Department of Market Analysis (DMA) was changed to the Department of Market Monitoring (DMM).

of new generation capacity was added to SP15 in 2005 (2,376 MW) and California realized more new generation investment in 2005 than any other ISO[2], new generation investment within Southern California has not kept pace with the significant load growth in that region and unit retirements. This has resulted in a higher reliance on imported power from the Southwest, Northwest, and Northern California. This dependence on imports, coupled with tight reserve margins, makes Southern California very vulnerable to reliability problems should there be a major transmission outage. Moreover, much of the existing generation within Southern California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July, with loads exceeding 40,000 MW for all but two days beginning July 11 and into early August 2005. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California but such investments are not likely to occur absent long-term power contracts. The California spot market alone is not going to bring about the major investments needed to maintain a reliable electricity grid.

The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2005 indicates potential spot market revenues fell significantly short of the unit's annual fixed costs. This marks the fourth straight year that the DMM's analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. This result underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Unfortunately, long-term energy contracting by the state's major investor owned utilities (IOUs) has been very limited. In its 2005 Integrated Energy Policy Report (2005 Energy Report), the California Energy Commission (CEC) reports that, "Utilities have released some Request for Offers (RFOs) for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW out of approximately 12,500 MW under recent solicitations,"[3] and notes that, "California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing."[4] The report notes that the predominance of short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs, "Continuing short-term procurement for local reliability prolongs reliance on aging units that could otherwise be re-powered economically under the terms of longer-term contracts and thereby provide similar grid services at a more competitive price."[5]

In its report, the CEC recommends that the California Public Utilities Commission (CPUC) require the IOUs to sign sufficient long-term contracts to meet their long-term needs and allow for the orderly retirement or re-powering of aging plants by 2012. One of the major impediments to long-term contracting by the IOUs is concern about native load departing to energy service providers, community choice aggregators, and publicly owned utilities, which could result in IOU over-procurement and stranded costs. While this is a legitimate concern, it can be addressed through regulatory policies such as exit fees for departing load and rules governing returning load (i.e., load that leaves the IOU but later wants to return).

While long-term contracting is critical for facilitating new investment, it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Though the CPUC has made significant progress in 2005 in advancing its

[2] FERC Winter 2005-2006 Energy Market Update, February 16, 2006 (http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf)

[3] 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.

[4] 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.

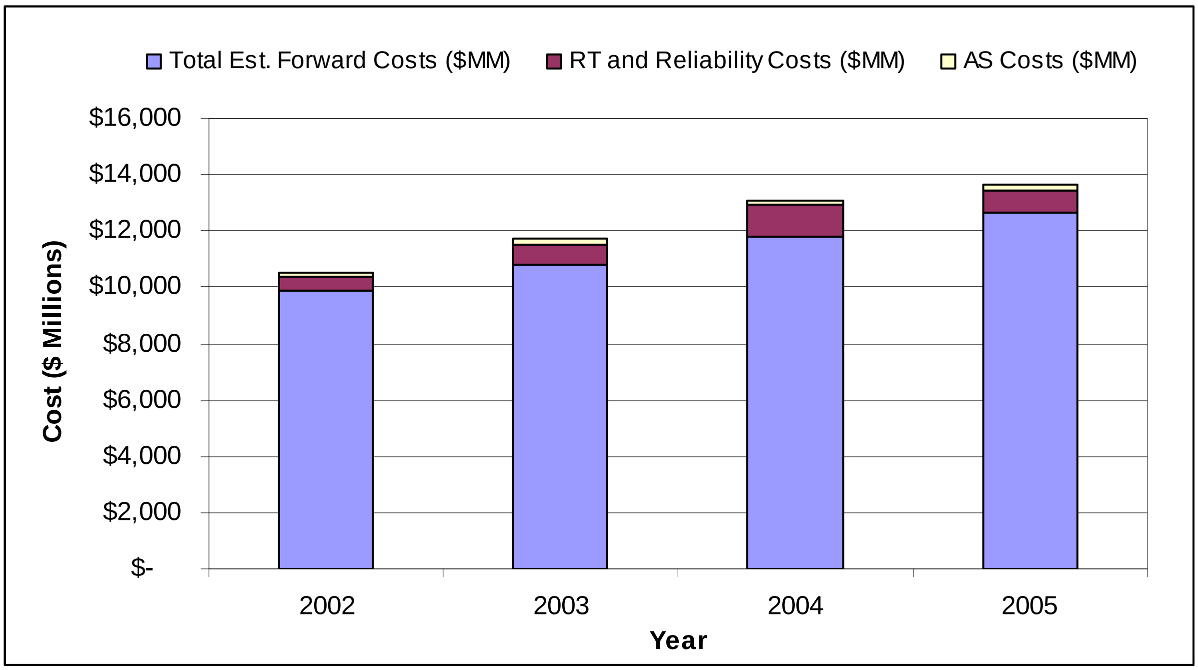
[5] 2005 Integrated Energy Policy Report, California Energy Commission, p. 61.

Resource Adequacy framework, delays in the development and implementation of local reliability requirements could further impede new generation development in critical areas of the grid. Going forward, effective local reliability requirements are critical to facilitating needed generation investment and ensuring reliable grid operation and stable markets.

Total Wholesale Energy and Ancillary Service Costs

Total estimated wholesale energy and ancillary service costs increased by 3 percent in 2005 from $13.1 billion in 2004 to $13.6 billion in 2005.[6] The forward energy cost component increased in 2005 by 6.7 percent, mainly due to higher natural gas prices. However, real-time and reliability costs declined in 2005 by 29 percent from 2004 levels due to a significant decline in real-time intra-zonal congestion costs.

Figure E.1 2002 – 2005 Wholesale Energy Cost Components



Market Rule Changes

Real Time Market Application (RTMA)

Calendar year 2005 was the first full year under the CAISO's new real-time market design. The new Real Time Market Application (RTMA) was designed to address significant shortcomings in the prior real-time dispatch and pricing application (BEEP).[7] However, since its implementation, several issues have been raised concerning RTMA performance. One of the major concerns

[6] Unlike previous annual reports, the annual cost estimates shown here include the cost of RMR dispatch. This cost is included in the category shown in Figure E.1 as "RT and Reliability Costs."
[7] Balancing Energy and Ex-Post Pricing (BEEP) software.

cited is a perceived high degree of price and dispatch volatility. It should be noted that a real-time imbalance energy market is inherently volatile due to the fact it is clearing supply and demand imbalances on nearly an instantaneous basis. A high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids.

In October 2005, the DMM conducted an in-depth market performance assessment of RTMA.[8] One of the key findings of this assessment is that the volatility of 5-minute prices in the CAISO Real Time Market (from one interval to another within each operating hour) has increased significantly since implementation of the RTMA software. In addition, the volatility of individual generating unit dispatches has also increased significantly since implementation of RTMA. Much of the increase in price and dispatch volatility occurring since implementation of RTMA may be attributed to certain design features included in RTMA, which were developed to improve market efficiency. These include the following:

- **Increased Reliance on Market Energy Bids versus Regulation.** RTMA is specifically designed to increase reliance on Real Time Market energy bids to follow short-term fluctuations in demand, which may otherwise be met by the use of regulation energy. During many periods, however, the supply of highly flexible, fast ramping resources offered into the Real Time Market has been limited, so that increased reliance on bids necessarily results in higher price volatility.
- **Prices Set by Marginal Bids Dispatched to Meet Imbalance Each Interval.** Prices under RTMA are set based on the bid of the marginal resource dispatched to meet demand within each interval. Prior to RTMA, the real-time market clearing price (MCP) could be “stuck” for multiple intervals by a high priced bid that was dispatched in a previous interval, but was no longer the marginal unit dispatched in subsequent intervals. RTMA was specifically designed to eliminate the “stuck price” issue that existed in the prior BEEP software.
- **Market Clearing of Incremental and Decremental Bids.** Rather than simply dispatching the bids necessary to meet the projected imbalance of the CAISO system, RTMA dispatches all remaining incremental and decremental bids for supplemental energy with “overlapping” prices (i.e., incremental bids offered at a price lower than the price of decremental energy bids submitted by other participants). This feature was incorporated into RTMA to allow greater overall market efficiency, and to encourage participants to submit increased volumes of incremental and decremental bids.

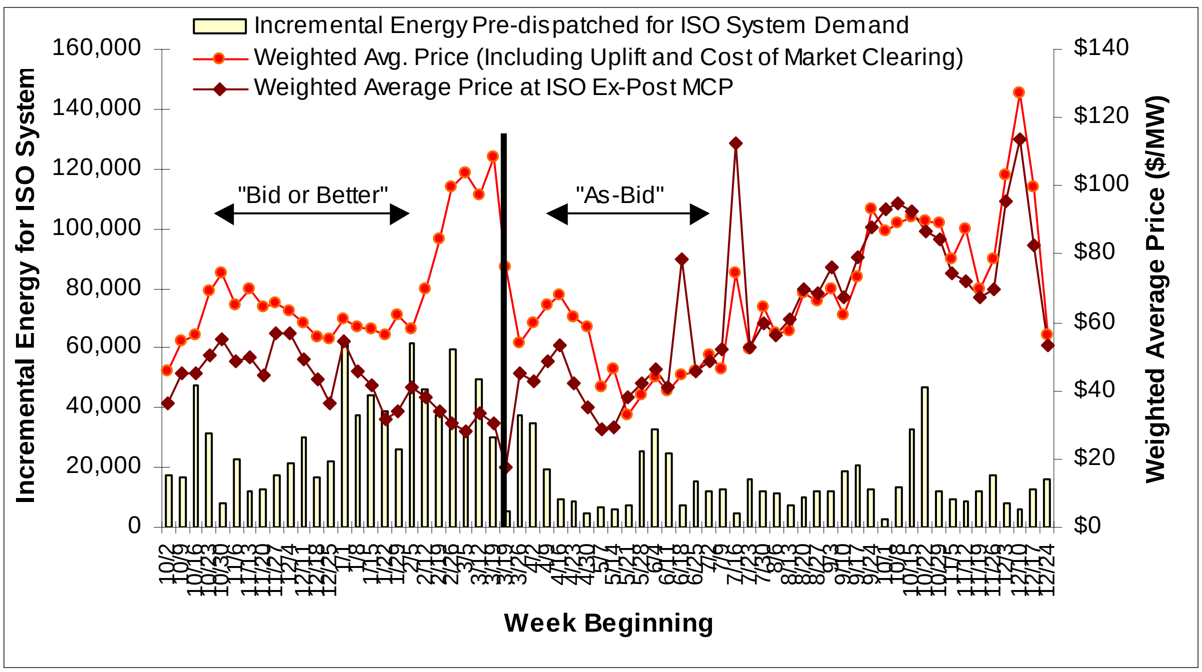
Although RTMA has increased the volatility of prices and dispatches within each operating hour, this appears to be primarily the result of various features of RTMA designed to increase the responsiveness of prices and dispatches to system imbalance conditions in each 5-minute interval. Upon close examination, the fluctuations in prices and dispatches under RTMA closely mirror actual system imbalance conditions.

One problematic feature of the RTMA design that was corrected in 2005 related to the manner in which pre-dispatched inter-tie bids were settled. Under the original RMTA settlement rules, pre-dispatched inter-tie bids were settled based on a “bid or better” method in which the

[8] Assessment of Real-time Market Application (RTMA) Performance, DMM Report, October 12, 2005 (http://www.caiso.com/docs/09003a6080/37/8c/09003a6080378c2c.pdf)

dispatched inter-tie bid was settled at its accepted bid price or the real-time price, whichever was more favorable to the bid owner. Under these rules, import dispatches were paid the higher of the market clearing price or their bid price and export dispatches were charged the lower of the market clearing price or their bid price. Monitoring of this market feature revealed that market participants were bidding imports and exports across the ties in such a way that increased the probability of having import bids accepted in the pre-dispatch that were priced above the real-time MCP and, consequently, paid an uplift for the difference between the bid price and the MCP. Evaluation of this practice indicated that these uplift charges were pervasive and excessive, leading the CAISO to file with FERC an amendment (Amendment 66) to the market design that changed the settlement of pre-dispatched import bids from “bid or better” to “as-bid.” Under an ‘as-bid’ settlement, these bids are paid the bid price if dispatched, and are not eligible to receive the MCP if the MCP is higher than the bid price. This change is settlement for pre-dispatched energy at the inter-ties removed the incentive for participants to bid strategically in the Real Time Market to capture extra-marginal uplift payments from bids over the real-time MCP. Since implementation of this settlement change on March 25, 2005, the prices for pre-dispatched energy from import/export bids have tracked much more closely with real-time market prices set by resources within the CAISO system subsequently dispatched within each operating hour. This can be seen in Figure E.2. In addition, the amount of pre-dispatch inter-tie bids eligible for an uplift has declined significantly since the settlement rule change.

Figure E.2 Price Comparison of Pre and Post Amendment 66

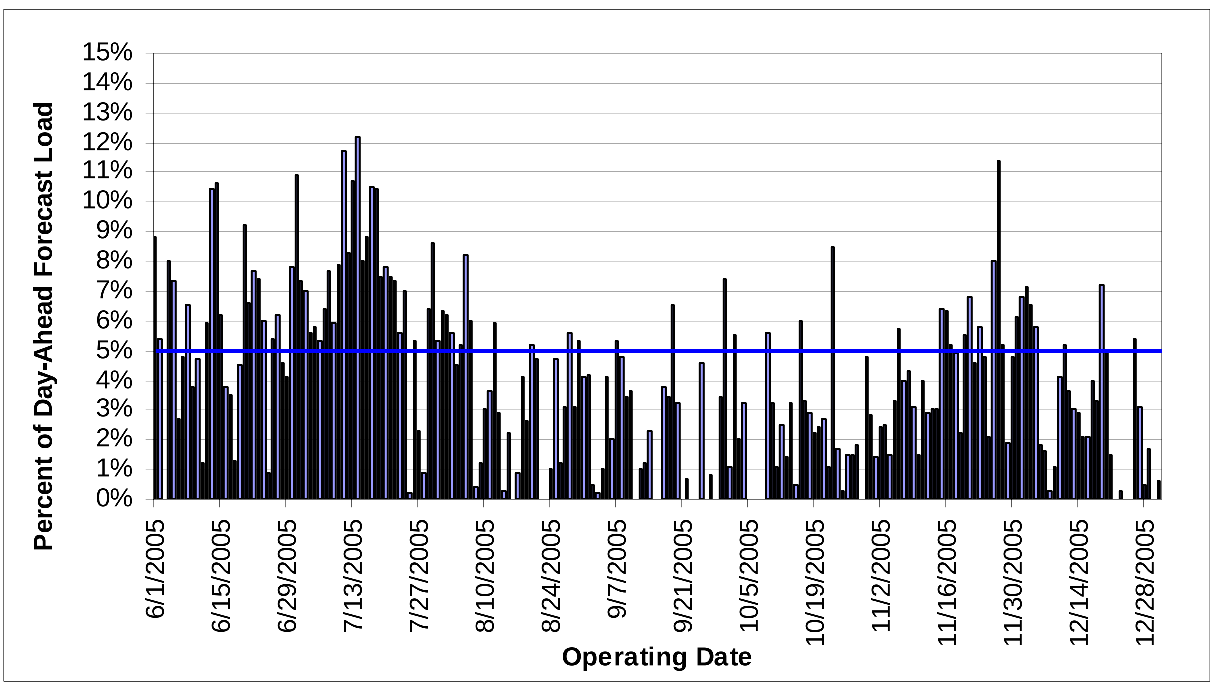


Load Scheduling Practices

With the onset of peak summer demand conditions in early July, CAISO Operations raised concerns about load under-scheduling in the Day Ahead Market. The concern predominately related to shortfalls between the CAISO day-ahead forecasted load and the level of final day-ahead load schedules. To the extent such shortfalls exist, the CAISO operators need to commit additional units through the Must Offer Obligation (MOO) waiver denial process, which puts additional administrative burdens on operational staff and introduces significant commitment uplift costs to the market. More fundamentally, it raises a concern about whether Load Serving Entities (LSEs) have adequately planned for meeting their peak load obligations. During this time, day-ahead schedules had been as much as 12 percent less than the day-ahead forecast and had caused significant commitment of resources under the must-offer waiver denial process.

In response to this situation, the CAISO entered into a Memorandum of Understanding on July 15 that called for Scheduling Coordinators (SCs) having load in the CAISO Control Area to agree to schedule at least 95 percent of their forecasted requirement in the Day Ahead Market. On November 21, 2005, this scheduling principle was codified into the CAISO Tariff through Amendment 72. Figure E.3 shows day-ahead load schedules as a percent of day-ahead forecasted load for the period June 1-December 31, 2005, and demonstrates that load schedules were much closer to the 95 percent requirement beginning in late July and continuing through the rest of the year. However, the second half of November was a notable period, in which day-ahead under-scheduling was at or above the 5 percent level. This pattern coincides with abnormally high natural gas prices. These high natural gas prices may have impacted the spot bilateral procurement costs so as to shift some procurement from the Day Ahead Market to the day-of markets. As natural gas prices declined in late December and into January of 2006, load scheduled in the Day Ahead Market was predominantly above the 95 percent level.

Figure E.3 Percent of CAISO Forecast Total Load Not Scheduled in the Day Ahead Market



General Market Conditions

Demand

Loads in 2005 were only slightly above those in 2004 on an overall basis. The relatively modest increase was due to unusual weather patterns, which included very mild temperatures in the early and late part of the summer. However, a prolonged heat wave did occur between July 11 and August 7. While not the hottest on record, the July-August 2005 heat wave lasted an exceptionally long time without respite and extended to most areas across California. It resulted in four straight weeks of daily peak loads above 40,000 MW, with the exception of two Sundays, which were just shy of that level. The CAISO's 2005 peak load of 45,431 MW on July 20 was slightly lower than the 2004 peak of 45,597 MW on an absolute basis, but was effectively slightly higher than the 2004 peak when adjusted for the departure of approximately 200 MW of Western Area Power Administration load from the NP26 portion of the CAISO service area on January 1, 2005. Table E.1 shows two sets of annual load statistics for the CAISO Control Area, statistics based on actual loads, and statistics based on adjusted loads that reflect changes to the CAISO Control Area and adjustments for the 2004 leap year.

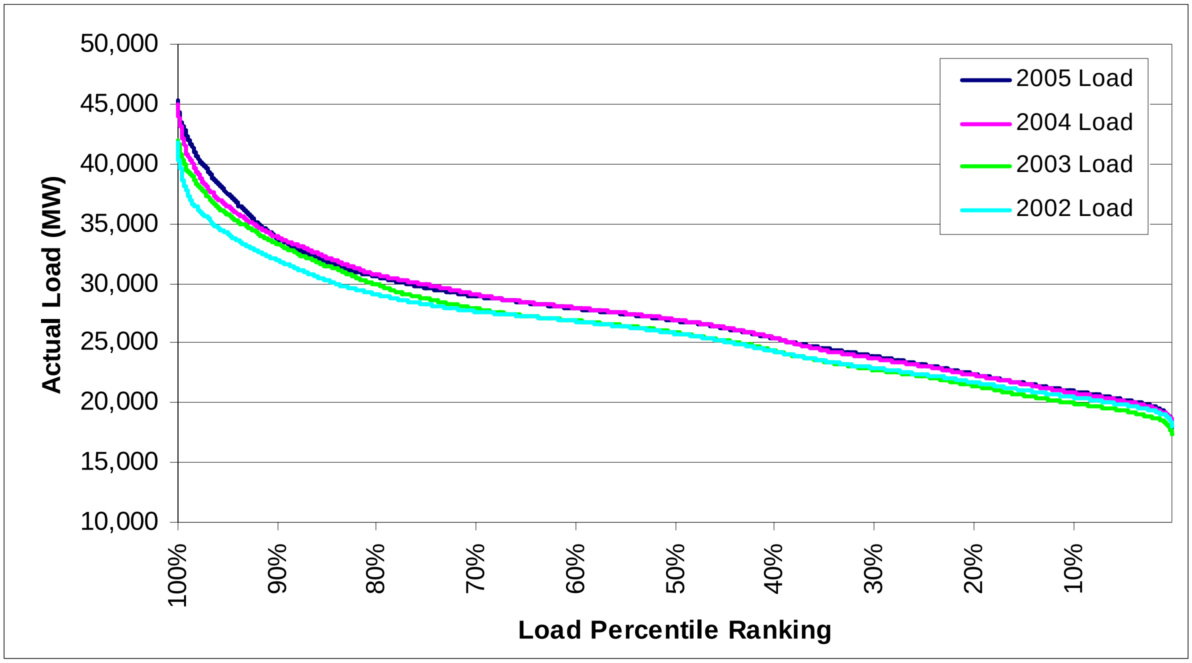
Table E.1 Load Statistics for 2001 – 2005*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2001 Actual	26,004		227,795	41,155	
2002 Actual	26,572	2.2%	232,771	42,352	2.9%
2003 Actual	26,329	-0.9%	230,642	42,581	0.5%
2004 Actual	27,298	3.7%	239,786	45,597	7.1%
2005 Actual	26,992	-1.1%	236,450	45,431	-0.4%
2001 Adjusted	24,556		215,111	39,516	
2002 Adjusted	25,737	4.8%	225,456	41,890	6.0%
2003 Adjusted	26,027	1.1%	227,997	42,058	0.4%
2004 Adjusted	26,933	3.5%	235,933	45,079	7.2%
2005 Adjusted	26,947	0.1%	236,056	45,431	0.8%

* Adjusted figures are normalized to account for leap year, day of week, and changes in CAISO Control Area.

Figure E.4 depicts load duration curves for each of the last four years. Because load in 2005 was generally similar to 2004 due to milder weather, the 2005 curve generally follows the 2004 curve. However, the July-August 2005 heat wave results in the high portion of the 2005 curve (on the left side of the chart) being slightly above the 2004 curve. The 2005 loads were generally above that of 2003 and 2002, indicating a general trend of load growth. For example, when adjusting for the changes in the CAISO footprint, only 0.3 percent of hours between January and November exceeded 40,000 MW in 2002, while 2.5 percent did so in 2005.

Figure E.4 Hourly Load Duration Curves



Significant load growth in the southern portion of the CAISO Control Area (SP15) has presented some reliability challenges during peak summer days. The SP15 peak of 26,459 MW, set on July 21, was 716 MW above the previous regional peak, and SP15 load came within 20 MW of that peak again on July 22. This indicates a year-to-year regional peak load growth rate of approximately 2.7 percent, continuing to reflect the population growth in inland areas such as San Bernardino and Palm Springs.

Supply

Approximately 3,300 MW of new generation capacity was added to the CAISO Control Area in 2005, which represented the largest annual increase over the five-year period of 2001-2005 and, as noted earlier, represented more new generation investment in 2005 than any other ISO. The majority of this new generation was in SP15. However, projected new generation for 2006 is much lower at only 441 MW. Over the six-year period from 2001-2006, approximately 14,000 MW of new generation will have been added to the CAISO Control Area with approximately equal amounts located in Northern and Southern California (NP26, SP15). However, during this same period a significant amount of generation has or is scheduled to retire. Approximately 5,500 MW of generation capacity will be retired by 2006 resulting in a control area-wide net increase in generation of approximately 8,600 MW. The majority of unit retirements are in SP15, which reduces the total net new generation in that region to only 2,557 MW. Moreover, when an annual load growth in SP15 of 2 percent is considered, the load growth exceeds the net new generation by 537 MW. These figures are summarized in Table E.2. The 1,320 MW of retirements projected in SP15 for 2006 represent the coal-fired Mohave Units 1 and 2.[9] Low

[9] Though the maximum capacity of these two units is 1,580 MW, not all of that capacity has been historically scheduled with the CAISO. The 1,320 MW figure is more reflective of historical availability.

levels of net-generation additions to SP15 have contributed to the summer reliability challenges for that region.

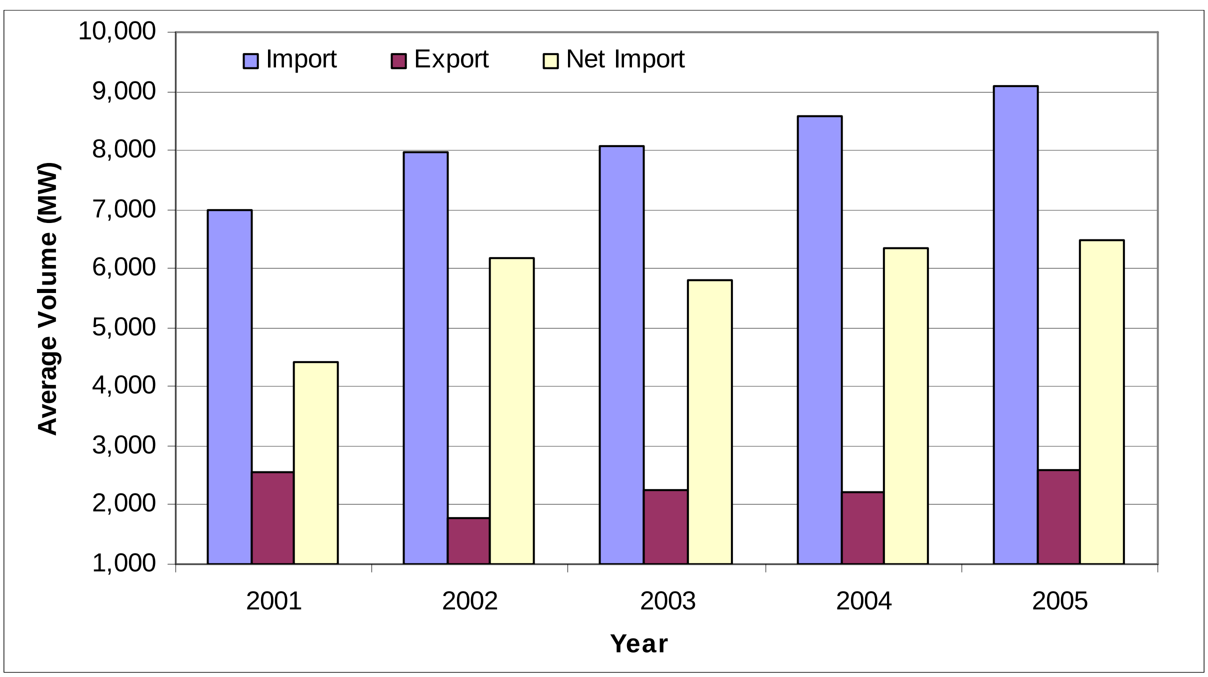
Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	Projected 2006	Total Through 2006
SP15							
New Generation	639	478	2,247	745	2,376	352	6,837
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	(4,280)
Forecast Load Growth*	491	500	510	521	531	542	3,094
Net Change	148	(1,184)	565	48	1,395	(1,510)	(537)
NP26							
New Generation	1,328	2,400	2,583	3	919	89	7,322
Retirements	(28)	(8)	(980)	(4)	0	(215)	(1,235)
Forecast Load Growth*	389	397	405	413	422	430	2,456
Net Change	911	1,995	1,198	(414)	497	(556)	3,631

* Assumes 2% peak load growth using 2005 forecast from 2005 Summer Assessment.

Imports continue to play a key role in meeting demand. Figure E.5 shows annual gross imports, exports, and net imports for the five-year period covered by 2001-2005. Net imported energy increased for the fifth year in a row with net imports over the entire year in 2005 increasing by approximately 2 percent from 2004 despite similar total load levels.

Figure E.5 Average Annual Imports, Exports, and Net Imports (2001 – 2005)



With respect to availability of hydroelectric supply, snowfall in the California Sierra Nevada and in other Southwest ranges was generally well above average during the winter of 2005, which provided for robust runoff and storage among CAISO hydroelectric resources during the spring and summer of 2005. This largely offset the unusually low supply from the Pacific Northwest, which suffered a below-average snowpack. Due primarily to the robust snowpack and relatively slow melt within California, and, to a lesser extent, a wet late fall, CAISO hydroelectric production in 2005 was near the top of the recent five-year range for most of the year.

Generation Outages

Scheduled and forced generation outages were generally lower than last year during the off-peak seasons but higher during the peak summer months (Figure E.6). Forced outage levels were particularly high during July 2005. During the aforementioned July-August heat wave, the CAISO Control Area's entire generation fleet was operating seven days per week. For the entire duration of the heat wave, which lasted from July 11 to August 7, CAISO loads exceeded 40,000 MW on every day except 2 Sundays, where peaks were just shy of that level. This heat wave was unusually long, and required that generation remain on continuously, even on weekends. Consequently, typical weekend maintenance was deferred, contributing to an unusually high forced outage rate in July. With the exception of July, forced outages during the summer season were comparable to last year. Overall outages (planned and forced) were higher in September compared to September 2004 due to more planned outages, which were likely approved because of unusually low load levels in September. Figure E.7 compares annual forced outage rates since 2000. Despite the high outage rate in July, the overall forced outage rate in 2005 was the lowest since 2000. This is due primarily to the substantial increase in new generation units since 2000, which has a decreasing effect on outage rates.

Figure E.6 Monthly Average Planned and Forced Outages (2002 – 2005)

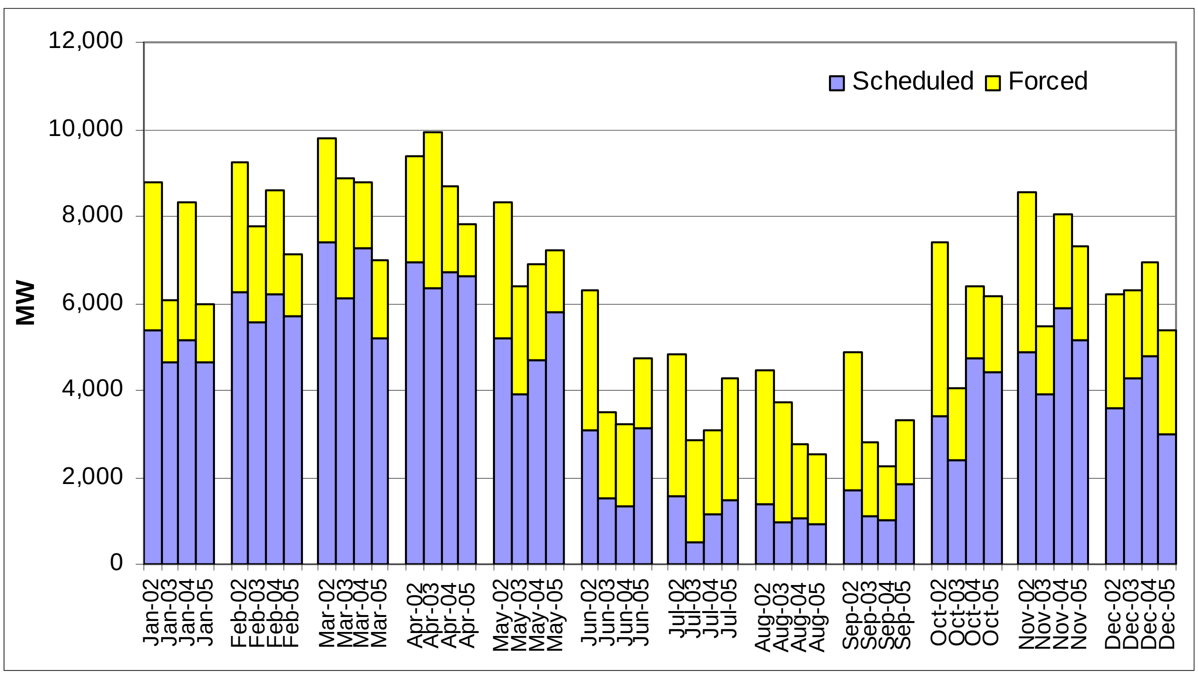
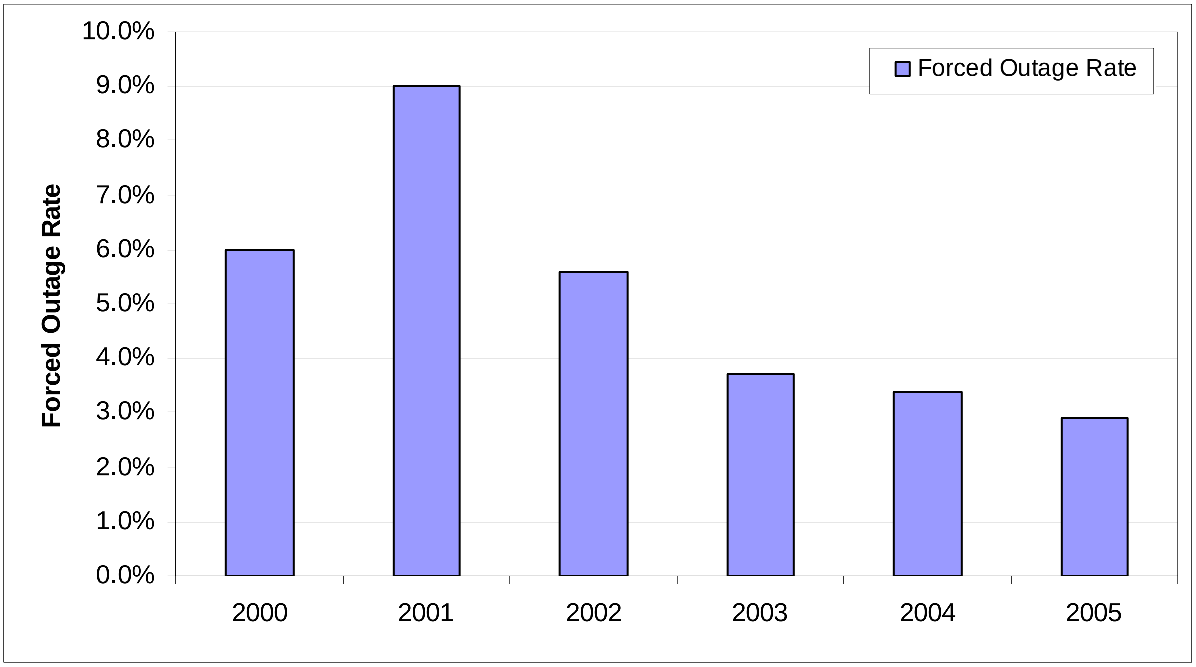


Figure E.7 Annual Forced Outage Rates (2000 – 2005)



Reserve Margins[10]

The system reserve margin, the ratio of available generation over and above actual load to actual load during the peak load hour, increased slightly from 2004 from 15.3 percent in 2004 to 16.9 percent in 2005 (Figure E.8). While the peak load remained substantially the same between 2004 and 2005, the amount of available generation also increased. The overall reserve margin in 2005 was achieved largely due to both a high level of net imported energy during the peak hour of 8,284 MW, and a high level of available internal generation. It is important to note that the system reserve margin does not reflect tight supply conditions resulting from deliverability constraints into the Southern California load center. Constraints limiting the amount of imported energy on the transmission system result in regional differences in reserve margins. While similar levels of new generation have come on line in Northern and Southern California during the last several years, demand growth has been greater in the South. Inadequate reserves will become an increasingly greater concern in future years unless additional generation is built, retirements of generating units are delayed, the transmission system is improved, and additional energy efficiency measures are implemented. Figure E.9 shows the SP15 and NP15 reserve margins for the Southern California peak load day that occurred on August 21, 2005. The SP15 reserve margin was only 6 percent due to generation outages and transmission constraints, while the NP15 margin was a more comfortable 23 percent.

[10] The reserve margins represented here illustrate the ratio of excess available generation (i.e., available generation minus load) to load. Available generation is defined as total generation less planned and forced outages. Capacity out on must-offer waivers is considered available for this analysis. This is not the same as an operating reserve margin where units must be synchronized with the grid.

Figure E.8 Reserve Margins During Annual Peak Load Hour (1999 – 2005)

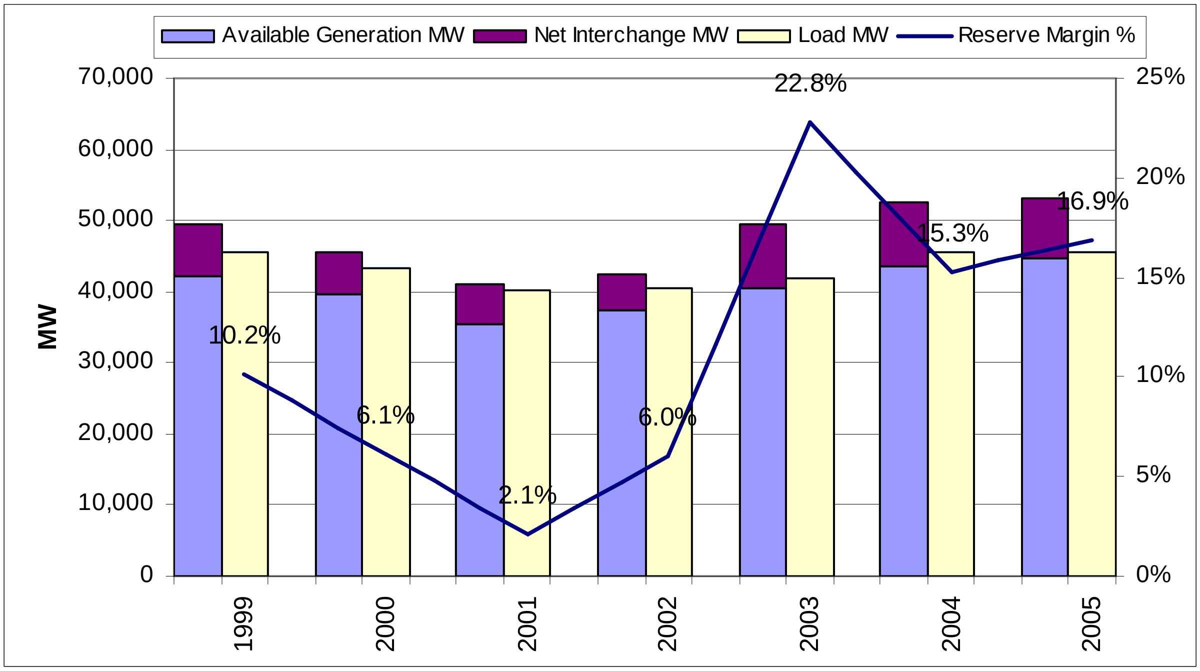
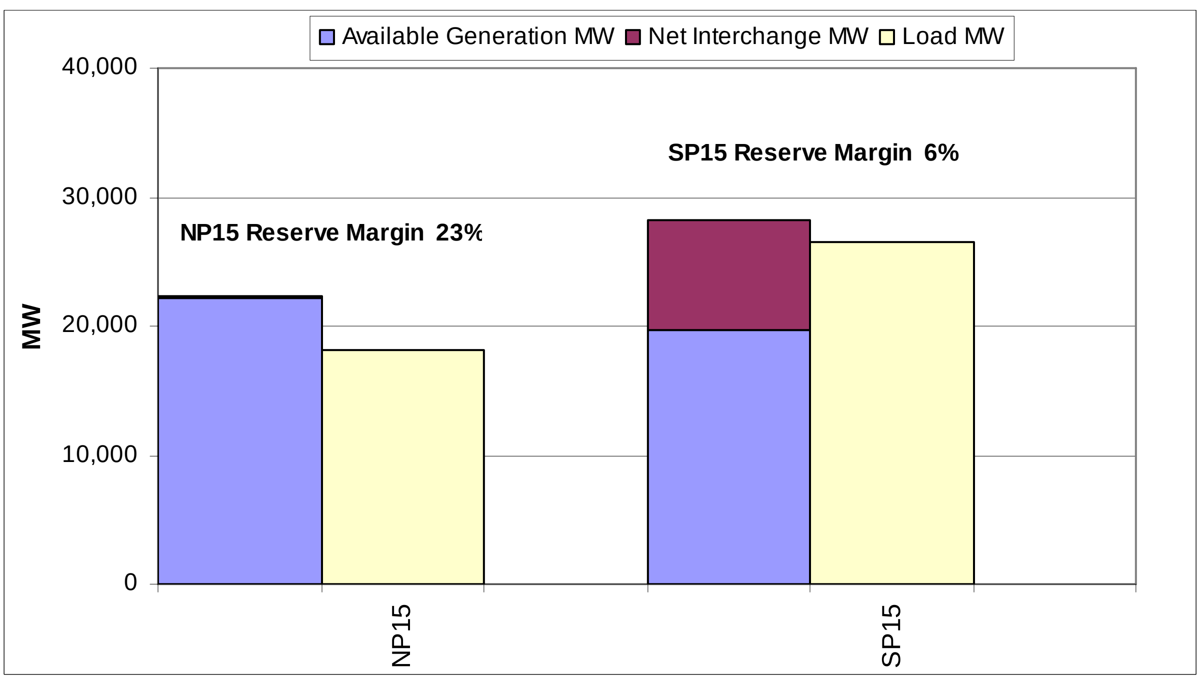


Figure E.9 Zonal Reserve Margins During SP15 Peak Load Hour (August 21, 2005)



Short-term Energy Market Performance

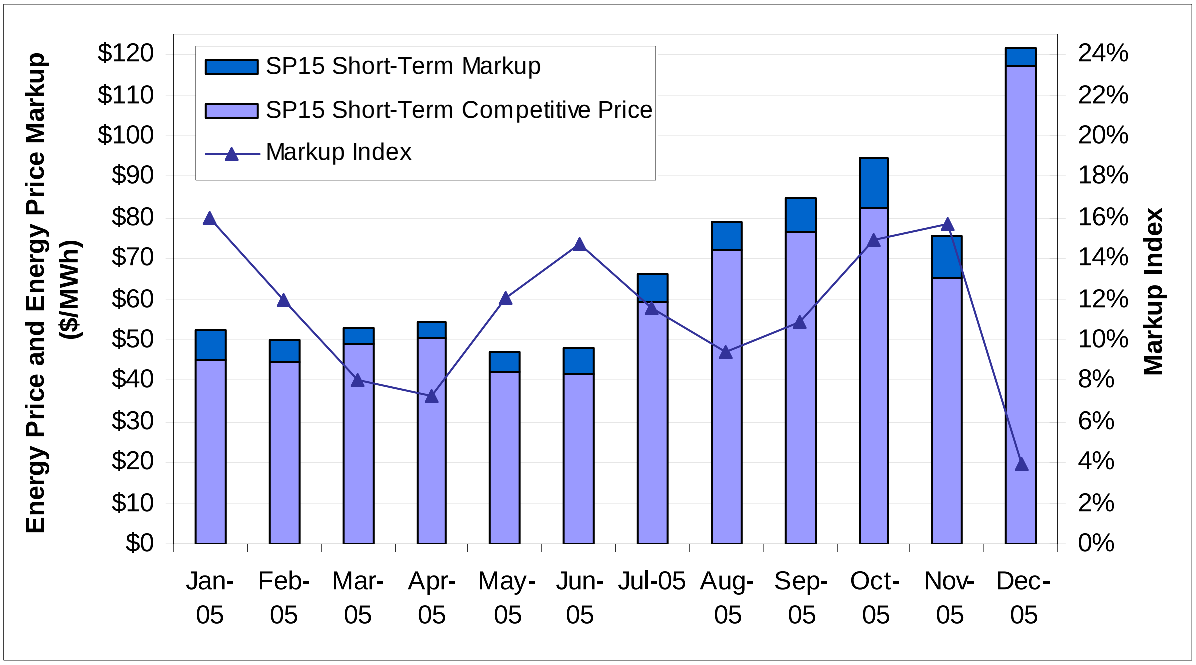
The significant number of long-term contracts entered into by the state of California in 2001 and by load serving entities since then combined with the large amount of new generation added to the western energy markets provided effective market power mitigation in the 2005 short-term energy markets. When load serving entities are adequately supplied though longer-term energy arrangements, they substantially reduce their exposure to market power in the spot market and, more generally, high spot market prices. Adequate supply also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures are in place to reduce the risk of market manipulation and opportunistic exploitation of contingencies and extreme circumstances. However, mitigation should not excessively dampen spot market volatility, as that may encourage load serving entities to reduce their forward contract cover and rely more on the spot markets.

Estimated Mark-up of Short-Term Bilateral Transactions

Having no formal forward energy market makes a comprehensive review of competitiveness difficult due to lack of reporting on transactions in the short-term bilateral energy market. The DMM has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[11] an independent energy information company featuring the first hourly wholesale power indexes in the WECC, and short-term purchase cost information provided by the state's three investor owned utilities. The competitive benchmark prices are calculated using a production cost model that determines the hourly system marginal cost by incorporating detailed generation unit and system cost information. Figure E.10 shows the monthly average short-term mark-up for SP15. The NP15 results were similar and can be found in Chapter 2, which also includes a detailed description of the methodology and assumptions used in the analysis. SP15 short-term mark-ups ranged between 4 percent and 16 percent (compared to between 2 percent and 20 percent in 2004), indicating competitive market conditions in the short-term wholesale energy markets in California. The highest monthly average mark-ups occurred in the months of October, November, and January. The higher mark-up in these periods is primarily a result of the tighter supply conditions in the market resulting from planned outages of many resources. Overall, the index indicates that short-term wholesale energy markets produced competitive outcomes in 2005 with mark-up averaging around 11 percent.

[11] http://www.powerdexindexes.com/.

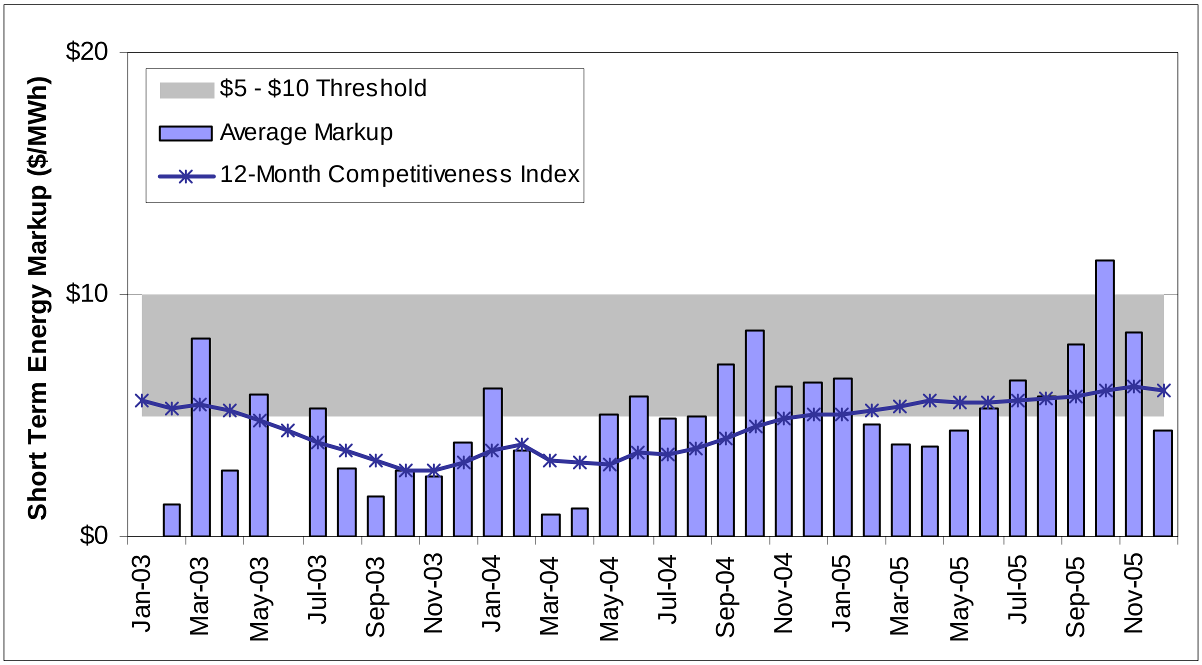
Figure E.10 Short-term Forward Index – SP15 (2005)



Twelve-Month Competitiveness Index

Another index the CAISO uses to evaluate market competitiveness is the 12-month competitiveness index. The CAISO developed the index to measure market outcomes over a long period of time and to compare them to expected competitive market outcomes. The index is a volume-weighted twelve-month rolling average of the short-term energy mark-up above estimated competitive baseline cost. The index provides a benchmark to measure the degree of market power exercised in the California short-term energy market during a 12-month period. Experience has shown that the market is workably competitive when the index is within a range of approximately $5 to $10/MWh or below. The index, which crossed this threshold in May 2000 and remained very high during the California energy crisis, served as a barometer for uncompetitive market conditions. The index moved back into the competitive range in May 2002 and has remained in that range through 2005. This indicates that the short-term energy market in California that stabilized in late 2001 has produced fairly competitive results over the past four years. Figure E.11 below shows the market competitive index values for the past three years (2003-2005).

Figure E.11 Twelve-Month Market Competitiveness Index



Structural Measure of Market Competitiveness: Residual Supply Index

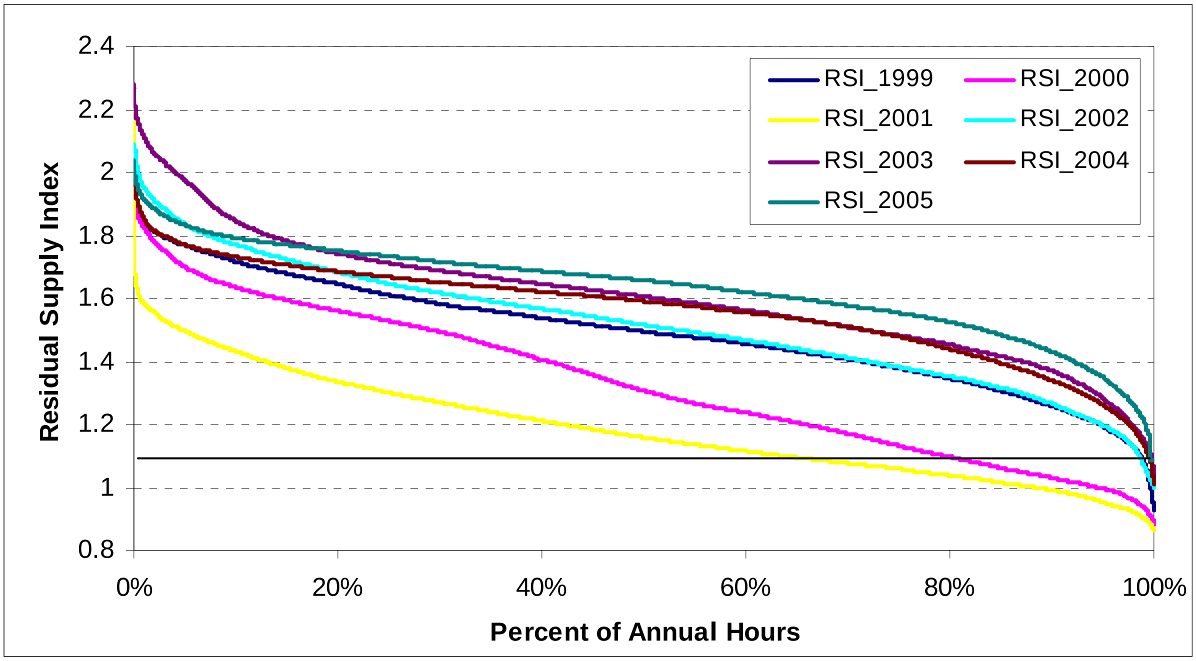
The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2005 were generally higher than in 2003 and 2004, which were the highest of the past five years. Using an RSI level of 1.1 to compare between years,[12] in 2005 the RSI levels were less than 1.1 in less than 0.30 percent of the hours (only 5 hours out of 8760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2005 were again significantly more competitive than in 2000 and 2001 as a result of the addition of new generation and high levels of net imports over the period. The RSI levels are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2005. The significant amount of long-term contracts entered into since 2001 have also led to more competitive market outcomes, although the impacts of contracting are not accounted for in this analysis as it is directed at reflecting the physical aspects of the market. The RSI analysis shows that the underlying physical infrastructure was much more favorable for competitive market outcomes in

[12] Historically, market power can be prevalent with an RSI of 1.1 due to estimation error and the potential for tacit collusion among suppliers.

the period 2002 through 2005 than 2001 as reflected by the higher RSI levels. Figure E.12 compares RSI duration curves for the past seven years (1999 – 2005).

Figure E.12 Hourly Residual Supply Index (1999 – 2005)



Revenue Adequacy of New Generation

Another benchmark often used for assessing the competitiveness of markets is the degree to which prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. However, given lack of information on prices paid in the current long-term bilateral energy and capacity markets, our analysis examined the extent to which spot markets contributed to the economics of investment in new supply capacity given observed prices over the last four years. Clearly a plant would not be built on the expectation of full cost recovery by selling solely into the CAISO's real-time imbalance energy and ancillary service markets. However, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in these markets over the year. Chapter 2 includes a detailed explanation of the costs and assumptions used in the analysis.

The assessment of the potential revenues a new generation facility (combined cycle or combustion turbine) could have earned in California's spot market in 2005 indicates potential spot market revenues fell significantly short of the unit's annual fixed costs (Figure E.13 and Figure E.14). This marks the fourth straight year that the DMM's analysis found that estimated

[13] "Comparative Cost of California Central Station Electricity Generation Technologies," California Energy Commission, Report # 100-03-001F, June 5, 2003, Appendices C and D.

spot market revenues failed to provide sufficient fixed cost recovery for new generation investment.

Figure E.13 Financial Analysis of New CC Unit – SP15 (2002 – 2005)

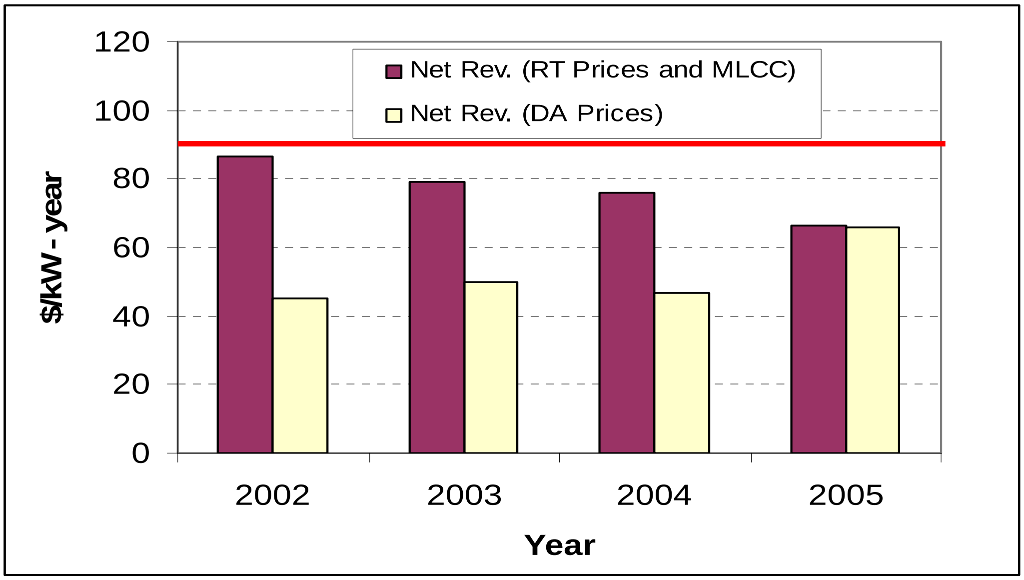
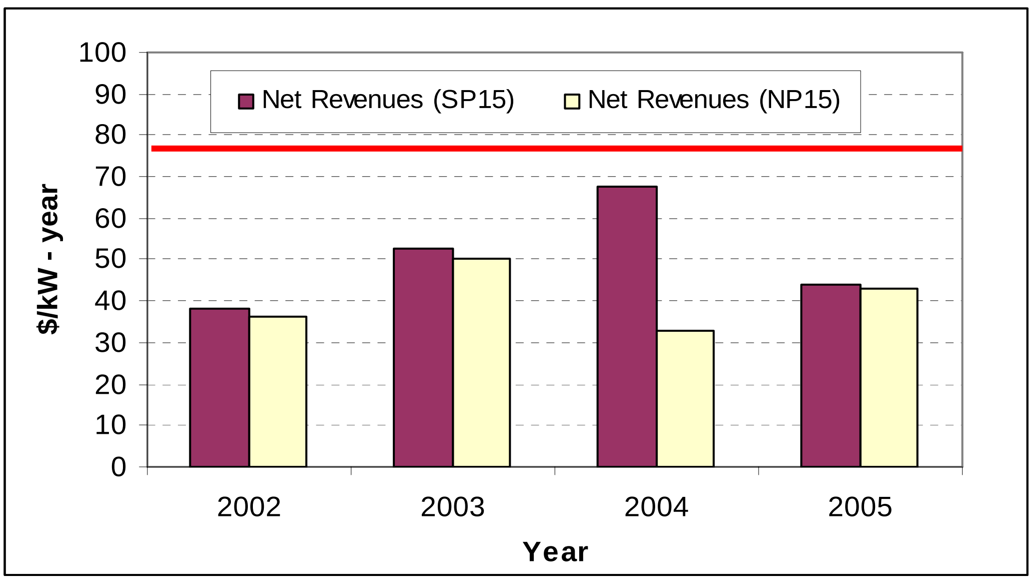


Figure E.14 Financial Analysis of New CT Unit (2002 – 2005)



Given the need for new generation investment in Southern California, as reflected in the relatively tight supply margins that occurred in that region during peak summer demand periods over the past two years and documented reliability concerns cited in the CAISO 2005 Summer

Operations Assessment,[14] the finding that estimated spot market revenues failed to provide for fixed cost recovery of new generation investment in this region in both of these years raises two issues. First, it underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Such a procurement framework would need to be coupled with local procurement requirements to ensure energy or capacity procurements is occurring in the critical areas of the grid where it is needed. Second, it suggests there are inadequacies in the current market structure for signaling needed investment. Future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, local ancillary service procurement, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation in November 2007, will provide some of these elements (LMP, some degree of scarcity pricing, and capability to procure ancillary services locally). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and comparable programs for non-CPUC jurisdictional entities.

Utilization of the Must-Offer Obligation (MOO)

The Must-Offer Obligation (MOO) refers to a CAISO Tariff provision that requires all non-hydroelectric generating units that participate in the CAISO markets or use the CAISO Controlled Grid to bid all available capacity into the CAISO Real Time Market in all hours. This provision originated from an April 26, 2001, FERC Order adopting a prospective monitoring and mitigation plan for real-time California wholesale energy markets and has been extended through a series of subsequent FERC orders. For long-start-time units, this obligation extends into the day-ahead time frame to enable the CAISO to issue start-up instructions (or deny shut-down requests) for units the CAISO expects to need the next day. Units that are denied shut-down requests under the MOO are paid for their minimum load energy using a cost-based formula and are eligible to earn market revenues on ancillary service and real-time energy sales to the CAISO. Additionally, units that are committed under the MOO receive a second payment for their minimum load energy through receiving the real-time market clearing price for that energy.

Use of the MOO for reliability services has been extensive over the past three years, although costs associated with this mechanism declined significantly in 2005. Total MLCC costs for 2003-2005 (in millions) were $125, $287, $127, or $539 for the entire three years. While use of the MOO has subsided in 2005, these figures demonstrate the CAISO's continued reliance on and need for the MOO to provide reliability services. The second payment on minimum load, discussed above, comes to about $217 million for the 2003-2005 period, bringing the total non-market compensation for these units to $756 million for this three-year period.

While $756 million paid out to units subject to MOO is a significant revenue source, it should be noted that the majority of these revenues go to a limited subset of units. Eighty percent of the total combined payments for 2005 (MLCC and the second energy payment) were paid to roughly 34 percent of the units committed under the MOO. In the context of providing an additional source for revenue adequacy, the concentrated distribution of payments to a smaller subset of units provides little additional revenues to the larger subset of units receiving only 20 percent of the total payments.

[14] See http://www.caiso.com/docs/09003a6080/35/46/09003a60803546fd.pdf

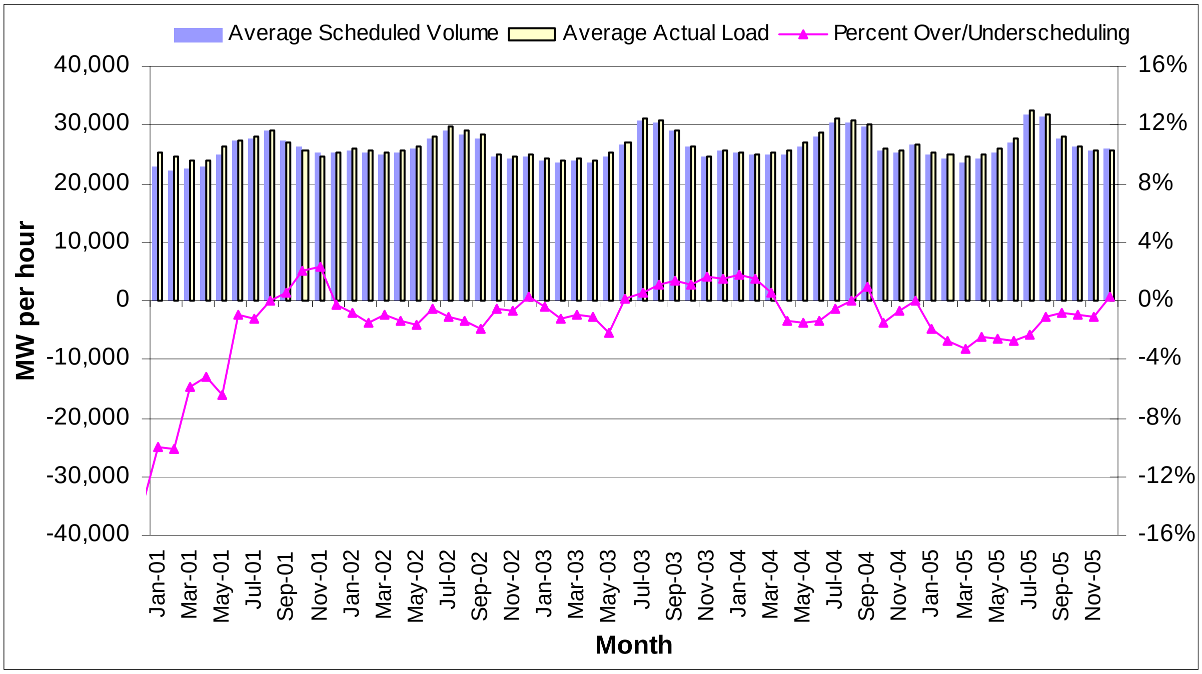
Although the MOO provides cost compensation plus a second market-based payment for minimum load as well as opportunity for market revenues from providing A/S and real-time energy, generation owners have argued that there is insufficient fixed cost recovery provided by the MOO provisions and that units committed via the MOO are providing a reliability service (in addition to energy and A/S) for which they are not being compensated.

In addition, the MOO may provide a potential disincentive for LSEs to enter into long-term contracts with generation owners as LSEs may find it financially advantageous to rely on the MOO for a unit's reliability service rather than contract directly for that service. Bilateral contracts with LSEs could provide generator owners with a more stable and targeted revenue source for fixed cost recovery than is provided under the current MOO structure and thus provide a better opportunity for generator owners to cover their going forward fixed costs. The concern that LSEs might rely on the MOO mechanism rather than contract with the generation resources that are frequently subject to MOO should largely be addressed by the CPUC Resource Adequacy requirements that are going into effect in 2006 – though its effectiveness may be undermined by the lack of locational capacity requirements in 2006. Additionally, the use of RMR or other potential CAISO contracting mechanisms may help to further ensure units that are critical for reliability have adequate mechanisms and opportunities for fixed cost recovery.

Real-time Energy Market

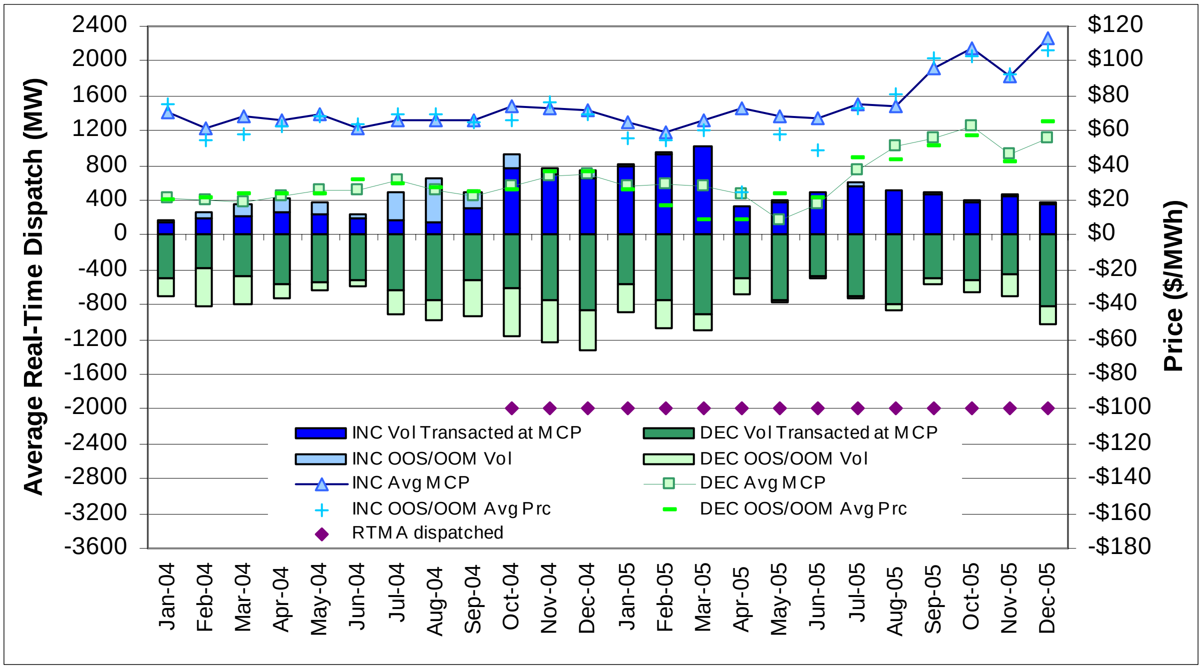
For the fourth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2005. Monthly average forward energy schedules were within 2 percent of actual load as shown in Figure E.15. Real-time balancing energy was again overwhelmingly in the decremental direction as forward schedules plus unscheduled minimum load energy from units committed under the must-offer obligation resulted in frequent over-generation in the real-time imbalance energy market. Frequently, in-sequence incremental dispatch was limited to balancing out-of-sequence decremental dispatches of generation at Mexicali, Mexico or in the Palo Verde area in Arizona to manage intra-zonal congestion and to ensure compliance with the Southern California Import Transmission Nomogram (SCIT), a technical limit on the volume of power that can instantaneously be imported into the SP15 zone.

Figure E.15 Monthly Average Loads and Scheduling Deviations (2001 – 2005)



As shown in Figure E.16, monthly average prices for incremental energy in 2005 were stable, averaging between $60 and $80/MWh from January-August but increasing significantly in the September-December period due to the dramatic increase in natural gas prices resulting from the Gulf Coast hurricanes. Average monthly incremental prices during that three-month period ranged between $90 and $117/MWh. Average monthly prices for decremental energy were also stable, generally ranging between $20 and $40/MWh for most of 2005 but increasing to the $40 to $60 range in the August-December period.

Figure E.16 Monthly Average Real-time Prices (2004-2005)



Competitiveness of Real-time Energy Market

The DMM uses a real-time price-to-cost mark-up index to measure market performance in the Real Time Market. This index compares Real Time Market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[15] While an index based upon the small volume of transactions in the Real Time Market is not necessarily indicative of overall wholesale market competitiveness, it provides a useful metric for Real Time Market performance. Throughout 2005, monthly mark-ups were less than 20 percent and averaged approximately 13 percent, indicating a reasonably healthy real-time energy market (Figure E.17).

The CAISO also uses a Residual Supplier Index (RSI), described earlier, to measure real-time market competitiveness. Figure E.18 shows there is a strong relationship between high real-time incremental market clearing prices and low RSI values. We expect this as lower RSI values indicate less competitive market conditions. Although the real-time energy markets throughout 2005 usually produced competitive outcomes, there were often short periods of time when most of the available real-time energy supply offered to the CAISO had to be dispatched to meet imbalance energy requirements. This often occurred during periods of significant load ramps. During these periods, pivotal suppliers were present and price spikes often occurred, not necessarily due to a lack of resources supplying energy to the real-time imbalance market, but due to insufficient ramping capability of those resources to meet ramping needs.

[15] The original real-time price-cost mark-up index used system marginal cost based on all resources available for day-ahead scheduling. That competitive benchmark is more applicable to measure competitiveness of day-ahead and short-term energy markets. Only a subset of those resources is used in the calculation of the real-time mark-up.

Figure E.17 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market

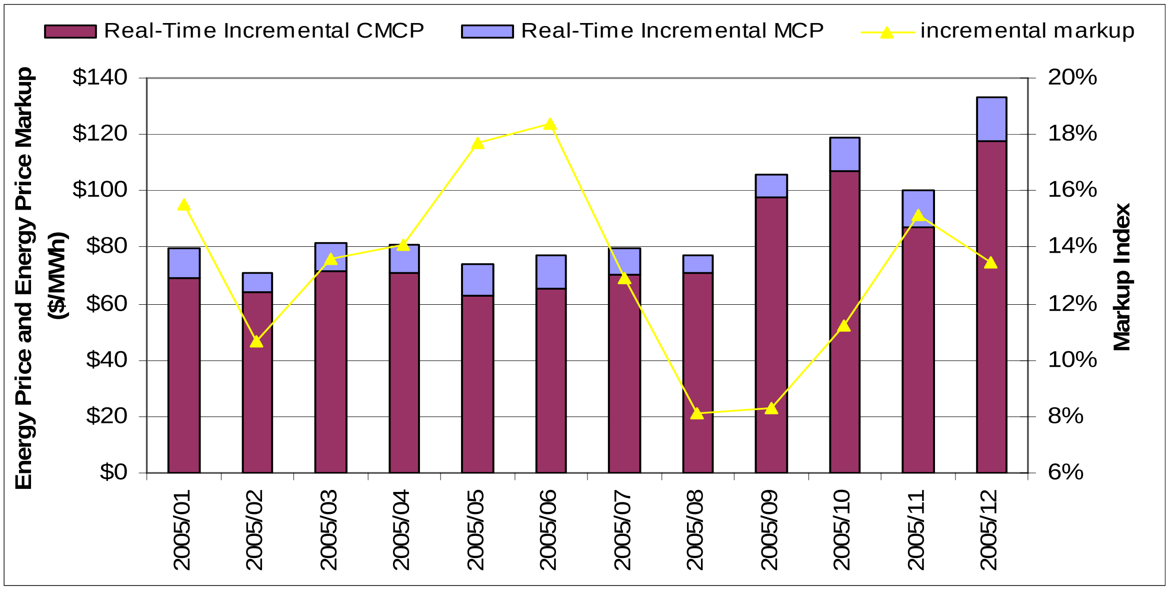
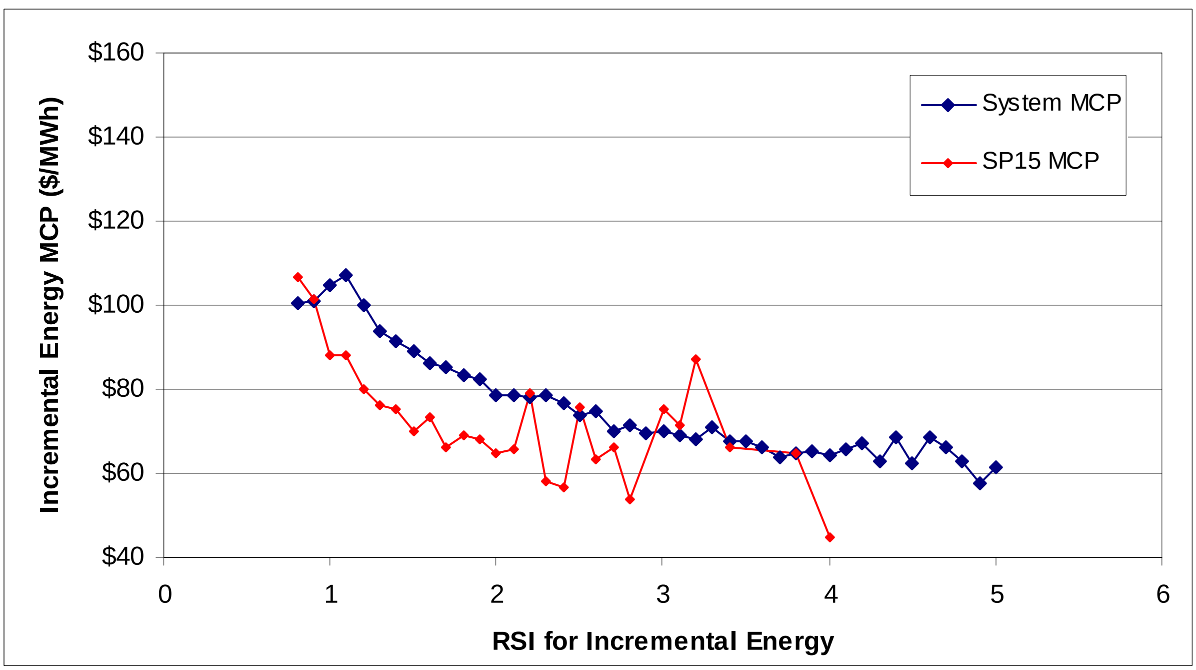


Figure E.18 RSI Relationship to Average Hourly Real Time Incremental Market Clearing Prices



Real-time Congestion (Intra-zonal)

Intra-zonal congestion occurs when power flows overload the transfer capability of grid facilities within the congestion zones that are modeled and managed in the CAISO day-ahead and hour-ahead congestion management system. Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission to allow access to competitively priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together with insufficient transmission to allow the energy to flow out of the pocket area. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Typically, there is very limited competition within load or generation pockets, since just one or two suppliers own the bulk of generation within such pockets. As a result, intra-zonal congestion is closely intertwined with the issue of locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise locational market power.

One of the major success stories in 2005 is the sharp reduction in intra-zonal congestion costs. In 2005, intra-zonal congestion costs totaled $203 million, compared to $426 million in 2004, representing a 52 percent decrease (Table E.3). Intra-zonal congestion cost is comprised of three components 1) MLCC for units denied must-offer waivers, 2) RMR Costs, and 3) real-time redispatch costs. The main contributors to this decrease were a decline in MLCC costs from $274 million in 2004 to $114 million in 2005 and a decline in real-time redispatch costs from $103 million in 2004 to $36 million in 2005. RMR costs for intra-zonal congestion increased slightly in 2005 ($53 million in 2005, $49 million in 2004). Units committed under the MOO declined significantly in 2005 from the high levels seen in 2004 due in large part to resolution of transmission congestion issues frequently experienced at Sylmar and an increase of 500 MW in the SCIT limit that was implemented in January 2005. Both of these factors resulted in a significant decrease in additional unit commitments in SP15 for 2005 and consequently reduced the MLCC costs. The decline in total redispatch costs can be attributed to both a decline in incremental and decremental OOS dispatches. For incremental OOS dispatch, the largest drop in redispatch costs results from less mitigation occurring at the Sylmar substation, which is likely the result of the bank upgrade performed at Sylmar and completed in late 2004. Similarly, incremental redispatch costs for real-time congestion management at SCIT dropped significantly in 2005 – likely due to the 500 MW increase in the SCIT limit that went into effect in January 2005. Decremental OOS energy cost in 2005 was down to $31.4 million, or about half of the 2004 cost. The new transmission line installed at Miguel alone created savings of $21 million in redispatch costs. The remainder of the decline in decremental OOS redispatch costs can be primarily attributed to a reduced need to manage congestion at SCIT, South of Lugo, and Sylmar.

Table E.3 Comparison of 2004 and 2005 Monthly Intra-zonal Congestion Costs by Category

	MLCC			RMR			R-T Redispatch			Total		
	2003	2004	2005	2003	2004	2005	2003	2004	2005	2003	2004	2005
January	$6	$12	$8	$0	$3	$3	$1	$4	$6	$7	$19	$16
February	$6	$13	$4	$1	$4	$3	$0	$7	$3	$7	$23	$10
March	$6	$20	$3	$0	$4	$4	$1	$8	$3	$7	$31	$10
April	$4	$18	$6	$1	$4	$5	$2	$5	$3	$7	$27	$14
May	$1	$22	$14	$3	$3	$5	$0	$4	$2	$3	$28	$20
June	$2	$25	$7	$2	$3	$2	$0	$2	$0	$4	$30	$9
July	$3	$29	$13	$2	$6	$4	$0	$11	$1	$5	$47	$18
August	$13	$29	$14	$4	$5	$7	$9	$15	$1	$25	$50	$22
September	$10	$23	$8	$3	$4	$7	$6	$12	$3	$19	$39	$18
October	$11	$21	$13	$6	$4	$7	$8	$18	$4	$25	$43	$25
November	$9	$29	$12	$2	$5	$4	$2	$9	$6	$13	$44	$22
December	$9	$33	$11	$3	$4	$2	$17	$8	$5	$29	$45	$18
Totals	**$78**	**$274**	**$114**	**$27**	**$49**	**$53**	**$46**	**$103**	**$36**	**$151**	**$426**	**$203**

Ancillary Services Market

In the Ancillary Service Markets, prices were stable but generally higher than last year, following a similar trend to energy prices. The average ancillary service price across all services (Regulation Up, Regulation Down, Spin, Non-Spin) was $10.72/MW in 2005, compared to $8.63/MW in 2004. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.19). Bid insufficiency was down considerably from 2004 in all the Ancillary Service Markets, both in terms of the number of hours having insufficient bids and in the total quantity (MW) of bid deficiency (Figure E.20). The primary reason for the reduction in insufficiency in 2005 compared to 2004 is zonal procurement of reserves. Figure E.20 shows a comparison of monthly insufficiency figures for both years and indicates that the CAISO experienced dramatically higher bid insufficiency between August and December of 2004, which is also the period of time when the CAISO would split the reserve markets and procure by zone (as opposed to system-wide) under circumstances where transmission between NP15 and SP15 was sufficiently limited and would not facilitate reserves from one zone relieving contingencies in the other zone.

Figure E.19 Annual A/S Prices and Volumes, 1999 - 2005

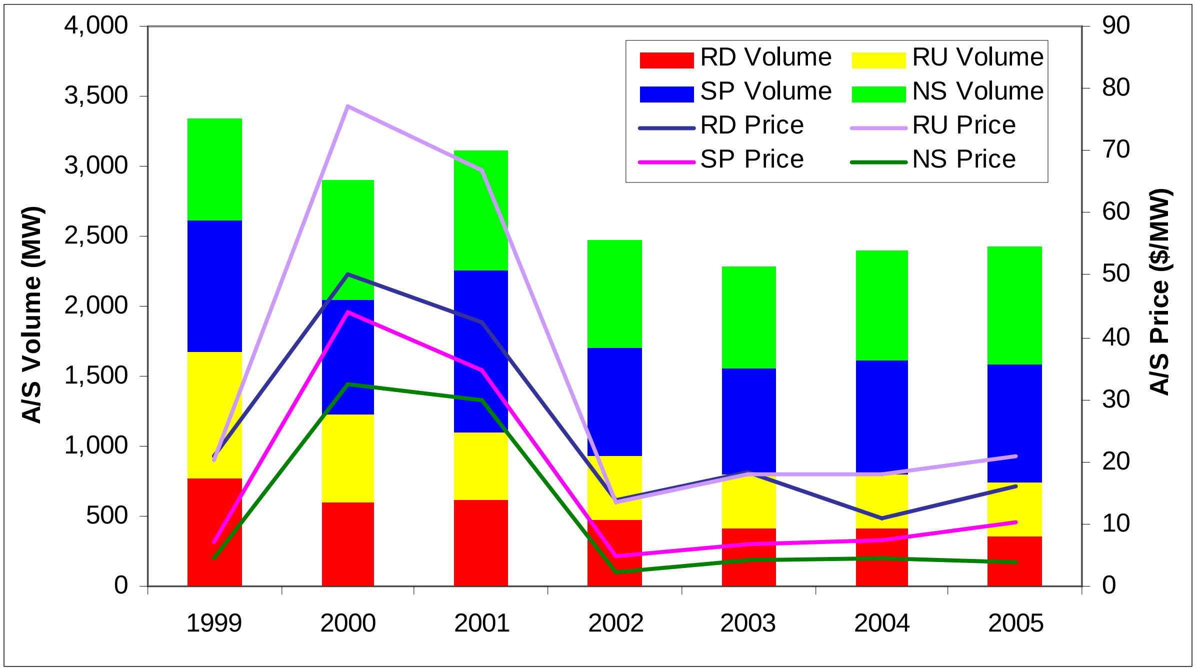
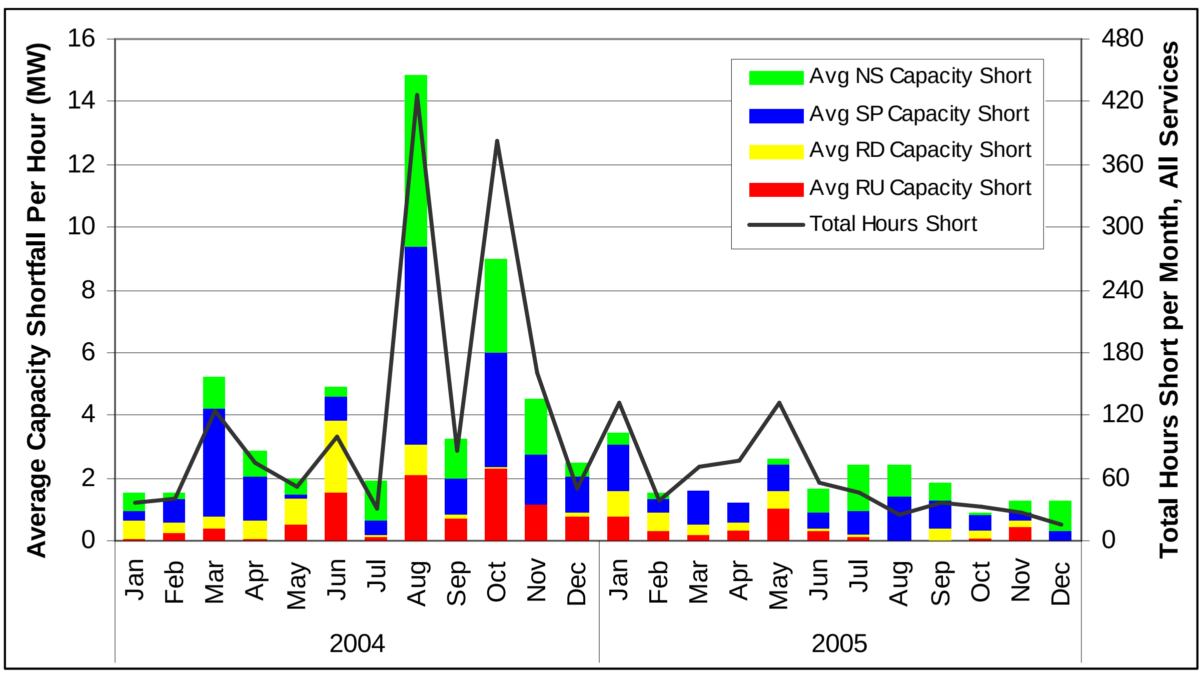


Figure E.20 Bid Insufficiency by Capacity and Hour

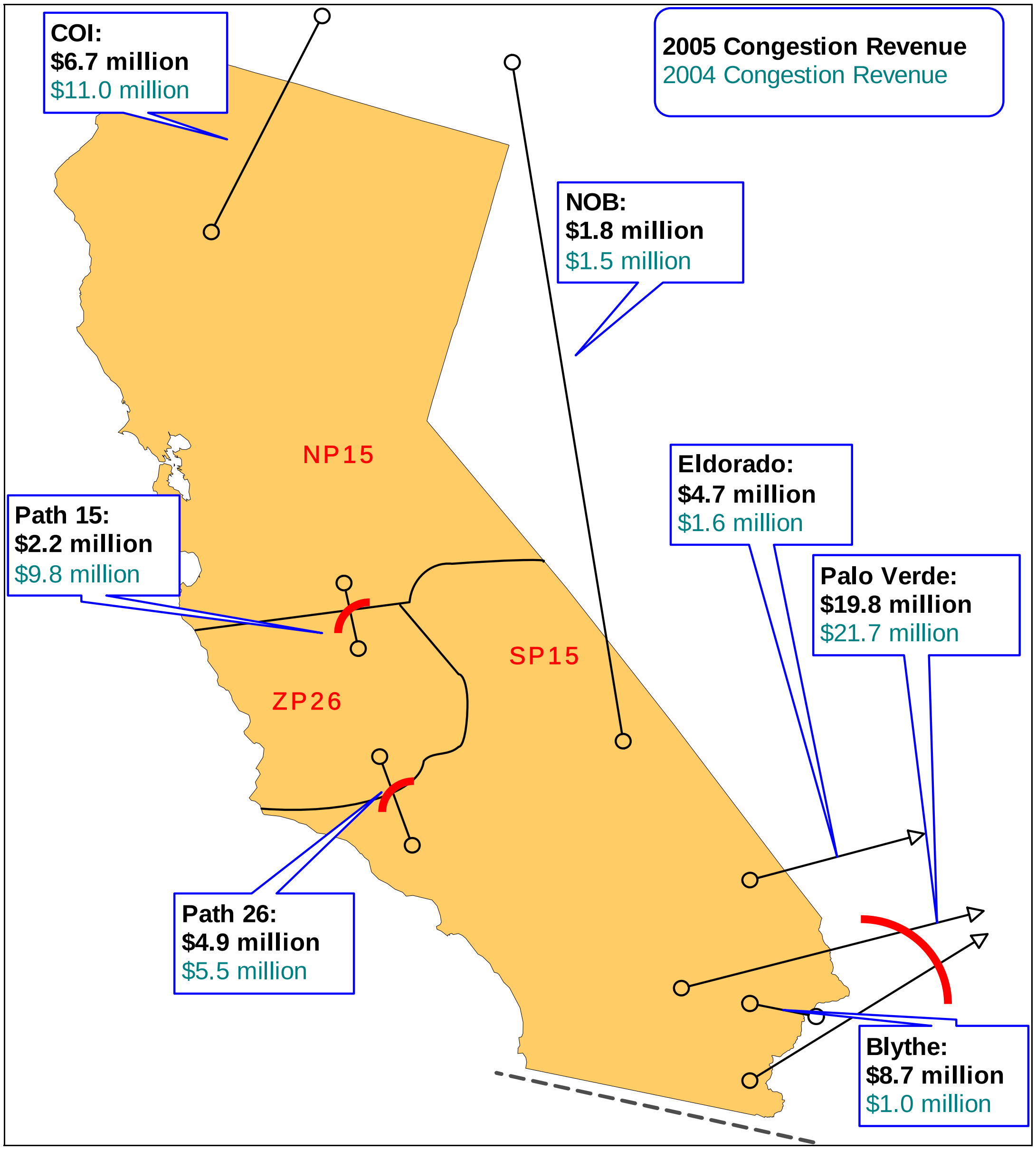


Inter-zonal Congestion Market

The CAISO Inter-Zonal Congestion Management market was also generally stable and competitive in 2005. Total inter-zonal congestion costs in 2005 were $54.6 million, slightly lower than the $55.8 million in 2004. Figure E.21 shows the total annual congestion costs for the most commonly congested paths in 2004 and 2005. Congestion costs on Path 15 went from $9.8 million in 2004 to $2.2 million in 2005. Not surprisingly, Palo Verde had the highest congestion costs in 2005 at $19.8 million (compared to $21.7 million in 2004, which was also the highest). Congestion costs on COI totaled $6.7 million (compared to $11 million in 2004). Interestingly, the path with the second highest congestion costs in 2005 was Blythe, a relatively small path (Max OTC 218 MW with a normal rating of 168 MW) that is part of the interface between SP15 and the Southwest into Arizona. Congestion costs on Blythe totaled $8.7 million in 2005, compared to approximately $1 million in 2004. Most of the 2005 congestion on Blythe was related to Blythe area load fluctuation, which resulted in lower ratings for the Blythe branch group.

The two most frequently congested transmission paths in 2004, the California-Oregon Inter-tie (COI) from the Northwest and Palo Verde branch group from the Southwest, remained the top two congested paths in 2005 with COI being congested in 18 percent of the hours in the Day Ahead Market (compared to 27.5 percent in 2004) and Palo Verde congested in 23 percent of the hours (compared to 22 percent in 2004). Of the internal paths, Path 26 was frequently congested in the north-to-south direction before its rating was increased on June 27, 2005, while Path 15 was much less congested in either direction compared to 2004 due to upgrades that became effective in December 2004.

Figure E.21 California ISO Major Congested Inter-ties and Congestion Costs



Summary and Conclusions

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2005, low levels of new generation investment in Southern California coupled with unit retirements and significant load growth has created reliability challenges for this region during the peak summer season. Low levels of new generation investment within Southern California coupled with significant load growth has resulted in a higher reliance on imported power from the Southwest, Northwest, and Northern California. This dependence on imports, coupled with tight reserve margins, makes Southern California very vulnerable to reliability problems should there be a major transmission outage. Moreover, much of the existing generation within Southern California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July, with loads exceeding 40,000 MW for all but two days beginning July 11 and into early August 2005. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California but such investments are not likely to occur absent long-term power contracts. The California spot market alone is not going to bring about the major investments needed to maintain a reliable electricity grid.

The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2005 indicates potential spot market revenues fell significantly short of the unit's annual fixed costs. This marks the fourth straight year that DMM's analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. This result underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Unfortunately, long-term energy contracting by the state's major investor owned utilities has been very limited. In its 2005 Integrated Energy Policy Report (2005 Energy Report), the CEC reports that, "Utilities have released some Request for Offers (RFOs) for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW out of approximately 12,500 MW under recent solicitations,"[16] and notes that, "California has 7,318 MW of approved power plant projects that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing."[17] The report notes that the predominance of short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs.

In its report, the CEC recommends that the CPUC require the IOUs to sign sufficient long-term contracts to meet their long-term needs and allow for the orderly retirement or re-powering of aging plants by 2012. One of the major impediments to long-term contracting by the IOUs is concern about native load departing to energy service providers, community choice aggregators, and publicly owned utilities, which could result in IOU over-procurement and stranded costs. While this is a legitimate concern, it can be addressed through regulatory policies such as exit fees for departing load and rules governing returning load (i.e., load that leaves the IOU but later wants to return).

While long-term contracting is critical for facilitating new investment in must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Though the CPUC has made significant progress in 2005 in advancing its Resource Adequacy framework, delays in the development and implementation of local reliability requirements could further impede new generation development in critical areas of the grid. Going forward, effective local reliability requirements to facilitate needed generation investment is critical for ensuring reliable grid operation and stable markets.

[16] 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.
[17] 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.

1. Market Structure and Design Changes

1.1 Introduction/Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2005. New market design elements in 2005 include the first full year of operation under the new Real-time Market Application software (RTMA), changes to the RTMA settlement rules for pre-dispatched inter-ties, and a 95 percent load scheduling requirement. Significant infrastructure changes include numerous generation retirements and additions, various transmission upgrades implemented in 2005 and future projects, and numerous changes to the CAISO Control Area operation. In addition, this chapter provides an update on policy efforts to address resource adequacy.

1.2 Market Design Changes

1.2.1 Real Time Market Application (RTMA)

1.2.1.1 RTMA Overview

On October 1, 2004, the CAISO implemented a new software application for running its real-time imbalance energy market. The application, Real Time Market Application (RTMA), was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex Post Pricing, BEEP). 2005 marked the first full year of RTMA operation.

RTMA is designed to receive bids to provide real-time energy, calculate the imbalance energy requirement for the next dispatch interval, and provide an economically optimized set of dispatch instructions to meet the imbalance energy need at least cost subject to resource and transmission grid constraints. Specific enhancements to BEEP that RTMA was designed to provide include:

- Replacement of the Target Price mechanism[1] with economic dispatch (or "market clearing") of all incremental and decremental energy bids with "price overlap" (i.e.,

[1] Prior to RTMA, the Target Price mechanism was utilized by the CAISO to ensure that the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants utilized by the BEEP software was monotonically non-decreasing. Prior to any adjustments by the Target Price mechanism, the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants typically included some "price overlap," or decremental bids with a bid a price higher than the bid price of some the incremental bids. Such a non-monotonic bid curve would result in real-time prices that increased as the ISO switched from inc'ing energy to dec'ing energy. To avoid this, the CAISO developed a Target Price mechanism that would set the system bid curve for the overlapping portion of incremental and decremental bids of eligible resources equal to the bid price at the point where the overlapping bids intersect. This point is referred to as the "Target Price". Initially, all resources (including imports) were eligible to set the Target Price. However, due to gaming potential with this open provision, eligibility to set the Target Price was later (October 2001) restricted to generating units with Participating Generator Agreement and loads with Participating Load Agreement; moreover only capacity that could be dispatched in 10 minutes could set the Target Price.

bids to sell energy (incremental energy bids) at a price lower than the price of bids to buy energy (decremental energy bids).

- Enhanced treatment of resource operating constraints, such as ramp rates, forbidden operating ranges,[2] minimum run times, and start-up times. In addition to lowering uninstructed deviations by increasing the overall feasibility of dispatch instructions. These improvements were necessary in order for the CAISO to gain approval to implement an Uninstructed Deviations Penalty (UDP) from the Federal Energy Regulatory Commission (FERC).
- Optimization of dispatch instructions based on a two-hour “look ahead” period, rather than dispatch of bids in economic merit order for each individual interval.
- Improved system responsiveness and efficiency due to use of a 5-minute dispatch interval, rather than the previous 10-minute interval.
- Increased reliance on automated dispatch instructions.

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA will set generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour’s bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches, (i.e., dispatches prior to the operating hour), hourly inter-tie bids.

Since its implementation, several issues have been raised concerning RTMA performance. One of the major concerns cited is a perceived high degree of price and dispatch volatility. A detailed review of RTMA performance is provided in Chapter 3. One notable aspect of RTMA – settlement rules for pre-dispatched inter-tie bids, was found to be particularly problematic in early 2005 and required a Tariff modification. This issue is discussed below.

1.2.1.2 Settlement of Pre-Dispatched Inter-tie Bids under RTMA

The RTMA design included two significant modifications relating to the dispatch and settlement of import/export bids over inter-ties with neighboring control areas.

- **Market Clearing of Import/Export Bids**. One of the central features of RTMA was the establishment of a market clearing mechanism, under which bids for incremental energy to

[2] Forbidden operating ranges are those operating ranges in which a resource may not operate for an extended period, but must run through as quickly as possible. A unit therefore may not provide regulation service within a forbidden operating region, because that could require the unit to operate within the forbidden region for some period of time.

provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or "cleared" against each other. RTMA applies this market clearing algorithm to all remaining bids after bids needed to meet projected CAISO imbalance energy demand are accepted. This market clearing mechanism, which is incorporated in all other major ISO market designs, was incorporated into the RTMA software to promote greater economic efficiency, encourage participation in the CAISO Real Time Market, and avoid problems with the alternative Target Price mechanism previously employed to resolve incremental and decremental bids with such price overlap.

- **Bid or Better Settlement Rule for Import/Export Bids.** A second key feature of RTMA as initially implemented was settlement of pre-dispatched import/export bids on a "bid or better" basis. Under the "bid or better" settlement rule, hourly import bids pre-dispatched by the CAISO were paid the higher of their bid price or the ex-post Market Clearing Price (MCP). The ex-post MCP is determined by clearing dispatchable bids submitted by resources within the CAISO Control Area on a 5-minute basis. Meanwhile, pre-dispatched export bids were charged the lower of their bid price or the ex-post MCP. This settlement rule was adopted to encourage participation in the real-time market by imports and exports, which are prohibited from setting the real-time market price under market rules established by the Federal Energy Regulatory Commission (FERC). Although the CAISO software pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In cases when MCPs were lower/higher than bid prices of pre-dispatched import/export bids, additional payments or decreased charges applied to pre-dispatched import/export bids were recovered through uplift charges assessed to other CAISO participants based on uninstructed deviations and gross load.

In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the "bid or better" settlement rule. Under the "bid or better" settlement rule, the CAISO incurred uplift charges whenever actual ex-post MCPs were either higher or lower than the projected prices used to clear import/export bids. For example, when ex-post MCPs were higher than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched imports bid at prices in excess, but export bids cleared against these import bids were only charged the ex-post MCP. Conversely, when ex-post MCPs were lower than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched exports bid at prices lower than the ex-post MCP, but import bids cleared against these export bids were paid the full ex-post MCP.

In spring 2005, this basic market design flaw was exacerbated by significant divergences between the projected prices used to clear import/export bids, and the actual ex-post MCPs caused by another problem with the way that the RTMA software accounted for uninstructed deviations by resources within the CAISO. Specifically, the initial RTMA software projected uninstructed deviations by assuming that resources within the CAISO would seek to return to their scheduled operating level. This approach tended to underestimate positive uninstructed energy provided by many units, such as run-of-river hydro, Qualifying Facilities (QFs), and units operating at minimum load due to must-offer waiver denials. Since the RTMA software systematically underestimated uninstructed energy from these resources, ex-post MCPs tended to be significantly lower than projected prices used in pre-dispatching import/export bids. Combined with the basic design flaw of the "bid or better" settlement rule, this systematic price divergence created excessive uplift for import/export bids dispatched due to the market clearing feature of RTMA. This flaw in how uninstructed deviations were treated in RTMA was identified relatively quickly after RTMA implementation, but due to the lead-time for development and implementation of an enhanced algorithm this problem was not fixed until March 24, 2005.

In addition, analysis of participant bidding behavior suggests that some market participants took advantage of these market design flaws and conditions by bidding imports and exports in a manner that increased the probability of having off-setting import and export bids accepted in the pre-dispatch, which resulted in uplift payments being made for the difference between bid prices and the ex-post MCP, despite the fact that no net energy was being delivered to the CAISO system as a result of these off-setting import and export bids.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the marketing clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the “bid or better” settlement rule for pre-dispatched import/export bids to an “as-bid” settlement rule. Under an “as-bid” settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an “as-bid” settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

The Department of Market Monitoring (DMM) has been monitoring the impact of this market design change on market efficiency and uplift charges since implementation of the “as-bid” settlement rule on March 25, 2005. Both volumes and costs were increasing from the start of RTMA through the late-March implementation of the change in settlement of these transactions via Amendment 66. Once Amendment 66 was implemented, the volume of bids dispatched for market clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically. A detailed analysis showing the impact of this settlement rule change is provided in Chapter 3.

1.2.2 Day-Ahead Under-scheduling of Load – Amendment 72

With the onset of peak summer demand conditions in early July, CAISO Operations raised concerns about load under-scheduling in the Day Ahead Market. The concern predominately relates to shortfalls between the CAISO day-ahead forecasted load and the level of final day-ahead load schedules. To the extent such shortfalls exist, the CAISO operators need to commit additional units through the Must-Offer Obligation (MOO) waiver denial process, which puts additional administrative burdens on operational staff and introduces significant commitment uplift costs to the market. More fundamentally, it raises a concern about whether Load Serving Entities (LSEs) have adequately planned for meeting their peak load obligations.

Throughout the initial summer months, the CAISO committed significant amounts of capacity under the MOO to cover expected shortfalls in day-ahead schedules relative to day-ahead forecasted peak load. CAISO operators commit capacity to make up this shortfall to ensure that sufficient capacity is online in time to meet the next day’s peak load. During this time, day-ahead schedules had been as much as 12 percent less than the day-ahead forecast and had caused significant commitment of resources under the must-offer waiver denial process. This has resulted in daily Minimum Load Cost Compensation (MLCC) system costs in excess of $700,000 in July.

The CAISO recommendation for addressing this issue was to require LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market so that Grid Operators would not have to commit additional units in the CAISO’s day-ahead must-offer process to ensure enough capacity was online to meet load in the Real Time Market. In late July, the three IOUs began voluntary efforts to meet the day-ahead scheduling target of 95 percent. On September 22, the CAISO filed Tariff Amendment 72 with the FERC to require all LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market and FERC accepted the terms of the filing in an Order dated November 21, 2005.

In addition to an explicit day-ahead scheduling requirement, the CAISO began publishing more timely information regarding the potential cost of under-scheduling, namely estimates reflecting the per-MWh cost of under-scheduled load in the day-ahead timeframe in terms of MLCC resulting from the additional units that had to be committed to cover the under-scheduled load. This was done so that LSEs would consider costs to day-ahead under-scheduling that more fully reflected the actual costs of deferring procurement to the Hour Ahead or Real Time Markets.

As a result of these efforts, the CAISO has observed higher proportions of total load scheduled in the Day Ahead Market, with much fewer instances in which less than 95 percent of actual load was scheduled in the Day Ahead Market. This trend began shortly after the 95 percent scheduling practice was implemented and has continued through the first quarter of 2006 with a brief exception in November of 2005, coincident with very high natural gas prices and potential resulting shifts in spot procurement timing. As to the impact that the higher level of load scheduling has had on must-offer waiver denials, an assessment of the use of the Must-Offer Obligation to commit units to meet “System” requirements indicates that overall MOO commitments for “System” requirements are down for August-December 2005 compared to the same months in 2004. Another issue related to the scheduling requirement is whether or not the additional load scheduled in the day-ahead is met by physically feasible schedules. An indicator for this is the use of MOO unit commitments and the use of out-of-market dispatches in real-time to relieve transmission constraints. Both of these costs have declined for August-December 2005 compared to the same months in 2004, however, this may be due to other factors including transmission upgrades. A detailed assessment of load scheduling practices and the impact of Amendment 72 is provided in Chapter 2.

1.3 Generation Additions and Retirements

1.3.1 New Generation

Approximately 3,295 MW of new generation began commercial operation within the CAISO Control Area in 2005, most of which has signed Participating Generator Agreements with the CAISO. This includes 176 MW of previously mothballed generation owned by Reliant Energy Services that returned to service in 2005. A majority of the new resources constructed were natural gas-fired combustion turbine or combined cycle facilities. Table 1.1 shows the new generation projects that began commercial operation in 2005.

Table 1.1 New Generation Facilities Entering Commercial Operation in 2005

Generating Unit	*Owner or QF ID*	*Net Dependable Capacity (MW)*	*Commercial Operation Date*
El Sobrante Landfill Gas Generation	WM Energy Solutions	1.4	01-Jan-2005
Eurus Oasis Project	Eurus Energy	65	01-Jan-2005
Fresno Cogeneration Expansion Project	Fresno Cogen Partners, LP	50.5	14-Jan-2005
Sunrise Power Project Phase 3B	Sunrise Power Company, LLC	19	18-Feb-2005
Clearwater Combined Cycle Project	City of Corona	32	28-Feb-2005
Kimberlina Power Plant	Clean Energy Systems, Inc.	5.5	28-Feb-2005
Pico Combined Cycle Plant (Donald Von Raesfeld Power Plant)	Silicon Valley Power	147	18-Mar-2005
El Dorado Power House Unit 1	El Dorado Irrigation District	10	01-Apr-2005
El Dorado Power House Unit 2	El Dorado Irrigation District	10	01-Apr-2005
Pastoria Project Phase 1	Calpine	250	01-Apr-2005
Ellwood Generating Station (return from mothball status)	Reliant	56.1	01-Apr-2005
Mandalay 3 GT (return from mothball status)	Reliant	120	01-Apr-2005
Exxon Mobile Torrance Project	Exxon Mobile	85	01-Jun-2005
Metcalf Energy Center	Calpine	600	30-Jun-2005
Pastoria Project Phase 2	Calpine	500	30-Jun-2005
Miramar Energy Facility	Ramco Generation Unit	47	27-Jul-2005
KRCD Peaking Project	Kings River Conservation District	96	19-Sep-2005
Malburg Generation Station	City of Vernon	134	17-Oct-2005
Mountainview Power Project Power Block 3	Edison International	525	10-Dec-2005
Palomar Energy Project (PEP)	Palomar Energy, LLC	541	30-Oct-2005
Total Generating Capacity for 2005		**3,294.5**	

Source: California ISO Grid Planning Department

Reliant Energy Services' Mandalay 3 and Ellwood Generating Station facilities returned to service in 2005 after having been mothballed in 2003. As part of Reliant's settlement in the various Western Energy Markets investigations (PA02-2-000, EL03-59-000 et al.), Reliant committed to auctioning capacity from its Etiwanda 3 and 4, Mandalay Bay 3, and Ellwood facilities for three twelve-month periods through unit-contingent, gas tolling contracts. Failure to solicit bids resulted in Reliant mothballing these facilities. In July 2004, Reliant entered into a Reliability Must Run (RMR) agreement with the CAISO for capacity from Etiwanda 3 and 4 through December 2004. In September 2004, Reliant entered into a bilateral power-purchase agreement with Southern California Edison (SCE) for the capacity from Etiwanda 3 and 4, totaling 640 MW. In February 2005, Reliant entered into bilateral power-purchase agreements with unnamed counter-parties for the capacity from Mandalay 3 and the Ellwood Generating Facility, totaling 176 MW.

1.3.2 Retired Generation

Approximately 450 MW of generation capacity was removed from service in 2005, all of which was located in the SP15 congestion zone. Upon expiration of the long-term power purchase agreement with the California Department of Water Resources (CDWR), Dynegy determined that it was no longer economically feasible to operate its Long Beach Facilities, and retired them in 2005.

Table 1.2 Retired Generation Facilities in 2005

Generating Unit	*Capacity (MW)*
Long Beach 1, 2, 4, 5, 6, 7, and 9	450

Generation capacity in the CAISO Control Area changed by the following net amounts in 2005:

Table 1.3 Generation Change in 2005

Congestion Zone	*Generation Additions (MW)*	*Generation Reductions (MW)*	*Net Change (MW)*
NP15	913.5	0.0	913.5
SP15	2,375.5	-450.0	1,925.5
ZP26	5.5	0.0	5.5
CAISO Control Area	**3,294.5**	**-450.0**	**2,844.5**

1.3.3 Anticipated New and Retired Generation in 2006

The CAISO projects the construction of 441 MW of new generation through August 2006, of which 215 MW are expected to be commercially available prior to the anticipated summer peak season.

Table 1.4 Planned Generation Facilities in 2006

Generating Unit	*Net Dependable Capacity (MW)*	*Expected Parallel Date*
Rancho Penasquitos Hydro Facility	5	01-Mar-2006
Riverside Energy Center	96	15-Mar-2006
Chula Vista Repower	44	20-Apr-2006
Escondido Repower	44	20-Apr-2006
Otay 3	4	15-May-2006
Fresno Cogeneration Expansion Project	22	31-May-2006
Fresno Cogen ICE Unit	1	15-Jun-2006
Lake Mendocino Hydro	4	01-Jul-2006
PALCO	7	01-Jul-2006
Pastoria Expansion	159	31-Jul-2006
Bottle Rock Power	55	01-Aug-2006
Total Planned Generation in 2006	**441**	

Mohave 1 and 2 are both expected to retire in 2006. Hunters Point 1 and 4 are also expected to retire in 2006.

Table 1.5 Planned Generation Retirements in 2006

Generating Unit	***Capacity (MW)***
Mohave 1	790
Mohave 2	790
Hunters Point 1	52
Hunters Point 4	163
Total Planned Retirements for 2006	**1,795**

1.4 Transmission System Enhancements and Operational Changes

1.4.1 Inter-Zonal (Between Zone) Transmission System Enhancements

The only major inter-zonal transmission upgrade in 2005 was Path 26. The Path 26 enhancement greatly reduced congestion on Path 26 for the second half of 2005. Also notable is the Path 15 upgrade that became effective on December 7, 2004. Congestion on Path 15 was significantly lower in 2005 than in 2004 due to the upgrade.

1.4.1.1 Path 26 Enhancement

Path 26 consists of three 500kV lines, connecting the Midway and Vincent substation, between the CAISO congestion regions ZP26 and SP15. The north-to-south rating on the path has recently been increased from 3,400 MW to 3,700 MW. The Path 26 accepted rating of 3,700 MW was approved on May 2, 2005, by the Western Electricity Coordinating Council (WECC). On April 22, 2005, the CAISO submitted a Comprehensive Progress Report to the WECC's Technical Studies Subcommittee (TSS) to increase the north-south rating on Path 26 from 3,700 MW to 4,000 MW for 2005 and beyond by modifying the existing Path 26 Special Protection System (SPS). The existing SPS would be modified to curtail up to 1,400 MW of generation in the Midway area and about 500 MW of load in Southern California to mitigate contingency line overloading on the Midway – Vincent No. 3 500kV line in the event of a double line contingency (N-2) of the Midway – Vincent Nos. 1 and 2 500kV lines. The submission of the progress report placed the project in Phase 2 of the WECC path rating process.

1.4.1.2 Path 15 Upgrades

Before its upgrade in 2004, Path 15 consisted of two 500kV transmission lines between Pacific Gas and Electric (PG&E)'s Los Banos Substation on California's Central Valley (the northern terminus of the path) and the Gates Substation (the southern terminus of the path). Path 15 was one of the State's worst transmission bottlenecks. Table 1.6 summarizes the total congestion cost on Path 15 during the past six years.

Table 1.6 Historical Inter-Zonal Congestion Cost on Path 15

Year	Congestion Cost ($)	
2000	$	170,781,477
2001	$	43,260,325
2002	$	483,300
2003	$	689,856
2004	$	9,763,589
2005	$	2,177,498

In June 2002, the CAISO Governing Board unanimously approved the Path 15 Upgrade Project as a necessary and cost-effective addition to the CAISO Controlled Grid. The Path 15 Upgrade Project consisted primarily of a new, single, 83-mile, 500kV transmission line and associated substation facilities extending between the Los Banos Substation and the Gates Substation. The $300 million project was a partnership between PG&E, the Western Area Power Administration (WAPA), and a private company called Trans-Elect. WAPA set new towers and conductors, and PG&E upgraded substations on either end of the new line. PG&E, WAPA, and Trans-Elect each own a portion of the transmission rights to the new line and the CAISO operational control of the new facility along with the original Path 15 infrastructure. The new line increased the Path 15 capacity from 3,900 MW to 5,400 MW for the south-to-north direction.

The long-awaited Path 15 Upgrade was completed and turned over to the CAISO's operation on December 7, 2004. Upgrade of Path 15 started commercial use at 12:01am on December 22 in the Hour Ahead Market and the Day Ahead Market use began on December 23. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The maximum hourly final flow was 4,747 MW in 2005 (south-to-north direction), which is a 25 percent increase compared to the maximum hourly flow in 2004.

1.4.2 Intra-Zonal (Within Zone) Transmission System Enhancements

1.4.2.1 "South of Lugo" Upgrades

South of Lugo transmission facilities have historically experienced significant Intra-Zonal Congestion. The constraint consists of three 500 kV lines that emanate from the Lugo substation and feed into the LA Basin area. The path operates under the N-2 operating criteria, meaning that if any two lines fail, the remaining line has to be able to absorb the energy that shifts onto it.

The internal limit on this grouping of lines was 4,400 MW. On May 27, 2004, the CAISO upgraded the path rating of 4,400 MW to 4,800 MW. On July 29, 2004, CAISO upgraded the rating from 4,800 to 5,100 MW (depending on grid conditions). The CAISO planned further upgrades for 2005 and these were completed on June 22, 2005. SCE added equipment that allowed the CAISO to boost the rated capacity of the grid in the Victorville/Norco/Ontario area by 500 MW to 5,600 MW. The upgrade reduced congestion and increased available supply to the LA Basin.

1.4.2.2 Pastoria Reconductoring

Transmission lines South of Pastoria, specifically the Pastoria – Pardee 220 kV line, Pastoria – Bailey – Pardee 220 kV line, and Pastoria – Warne – Pardee 220 kV line were inadequate to accommodate the output from the new generation that was installed in the region in 2005 along with output from the existing Big Creek hydroelectric facility, creating a generation pocket that, at times, resulted in excess redispatch costs associated with managing Intra-Zonal Congestion at South of Pastoria. To better accommodate the additional generation, SCE began a reconductoring of both the Pastoria – Pardee line and the Pastoria – Bailey line, which will help relieve congestion coming out of the generation pocket going forward. The reconductoring work is expected to be finished for the Pastoria – Pardee line in March 2006, and for the Pastoria – Bailey line in June 2006.

1.4.2.3 New Miguel-Mission Line

The Miguel substation and its associated congestion has been one of the CAISO's most significant intra-zonal problems since July 2003. The nature of the constraint has been twofold. First, the substation was limited by the 500/230 step-down transformer bank capacity at the Miguel substation itself. This limit was approximately 1,120 MW. Second, the substation was limited by the N-2 criteria on the two 230 kV lines emanating from the substation, meaning that if both of these lines tripped the remaining 138 kV system had to absorb the total energy. This limit was 1,100 MW.

In the second half of 2004, a number of upgrades were made to the system in the vicinity of the Miguel substation. A new 500/230 step-down transformer bank was added to the substation, new series capacitors were added to the Southwest Power Link (SWPL) line that feeds into the substation which results in reduced line impedance and increased power flow, and a small part of the 138 kV system was re-conductored. This new equipment went into service on October 31, 2004. Unfortunately, this did not significantly change the capacity of the substation. The static rating of the substation increased from 1,100 MW to 1,200 MW and the dynamic rating increased from 1,400 MW to 1,500 MW. The new 500/230 transformer bank resulted in more power reaching Miguel, so the Miguel congestion remained a significant cost issue and intra-zonal constraint. In addition, the N-2 criteria still remain as significant constraints.

The energization of the new Miguel Mission #2 230 kV line on June 6, 2005 further reduced the congestion in the Miguel-Mission area. This project involved taking one of the pre-existing 69 kV lines and increasing its voltage to 230 kV prior to the building of the second line. With CAISO approval and support, SDG&E accelerated the installation of a new 230 kV transmission line in an existing transmission corridor between the Miguel Substation near Chula Vista and the Mission Substation in Mission Valley in the San Diego area, increasing the capacity by 400 MW. The original in-service date for the project was June 2006. SDG&E shaved about a year off the project timeline.

All three upgrades (Path 26, South of Lugo, and the New Miguel-Mission line) together increased transmission capacity into Southern California by 1,000 MW.

1.4.3 Future Transmission Upgrades

The CAISO is responsible for evaluating the need for all potential transmission upgrades to promote economic efficiency and maintain system reliability. The CAISO developed clear standards both for reliability-based project evaluation and for economic-based project evaluation. More specifically, the CAISO developed the TEAM (Transmission Economic

Assessment Methodology) for economic-based project evaluation and has applied TEAM (or simplified TEAM) to a number of transmission projects and identified some economically beneficial projects. Some of the future transmission upgrades that the CAISO identified and approved are discussed in the following sessions.

1.4.3.1 STEP Short-Term Transmission Upgrades

The CAISO applied the simplified version of TEAM and identified a number of short-term transmission projects in the southwest region to be economically beneficial to the CAISO ratepayers. On June 18, 2004, the CAISO Board approved the Southwest Transmission Expansion Plan (STEP) short-term transmission upgrades for the southern portion of the CAISO grid. The proposed upgrades include the following:

- Series capacitors upgrades on the Hassayampa – North Gila – Imperial Valley 500 kV line from 1,200 MW (1,400 A) to a minimum of 1,900 MW (2,200 A). The Hassayampa – North Gila – Imperial Valley 500 kV line brings power from Arizona into the San Diego area.
- Series capacitors upgrades on the Palo Verde – Devers 500 kV line from 1,645 MW (1,900 A) to a minimum of 2,340 MW (2,700 A). The Palo Verde – Devers 500 kV line delivers power from Arizona into the Greater LA Basin.
- Devers 500/230 kV #2 transformer installation. This project includes the installation of a second 500/230 kV 1120 MVA transformer at Devers Substation. The installation of the second transformer is necessary to take full advantage of the series capacitor upgrades on the Palo Verde – Devers 500 kV line. Without the second Devers transformer, it would not be possible to increase the Palo Verde – Devers 500 kV line transfer capability significantly beyond its current rating.
- Dynamic Voltage Support Installation at Devers Substation. Dynamic voltage support is necessary to enable an increase in the imported energy while maintaining acceptable voltage conditions under the most limiting outage conditions.
- Series Capacitor and Phase-Shifting Transformer Installation at Imperial Valley Substation. The installation of the transformer is necessary to take full advantage of the series capacitor upgrades and to increase the operational flexibility of the system.
- Small West of Devers Upgrade such as installation of a series reactor on the Devers – San Bernardino No. 1 230 kV line.

The proposed STEP short-term transmission upgrades are planned to be completed by summer 2006.

1.4.3.2 New Palo Verde – Devers No. 2 500 kV Line

From July 2004 - February 2005, TEAM was used to evaluate the Palo Verde – Devers No. 2 500 kV line (PVD2). The PVD2 project was initially proposed by SCE and was identified as a potentially beneficial transmission expansion through the STEP process. The PVD2 project includes a new 230 mile 500 kV line between Harquahala Switchyard (near Palo Verde) and SCE's Devers Substation, rebuilding and reconductoring four 230 kV lines west of Devers, and voltage support facilities at the Devers area. On February 24, 2005, the CAISO Board approved the PVD2 project. Subsequently, CAISO and SCE filed with the California Public Utilities Commission (CPUC) in the matter of the application of SCE for a Certificate of Public Convenience and Necessity (CPCN). The CPUC is currently reviewing the case. If the CPUC approves the CPCN for the project as expected, the project could be on line in 2009, providing an additional 1,200 MW of transmission capacity from Arizona to Southern California.

1.4.4 Operational Changes

On November 30, 2005, the CAISO implemented the new Scheduling Applications (SA) Network Model C1, effective for the trade date December 1, 2005. This new scheduling/market model incorporated 5 major control area footprint change requests and the establishment of four new Metered Subsystems (MSS). Major changes are summarized as follows:

1.4.4.1 The COTP Transition to the SMUD Control Area

The new C1 model implemented the transfer of the California-Oregon Transmission Project (COTP) 500kV Transmission line. The CAISO's prior California-Oregon Intertie (COI) branch group consisted of 3 transmission lines, one of which is the COTP transmission line. The COTP project has elected to move the line to the Sacramento Municipal Utility District (SMUD) Control Area. The two remaining lines are referred to as the Pacific Alternating Current Intertie (PACI) lines. To reflect this transition, the COI branch group is renamed to the PACI branch group. The COI branch group consisted of the CAPJAK_5_OLINDA and the MALIN_5_RNDMT intertie points. The CAPJAK_5_OLINDA intertie will no longer be a scheduling point, and the MALIN_5_RNDMTN will be the only remaining tie that will transfer to the new PACI branch group. There are no physical line changes in the SA Network Model but a redrawing of the CAISO and SMUD Control Area boundaries was required. The result is the addition of two new interties and expiration of four interties.

Table 1.7 New and Expired Interties due to COTP Transition to SMUD

New Interties Effective 12/1/2005	Expired Interties Effective 12/1/2005
TRACY5_5_PGAE	CAPJAK_5_OLIDA
TRACY5_5_COTP	OLNDWA_2_OLIND5
	TRACYPP_2_TRACY5
	TRACYPP_2_WESTL

1.4.4.2 Modesto Irrigation District Transition

The Modesto Irrigation District (MID) elected to move to the SMUD Control Area. There will be two new interties from the MID control area transmission: WESTLY_2_TESLA and STNDFD_1_STNCSF.

1.4.4.3 Turlock Irrigation District Transition

The Turlock Irrigation District (TID) has elected to become an independent Control Area. There will be two new interties for TID in the CAISO Control Area: OAKTID_1_OAKCSF and WESTLY_2_LOSBNS.

1.4.4.4 Plumas-Sierra Interconnection

NCPA's Plumas substation was interconnected with SPPCO's Sierra substation at the Marble substation. The new C1 model created the New Plumas-Sierra Marble Substation Intertie Between the CAISO and Sierra Pacific Power Control Area. The new intertie for the Plumas-Sierra interconnection is MBLSPP_6_MARBLE.

1.4.4.5 New Metered Subsystem

There will be one new Metered Subsystem (MSS) for the City of Colton.

1.4.4.6 Utility Distribution Company to MSS Conversion

There will be three Utility Distribution Companies (UDCs) converting to MSS arrangements: City of Pasadena (implementation early 2006), City of Anaheim, and City of Vernon (implementation early 2006).

1.4.4.7 Pilot Pseudo Tie for the Calpine's Sutter Plant

Sutter Power Plant is a generation plant re-incorporated into the CAISO Control Area as a CAISO Participating Generator. The Sutter Power Plant is physically remote from the contiguous portion of the CAISO Control Area, and is located in an area where it is totally surrounded by the SMUD Control Area. The new C1 model implemented the Sutter Power Plant as a Pseudo Tie Pilot (a/k/a Remote Tie) resource in the SA Network Model. More specifically, a congestion zone SUTR inside of the NP15 zone is created and Sutter generator is modeled inside the SUTR zone. Also a branch group (between SUTR and NP15) is created as SUTTER_BG. The path limits are associated with the existing Tracy-Tesla 230kV intertie between SMUD and CAISO for the Calpine Sutter Generator, which is interconnected with the Western 230kV system within SMUD.

Table 1.8 and Table 1.9 provide a listing of the expired and new CAISO Branch Groups that resulted from these operational changes.

Table 1.8 New Branch Groups Due to Operational Changes

Branch Group	From Zone	To Zone	Interconnecting Control Area	Tie Point	Effective
MARBLESUB_BG	SR5	NP15	SPP	MBLSPP_6_MARBLE	new on 12/1/2005
OAKDALSUB_BG	TDZ1	NP15	TID	OAKTID_1_OAKCSF	new on 12/1/2005
PACI	NW1	NP15	BPA	MALIN_5_RNDMTN	new on 12/1/2005
STNDFDSTN_BG	SMDK	NP15	SMUD	STNDFD_1_STNCSF	new on 12/1/2005
SUTTRLOFF_BG	SMDM	SUTR	N/A	SUTTER_2_LAYOFF	new on 12/1/2005
SUTTRNP15_BG	SUTR	NP15	N/A		new on 12/1/2005
TRACYCOTP_BG	SMDH	NP15	SMUD	TRACY5_5_COTP	new on 12/1/2005
TRACYPGAE_BG	SMDL	NP15	SMUD	TRACY5_5_PGAE	new on 12/1/2005
WSLYTESLA_BG	SMDJ	NP15	SMUD	WESTLY_2_TESLA	new on 12/1/2005
WSTLYLSBN_BG	TDZ2	NP15	TID	WESTLY_2_LOSBNS	new on 12/1/2005

Table 1.9 Expired Branch Groups Due to Operational Changes

Branch Group	From Zone	To Zone	Interconnecting Control Area	Tie Point	Effective
COI _BG	NW1	NP15	BPA	MALIN_5_RNDMTN, CAPJAK_5_OLINDA	expired on 12/1/2005
OLNDAWAPA_BG	SMD1	NP15	SMUD	OLNDWA_2_OLIND5	expired on 12/1/2006
TRACYWAPA_BG	SMD4	NP15	SMUD	TRCYPP_2_TRACY5	expired on 12/1/2007
TRCYWSTLY_BG	SMD6	NP15	SMUD	TRCYPP_2_WESTLY	expired on 12/1/2008

1.5 Resource Adequacy - 2006 and Beyond

1.5.1 Resource Adequacy Requirements

The California Public Utilities Commission (CPUC) has been developing a capacity-based Resource Adequacy (RA) program that requires LSEs to procure specific levels of contracted for generation and demand products on an annual and monthly basis. This RA program is specifically designed to further system and local grid reliability by providing generation resources a revenue source to contribute towards fixed cost recovery and provide a revenue framework that will facilitate new generation investment in California.

The RA framework was intended to address reliability at two levels. The first is reliability at the system level, where the focus is on maintaining enough generation capacity to meet total peak system load with additional capacity in reserve to address forecast error and contingencies. The second is reliability at the local level, where generation resources need to be in place to meet load and provide reliability services in established transmission-constrained areas. Both of these RA requirements are important to reliability, short-term revenue adequacy, and to provide a framework for investment in infrastructure. However, when viewing existing reliability issues in the CAISO Control Area, generation capacity at the local or regional level is of primary concern, and this is especially true in SP15.

On October 27, 2005, the CPUC issued its *Opinion on Resource Adequacy Requirements* (Decision (D.) 05-010-042), "October Order", that laid additional detail regarding implementation of the RA program on June 1, 2006.[3] While the October Order made specific determinations on many of the design elements for the RA program, the following is a list of features important to this discussion:

- The RA requirement applies to system-level needs given that local requirements were deferred until procurement year 2007 after further development of the record.
- LSEs are required to procure enough (deliverable) capacity to cover 115 percent to 117 percent of forecast peak demand.
- Liquidated Damages (LD) contracts qualify to be counted toward meeting the system-level RA requirements, however these contracts will be phased out of the program between now and 2009.

[3] See CPUC Opinion on Resource Adequacy Requirements at http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION/50731.pdf.

- Resources that have sold RA capacity must make all of their capacity available to the CAISO markets.

This first stage in RA implementation provides a good framework for improving reliability, providing an additional source of revenue for cost recovery in the short-term, and providing a contracting and revenue framework that will incent investment in new generation. It is critical, however, that the CPUC continue its progress toward addressing short-term and long-term reliability at the local or regional level. Many of the existing resources that are located in traditional load pockets, or in areas that require resident generation to provide transmission congestion relief, are older higher-cost units. Many of these resources are located at points on the transmission grid where they are required both to meet load in that area and to provide reliability support. For these resources, cost recovery is critical to insure that these resources do not retire and leave these local reliability areas capacity deficient. In the same vein, providing incentives and opportunities for investment in new generation (or re-powering existing facilities) in these same constrained areas is vital to turning over the pool of existing aging generation resources and improving the efficiency of that pool.

Regarding the 2006 implementation of the RA requirement, the absence of a local capacity requirement coupled with the allowance of LD contracts creates a potential for LSEs to meet their system RA requirements by contracting with resources other than those described above, namely older higher-cost resources that provide needed support in local reliability areas. The potential consequence of this is that, given insufficient cost recovery opportunity provided by spot markets in California over the past several years, these resources may not receive sufficient revenues to justify maintaining operation. While the lack of local capacity requirements in 2006 creates this potential concern, an initial review of the 2006 annual system capacity RA showings indicates that many of the resources needed for local reliability needs have in fact been contracted with as part of the LSE's RA requirements.

The CPUC has established that a local RA requirement will be implemented for the 2007 procurement period, and that the use of LD contracts toward meeting system RA requirements will be largely phased out by 2009. It is anticipated that these two features of the RA program will mitigate the threat that resources critical to the maintenance of local and regional reliability will choose to retire given the inability of the California spot markets over the past several years to provide sufficient revenues to justify maintaining their operation. Over the longer term, the RA program as well as the CAISO's coordinated grid planning process is intended to provide the incentives to replace such units with more efficient generation to serve local reliability purposes or to construct additional transmission upgrades that can be installed to relieve the limiting factors creating these local reliability areas in the first instance. Nevertheless, for 2006 and beyond, there still exists a potential revenue adequacy issue that may impact the availability of resources in the CAISO Control Area. Given this concern, the CAISO may need to have an alternative interim backstop contracting mechanism, other than RMR contracts - due to their limited application, to ensure that generating units that are critical for reliability remain in operation.

2. General Market Conditions

2.1 Demand

Loads in 2005 were, by most measures, only slightly higher than those in 2004 on an overall basis. The relatively modest increase in 2005 loads is attributable to unusual weather patterns and the absence of a system-wide heat wave. While the California economy grew in 2005, weather was relatively mild throughout the year, with the notable exception of a prolonged heat wave between July 11 and August 7. In contrast, 2004 weather was fairly severe across several seasons. That year saw a very warm spring, with temperatures reaching over the 100-degree mark in inland areas, which resulted in a substantial decrease in daily peak loads between the spring months in 2004 and those in 2005. In addition, 2004 had an unusually late summer peak in September, which reached an all-time record high, also contributing to a decrease between peaks in September 2004 and September 2005.

While not the hottest on record, the July-August heat wave lasted an exceptionally long time without respite and extended to most areas across California. It resulted in four straight weeks of daily peak loads above 40,000 MW, with the exception of two Sundays, which were just shy of that level. The CAISO's 2005 peak load of 45,431 MW on July 20 was slightly lower than the 2004 peak of 45,597 MW on an absolute basis, but was effectively slightly higher than the 2004 peak when adjusted for the departure of approximately 200 MW of Western Area Power Administration (WAPA) load from the NP26 portion of the CAISO service area on January 1, 2005. Table 2.1 shows two sets of annual load statistics for the CAISO Control Area, statistics based on actual loads, and statistics based on adjusted loads that reflect changes to the CAISO Control Area and adjustments for the 2004 leap year.

Table 2.1 CAISO Annual Load Statistics for 2001 – 2005*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2001 Actual	26,004		227,795	41,155	
2002 Actual	26,572	2.2%	232,771	42,352	2.9%
2003 Actual	26,329	-0.9%	230,642	42,581	0.5%
2004 Actual	27,298	3.7%	239,786	45,597	7.1%
2005 Actual	26,992	-1.1%	236,450	45,431	-0.4%
2001 Adjusted	24,556		215,111	39,516	
2002 Adjusted	25,737	4.8%	225,456	41,890	6.0%
2003 Adjusted	26,027	1.1%	227,997	42,058	0.4%
2004 Adjusted	26,933	3.5%	235,933	45,079	7.2%
2005 Adjusted	26,947	0.1%	236,056	45,431	0.8%

* Adjusted figures are normalized to account for leap year, day of week, and changes in CAISO Control Area.

Table 2.2 compares four metrics of load changes to the same month's levels in the previous year, adjusted for changes in the CAISO footprint. Figure 2.1 compares CAISO loads for each hour in July 2004 and July 2005

Table 2.2 Rates of Change in Load: Same Months in 2005 vs. 2004[1]

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-05	1.5%	2.6%	1.1%	5.0%
February-05	1.5%	1.8%	2.2%	0.3%
March-05	-2.3%	-2.2%	-0.6%	-5.2%
April-05	-2.2%	-3.6%	-0.3%	-22.9%
May-05	-2.5%	-2.9%	-1.1%	-9.3%
June-05	-2.5%	-3.8%	0.4%	2.7%
July-05	5.6%	6.2%	5.1%	3.9%
August-05	4.3%	5.1%	4.1%	-1.5%
September-05	-5.7%	-9.0%	-2.1%	-11.9%
October-05	2.7%	2.9%	2.4%	3.9%
November-05	1.7%	1.8%	1.5%	-2.0%
December-05	-0.9%	0.0%	-2.5%	0.4%

Figure 2.1 California ISO System-wide Actual Loads: July 2005 vs. July 2004

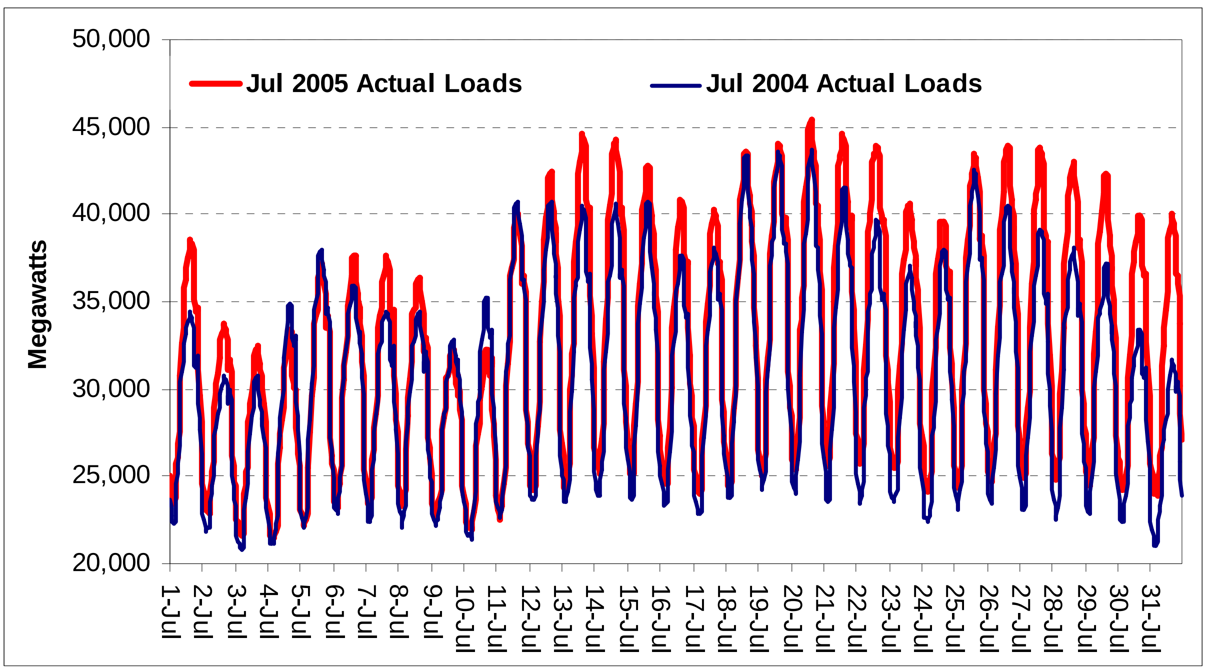


Figure 2.2 depicts load duration curves for each of the last four years, adjusted for CAISO footprint changes. Because load was generally lower in 2005 than in 2004 due to milder weather, the 2005 curve is very similar to the 2004 curve. However, the July-August 2005 heat

[1] Adjusted for change in NP26 load footprint.

wave resulted in the high portion of the 2005 curve (on the left side of the chart) being slightly above the 2004 curve. Load in 2005 was generally above that of 2003 and 2002, indicating a general trend of load growth. For example, when adjusting for the changes in the CAISO footprint, only 0.3 percent of hours between January and November exceeded 40,000 MW in 2002, while 2.5 percent did so in 2005.

Figure 2.2 California ISO System-wide Actual Load Duration Curves: 2002-2005[2]

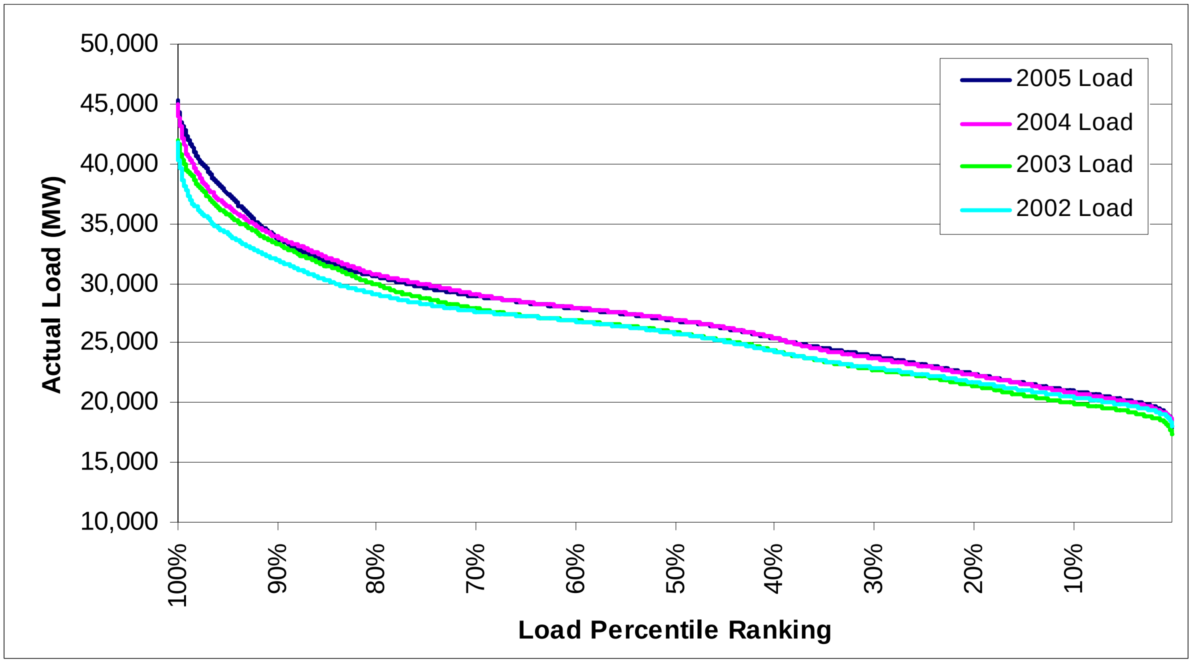


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO as a whole.

Table 2.3 CAISO Annual Load Change: 2005 vs. 2004

Zone	Avg. Hourly Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP26	0.9%	0.4%	2.3%	2.5%
SP15	-0.3%	-0.3%	-0.2%	2.8%
ISO Control Area	0.2%	0.0%	0.9%	0.7%

While NP26 load increased disproportionately in 2005, SP15 remains a greater concern going forward, as load growth in the greater Los Angeles area continues to outpace the development of transmission and generation infrastructure.

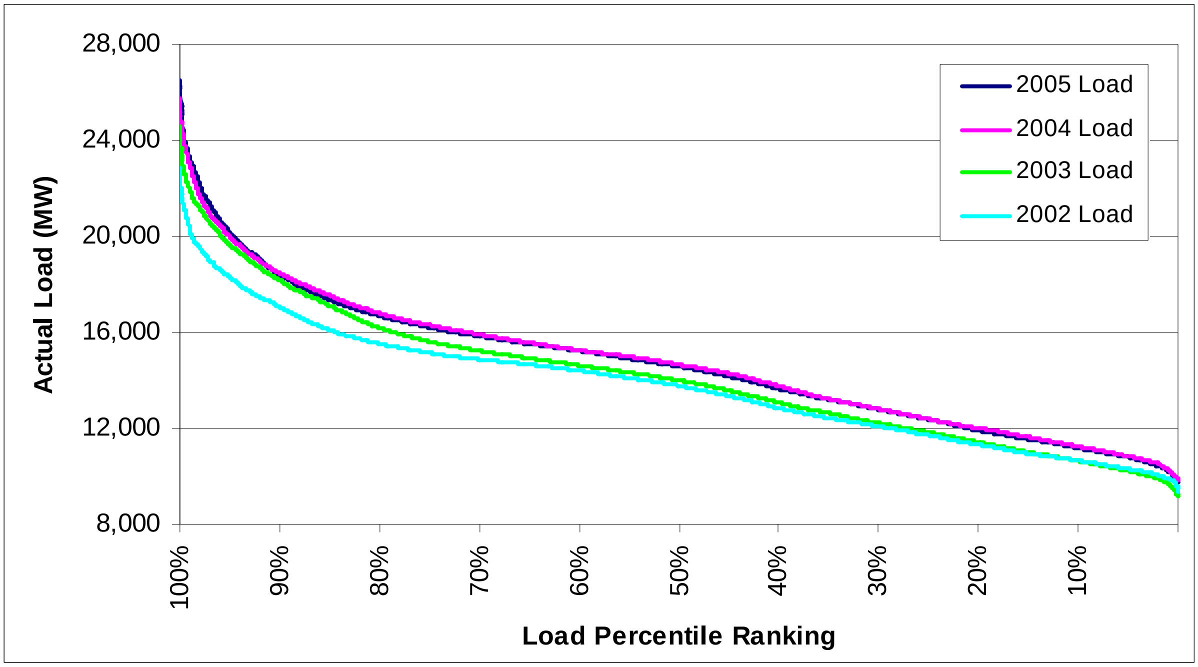
[2] All years are shown from January through November, as the CAISO NP26 load footprint changed in December 2005, and adjustment of prior years for this change was not possible. Years prior to 2005 are adjusted to account for previous footprint changes (exit of WAPA on 1/1/05, exit of SMUD on 6/19/02) and to compare similar days of the week (i.e., so that each year has the same number of Sundays, etc.)

The SP15 peak of 26,459 MW, set on July 21, was 716 MW above the previous regional peak, and SP15 load came within 20 MW of that peak again on July 22. This indicates a year-to-year increase in regional peak load of approximately 2.7 percent, continuing to reflect the population growth in inland areas such as San Bernardino and Palm Springs. Load statistics for SP15 are provided in Table 2.4 and Figure 2.3. The aforementioned extreme variations in weather patterns between 2004 and 2005 make it difficult to find any consistent trends in these data. However, the peak load increase within SP15 is evident in the load duration curves depicted in Figure 2.3. Note that loads in 0.5 percent of hours in 2002 were above 21,000 MW, while loads in 3.5 percent of hours in 2005 were above 21,000 MW.

Table 2.4 Rates of SP15 Load Change: Same Months in 2005 vs. 2004

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-05	0.2%	1.6%	-0.7%	5.3%
February-05	1.8%	2.1%	2.2%	1.2%
March-05	-2.8%	-2.8%	-1.1%	-10.7%
April-05	-2.6%	-3.8%	-1.0%	-23.6%
May-05	-3.7%	-3.7%	-4.0%	-13.3%
June-05	-2.9%	-3.4%	-2.1%	0.6%
July-05	3.9%	4.4%	2.7%	5.9%
August-05	4.6%	5.8%	3.1%	1.8%
September-05	-6.2%	-9.6%	-2.1%	-9.4%
October-05	3.3%	3.7%	3.4%	7.6%
November-05	2.3%	2.3%	1.5%	0.2%
December-05	-2.1%	-0.2%	-4.6%	-0.4%

Figure 2.3 SP15 Actual Load Duration Curves: 2002-2005[3]

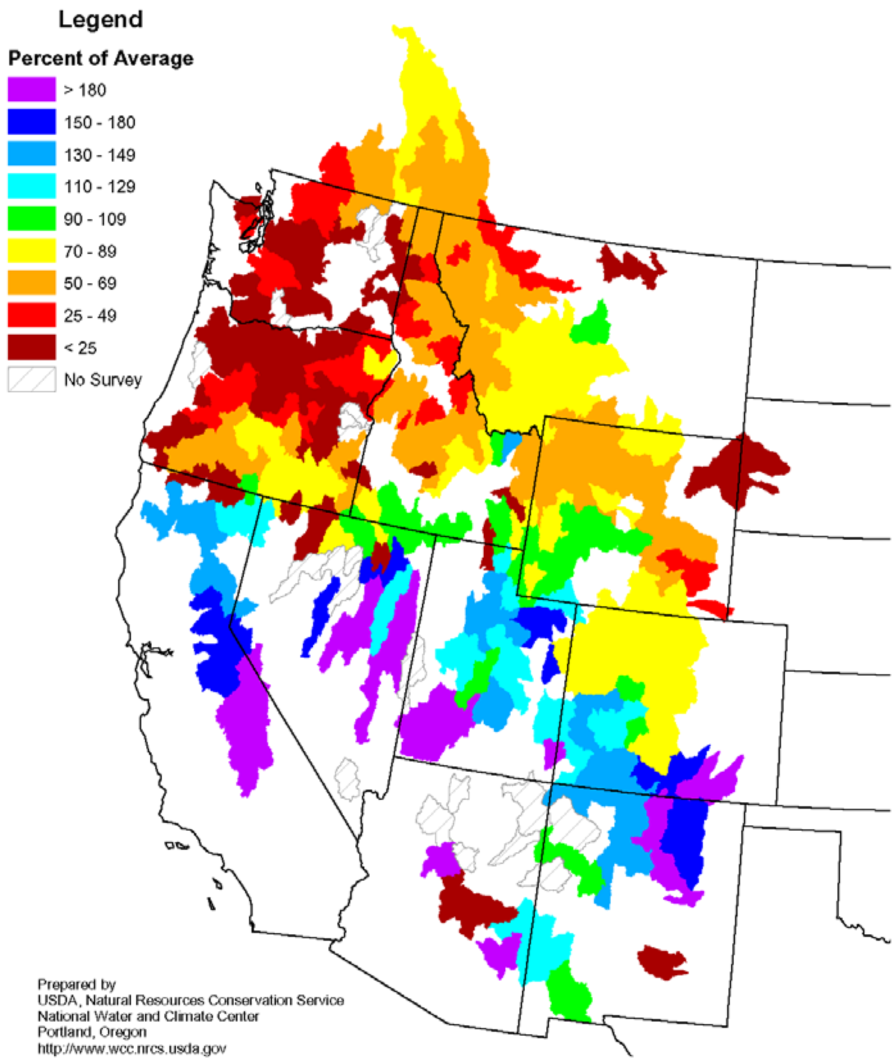


2.2 Supply

Hydroelectric. Snowfall in the California Sierra Nevada and in other Southwest ranges was generally well above average during the winter of 2005, which provided for robust runoff and storage among CAISO hydroelectric resources during the spring and summer of 2005. This largely offset the unusually low supply from the Pacific Northwest, which suffered a below-average snowpack. The graphic below shows mountain snowpack across the Western United States as of May 2005.

[3] All years are shown for all months, as there was no load adjustment within the SP15 load footprint. Previous years are adjusted to compare similar days of the week (i.e., so that each year has the same number of Sundays, etc.).

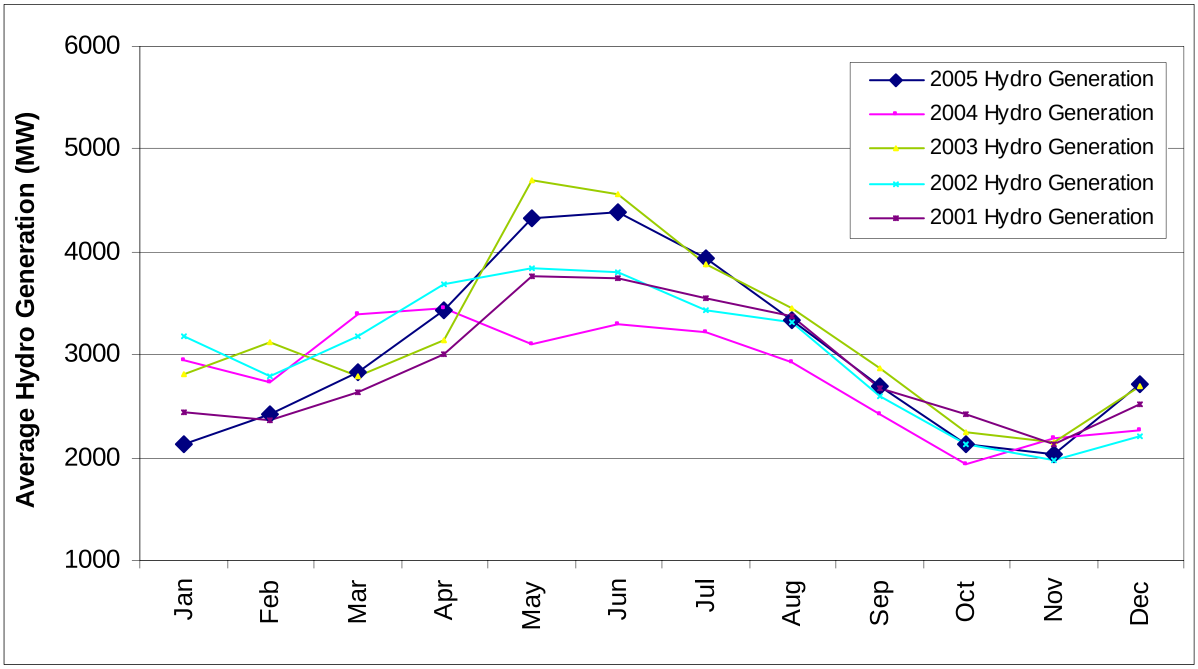
Figure 2.4 Mountain Snowpack in the Western U.S., May 1, 2005[4]



Due primarily to the robust snowpack and relatively slow melt within California, and, to a lesser extent, a wet late fall, hydroelectric production in 2005 was near the top of the recent five-year range for most of the year, as shown in Figure 2.5.

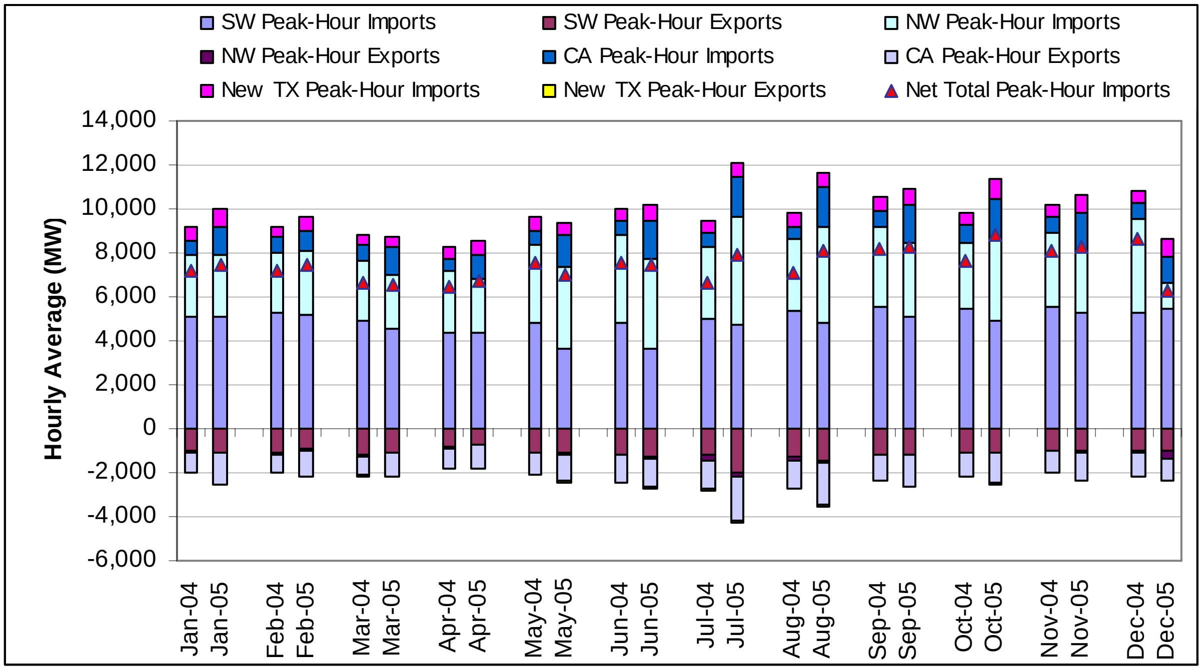
[4] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/cgibin/westsnow.pl.

Figure 2.5 Monthly Average Hydroelectric Production: 2001-2005



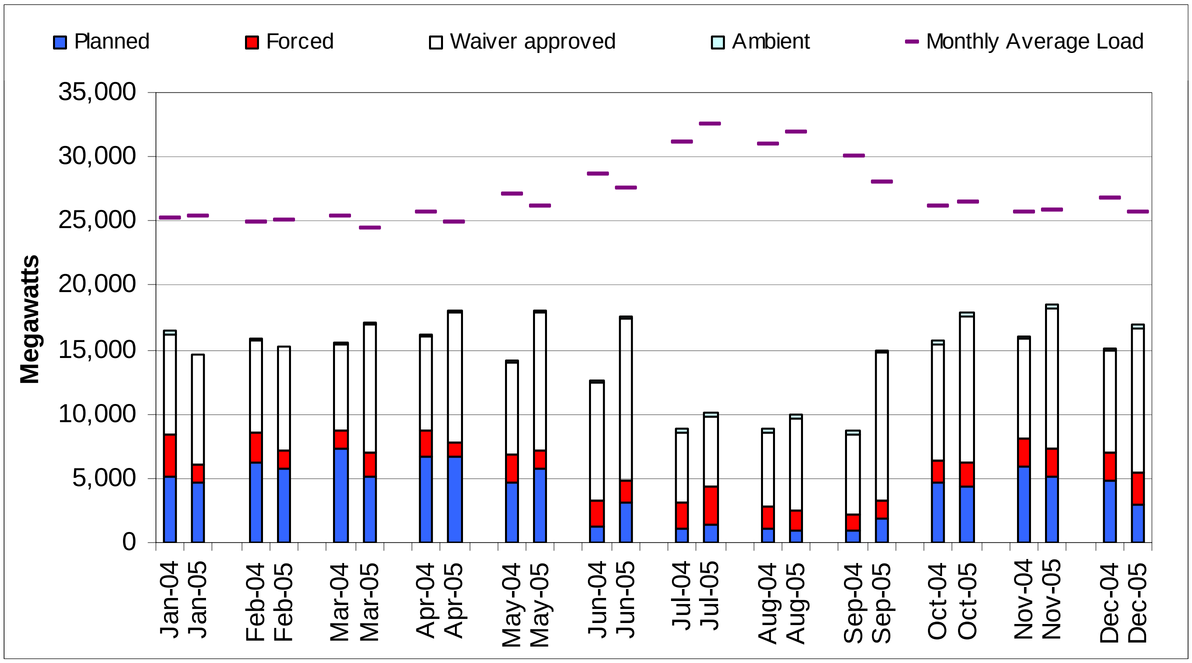
During the runoff season of May-June, the CAISO Control Area imported less power in 2005 than in 2004 overall, as its own spill condition, in addition to its other resources, was able to meet more of the load. Imports from the Northwest and other Northern California control areas increased during this period, due in part to power wheeled across the CAISO-managed grid to neighboring control areas in the Southwest. The heat wave that began in mid-July and continued through early August demanded the maximum level of imports available, resulting in year-to-year increases for those months. Figure 2.6 compares year-to-year imports and exports for each month in 2004 and 2005, and includes wheeled power.

Figure 2.6 Year-to-Year Comparison of Monthly Average Scheduled Imports and Exports: 2005 vs. 2004



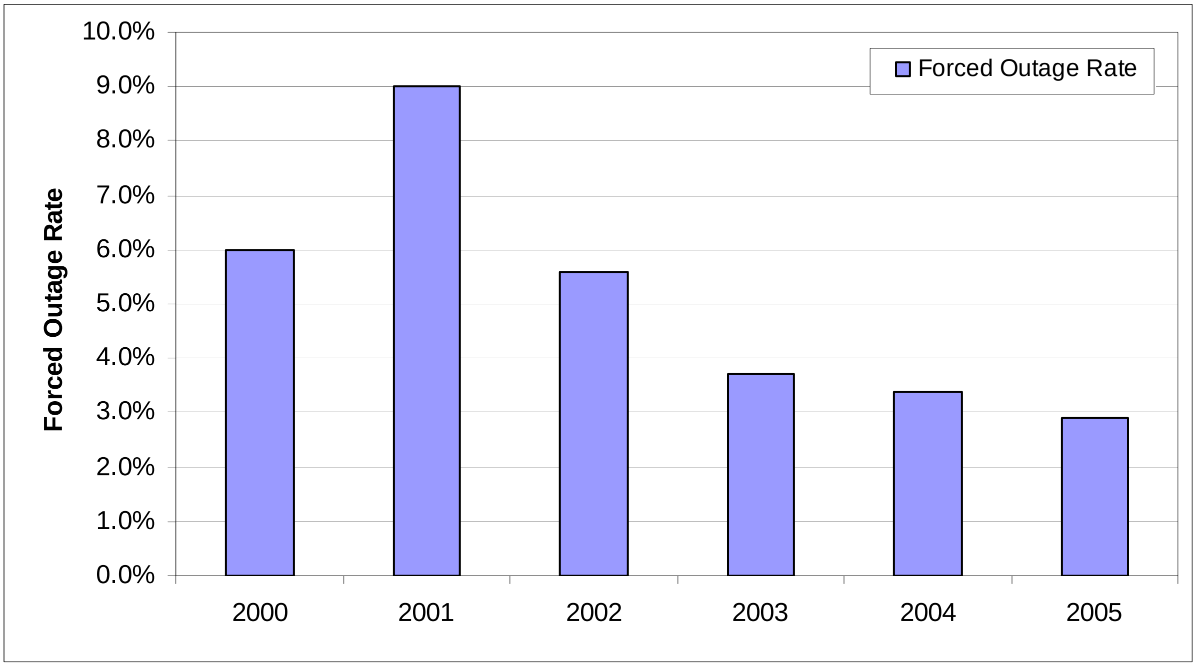
During the aforementioned July-August heat wave, the CAISO Control Area's entire generation fleet was operating seven days per week. For the entire duration of the heat wave, which lasted from July 11 to August 7, CAISO loads exceeded 40,000 MW on every day except 2 Sundays, where peaks were just shy of that level. This heat wave was unusually long, and required that generation remain on continuously, even on weekends. Consequently, typical weekend maintenance was deferred, contributing to an unusually high forced outage rate in July.

Figure 2.7 Year-to-Year Comparison of Monthly Average Outages: 2005 vs. 2004



Despite the high outage rate in July, the overall forced outage rate was the lowest since 2000. This is due primarily to the substantial increase in the generation base in 2005, which has a decreasing effect on outage rates. Figure 2.8 below compares annual forced outage rates since 2000.

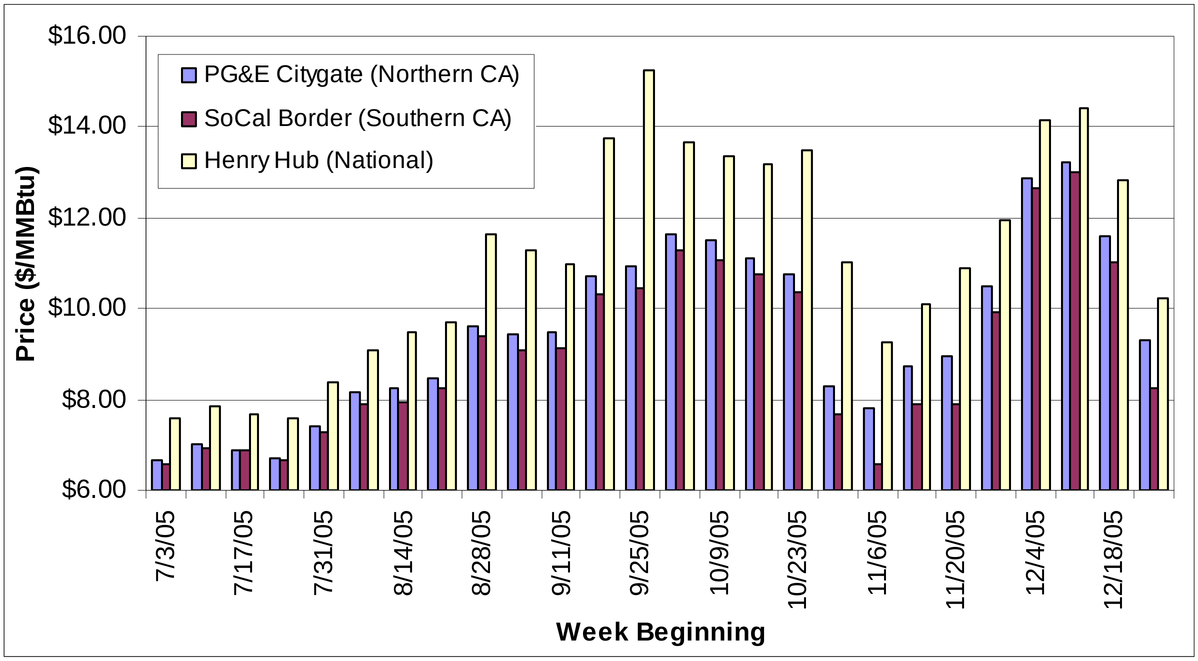
Figure 2.8 Year-to-Year Comparison of Forced Outage Rates: 2000-2005[5]



Natural gas prices increased substantially in 2005 over levels seen in 2004. Whereas gas prices in 2004 generally ranged between $5 and $7 per million British thermal units (mmBtu), national prices rose steadily in 2005, beginning in January, and peaking immediately following Hurricanes Katrina and Rita's destruction of national gas production and transportation infrastructure in the Gulf of Mexico region, during the week of August 30, 2005. As gas consumed in the West primarily comes from West Texas, New Mexico, and Canada, which were not affected by the hurricanes, Western markets traded at a discount of approximately $2/mmBtu to national prices. A cold snap across much of North America in December, coupled with limitations to the Gulf Coast transportation and production infrastructure, resulted in a second peak, with California prices reaching their highest levels since December 2000. Figure 2.9 shows weekly natural gas prices in 2005.

[5] This Annual Report now uses a methodology similar to one used by the California Energy Commission to count generation in the CAISO Control Area since 2001. As a result, forced outage rates differ slightly from those reported in previous Annual Reports.

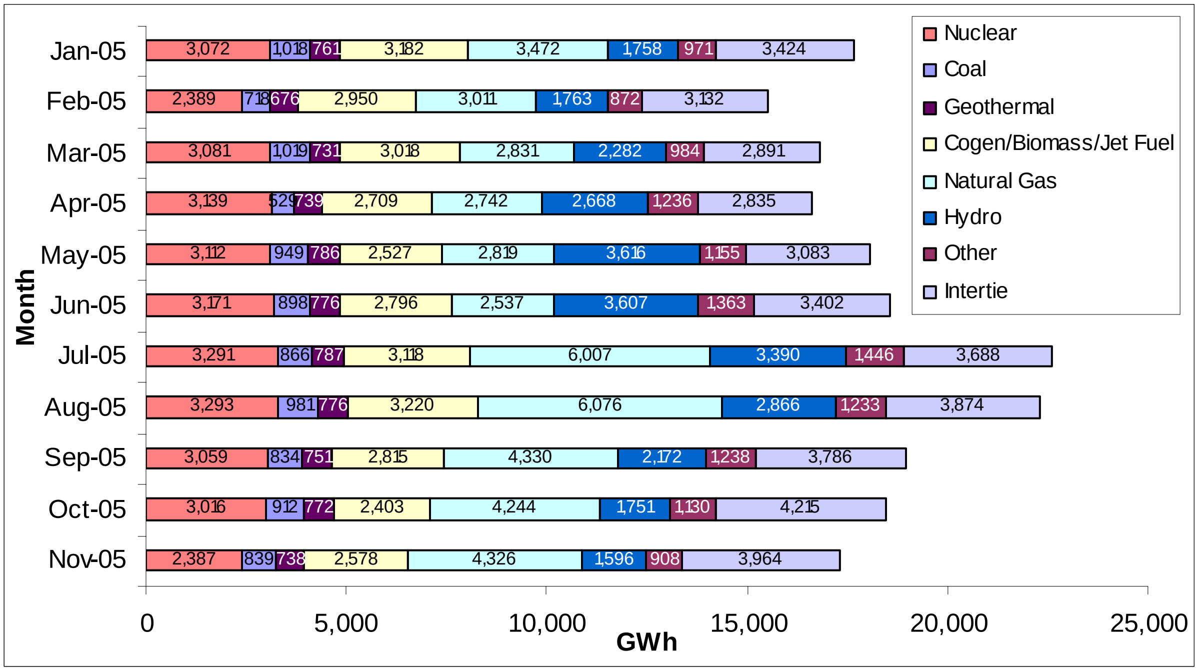
Figure 2.9 Weekly Average Gas Prices (July-06 to Dec-06)



2.2.1 Generation by Fuel

Base-load generation sources, such as nuclear, geothermal, cogeneration, and coal facilities, served between 36 and 47 percent of load each month in 2005. Between 16 and 23 percent of load was met by imports. The remaining 35 to 48 percent was served by a combination of natural gas-fired facilities, hydroelectric power, or some other generating resource. High loads in July and August resulted in substantial percentages of load being covered by natural gas-fired plants. In February and November the amount of nuclear generation decreased due to a forced outage at SONGS #2 in February and refueling outage at Diablo Canyon #1 in November. A summary of monthly energy generation by fuel type is provided in Figure 2.10.

Figure 2.10 2005 Monthly Energy Generation by Fuel Type



2.3 Total Wholesale Energy and Ancillary Services Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. This index has been updated in this report for operating years 2002-2005 to include reliability costs (must-offer minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs) with the real-time component.[6] The estimated total wholesale energy cost for 2005 was approximately $13.6 billion, compared to $13.1 billion in 2004.[7] The increase is largely due to higher natural gas prices, which were offset somewhat by lower reliability costs. The reliability costs are itemized individually below, in the All-In Cost Index. Table 2.5 shows the Wholesale Energy Cost Index by month for 2005, and annual summaries from 1998 through 2005.

[6] It was not possible to update the index to include these reliability cost components for prior years (1998-2001) due to some data limitations.

[7] This Annual Report uses an improved methodology to estimate unknown bilaterally contracted costs in 2002 through 2005. As a result, the 2002-2004 cost total reported here differs slightly from that reported in prior Annual Reports.

Table 2.5 Monthly Wholesale Energy Costs: 2005 and Previous Years

Month	ISO load (GWh)	Total Est. Forward Costs ($MM)	RT and Reliability Costs ($MM)	AS Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and A/S ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of A/S ($/MWh load)	AS as % of Wholesale Cost	Avg Cost of Energy & AS ($/MWh load)
Jan-05	18,876	941	83	19	1,024	1,043	54.23	1.02	1.8%	55.25
Feb-05	16,784	831	68	16	899	915	53.54	0.97	1.8%	54.51
Mar-05	18,211	923	78	18	1,001	1,019	54.98	1.00	1.8%	55.97
Apr-05	17,900	869	63	18	932	949	52.05	0.99	1.9%	53.04
May-05	19,411	897	70	21	966	988	49.78	1.11	2.2%	50.89
Jun-05	19,866	935	60	20	994	1,014	50.05	1.01	2.0%	51.06
Jul-05	24,163	1,233	69	32	1,302	1,333	53.88	1.31	2.4%	55.19
Aug-05	23,678	1,330	61	20	1,391	1,411	58.75	0.85	1.4%	59.60
Sep-05	20,187	1,199	67	14	1,266	1,280	62.70	0.70	1.1%	63.40
Oct-05	19,665	1,231	70	15	1,300	1,315	66.12	0.74	1.1%	66.87
Nov-05	18,556	1,040	65	15	1,105	1,120	59.53	0.82	1.4%	60.35
Dec-05	19,151	1,203	28	19	1,231	1,250	64.26	1.01	1.5%	65.26
Total 2005	236,449	12,630	780	228	13,410	13,638	56.71	0.96	1.7%	57.68
Total 2004	239,788	11,832	1,099	184	12,931	13,115	53.93	0.77	1.4%	54.70
Total 2003	230,668	10,814	696	199	11,510	11,709	49.90	0.86	1.7%	50.76
Total 2002	232,011	9,865	532	157	10,397	10,554	44.81	0.68	1.5%	45.49
Total 2001	227,024	21,248	4,586	1,346	25,410	26,756	114.63	6.07	5.3%	117.86
Total 2000	237,543	22,890	3,446	1,720	25,373	27,083	106.81	7.24	6.8%	114.01
Total 1999	227,533	6,848	562	404	7,028	7,432	30.89	1.78	5.7%	32.66
1998 (9mo)	169,239	4,704	1,061	638	4,913	5,551	29.03	3.77	13.0%	32.80

Notes to Wholesale Costs Table:

CAISO load is total energy consumed in GWh. Cost totals are in millions of dollars. Averages are in dollars per MWh of load served.

1998-2000:

Forward costs include estimated California Power Exchange (PX) and bilateral energy costs.

Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.

Estimated Bilateral Energy Cost based on the difference between hour-ahead schedules and PX quantities, valued at PX prices.

Beginning November 2000, CAISO Real-time Energy Costs include OOM Costs.

1998-2001:

RMR costs were not available and are not included. Must-Offer costs were not applicable.

2001 and 2002:

Sum of hour-ahead scheduled costs. Includes UDC (cost of production), estimated and/or actual CDWR costs, and other bilaterals priced at hub prices.

RT energy includes OOS, OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid.

2002 through 2005:

RT and reliability costs include real-time incremental balancing costs, decremental balancing savings, minimum-load compensation costs for resources committed per Must Offer Obligation, OOS/OOM costs, RMR fixed and variable costs.

2003:

Loads are unadjusted. CAISO included SMUD through 6/18/02. Load Jan-03 through Jun-03 may be lower than in 2002 due to SMUD exit.

2003 through 2005:

Forward energy costs revised slightly upward using a new methodology to include: utility-retained generation at estimated production costs, long-term contract (formerly managed by CDWR/CERS) estimated using 2002 delivery volumes; and short-term bilateral procurement estimated at utility-supplied procurement prices, when available, or Powerdex hour-ahead prices.

All years:

A/S costs include CAISO purchased and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund, if any.

Figure 2.11 shows that total annual wholesale energy costs have consistently increased each year since 2002. Some of this increase can be attributable to increases in the total annual load being served. For instance, total CAISO load served increased in the 2002-2004 time frame but declined in 2005. Another important factor is the impact of natural gas prices on energy prices. Much of the variation in energy prices across years can be directly attributed to the variation in the price of natural gas.

Figure 2.11 Total Wholesale Costs: 2002-2005

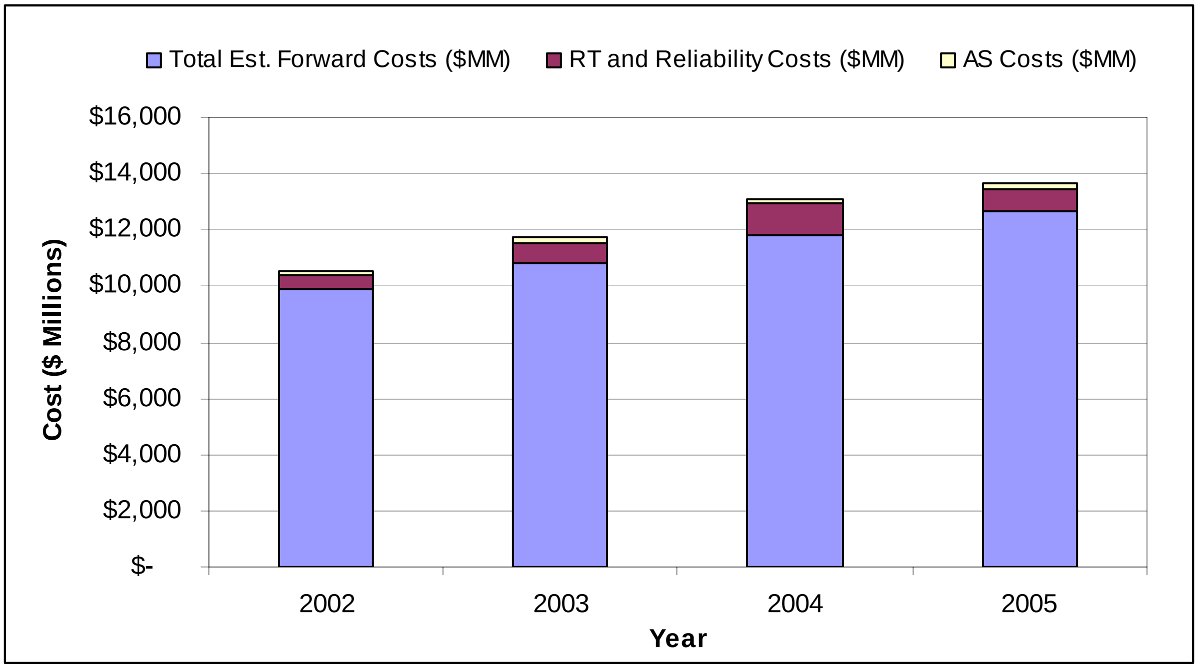
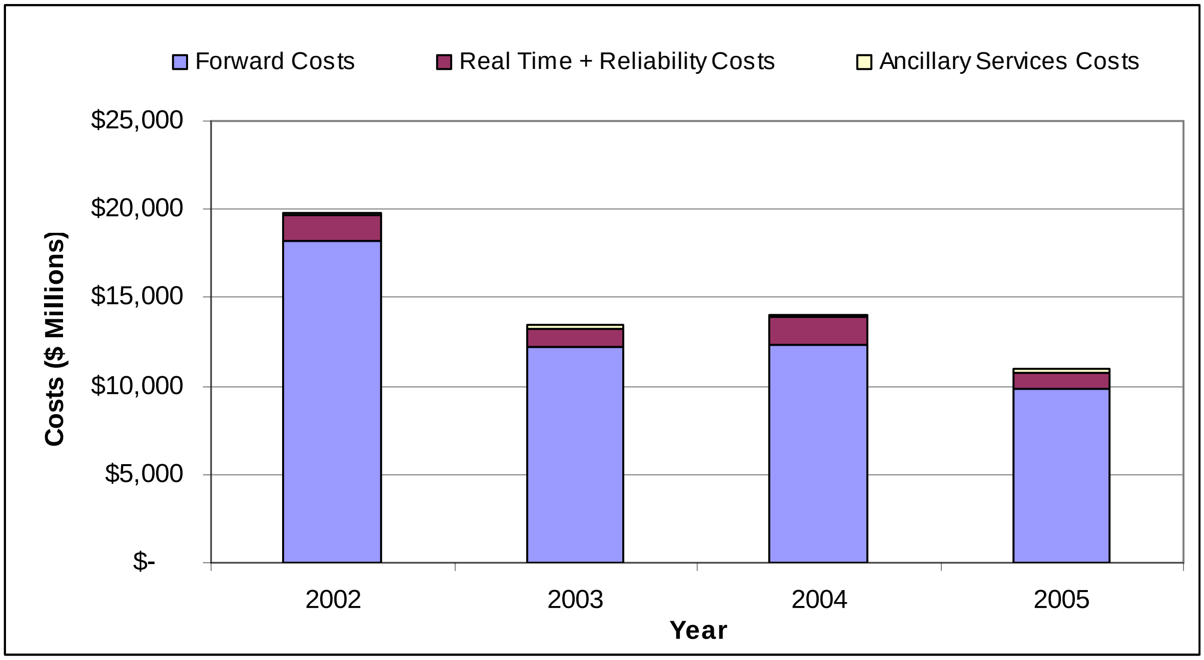


Figure 2.12 shows total annual wholesale energy costs normalizing for variations in natural gas prices[8] and indicates a general decline in total costs over this four-year period. The substantial decrease in normalized costs between 2002 and 2003 is likely due to the expiration of some costly long-term contracts entered into by the state of California in January 2001 as well as the entry of more efficient generation capacity (e.g., new combined cycle generation). Normalized costs increased slightly in 2004 due primarily to poor hydro conditions and out-of-season heat waves throughout the spring and in September, as well as by higher reliability costs for intra-zonal congestion management due to unit outages and transmission limitations. These

[8] Specific monthly energy costs (forward energy excluding grid management charges, real-time energy, MLCC, RMR pre-dispatch, and RMR real-time dispatch) were adjusted for variation in fuel price by multiplying each cost component by a monthly natural gas price index. The monthly natural gas price index was calculated by taking the simple average of the daily average spot gas price for Southern California for each month, and normalizing each month's average natural gas price by the average natural gas price for July 2004. This produces a monthly natural gas price index, such that the index value for the basis month of July 2004 is equal to one. The monthly energy costs are then divided by this monthly gas price index to produce a fuel price adjusted monthly energy cost. These adjusted costs are then added back in with the non-energy costs (grid management, fixed RMR payments, ancillary services) to produce the total adjusted monthly cost and summed for each year. A single hub price was used for the index for simplicity. Natural gas prices in the North, at PG&E Citygate, track closely with prices at the Southern California hub, with the exception of February through April of 2001.

additional costs offset any savings in 2004 due to further expirations of some state power contracts. The significant decrease in 2005 normalized costs is likely due to stronger hydro conditions in California and generally milder weather relative to 2004. The numerous transmission upgrades (described in Chapter 1) also contributed to decreased intra-zonal congestion management costs in 2005. The reduction in CAISO footprint had a small decreasing effect on 2005 costs.

Figure 2.12 Total Wholesale Costs Normalized to Fixed Gas Price: 2002-2005[9]



2.3.1 All-In Price Index

The "All-In Price Index" is a standardized metric developed by the FERC Office of Market Oversight and Investigation and several ISO market monitoring units, to provide, to the extent possible, an indicator of average wholesale energy costs that can be compared across electricity markets in several regions of the United States. The index includes adjustments to facilitate the comparison of providers with disparate features in an "apples-to-apples" manner. The All-In Price Index contains the average cost contributions of each of the following per megawatt-hour delivered to load:

- An estimate of forward energy costs, plus
- Real-time energy incremental costs, less
- Real-time decremental costs (negative), plus
- Minimum-load compensation[10] to units held on pursuant to the must-offer waiver denial process, plus
- Out-of-sequence energy costs, plus

[9] July 2004 gas price ($5.70/mmBtu) used as standard. All actual energy costs normalized; costs of grid management, ancillary services and fixed RMR component remain nominal. O&M cost not used in normalization.
[10] MLCC include start-up and no-load costs paid to generation units that are denied must-offer waivers.

- RMR costs, plus
- Market costs of ancillary services (with self-provided services estimated at market costs), plus
- Grid management charges for all services.

Table 2.6 shows the All-in Price Index values for 2002 through 2005 by contributing factor. The CAISO's All-In Price Index for 2005 was $57.68/MWh, compared to $54.70/MWh in 2004, $50.76/MWh in 2003, and $45.07/MWh in 2002, using equivalent methodologies.[11] The increase of approximately 5.4 percent since 2004 is due largely to the increases in natural gas prices. The increase in average energy costs in 2005 was moderated by a decrease in certain reliability service costs, such as RMR, out-of-sequence energy, and minimum load costs associated with the must-offer obligation (MOO). These cost elements were particularly high in 2004 due to an outage of San Onofre Nuclear Generating Station in the fall and various transmission limitations discussed in Chapter 6.

Figure 2.13 provides a comparison of the All-In Prices for 2002 through 2005. Figure 2.14 shows the all-in prices normalized against changes in natural gas prices, using the same methodology as discussed in the wholesale total costs section. The reasons for the decline in gas-normalized costs are also discussed in that section.

Table 2.6 All-In Price Index ($/MWh load): 2002-2005

	2002	2003	2004	2005	Change '04-'05
Est. Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	40.92	45.77	48.21	52.35	4.13
Interzonal Congestion Costs	0.18	0.12	0.23	0.23	(0.00)
GMC (All charge types, including RT)	1.00	1.00	0.90	0.84	(0.06)
Incremental In-Sequence RT Energy Costs	0.49	0.63	0.86	1.55	0.69
Explicit MLCC Costs (Uplift)	0.26	0.54	1.21	0.52	(0.68)
Out-of-Sequence RT Energy Redispatch Premium	0.02	0.19	0.43	0.15	(0.28)
RMR Net Costs (Include adjustments from prior periods)	1.60	1.95	2.67	1.95	(0.73)
Less In-Sequence Decremental RT Energy Savings	(0.08)	(0.29)	(0.59)	(0.87)	(0.29)
Total Average Energy Costs	**44.39**	**49.90**	**53.93**	**56.71**	**2.79**
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	0.68	0.86	0.77	0.96	0.20
Total Average Costs of Energy and A/S ($/MWh load)	**45.07**	**50.76**	**54.70**	**57.68**	**2.98**

[11] The same improvement in the estimation of unknown bilateral forward costs used in the Total Wholesale Energy Cost Index was also used in the All-In Price Index. Thus, reported indices from 2004 and earlier differ from those reported in previous Annual Reports.

Figure 2.13 Annual All-In Prices: 2002-2005

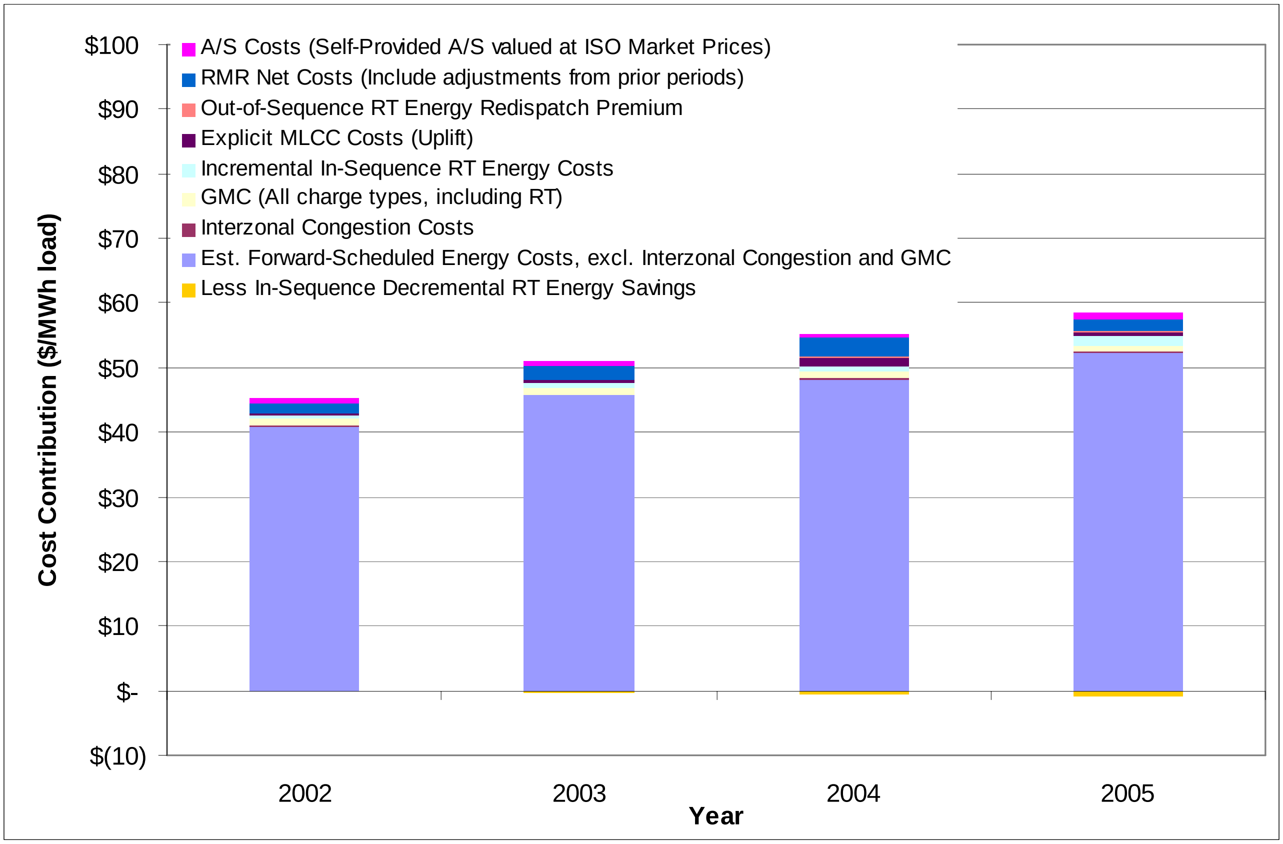
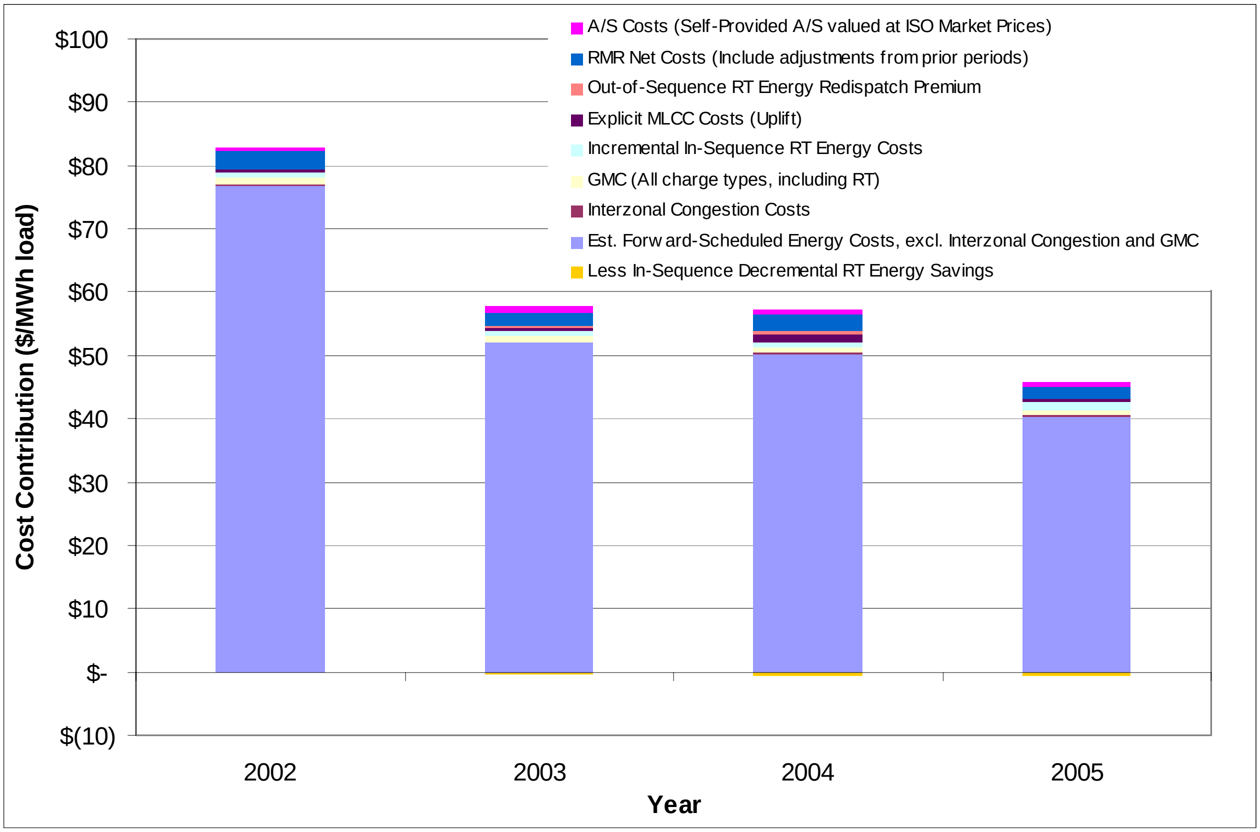


Figure 2.14 Annual All-In Prices Normalized for Natural Gas Price Changes: 2002-2005



Due to changes in data infrastructure and market structure, it was not possible to compare gas-normalized costs in recent years to the pre-crisis period of 1998 and 1999 explicitly. However, it is possible to make an approximation of gas-normalized costs based upon the annual wholesale cost figures provided in Table 2.5 for 1998 and 1999 and normalize these values using annual natural gas prices.[12] Similarly, monthly wholesale costs and gas prices from 2000 and 2001, as reported in the *Third Annual Report on Market Issues and Performance,*[13] can be used to estimate normalized costs for that period.[14] The estimated gas-normalized costs that result are summarized in Table 2.7 and Figure 2.15.

[12] Annual total energy costs in 1998 and 1999 were deflated by dividing by the ratio of Southern California border annual average gas prices to July 2004 average gas price ($5.70/mmBtu), and adding this gas price adjusted annual energy cost to the non-energy costs.
[13] California ISO Dept. of Market Analysis, January 2002.
[14] Monthly total energy costs in 1998 and 1999 deflated by dividing by the ratio of Southern California border monthly average gas prices to July 2004 average gas price ($5.70/mmBtu), and added to non-deflated non-energy costs.

Table 2.7 Annual Nominal and Gas-Normalized Wholesale Costs, 1998-2005

Year	Gas Price ($/mmBtu)	ISO Load (GWh)	Nominal Total Costs ($MM)	Average Total Nominal Costs ($/MWh load)	Normalized Total Costs ($MM)	Average Total Normalized Costs ($/MWh load)
1998	$ 2.25	169,239	$ 5,551	$ 32.80	$ 12,825	$ 75.78
1999	$ 2.33	227,533	$ 7,432	$ 32.66	$ 17,268	$ 75.89
2000	$ 6.30	237,542	$ 27,092	$ 114.05	$ 26,003	$ 109.47
2001	$ 7.74	227,023	$ 26,702	$ 117.62	$ 23,169	$ 102.05
2002	$ 3.14	232,793	$ 10,554	$ 45.07	$ 19,170	$ 82.70
2003	$ 5.09	230,668	$ 11,709	$ 50.76	$ 13,263	$ 57.31
2004	$ 5.50	239,788	$ 13,115	$ 54.70	$ 13,620	$ 56.74
2005	$ 7.55	236,449	$ 13,638	$ 57.68	$ 10,714	$ 45.26

Figure 2.15 Average Nominal and Gas-Normalized Wholesale Costs, 1998-2005

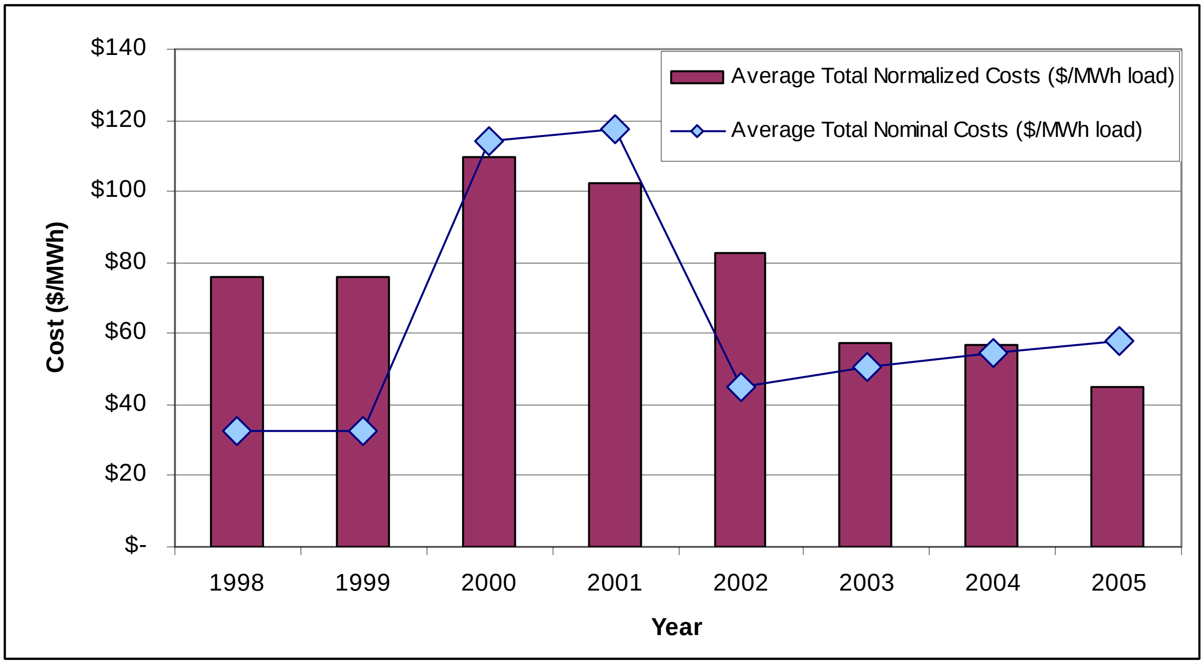


Figure 2.15 indicates that average total wholesale costs, when adjusted for changes in natural gas prices, have steadily declined since 2000, and the estimated gas-normalized average wholesale cost in 2005 is the lowest value over the entire eight-year period. As previously discussed, this trend is likely attributable to the significant amounts of new investment in efficient gas-fired generation that has occurred during the 2001-2005 period both in California and throughout the West, particularly the Southwest.

2.4 Market Competitiveness Indices

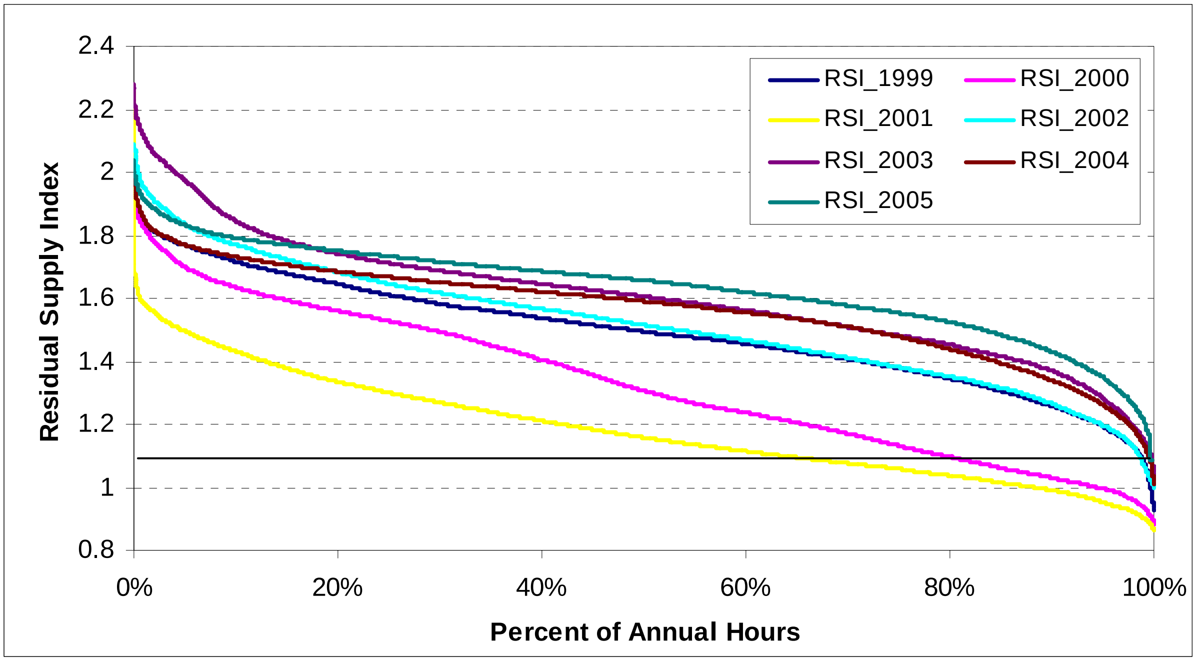
2.4.1 Residual Supplier Index: Measuring Competitiveness in Market Structure

The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2005 were generally higher than in 2003 and 2004, which were the highest of the past five years. Using an RSI level of 1.1 to compare between years,[15] in 2005 the RSI levels were less than 1.1 in less than 0.30 percent of the hours (only 5 hours out of 8,760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2005 were again significantly more competitive than in 2000 and 2001 as a result of the addition of new generation and high levels of net imports over the period. The RSI levels are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2005. The significant amount of long-term contracts entered into since 2001 have also led to more competitive market outcomes, although the impacts of contracting are not accounted for in this analysis as it is directed at reflecting the physical aspects of the market. The RSI analysis shows that the underlying physical infrastructure was much more favorable for competitive market outcomes in the period 2002 through 2005 than 2001 as reflected by the higher RSI levels. Figure 2.16 compares RSI duration curves for the past seven years (1999-2005).

[15] Historically, market power can be prevalent with an RSI of 1.1 due to estimation error and the potential for tacit collusion among suppliers.

Figure 2.16 Residual Supply Index (1999-2005)



2.4.2 *Short-term Energy Price-to-Cost Mark-up Analysis*[16]

Another index used to measure market performance in the California wholesale electricity markets is the price-to-cost mark-up. This is the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the most expensive, or marginal, unit of energy needed to serve load. The ratio of the volume-weighted average mark-up to marginal cost is a metric that can be used to identify market performance trends over time.

Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. The methodology has been updated to include data sources that were previously not available. However, there are still periods in calendar year 2004 for which short-term energy procurement information is not available. During these periods, hourly short-term forward price data purchased from Powerdex[17] is used as a substitute.

The CAISO continues to utilize a "single resource portfolio" methodology to meet the objective of developing a competitive benchmark for short-term bilateral energy markets. The methodology depends on several assumptions: every asset in the portfolio bids competitively, all bids are at marginal cost, and the portfolio clears against the total of actual historical hour-ahead generation schedules in each hour of benchmark development.

[16] Short-term energy is defined as forward purchased energy purchased within 24 hours of real-time operation.

[17] Powerdex is an independent energy information company that surveys buyers and sellers of energy at key Western hubs and compiles hourly prices. http://www.powerdexindexes.com - 5703 Spellman Road, Houston, TX, 77096

Additional conditions were necessary to develop the competitive short-term bilateral market clearing price benchmark. All of the resources in the portfolio are assigned unit commitment levels based on historical hour-ahead schedules. Hydroelectric units in the portfolio are optimally dispatched to reflect total metered output for the given week in history. Pumped storage generation units optimally pump and generate within the bounds of storage and release constraints as well as pumping efficiency. Resources in the cogeneration, renewable and QF classes, in addition to resources with unknown variable costs, were forced to operate in direct accordance with their forward energy schedules. California imports are modeled to flow economically, bound by hourly inter-tie availability, and are priced at historical Powerdex hub price levels for the California-Oregon Border (COB) and Palo Verde (PV).

The CAISO market model utilizes PLEXOS for Power Systems™ as the market simulation tool. PLEXOS employs a linear programming based production cost model, which allows for co-optimization with ancillary service markets. PLEXOS for Power Systems™ is produced by Drayton Analytics, Pty Ltd.[18] The majority of data used by the model are sourced from CAISO market operations records. When variable cost information is not available through operations data, the CAISO attempts to obtain it from data purchased from Global Energy Decisions, Inc.[19] Global Energy Decisions is also the source for the pumped storage reservoir volumes and pump efficiency data employed in the model.

For calendar year 2005, the CAISO observed short-term mark-ups ranging from 4 to 16 percent, compared to 1.2 to 22.5 percent in the prior year. Figure 2.17 and Figure 2.18 summarize competitiveness in the short-term forward energy markets. SP15 posted eight months with mark-ups greater than 10 percent while NP15 logged five such months. Months with the greatest mark-ups were October and November, corresponding to a significant amount of generation being off-line for seasonal maintenance. On the whole, 2005 short-term forward markets functioned effectively, leading largely to competitive pricing in both the NP15 and SP15 regions.

[18] http://www.draytonanalytics.com - PO Box 13, North Adelaide, SA 5006, Adelaide, Australia
[19] http://www.globalenergy.com/ - 2379 Gateway Oaks Dr., Suite 200, Sacramento, CA, 95833

Figure 2.17 2004 Short-term Forward Market Index – NP15

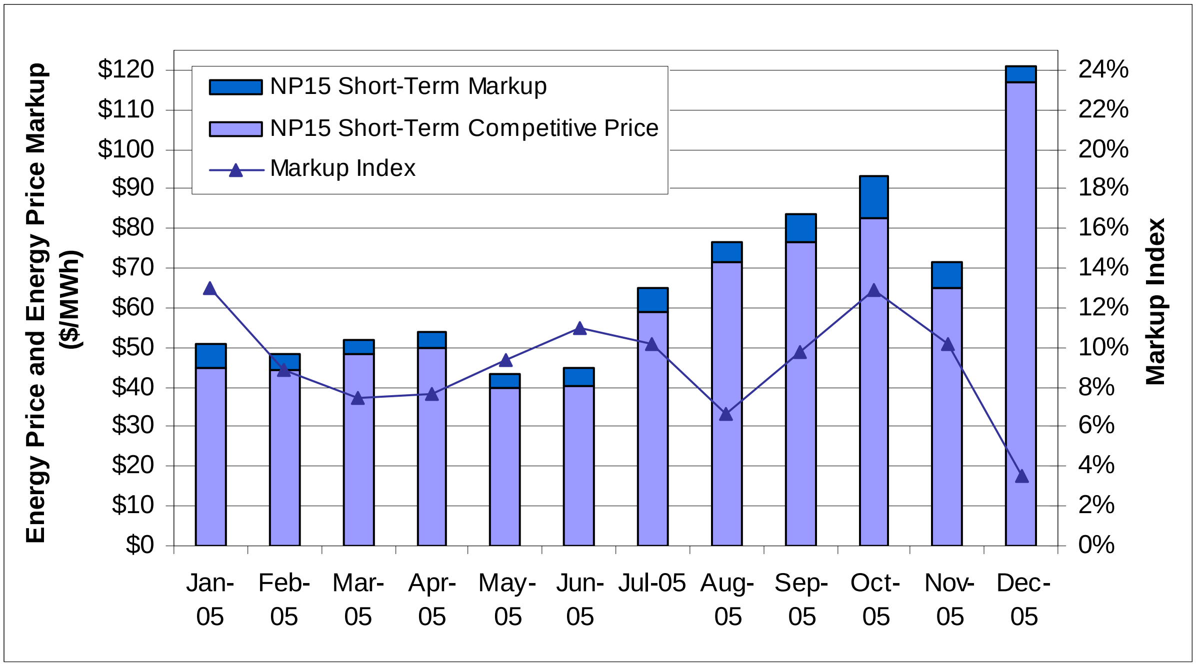
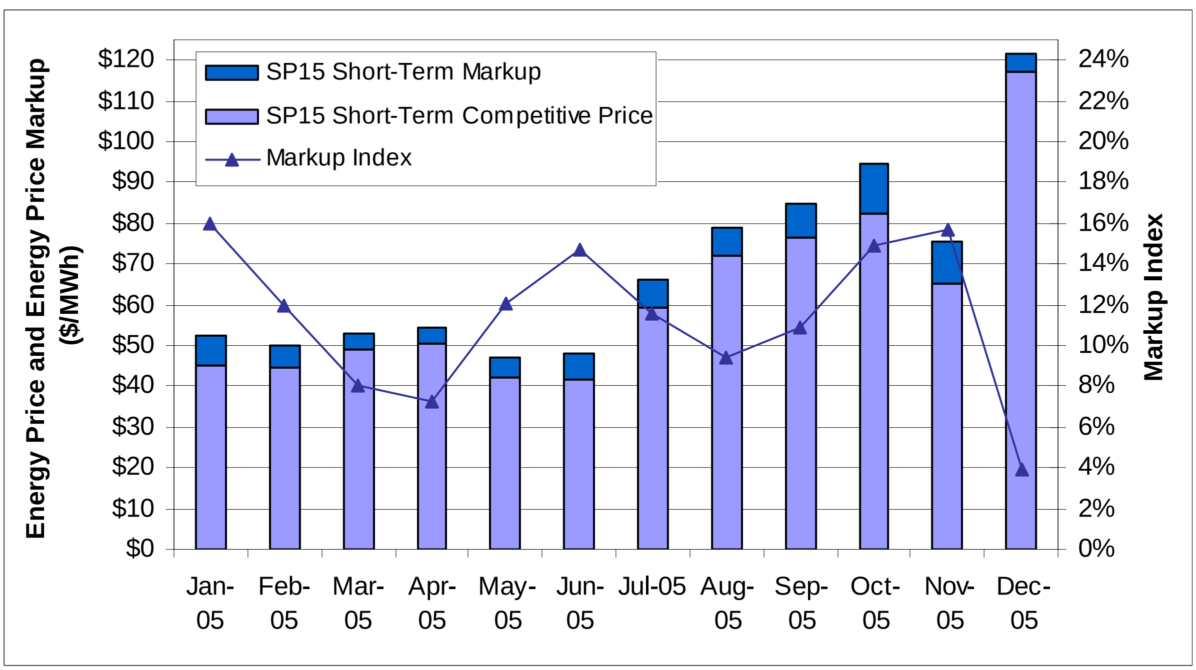


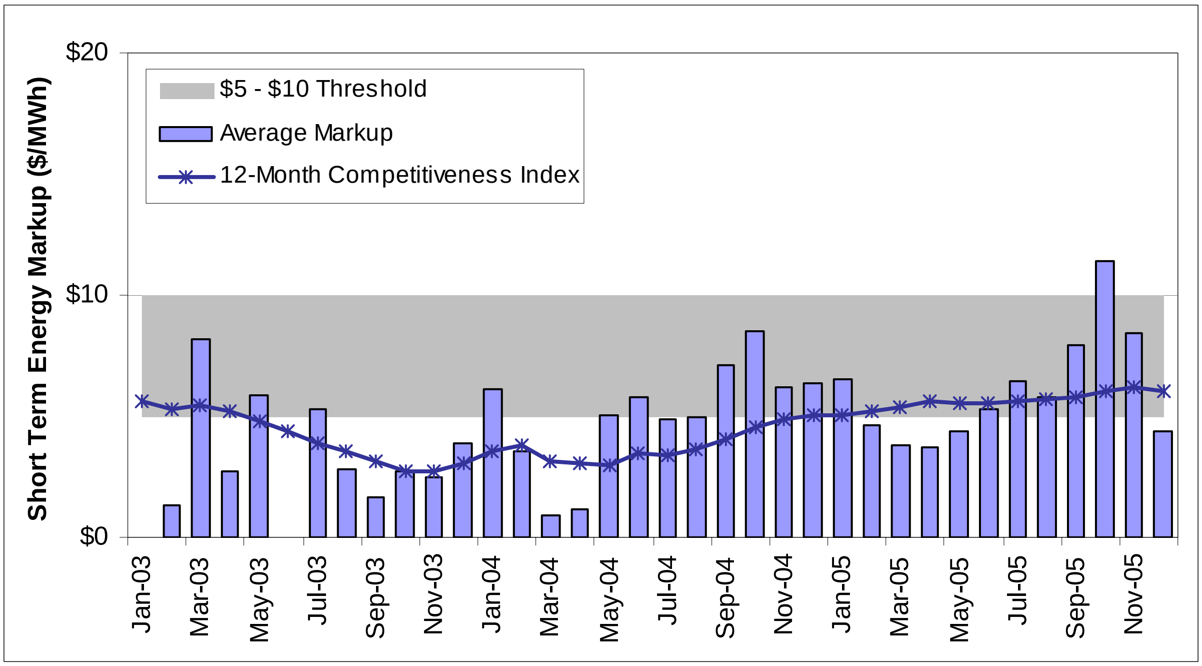
Figure 2.18 2004 Short-term Forward Market Index – SP15



2.4.3 Twelve-Month Competitiveness Index

The CAISO employs several indices during market competitiveness assessments. The index in Figure 2.19 serves to measure market outcomes over extended time periods against estimated perfectly competitive market outcomes. The 12-Month Competitiveness Index is a rolling average of the short-term energy mark-up above approximated competitive prices. The CAISO assumes that the short-term energy market is subject to little or no exercise of market power when the index is near or below a $5 to $10 per MWh range.

Figure 2.19 Twelve-Month Competitiveness Index



2.4.4 Real-time Market Price to Cost Mark-up

The real-time price-to-cost mark-up index is designed to measure real-time imbalance market performance. This index detects trends in the price-to-cost ratio. Sporadic price spikes due to operational constraints such as shortage of ramping capability have limited impact on this real-time mark-up. This index is a somewhat conservative measure of a competitive baseline price since it only takes into account generation units that were dispatched by the CAISO. By only including dispatched units in determining the competitive baseline price, this metric does not account for any possible economic withholding of units that bid higher than the market clearing price. This methodology assumes that high-priced bids above the market clearing price correspond to high costs which will usually produce a higher estimated competitive baseline price (and lower mark-up). The methodology also discounts physical withholding by assuming that units that are forced out of service are not available for legitimate reasons and that generators that do not bid in all of their available capacity will have that capacity bid in for them by the CAISO under the must-offer obligations.

Figure 2.20 and Figure 2.21 show the monthly average mark-up for incremental and decremental real-time energy dispatched in 2005, respectively. As shown in these figures, the incremental Real Time Market mark-up overall is relatively stable, with estimated mark-ups ranging from 8 percent to 20 percent. However, the decremental Real Time Market mark-up seems to reflect seasonal trends. In spring and early summer, it was common to see negative (-$0.01) bids on the decremental side setting prices, reflecting certain hydro units that were operating under water management constraints. When such bids set the market clearing price, they tend to increase mark-ups in the decremental market. This is the main reason behind the high decremental mark-ups in the first half of 2005 that peaked in May and June. Starting in July, mark-ups in the decremental market returned to a range under 20 percent.

Figure 2.20 Real-time Incremental Energy Mark-up above Competitive Baseline Price

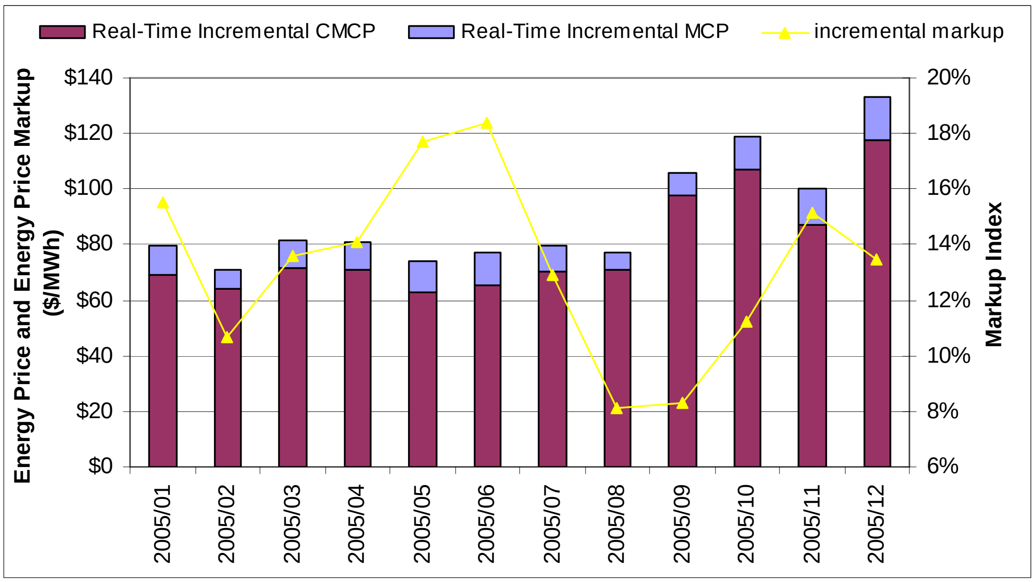


Figure 2.21 Real-time Decremental Energy Mark-up below Competitive Baseline Price

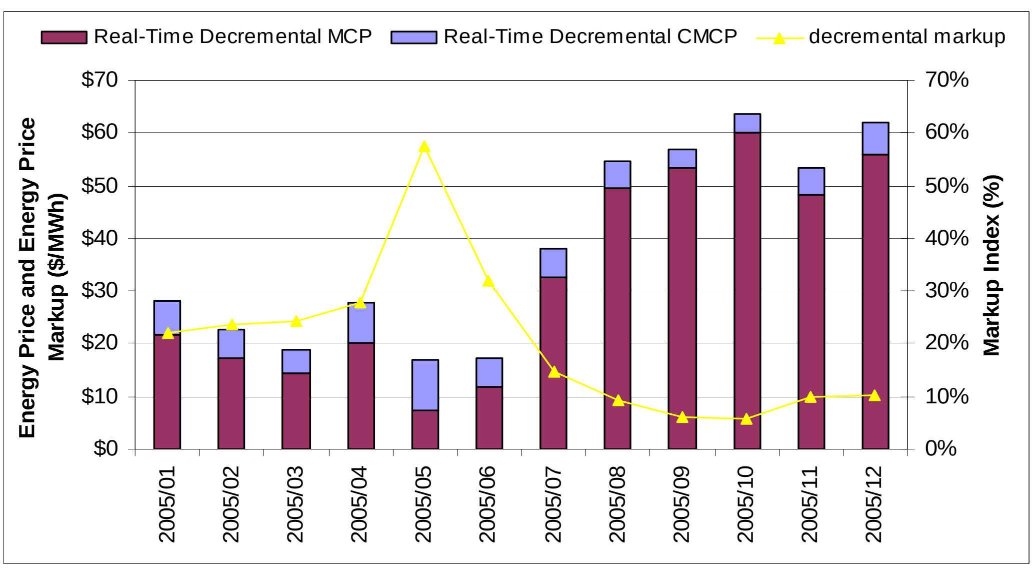
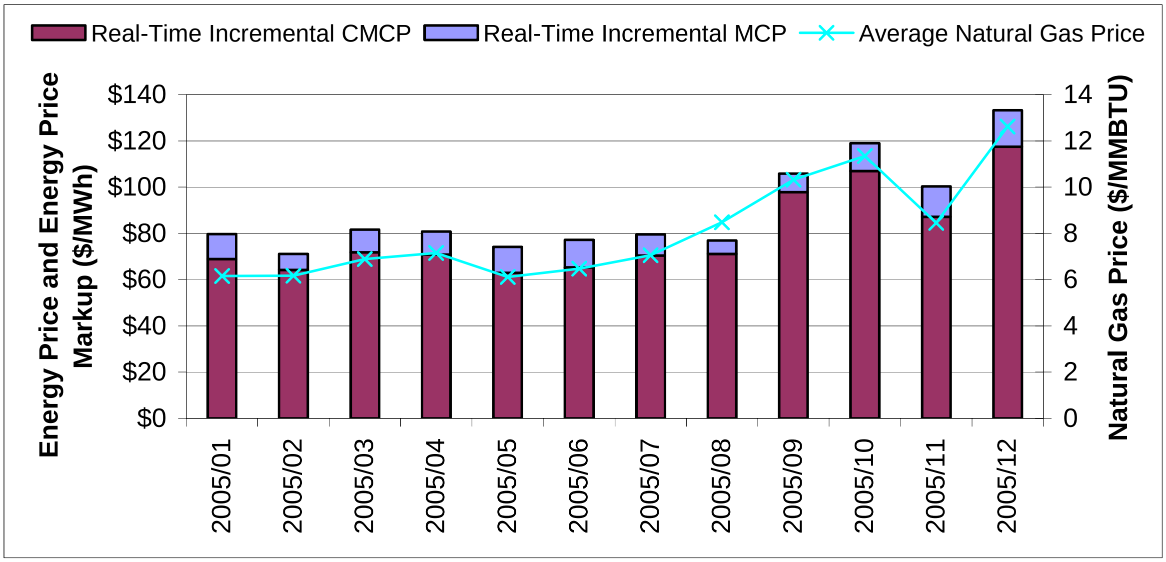


Figure 2.22 shows that the monthly weighted market clearing prices and competitive market clearing prices tend to be highly correlated with monthly averaged natural gas prices.

Figure 2.22 CMCP Relation to Natural Gas Prices



2.4.5 Real-time market Residual Supplier Index (RSI) Analysis

The DMM has also been applying the RSI to the Real Time Market to measure the competitiveness of both the incremental and decremental sides of the imbalance energy market. When the Real Time Market splits, supply and demand conditions are restricted within each individual zone. It is appropriate to calculate zonal RSIs in such circumstances. On the incremental side, when the market splits, NP15 often has abundant supply and the market is generally competitive, whereas SP15 has greater demand and relatively less supply. Figure 2.23 shows an RSI curve for the CAISO as a whole for incremental supply when the market is not split, and for SP15 when the market is split, which shows that SP15 often has lower RSI values. Figure 2.24 shows that real-time energy prices (System and SP15) are strongly negatively correlated with RSI values where lower RSI values generally result in higher real-time energy prices.

Figure 2.23 RSI Duration Curve for Incremental Energy

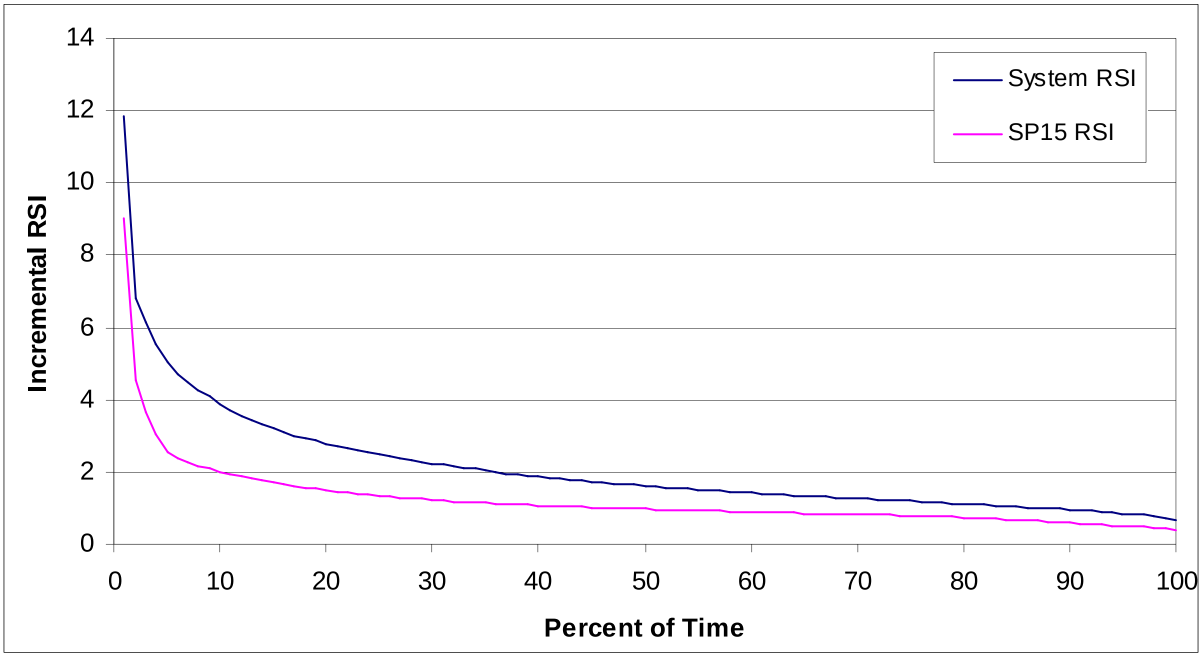


Figure 2.24 RSI Relationship to Real-time Incremental Market Clearing Prices

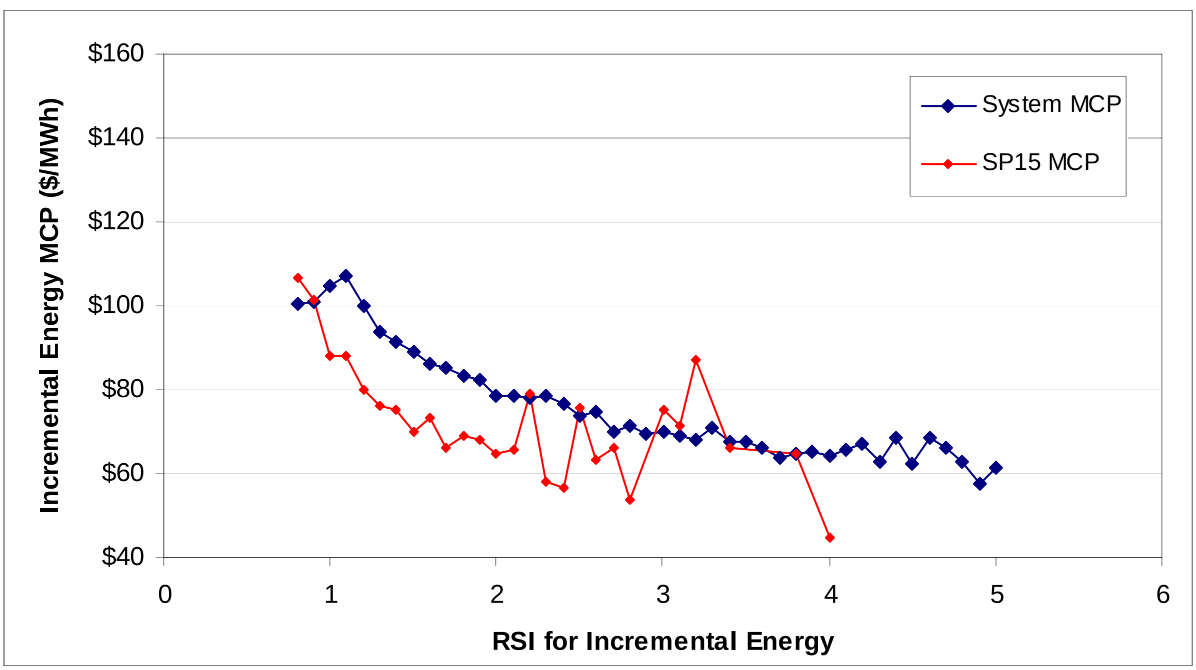


Figure 2.25 shows the RSI duration curve during decremental dispatch periods. In 2005, RSI values dipped below 1.0 in 15 percent of the periods. RSI values for decremental supply tend to be low in off-peak hours when generators are operating close to their minimum output level and unwilling or unable to offer decremental bids. On average, low RSI values result in low market clearing prices for those periods CAISO needs to dispatch decremental energy to balance the market (Figure 2.26).

Figure 2.25 RSI Duration Curve for Decremental Energy

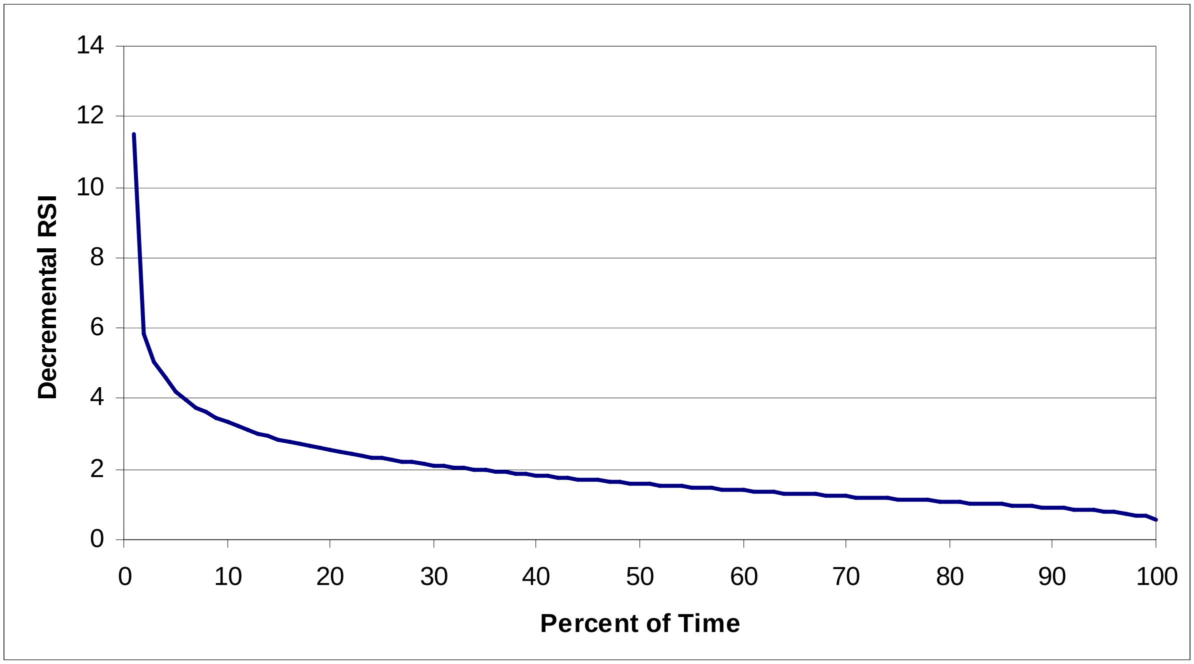
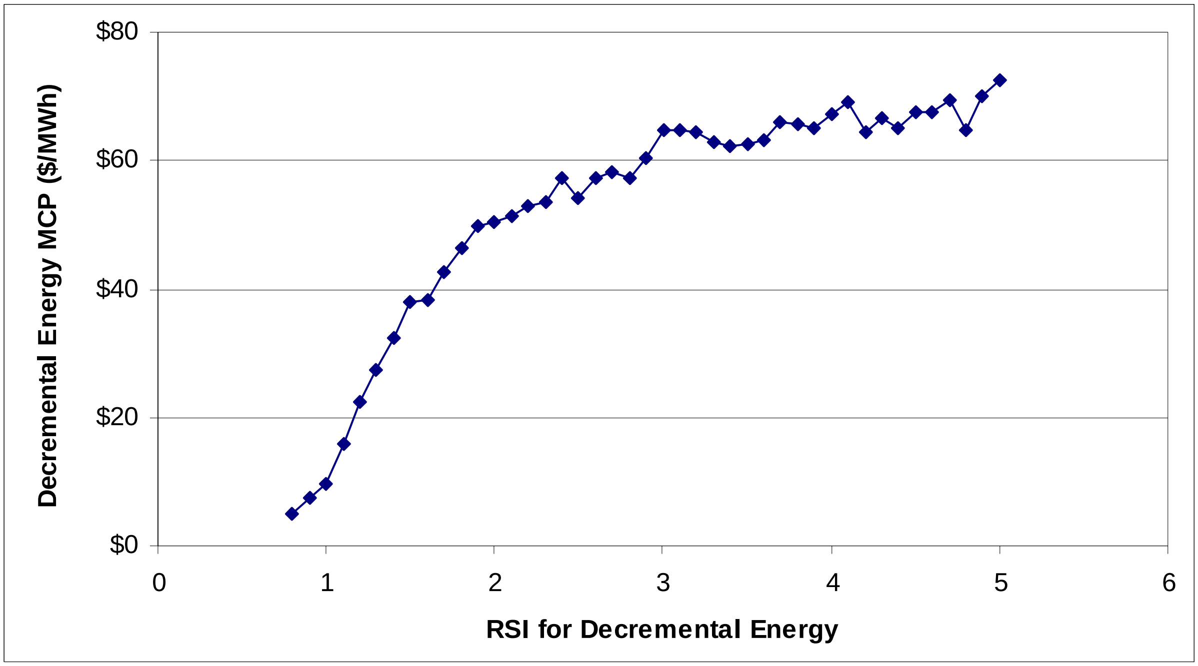


Figure 2.26 RSI Relationship to Real-time Decremental Market Clearing Prices



2.5 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past five years (2001-2005), investment in Southern California has not kept pace with unit retirements and load growth. Moreover, there is a continued reliance on very old and inefficient generation to meet Southern California reliability needs. Going forward, it is imperative that California has an adequate market/regulatory framework for facilitating new investment in the critical areas of the grid where it is needed, particularly Southern California. This section examines some of the issues that possibly affect incentives for new generation investment. It begins with an assessment of the extent to which spot market revenues in 2005 were sufficient to cover the annualized fixed cost of new generation. This is followed by an examination of the use of the Must Offer Obligation to meet reliability needs in 2005 and the potential impacts that this mechanism may have on incentives for long-term contracting. A review of the generation additions and retirements for 2001 through 2005 and projections for 2006 is provided next. This section concludes with a review of the continued reliance on older generation facilities and a discussion of the critical need for a long-term procurement framework for facilitating new investment.

2.5.1 Revenue Adequacy for New Generation Investment

This section examines the extent to which spot market prices provide sufficient revenues to cover the annualized fixed costs of two types of generating units (combined cycle and combustion turbine). It is important to note that spot markets are inherently volatile and as such never guarantee fixed cost recovery, particularly if the market is over-supplied. Moreover, given the lead-time needed for new generation investment, current spot market prices may not be the best indicator for new investment. Expectations on future spot market prices – based on expectations of future supply and demand conditions – are likely to be a stronger driver for long-term contracting, which is the primary means for facilitating new investment. To the extent existing units are critical to meeting reliability needs, their annual fixed costs should be recoverable through a combination of long-term bilateral contracts and spot market revenues. Nonetheless, examining the extent to which current spot market prices alone can contribute to fixed cost recovery for new investment has proven to be an important market metric that all ISO's measure.

The annualized fixed costs used in this analysis are obtained from a California Energy Commission (CEC) report,[20] which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be $90/kW-year and $78/kW-year, respectively. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.8 and Table 2.9. It should be noted that the finance costs shown in these tables do include a rate of return on capital for equity investment.

[20] "Competitive Cost of California Central Station Electricity Generation Technologies," California Energy Commission, Report # 100-03-001F, June 5, 2003, Appendices C and D.

Table 2.8 Analysis Assumptions: Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Heat Rates (MMBtu/kWh)	
Maximum Capacity	7,100
Minimum Operating Level	8,200
Financing Costs	$75 /kW-yr
Fixed Annual O&M	$15 /kW-yr
Other Variable O&M	$2.4/MWh
Startup Costs	
Gas Consumption	1,850 MMBtu/start
Fixed Cost Revenue Requirement	**$90/kW-yr**

Table 2.9 Analysis Assumptions: Typical New Combustion Turbine Unit

Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financing Costs	$58 /kW-yr
Fixed Annual O&M	$20 /kW/year
Other Variable O&M	$10.9/MWh
Startup Costs	
Gas Consumption	180 MMBtu
Fixed Cost Revenue Requirement	**$78/kW-yr**

2.5.1.1 Methodology

To provide a longer-term perspective, the net revenue analysis provided in this year's Annual Report was conducted over a 4-year period (2002-2005). Some improvements were made to the net revenue analysis methodology used in the *2004 Annual Report* to provide a better estimate of potential spot market revenues. For consistency, these modifications were applied over the 4-year study period. Consequently, the numbers shown in this report differ from those shown in the *2004 Annual Report*, though the fundamental findings are the same.

Two methodologies were used to calculate the net revenues earned by the hypothetical combined cycle described in Table 2.8. The first was based on market participation limited to the Real Time Market with some additional revenues estimated for MLCC under the current must-offer provisions. A second was based on participation limited to the day-ahead spot energy markets and the CAISO Ancillary Service Market. The specific methods used for both of these approaches are described below.

Combined Cycle – Net Revenue Methodology

The operational and scheduling assumptions used to assess the potential revenues that could be earned by a typical new combined cycle unit from sales in the CAISO's real-time energy market are summarized below:

1. An initial operating schedule was determined based on real-time energy prices and the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.8. The unit was scheduled up to full output when hourly prices exceed variable operating costs.

2. The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when real-time prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded real-time energy prices.

3. A series of simplified ramping constraints were applied to the unit's schedule to approximate the degree to which the unit would need to deviate from this schedule given the unit's ramp rate.

4. All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

5. Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues by 5 percent.

Potential revenues that could be earned by a typical new combined cycle unit from sales in the day-ahead bilateral spot markets were assessed using the same methodology described above, except that energy prices used in the analysis were based on the hourly spot market price index published by Powerdex on a subscription basis and ancillary service revenues were calculated by assuming the unit could provide 80 MW of non-spinning reserve each hour. Revenues from sales of non-spinning reserve were based on day-ahead market prices.

Combustion Turbine – Net Revenue Methodology

Potential revenues that could be earned by a typical new simple cycle combustion turbine in the CAISO's real-time energy market were calculated using a more simplified model, as described below:

1. For each hour, it was assumed the unit would operate if the average hourly real-time price exceeded the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.9. The unit was scheduled up to full output when hourly prices exceeded variable operating costs.

2. Ancillary service revenues were calculated by assuming the unit could provide 80 MW of non-spinning reserve each hour. Revenues from sales of non-spinning reserve were based on day-ahead market prices.

3. All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

4. Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues from real-time energy and non-spinning reserve sales by 5 percent.

2.5.1.2 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year's revenue analysis includes additional analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated exclusively in the day-ahead bilateral market and contrasts those estimates with net revenues earned from the same unit participating exclusively in the CAISO real-time market. These results are summarized in Table 2.10 and show a consistent downward trend in the net revenues a hypothetical combined cycle would earn from participating exclusively in the CAISO real-time energy market over the four-year period (2002-2005). The analysis is not as clear for the net revenues the unit would earn participating exclusively in the day-ahead bilateral energy market and CAISO Day Ahead Ancillary Service Market, which show fairly consistent net revenues in the 2002-2004 period with an increase in 2005. However, under all scenarios (day-ahead and real-time), the estimated net revenues are well below the $90/kW-yr annualized cost of the unit.

Table 2.11 shows the estimated net revenues that a hypothetical combustion turbine (CT) would have earned by participating exclusively in the CAISO Real Time Market. Similar to the combined cycle analysis, the estimated revenues for a hypothetical CT fall well short of the $78/kW-yr annualized costs for all years (2002-2005).

Table 2.10 Financial Analysis of New Combined Cycle Unit (2002 – 2005)

Real-Time Market Revenue Analysis

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	58%	59%	44%	47%	39%	44%	54%	57%
Energy Revenue ($/kW - yr)	$208.4	$215.0	$217.4	$233.4	$190.8	$223.3	$320.9	$339.5
MLCC ($/kW - yr)		$10.6		$22.6		$31.0		$38.5
A/S Revenue ($/kW - yr)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Operating Cost ($/kW - yr)	$135.9	$138.9	$171.3	$176.7	$163.3	$178.4	$303.8	$311.5
Net Revenue w MLCC ($/kW - yr)	$72.5	$86.7	$46.1	$79.3	$27.5	$75.9	$17.1	$66.6
Net Revenue w/o MLCC ($/kW - yr)	$72.5	$76.2	$46.1	$56.7	$27.5	$44.9	$17.1	$28.1

Day-Ahead Market Revenue Analysis

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	61%	62%	53%	54%	58%	59%	57%	59%
Energy Revenue ($/kW - yr)	$176.9	$189.8	$235.7	$246.0	$270.6	$274.6	$378.9	$386.9
MLCC ($/kW - yr)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
A/S Revenue ($/kW - yr)	$0.5	$0.4	$0.7	$0.5	$0.9	$0.8	$1.2	$1.2
Operating Cost ($/kW - yr)	$141.2	$145.1	$196.1	$196.8	$235.3	$228.6	$320.2	$322.3
Net Revenue ($/kW - yr)	$36.2	$45.2	$40.3	$49.8	$36.2	$46.8	$59.9	$65.8

Table 2.11 Financial Analysis of New Combustion Turbine Unit (2002-2005)

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	34%	35%	15%	19%	9%	14%	8%	10%
Energy Revenue ($/kW - yr)	$156.5	$162.1	$118.1	$142.4	$72.8	$121.7	$87.5	$107.5
A/S Revenue ($/kW - yr)	$5.8	$5.6	$19.6	$18.2	$14.1	$27.4	$19.3	$18.5
Operating Cost ($/kW - yr)	$125.9	$129.4	$87.3	$108.0	$54.0	$81.6	$63.7	$82.0
Net Revenue ($/kW - yr)	$36.4	$38.3	$50.4	$52.7	$32.8	$67.5	$43.1	$44.1

The results shown in Table 2.10 and Table 2.11 indicate that net revenues appear to be sufficient to cover a unit's fixed operating and maintenance (O&M) costs on an annual basis. These fixed O&M costs are the fixed costs that a unit owner would be able to avoid incurring if the unit were not operated for the entire year (i.e., mothballed). Note that variable (fuel) costs (including start-up costs) are automatically covered since the simulation nets these costs against revenues to calculate net revenue. Fixed O&M costs, as reported by the CEC,[21] are $15/kW-year for a combined cycle unit and $20/kW-year for a combustion turbine unit. Net revenues sufficient to cover fixed O&M costs should be sufficient to keep a unit operating from year to year.

However, the results also show that total fixed cost recovery, fixed O&M cost plus the cost of capital, was not achieved for either generation technology in any of the four years. In the case of the combustion turbine unit, net revenues generally did not come close to the total fixed cost estimate of $78/kW-year, except in the case of SP15 in 2004, which was still deficient by

[21] "Competitive Cost of California Central Station Electricity Generation Technologies," California Energy Commission, Report # 100-03-001F, June 5, 2003, Appendices C and D.

roughly $10.50/kW-year. The same result is true for combined cycle units, where the total fixed cost of $90/KW-year is never fully reached even when potential MLCC revenues are accounted for.

Given the need for new generation investment in southern California, as reflected in the relatively tight supply margins that occurred in that region during peak summer demand periods over the past two years and documented reliability concerns cited in the CAISO 2005 Summer Operations Assessment,[22] the finding that estimated spot market revenues failed to provide for fixed cost recovery of new generation investment in this region in both of these years raises two issues. First, it underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Such a procurement framework would need to be coupled with local procurement requirements to ensure energy or capacity procurement is occurring in the critical areas of the grid where it is needed. Second, it suggests there are inadequacies in the current market structure for signaling needed investment. Future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, local ancillary service procurement, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation in November 2007, will provide some of these elements (LMP, some degree of scarcity pricing, and capability to procure ancillary services locally). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and comparable programs for non-CPUC jurisdictional entities.

2.5.2 The Must-Offer Obligation

The Must-Offer Obligation (MOO) refers to a CAISO Tariff provision that requires all non-hydroelectric generating units that participate in the CAISO markets or use the CAISO Controlled Grid to bid all available capacity into the CAISO Real Time Market in all hours. This provision originated from an April 26, 2001 FERC Order adopting a prospective monitoring and mitigation plan for real-time California wholesale energy markets and has been extended through a series of subsequent FERC orders. For long-start-time units, this obligation extends into the day-ahead time frame to enable the CAISO to issue start-up instructions (or deny shut-down requests) for units the CAISO expects to need the next day.

Use of the MOO for reliability services has been extensive over the past three years, although costs associated with this mechanism declined significantly in 2005 (see Chapter 6). While there are several notable differences between RMR and MOO, one important distinction is compensation. RMR units have a pre-negotiated compensation rate that is intended to cover all, or some portion, of the total cost of owning and operating that unit. As such, the RMR mechanism provides a very explicit and targeted revenue stream for fixed cost recovery so that these units will continue to operate and provide the needed local reliability service. Compensation has two general components under RMR: a payment to cover (all or a portion of) a unit's fixed costs and a payment to cover variable cost of production. By contrast, units that are committed by the CAISO under the MOO do not receive a pre-determined fixed payment intended to address fixed cost recovery. Instead, such units are paid for their minimum load energy using a cost-based formula and are eligible to earn market revenues on ancillary services and real-time energy sales to the CAISO. Additionally, units that are committed under

[22] See http://www.caiso.com/docs/09003a6080/35/46/09003a60803546fd.pdf

the MOO receive a second payment for their minimum load energy through receiving the real-time market clearing price for that energy. In the aggregate, this second payment has been roughly 40 percent of the MLCC payment. For perspective, total MLCC costs for 2003-2005 (in millions) were $125, $287, $119, or $531 for the entire three years. While use of the MOO has subsided in 2005, these figures demonstrate the CAISO's continued reliance on and need for the MOO to provide reliability services. The second payment on minimum load, discussed above, comes to about $214 million for the 2003-2005 period, bringing the total non-market compensation for these units to $745 million for this three-year period.

While $745 million paid out to units subject to MOO is a significant revenue source, it should be noted that the majority of these revenues go to a limited subset of units. Eighty percent of the total combined payments for 2005 (MLCC and the second energy payment) were paid to roughly 34 percent of the units committed under the MOO. In the context of providing an additional source for revenue adequacy, the concentrated distribution of payments to a smaller subset of units provides little additional revenues to the larger subset of units receiving only 20 percent of the total payments.

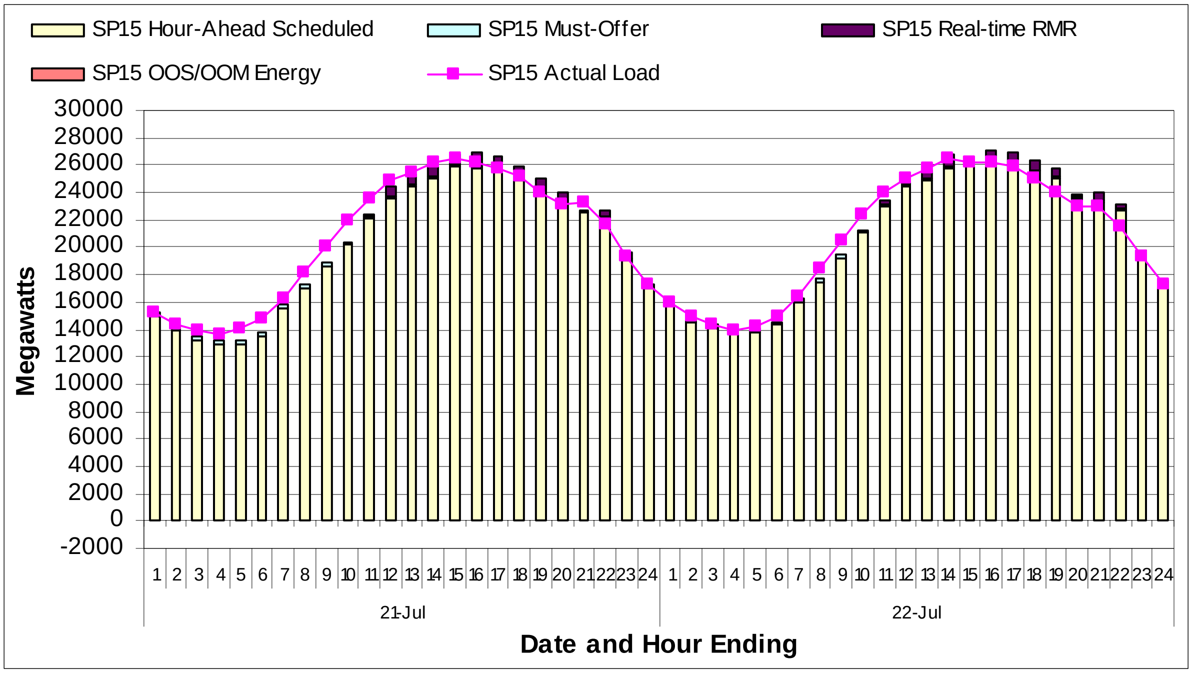
Although the MOO provides cost compensation plus a second market-based payment for minimum load as well as opportunity for market revenues from providing ancillary services and real-time energy, generation owners have argued that there is insufficient fixed cost recovery provided by the MOO provisions and that units committed via the MOO are providing a reliability service (in addition to energy and ancillary services) for which they are not being compensated.

In addition, the MOO may provide a potential disincentive to Load Serving Entities (LSEs) to enter into long-term contracts with generation owners as LSEs may find it financially advantageous to rely on the MOO for a unit's reliability service rather than contract directly for that service. Bilateral contracts with LSEs could provide generator owners with a more stable and targeted revenue source for fixed cost recovery than is provided under the current MOO structure and thus provide a better opportunity for generator owners to cover their going forward fixed costs. The concern that LSEs might rely on the MOO mechanism rather than contract with the generation resources that are frequently subject to MOO should largely be addressed by the CPUC Resource Adequacy requirements that are going into effect in 2006 – though its effectiveness may be undermined by the lack of locational capacity requirements in 2006. Additionally, the use of RMR or other potential CAISO contracting mechanisms may help to further ensure units that are critical for reliability have adequate mechanisms and opportunities for fixed cost recovery.

Though controversial, the MOO has proven to be an important tool for reliability and market competitiveness, particularly during peak summer demand periods. During the July-August heat wave in 2005, the MOO may have been a key factor in maintaining market competitiveness. In particular, during peak afternoons between July 18 and 23, the peak week of 2005, calculated system-wide residual supply indices range between 1.14 and 1.3. Had any unit withheld supply from the CAISO markets, these RSI indices would have been lower, and certain suppliers in that case likely would have been pivotal (i.e., able to exercise market power). However, whether it would have been a profitable strategy for such suppliers to exercise market power is a separate and more complicated question. Given the high level of forward contracting, profitable opportunities for the exercise of market power are much more limited than in prior years (e.g., 2000-2001).

The MOO also provided important reliability benefits in 2005. For example, on July 21, 2005, resources that were denied waivers from the MOO provided approximately 1,734 MW of generation. The Must-Offer energy plus RMR-contracted energy and other real-time energy from scheduled resources was sufficient to cover the difference between scheduled generation and load over this new SP15 peak of 26,459 MW, with only a single out-of-market transaction of approximately 1.67 MW for a system condition. The following chart compares SP15 load to zonal scheduled volume, must-offer procured generation operating at minimum load, RMR energy, and OOS/OOM procurement, for July 21 and 22, 2005.

Figure 2.27 SP15 Actual Load vs. Scheduled, Must-Offer, RMR, and OOS Energy, July 21-22, 2005



2.5.3 Generation Additions and Retirements

As discussed above, the current spot market structure coupled with a reliance on RMR and the MOO may not be providing sufficient market incentives for LSEs to enter into long-term contracts in critical areas of the grid. This apparent shortcoming may be compensated for in 2006 and beyond through regulatory means, particularly the CPUC Resource Adequacy requirements – provided this framework facilitates long-term procurement as opposed to short- to medium-term contracting. In the meantime, the continued reliance on an aging pool of generating units in California is a concerning trend. This subsection specifically addresses concerns regarding the aging pool of units in California and the potential need to either keep these units in operation or attract new investment to replace the capacity that may retire in the coming years. Table 2.12 shows generation additions and retirements, with a load growth trend figure. Note that while generation additions and retirements by zone show a net increase system-wide of 2,845 MW in 2005 and while more new generation was added to the CAISO Control Area than any other ISO in 2005[23], the total estimated net change in supply margins through 2006 is a negative 537 MW for SP15, indicating that new generation has not kept pace

[23] FERC Winter 2005-2006 Energy Market Update, February 16, 2006 (http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf)

with unit retirements and load growth in this region.[24] One of the consequences of this is the continued reliance on older generation facilities.

Table 2.12 Generation Additions and Retirements by Zone

	2001	2002	2003	2004	2005	Projected 2006	Total Through 2006
SP15							
New Generation	639	478	2,247	745	2,376	352	6,837
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	(4,280)
Forecast Load Growth*	491	500	510	521	531	542	3,094
Net Change	148	(1,184)	565	48	1,395	(1,510)	(537)
NP26							
New Generation	1,328	2,400	2,583	3	919	89	7,322
Retirements	(28)	(8)	(980)	(4)	0	(215)	(1,235)
Forecast Load Growth*	389	397	405	413	422	430	2,456
Net Change	911	1,995	1,198	(414)	497	(556)	3,631

* Assumes 2% peak load growth using 2005 forecast from 2005 Summer Assessment.

There is a large pool of aging units in California, with 46 units built before 1979 having an average age of 42 years as seen in Table 2.13. Figure 2.28 shows the percent of hours in a year that units built before 1979 are running. While the trend is declining, this older pool of units is still relied upon, to provide either energy or reliability services, for nearly 40 percent of the hours in the year. Because of the age and relative inefficiency of these units, they are likely to have net revenues below those reported in Section 2.5.1 and have less ability to recover even fixed O&M costs through spot market revenues. For these units, long-term contracting is especially necessary to ensure continued operation in the short-run and re-powering of these facilities in the longer-run if new investment is insufficient to provide replacement capacity.

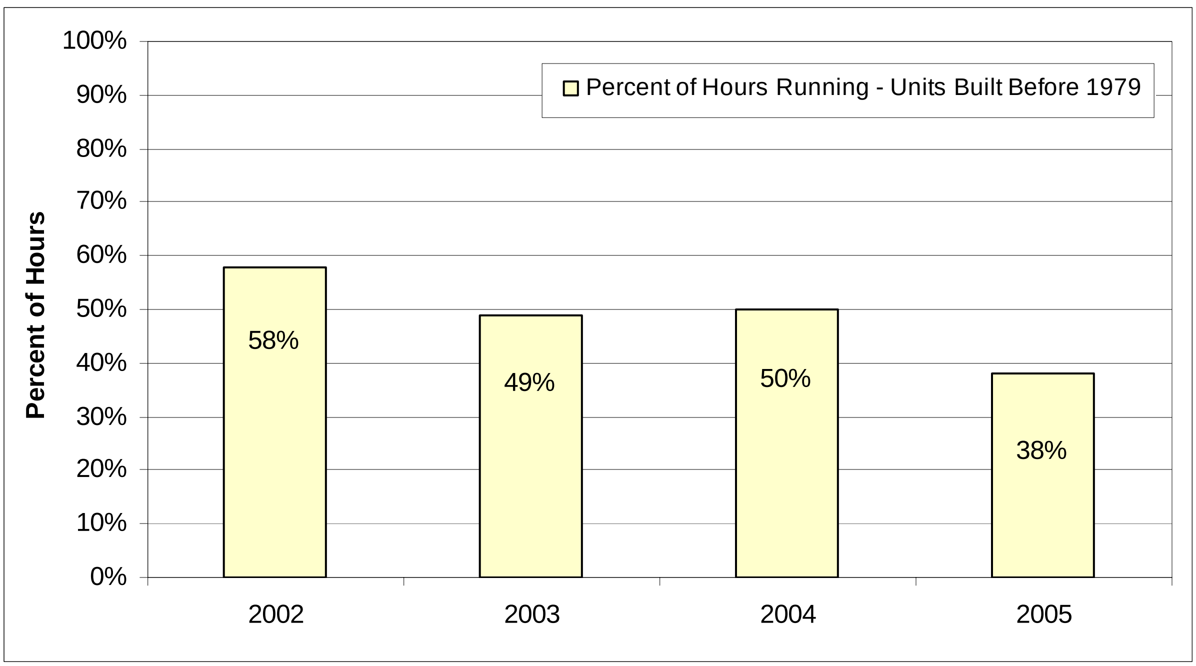
[24] It is important to note that this table only shows part of the supply picture in SP15. Some increased import capability to SP15 has also occurred. As discussed in Chapter 1, the Path 26 north-to-south rating was increased by 300 MW in 2005 and numerous other transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone. However, despite all of these improvements, meeting summer peak load demands in SP15 remains extremely challenging.

Table 2.13 Characteristics of California's Aging Pool of Resources

	Number of Units	Unit Capacity[1]	Average Unit Age (Years)[2]	Capacity Factor[3]	Percent of Hours Running[4]
North of Path 26	13	4,642	44	17%	36%
South of Path 26	33	9,304	42	12%	35%
Total	**46**	**13,946**	**42**	**14%**	**35%**

[1] Total active unit capacity as of date of publication.
[2] Based on build date.
[3] Based on 2005 data. Does not adjust for unit outages.
[4] Based on 2005 data. Percent of all hours in year where unit showed positive metered generation.

Figure 2.28 Percent of Hours Running for Units Built Before 1979



Unfortunately, long-term energy contracting by the state's major investor owned utilities has been very limited and may therefore perpetuate the need to rely on this aging power fleet. In its 2005 Integrated Energy Policy Report (2005 Energy Report), the CEC reports that, "Utilities have released some Request for Offers (RFOs) for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW out of approximately 12,500 MW under recent solicitations,"[25] and notes that, "California has 7,318 MW of approved power plant projects

[25] 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.

that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing."[26] The report notes that the predominance of short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs, "Continuing short-term procurement for local reliability prolongs reliance on aging units that could otherwise be re-powered economically under the terms of longer-term contracts and thereby provide similar grid services at a more competitive price."[27]

In its report, the CEC recommends that the CPUC require the IOUs to sign sufficient long-term contracts to meet their long-term needs and allow for the orderly retirement or re-powering of aging plants by 2012. One of the major impediments to long-term contracting by the IOUs is concern about native load departing to energy service providers, community choice aggregators, and publicly owned utilities, which could result in IOU over-procurement and stranded costs. While this is a legitimate concern, it can be addressed through regulatory policies such as exit fees for departing load and rules governing returning load (i.e., load that leaves the IOU but later wants to return).

While long-term contracting is critical for facilitating new investment it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Though the CPUC has made significant progress in 2005 in advancing its Resource Adequacy framework, delays in the development and implementation of local resource adequacy requirements could further impede new generation development in critical areas of the grid. Going forward, an effective local resource adequacy framework to facilitate needed generation investment is critical for ensuring reliable grid operation and stable markets.

2.6 Load Scheduling Practices

As discussed in Chapter 1, with the onset of peak summer demand conditions in early July, CAISO Operations staff raised concerns about load under-scheduling in the Day Ahead Market. The concern predominately relates to shortfalls between the CAISO day-ahead forecasted load and the level of final day-ahead load schedules. To the extent such shortfalls exist, the CAISO operators need to commit additional units through the MOO waiver denial process, which puts additional administrative burdens on operational staff and introduces significant commitment uplift costs to the market. More fundamentally, it raises a concern about whether LSEs have adequately planned for meeting their peak load obligations.

Throughout the initial summer months, the CAISO committed significant amounts of capacity under the MOO to cover expected shortfalls in day-ahead schedules relative to day-ahead forecasted peak load. CAISO operators commit capacity to make up this shortfall to ensure that sufficient capacity is online in time to meet the next day's peak load. During this time, day-ahead schedules had been as much as 12 percent less than the day-ahead forecast and had caused significant commitment of resources under the must-offer waiver denial process. This resulted in daily MLCC system costs in excess of $700,000 in July.

The CAISO recommendation for addressing this issue was to require LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market so that Grid Operators would not have to commit additional units in the CAISO's day-ahead must-offer process to insure enough capacity was online to meet load in the Real Time Market. In late July, the three IOUs began voluntary efforts to meet the day-ahead scheduling target of 95 percent. On September 22, the

[26] 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.
[27] 2005 Integrated Energy Policy Report, California Energy Commission, p. 61.

CAISO filed Tariff Amendment 72 with the FERC to require all LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market. FERC accepted the terms of the filing in an Order dated November 21, 2005.

Figure 2.29 and Figure 2.30 depict day-ahead under-scheduling by LSEs during peak operating hours as a percent of the CAISO day-ahead load forecast in SP15 and NP26. These figures illustrate the nature of the under-scheduling problem. The two key series in these figures are Day Ahead Forecast Load and Day Ahead Scheduled Load, which show that day-ahead under-scheduling of load was primarily a problem in NP26 and had reached twenty percent of forecast load north of Path 26 (NP26) during the peak hours in June and July of 2005.

Figure 2.29 Forecast, Schedule and Actual Load for Peak Load Hours in SP15 - June and July of 2005

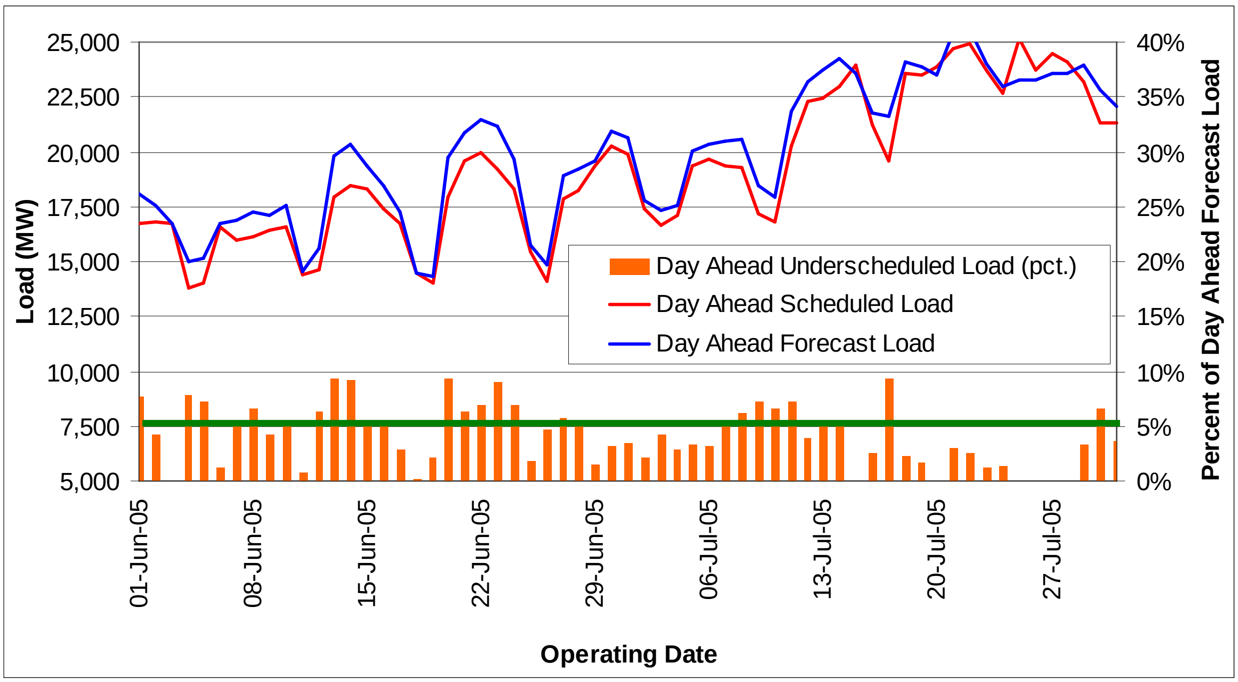
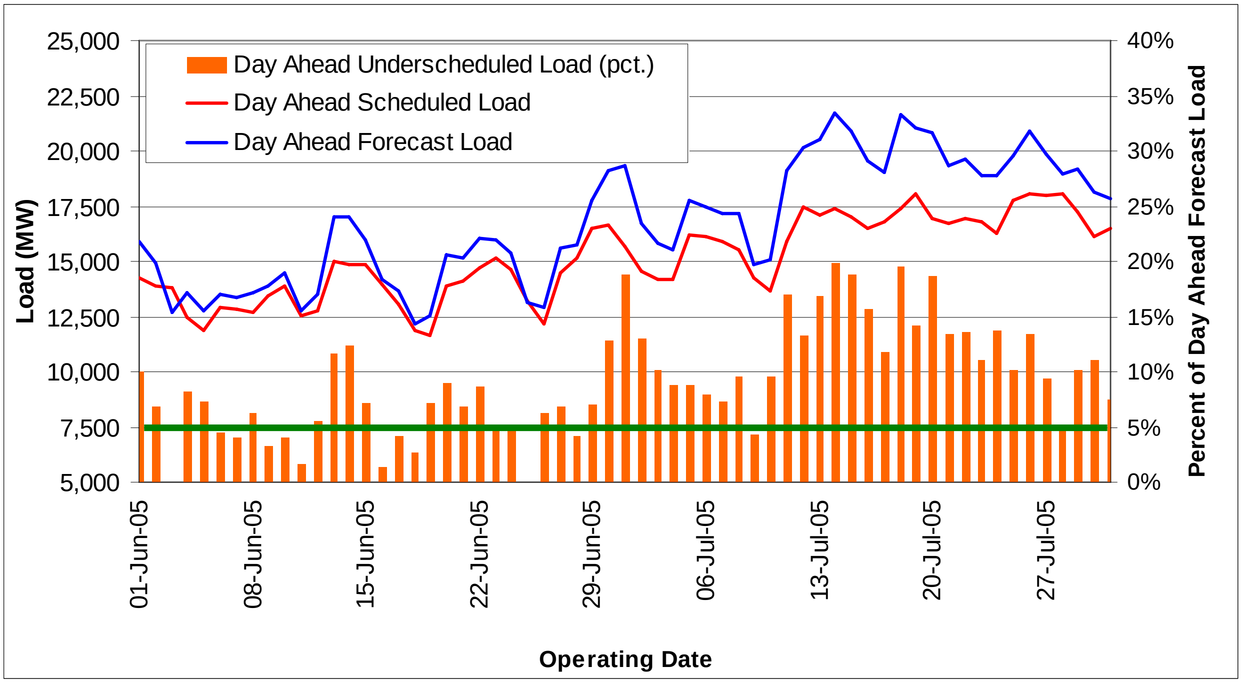
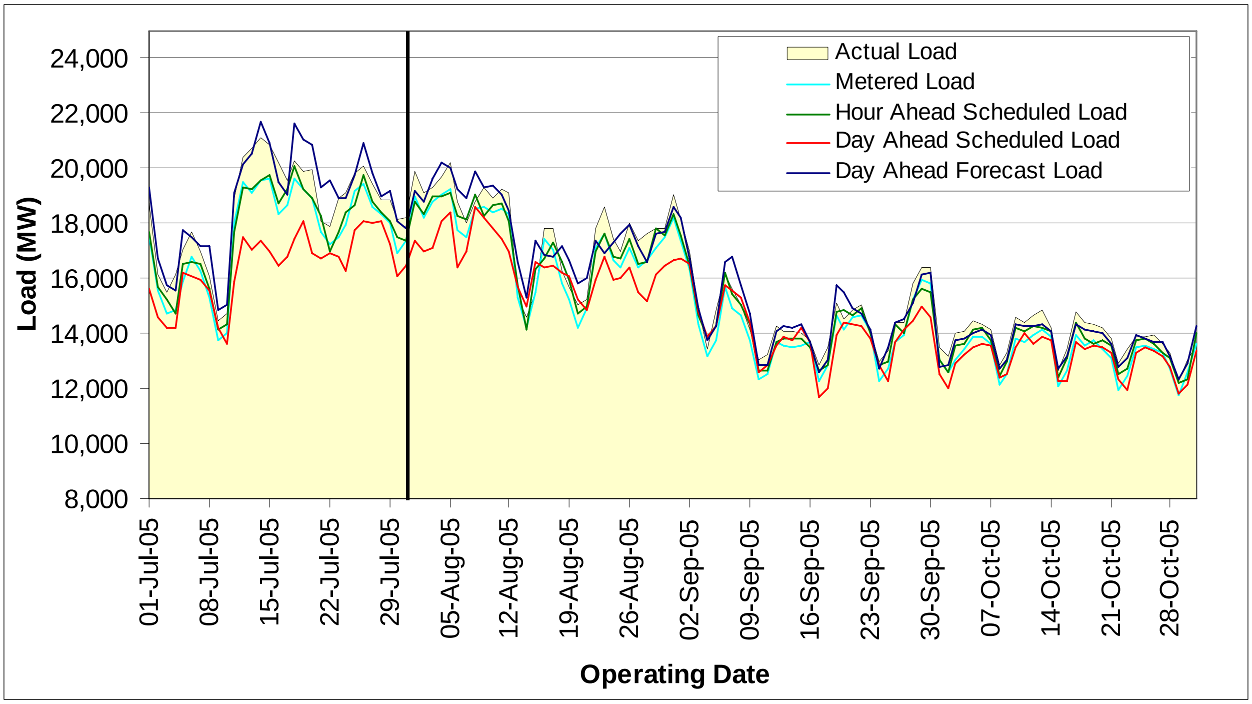


Figure 2.30 Forecast, Schedule and Actual Load for Peak Load Hours in NP26 - June and July of 2005



A more complete picture of scheduling practices in NP26 is presented in Figure 2.31 below. The day-ahead under-scheduling of load during peak summer months is still evident in this figure, however, there are two additional points to be made regarding scheduling practices by LSEs and electricity requirements to meet imbalance needs relative to metered load. Figure 2.30 illustrates that LSEs in the NP26 zone did schedule, in aggregate, nearly one hundred percent of their metered load by the hour-ahead timeframe. This shows that LSEs were not leaning heavily on the imbalance market to meet over five percent of their load served, however, leaving a significant portion of load to be scheduled after the day-ahead required Grid Operators to take measures in the Day Ahead Market to ensure there were sufficient resources to meet forecast load in real-time. The second point deals with the difference between LSEs' metered load (Metered Load series in Figure 2.31) and the amount of electricity required by the CAISO to keep the grid in balance (Actual Load in Figure 2.31). The Actual Load metric is based on telemetered data from generation and tie points and represents the amount of electricity that is required to meet load in real-time. This metric differs from actual metered load values due primarily to transmission losses and unaccounted for energy. An additional factor is that some entities schedule with the CAISO on a net basis but are metered on a gross basis. Due to these differences, the Actual Load metric is on average about 5 percent, or 815 MW, greater than actual metered load on the peak hour of the day in the NP26 region. The CAISO often uses Actual Load in its analyses due to the immediate availability of this metric compared to the availability of actual metered load values, which are often not available until 45 or more days after the fact, and because Actual Load represents the amount of electricity that is required to meet load in real-time, including line losses and unaccounted for energy.

Figure 2.31 Forecast, Schedule and Actual Load for Peak Load Hour (July - October 2005)

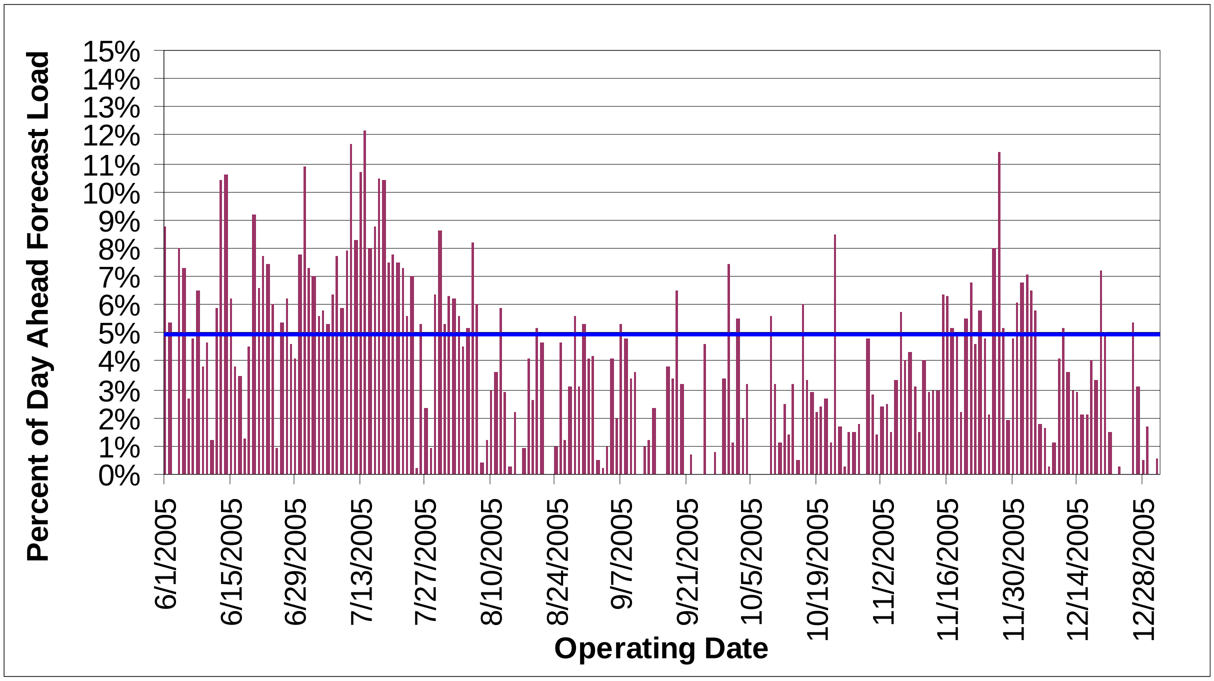


In addition to an explicit day-ahead scheduling requirement, the CAISO recognized that more timely information regarding the potential cost of under-scheduling in the Day Ahead Market would result in forward load-scheduling practices that more fully reflected the actual costs of deferring procurement to the Hour Ahead or Real Time Markets. To provide more timely information about the cost of deferring load-scheduling, the CAISO began posting estimates reflecting the per-MWh cost of under-scheduled load in the day-ahead in terms of the minimum load cost compensation (MLCC) resulting from the additional units that had to be committed to cover the under-scheduled load.

As a result of these efforts, the CAISO has observed higher proportions of total load scheduled in the Day Ahead Market, with instances in which less than 95 percent of actual load was scheduled in the Day Ahead Market declining significantly. Figure 2.32 shows this trend for the peak load hour of each day since June 1, 2005. There is a notable period, the second half of November, in which day-ahead under-scheduling was at or above the 5 percent level. This pattern coincides with abnormally high natural gas prices. These high natural gas prices may have impacted the spot bilateral procurement costs so as to shift some procurement from the Day Ahead Market to the day-of markets. As natural gas prices declined in late December and into January of 2006, load scheduled in the Day Ahead Market was predominantly above the 95 percent level.

While measuring the benefit to reliability of a higher level of load scheduled in the Day Ahead Market may not be feasible, one indicator of the benefit of implementing the 95 percent scheduling requirement is the change in must-offer waiver denials made to support system capacity requirements. An assessment of the use of the MOO to commit units to meet “System” requirements indicates that overall MOO commitments for “System” requirements are down for August-December 2005 compared to the same months in 2004. While this is not a conclusive finding (there may have been other factors affecting the need to commit units for "System" requirements), it is an indication that the 95 percent scheduling requirement has reduced the need to supplement the pool of market-committed units through the MOO. Another issue related to the scheduling requirement is whether or not the additional load scheduled in the Day Ahead Market is met by physically feasible schedules, or if the schedules are infeasible and creating additional costs through the need to manage intra-zonal congestion. An indicator for this is the use of MOO unit commitments and the use of out-of-market dispatches in real-time to relieve transmission constraints. Both of these costs have declined for August-December 2005 compared to the same months in 2004, however, again, this may be due to other factors including transmission upgrades (discussed further in Chapter 6).

Figure 2.32 Percent of CAISO Forecast Total Load Not Scheduled in the Day Ahead Market



2.7 Performance of Mitigation Instruments

2.7.1 Damage Control Bid Cap

The Damage Control Bid Cap for energy bids was binding more frequently in 2005 than in 2004, as shown in Figure 2.33. This is due largely to the increase in natural gas prices, which pushed production costs of certain gas-fired resources in the CAISO Control Area near the $250/MWh bid price cap. The $250 bid cap was binding in the real-time balancing market in approximately 0.4 percent of intervals in 2005, and in no intervals in 2004. Figure 2.33 shows interval prices within SP15 for all hours in 2004 and 2005, ordered from highest to lowest price. Figure 2.34 shows the same interval prices, normalized to the price of natural gas on January 1, 2004, which was $5.41/MMBtu. Figure 2.34 demonstrates that natural gas price increases appear to be responsible for the increased frequency of price cap hits in 2005.

Figure 2.33 SP15 Actual Interval Price Duration Curves: 2005 vs. 2004

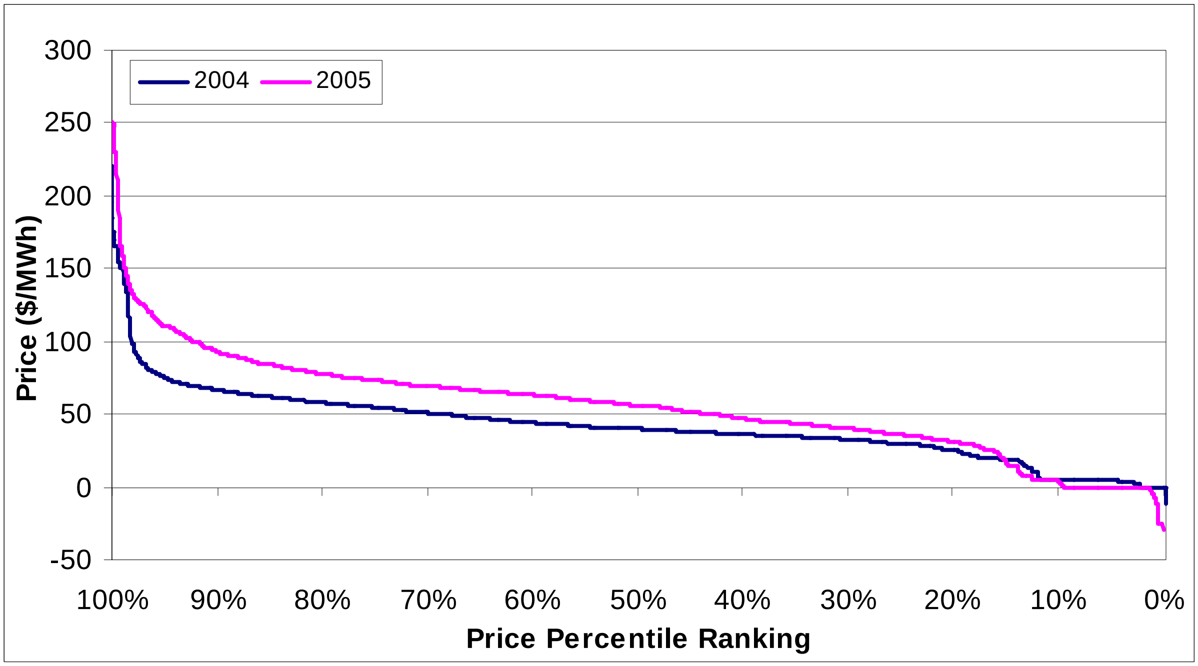
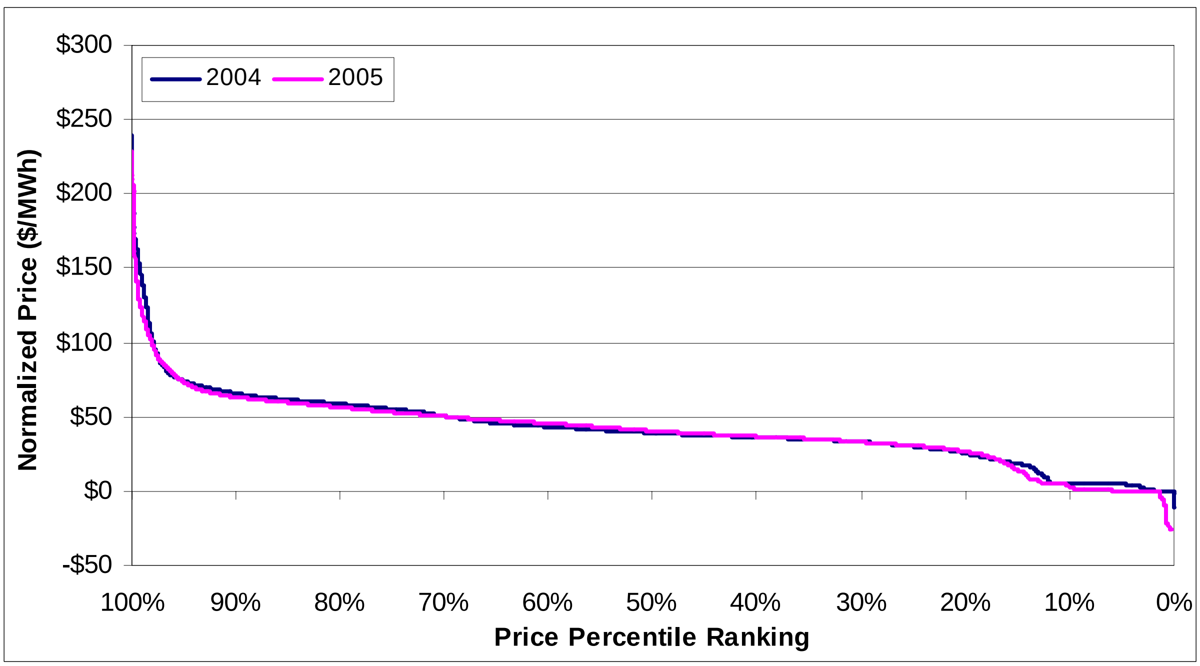


Figure 2.34 SP15 Interval Price Duration Curves, Normalized against Changes in Price of Natural Gas: 2005 vs. 2004[28]



[28] Prices adjusted for gas increases by normalizing to Southern California Border Average gas price on 1/1/04, which was $5.41/mmBtu. Assume $4/MWh operation and maintenance production cost.
Normalization formula: normalized price = (interval price - $4) * ($5.41/daily gas price) + $4

As electric production costs increased with higher gas costs, the CAISO Market Surveillance Committee (MSC) and the DMM recommended raising the maximum bid price from $250 to $400/MWh. This change was approved by FERC on January 13, 2006, and was effective the following day.

The July 22 peak is an example of the bid cap limiting price spikes. While prices increased in this hour to $249.99/MWh, the SP15 bid curve was relatively supply-inelastic ("steep") at the dispatch level during this price spike, as evidenced by the fact that SP15 load would have had to drop only 50 MW or so to pull the price below $200/MWh. Further analysis of this event is provided in Chapter 3.

The -$30/MWh price floor was binding in approximately 10 intervals in 2005 for in-sequence dispatches paid at the market-clearing price. All were in the last week of December, when gas prices were high and loads were low. Large negative prices are usually set by decremental bids. During this period, certain units faced costs for decrementing due to gas flow requirements or other operating limitations.

2.7.2 AMP Mitigation Performance

In addition to a Damage Control Bid Cap, the CAISO also has a bid conduct and market impact Automatic Mitigation Procedure (AMP) for addressing potential economic withholding. There are basically three components to the AMP.

a. A $91.87 predicted price screen for determining whether to apply bid conduct and market impact tests.

b. A bid conduct threshold equal to a bid increase relative to the unit's reference price of ($100/MWh, or 200 percent), whichever is lower.

c. A market impact threshold equal to a market price impact of ($50/MWh or 200 percent), whichever is lower.

All of the AMP procedures are run during the pre-dispatch process for selecting inter-tie bids and as such are based on predicted 15-minute interval prices within the hour. With respect to the price screen test, if any of the predicted 15-minute prices exceed $91.87/MWh, the bid conduct and market impact tests are applied. The market impact test is based on the average of all four 15-minute prices.

Since the deployment of RTMA, certain results of the AMP are no longer accessible for data analysis. In particular, the results of the predicted price screen used to determine whether AMP is activated are not available for analysis. Consequently, the scope of this analysis is limited to data that remains available.

As in previous years, AMP did not mitigate any bids for incremental energy in 2005. The frequency of AMP conduct test failures increased in the fourth quarter of 2005 (Table 2.14), as natural gas prices put upward pressure on production costs. This increased conduct test failure frequency for two reasons:

1. The likelihood of the MCP to be above $91.87/MWh increased as all bids, including decremental bids, migrated upward; and

2. Production costs rose quite sharply, particularly in September, following Hurricanes Katrina and Rita. As a result, suppliers increased their bids relatively abruptly. Bid reference levels, which are what submitted bids are

compared to in applying the conduct test, are adjusted for changes in gas prices using a monthly gas index. Consequently, the reference levels may not be adequately adjusted to compensate for a rapid increase in gas prices within a month and this diversion may trigger more bid conduct violations.

Table 2.14 Frequency of AMP Conduct Test Failures

	Conduct Test Failures
Jan-05	36
Feb-05	22
Mar-05	81
Apr-05	48
May-05	15
Jun-05	4
Jul-05	11
Aug-05	38
Sep-05	195
Oct-05	328
Nov-05	173
Dec-05	371

3. Real Time Market Performance

3.1 Overview

As noted in Chapter 1, 2005 marked the first full year of operation under the new Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing, BEEP).

RTMA is designed to receive bids to provide real-time energy, calculate the imbalance energy requirement for the next dispatch interval, and provide an economically optimized set of dispatch instructions to meet the imbalance energy need at least cost subject to resource and transmission grid constraints. Specific enhancements to BEEP that RTMA was designed to provide include:

- Replacement of the BEEP Target Price mechanism[1] with economic dispatch (or “market clearing”) of all incremental and decremental energy bids with “price overlap” (i.e., bids to sell energy (incremental energy bids) at a price lower than the price of bids to buy energy (decremental energy bids)).
- Enhanced treatment of resource operating constraints, such as ramp rates, forbidden operating ranges[2], minimum run times, and start-up times. In addition to lowering uninstructed deviations by increasing the overall feasibility of dispatch instructions, these improvements were necessary in order for the CAISO to gain approval to implement an Uninstructed Deviations Penalty (UDP) from the Federal Energy Regulatory Commission (FERC).
- Optimization of dispatch instructions based on a two-hour “look ahead” period, rather than dispatch of bids in economic merit order for each individual interval.
- Improved system responsiveness and efficiency due to use of a 5-minute dispatch interval, rather than the previous 10-minute interval.
- Increased reliance on automated dispatch instructions.

[1] Prior to RTMA, the Target Price mechanism was utilized by the CAISO to ensure that the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants utilized by the BEEP software was monotonically non-decreasing. Prior to any adjustments by the Target Price mechanism, the system-wide bid curve representing decremental and incremental real-time energy bids submitted by all participants typically included some “price overlap,” or decremental bids with a bid a price higher than the bid price of some the incremental bids. Such a non-monotonic bid curve would result in real-time prices that increased as the CAISO switched from incing energy to decing energy. To avoid this, the CAISO developed a Target Price mechanism that would set the system bid curve for the overlapping portion of incremental and decremental bids of eligible resources equal to the bid price at the point where the overlapping bids intersect. This point is referred to as the “Target Price”. Initially, all resources (including imports) were eligible to set the Target Price. However, due to gaming potential with this open provision, eligibility to set the Target Price was later (October 2001) restricted to generating units with Participating Generator Agreement and loads with Participating Load Agreement; moreover only capacity that could be dispatched in 10 minutes could set the Target Price.

[2] Forbidden operating ranges are those operating ranges in which a resource may not operate for an extended period, but must run through as quickly as possible. A unit therefore may not provide regulation service within a forbidden operating region, because that could require the unit to operate within the forbidden region for some period of time.

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA will set generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches (i.e., dispatches prior to the operating hour) hourly inter-tie bids.

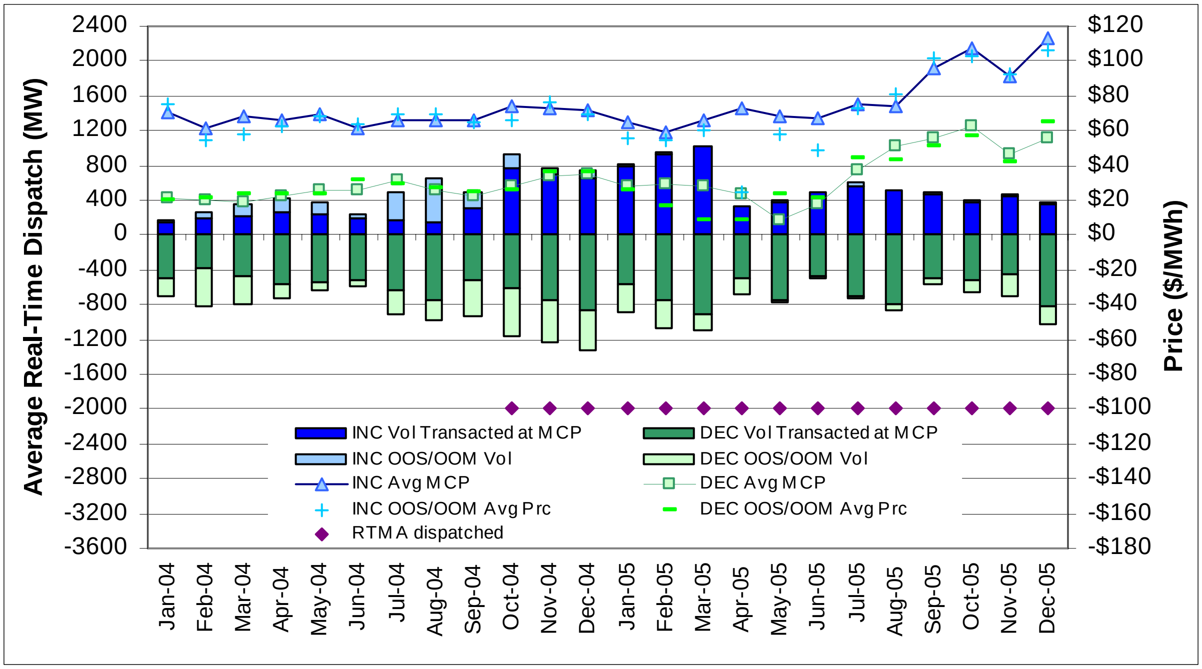
Since its implementation, several issues have been raised concerning RTMA performance. One of the major concerns cited is a perceived high degree of price and dispatch volatility. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. Section 3.3 provides a more in-depth assessment of RTMA performance. One notable aspect of RTMA – settlement rules for pre-dispatched inter-tie bids, was found to be particularly problematic in early 2005 and required a modification to the CAISO Tariff. A review of the impact from this Tariff change is provided in Section 3.3. Another important aspect of RTMA is a load bias feature that allows operators to manually adjust the load forecasts that are used to determine optimal dispatch in RTMA. A review of the relationship between the use of load bias and the use of regulation energy is examined in Section 3.3. One element of RTMA that has not been implemented is the penalty provisions for deviations from dispatch instructions (Uninstructed Deviation Penalty (UDP)). This element has not been implemented because uninstructed deviations have been relatively moderate since RTMA was implemented. An analysis of uninstructed deviations under RTMA is also provided in Section 3.3.

3.2 Real Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy, both in and out-of-sequence (OOS), in 2004 and 2005. Monthly average prices for incremental energy in 2005 were stable, averaging between $60 and $80/MWh from January - August but increasing significantly in the September - December period due to the dramatic increase in natural gas prices resulting from the Gulf Coast hurricanes. Average monthly incremental prices during that four-month period ranged between $90 and $117/MWh. Average monthly prices for decremental energy were also stable, generally ranging between $20 and $40/MWh for most of 2005 but increasing to the $40 to $60 range in the August - December period. As in 2004, in-sequence dispatch volumes were overwhelmingly decremental in most months of 2005.

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2004-2005)



Decremental volumes were significantly larger than incremental volumes in 2005, due in part to the presence of uninstructed energy and energy that was not recognized by RTMA. As these cause energy in the system above levels predicted from hour-ahead schedules and other CAISO-committed sources, RTMA must balance the system in real-time by decrementing resources below their schedules.

Figure 3.2 compares average annual Real Time Market prices by zone (NP15, SP15) for 2001 through 2005. Real-time prices were on average higher in 2005 than in the previous three years, but this was mainly due to a steady increase in natural gas prices over this period.

Figure 3.2 Average Annual Real-Time Prices by Zone (2001-2005)

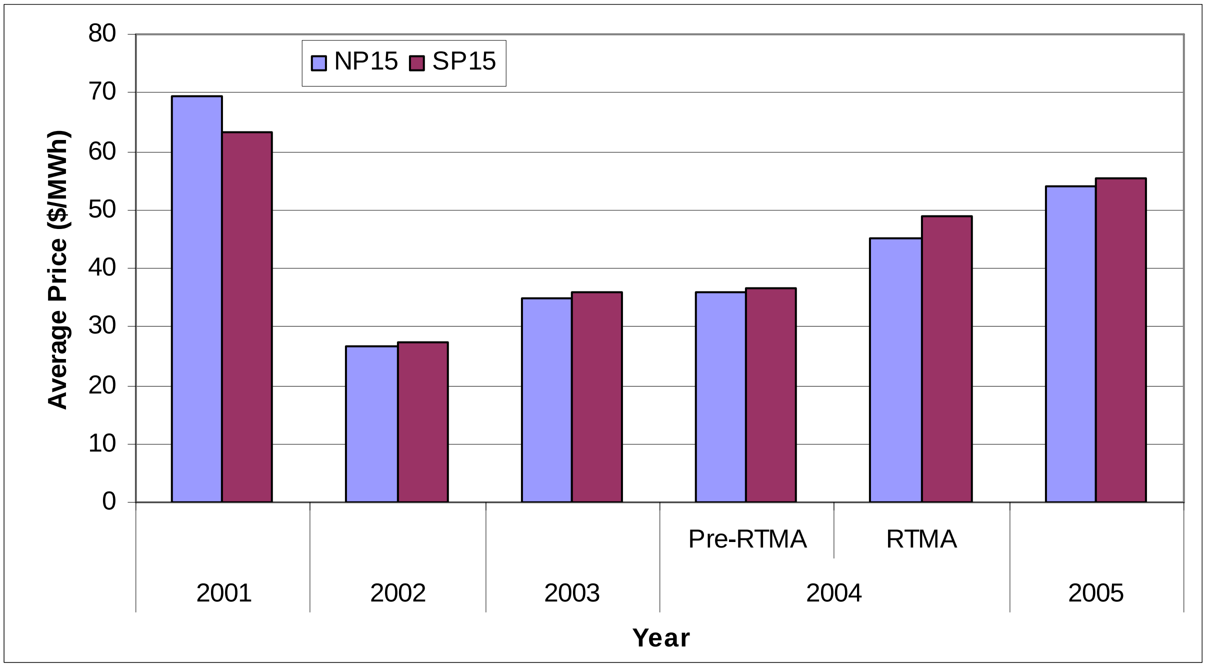


Figure 3.3 shows SP15 real-time price duration curves for 2003 through 2005 and indicates that real-time interval prices in 2005 were consistently higher than in the past two years, predominately because of higher natural gas prices. Figure 3.3 also shows that the Real Time Market posted a price of -$0.01/MWh in approximately 6 percent of intervals in 2005. This price was set by a hydroelectric resource when it had limited ability to reduce output due to a water management constraint. As real-time over-generation conditions were frequent in 2005, particularly during the spring runoff season (as discussed in Chapter 2), this unit was often marginal, as its bids were often large in volume, particularly when few other resources were available to be decremented, such as at night or during the morning ramp.

Figure 3.3 SP15 Price Duration Curves (2003-2005)

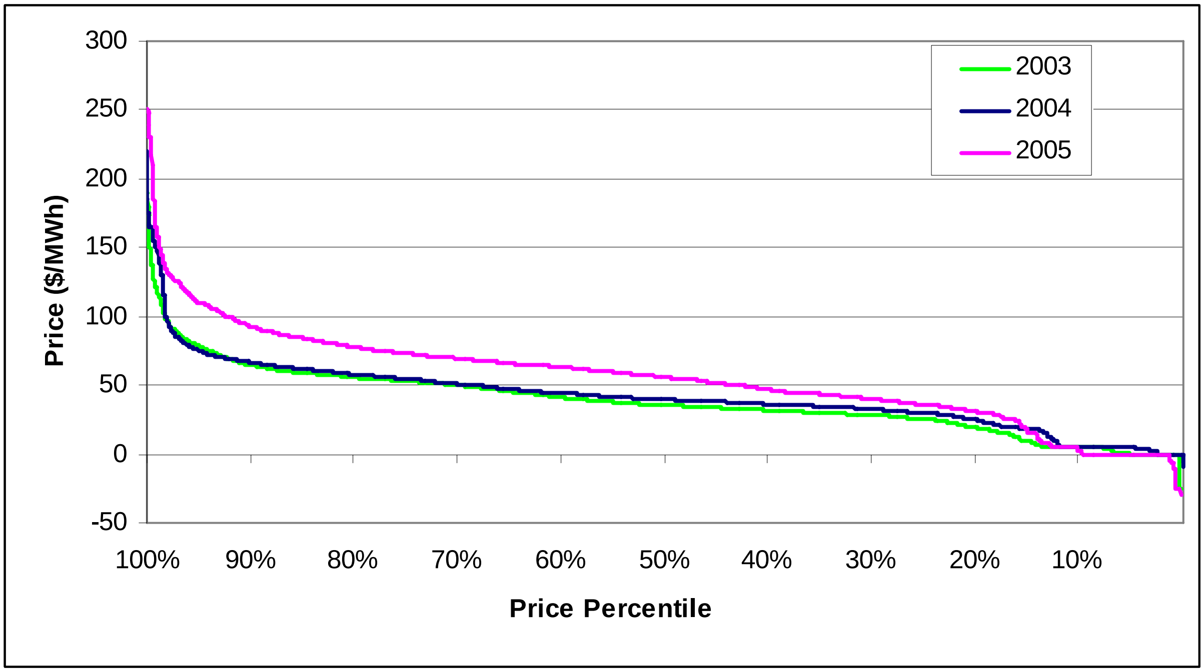
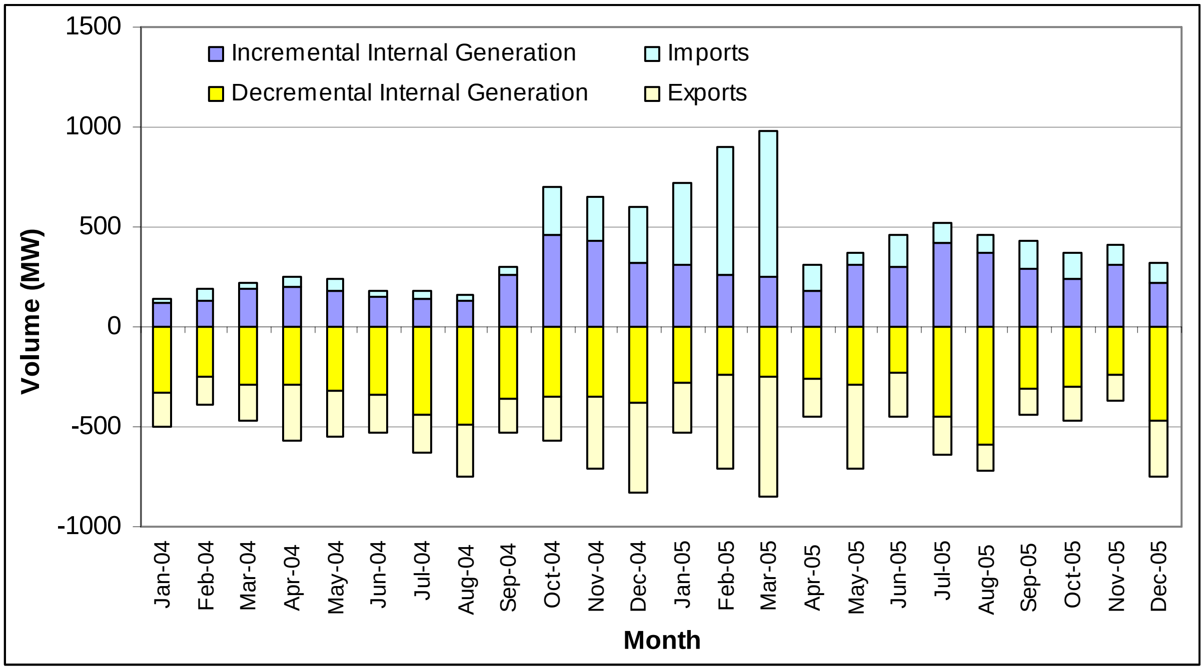


Figure 3.4 shows the monthly average dispatch volumes for internal generation, imports and exports for 2004 to 2005. With the exception of the four-month period of December 2004 - March 2005, internal resources constituted the majority of RTMA dispatches. The increase in inter-tie dispatches during the December 2004 - March 2005 time period is attributable to the “bid or better” settlement rules for inter-tie bids that are pre-dispatched under RTMA. This rule, coupled with the increasing volume of market clearing inter-tie bids, created significant market uplifts and resulted in a modification to the CAISO Tariff that replaced the “bid or better” settlement with an “as-bid” settlement rule. The impact of this rule change can be seen in Figure 3.4 by the highly pronounced decrease in inter-tie dispatch volumes beginning in April 2005. This issue is discussed in greater detail in Section 3.3.

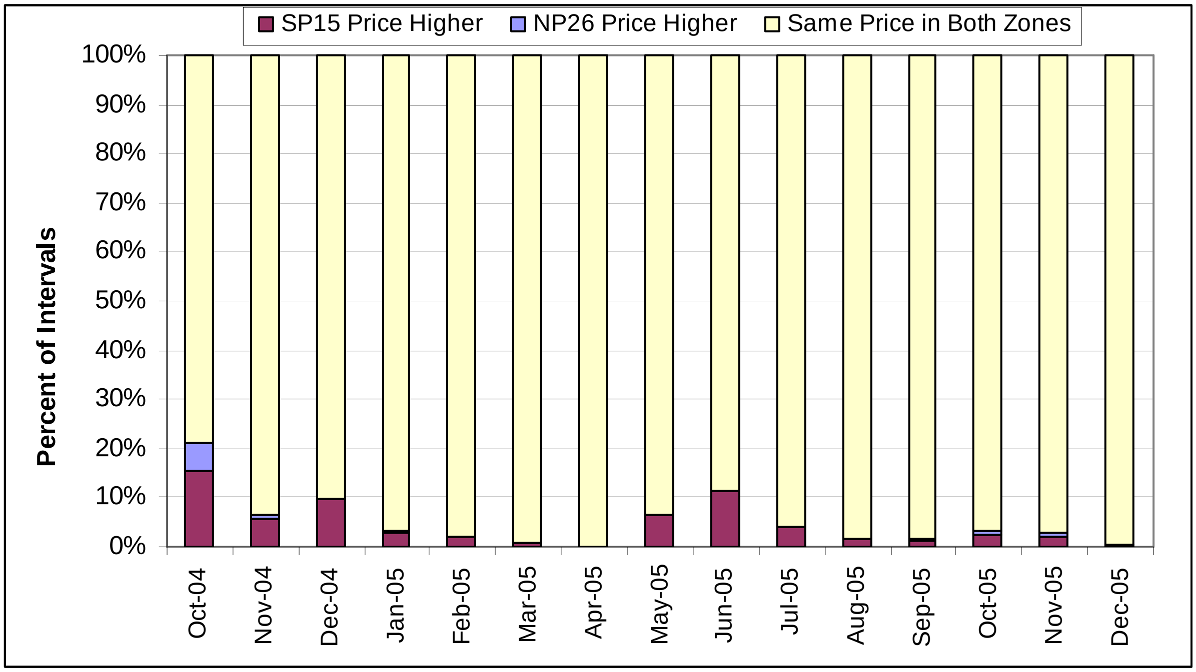
Figure 3.4 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2004-2005)



3.2.2 Real-Time Inter-Zonal Congestion

Despite an increase in the north-to-south rating for Path 26 of 300 MW (3,400 to 3,700 MW) in May 2005, real-time north-to-south congestion periodically occurred on Path 26 throughout 2005, generally when loads were high in Southern California and lower cost generation was available in Northern California. Prices differed between NP26 and SP15 in approximately 3.1 percent of intervals in 2005 due to real-time congestion on Path 26 or limitations due to the Southern California Import Transmission Nomogram (SCIT). Prior to the upgrade of Path 15 in 2004, real-time congestion was generally in the south-to-north direction, which resulted in higher prices in NP26 and lower prices in SP15. However, since the Path 15 upgrade coupled with a significant amount of new generation in Northern California, congestion in the north-to-south direction has been more frequent. This typically occurred due to the Southern California Import Transmission (SCIT) constraint, which can be mitigated either by splitting the Real Time Market or by using out-of-sequence dispatches within SP15 (Intra-Zonal Congestion management). On other occasions, the CAISO market experienced real-time congestion in the north-to-south direction on Path 26, due to unscheduled counter-clockwise flow within the Western Interconnection. Figure 3.5 shows the monthly count of market splits since September 2004.

Figure 3.5 NP26-SP15 Market Price Splits (October 2004 - December 2005)



3.2.3 Periods of Market Stress

3.2.3.1 July 21-22 Stage Emergencies

An extended heat wave that began on July 11, 2005, continued unabated into August. With no break from high loads, forced generator outages increased during the third week in July contributing to the issuance of Stage 2 emergencies on July 21 and 22. System Conditions in Southern California were sufficiently severe to cause Path 26 to be overloaded in real-time despite the path having its north-to-south rating increased from 3,400 to 3,700 MW in May 2005.

On July 21, low voltage in the area of the Devers Substation near Palm Springs necessitated the declaration of a Stage 2 transmission emergency, as loads in Southern California reached a new peak of approximately 26,459 MW. The CAISO called upon utilities to drop interruptible loads in accordance with their service agreements when operating reserves fall below 5 percent of load. Meanwhile, the CAISO was only able to accept real-time bids from internal resources due to the low-voltage event, and thus declined bids from imports. The RTMA price remained at $120.22/MWh for most of the period between 1:40 and 3:05 pm, and then increased to $172.99/MWh for most of the period between 3:10 and 4:05 pm. The $120.22/MWh price was set by a new combined-cycle resource in SP15; the $172.99 price was set by a non-spinning reserve bid from a combustion turbine resource, also in SP15. Both resources had energy bids within the AMP Conduct Test thresholds.

On Friday, July 22, CAISO load approached 43,960 MW, considerably less than the system-wide record of 45,386 MW set on July 20. However, SP15 load was within 20 MW of its record load set on July 21. At approximately 1:48 pm, a neighboring control area lost a resource, causing an overload of Path 26. The CAISO declared a Stage 2 emergency, and called for interruptible and state water pump loads to be curtailed. From 1:40 to 3:50 pm, the RTMA market-clearing price within SP15 was $249.99/MWh, once cent below the soft bid cap. During this time, the zonal bid stack was fully dispatched. No Scheduling Coordinator submitted any real-time bids above $250/MWh during this price spike.

While the SP15 price was at $249.99/MWh, several units had bid in excess of their reference level thresholds, failing the AMP Conduct Test. However, all such units were located within NP15, where the market-clearing price ranged between $10 and $48.74/MWh, as units there were being decremented to relieve the congestion on Path 26.

Because the SP15 bid curve was relatively inelastic ("steep") at the dispatch level during this price spike, SP15 load would have had to drop only 50 MW or so to pull the price below $200/MWh, illustrating potential gains to Load Serving Entities (LSEs) and their customers from expanded load response programs that are triggered by the real-time price.

3.2.3.2 August 25 Load Shedding Event

Unexpected high loads resulting from temperatures that were 14 degrees above forecast in Southern California on August 25, combined with the sudden loss of the Pacific DC inter-tie, resulted in the loss of interruptible and firm load for a brief period. During this time, real-time prices reached $120.92/MWh, significantly below the $250/MWh price cap due to out-of-merit dispatch of higher priced contingency only bids.

DMM reviewed the dispatch procedures followed during the load shedding event on August 25 to determine why higher priced contingency only reserve bids that were dispatched out-of-merit during the critical hours were not cleared and eligible to set the Real Time Market price in SP15. Ancillary Service (A/S) energy bids marked as contingency reserve cannot be dispatched by the RTMA under normal conditions. The bid segments associated with contingency reserve are therefore unavailable for market dispatch or to set the price unless the contingency flag is cleared (i.e., a contingency occurs that enables operators to release the contingency reserve energy bids into the real-time market for dispatch). Had the contingency flag been cleared on these bids, making the associated energy eligible for in-merit dispatch and eligible to set the price, the RTMA price would have been set near the price cap of $250/MWh.

DMM raised this issue with Market Operations and based on the circumstances (no skipped bids and out-of-sequence dispatch of units that should have had their contingency flag cleared) recommended to Market Operations that prices be corrected to reflect the marginal unit dispatch during those intervals. Market Operations also reviewed the events and concurred that the marginal bid during certain dispatch intervals in hours ending 16 and 17 on August 25 should have been $249.99/MWh. As such, the interval prices were corrected.

3.2.4 Bidding Behavior

Figure 3.6 and Figure 3.7 respectively show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for the period covering RTMA operation (October 2004 to December 2005). Most notable in Figure 3.6 is the significant increase in the percentage of higher priced incremental energy bids beginning in July 2005 and steadily increasing through the fall. This trend is largely attributable to the increase in natural gas prices that occurred during this period. Additionally, some resources bid very low prices for decremental energy, at times below $0/MWh, particularly during April - June 2005. The category in Figure 3.7 representing bids in the range of -$1/MWh to $0/MWh consisted largely of the -$0.01/MWh hydroelectric bids discussed in Section 3.2.1.

Figure 3.6 SP15 Incremental Energy Bids by Bid Price Bin: Oct-04 to Dec-05

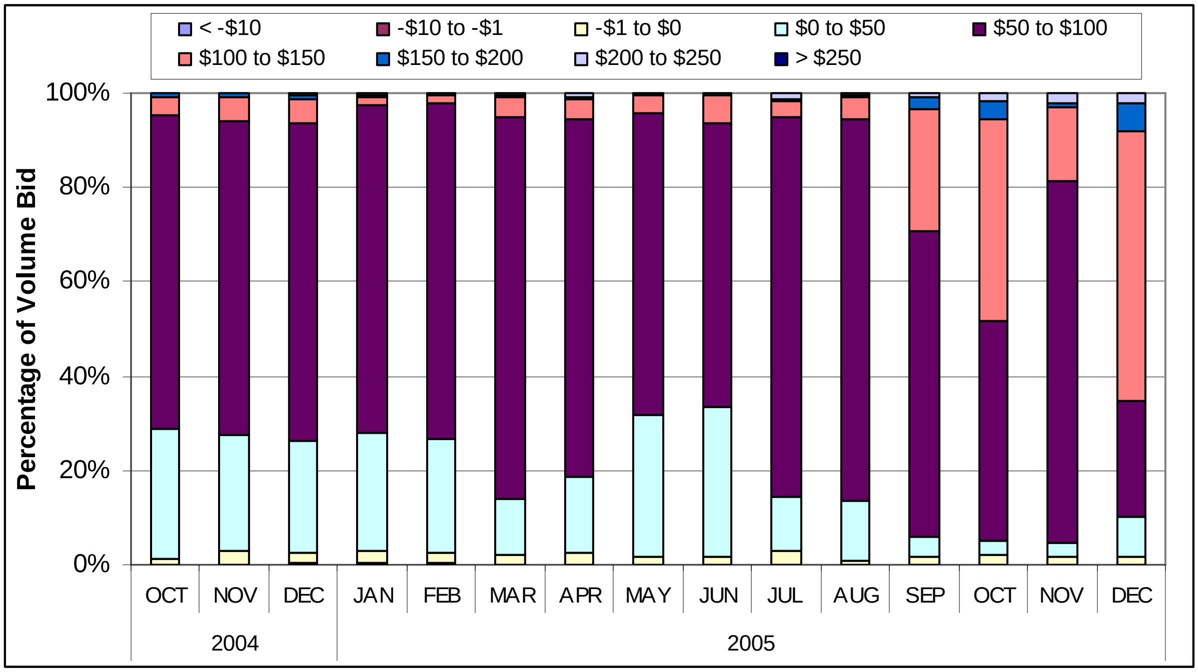
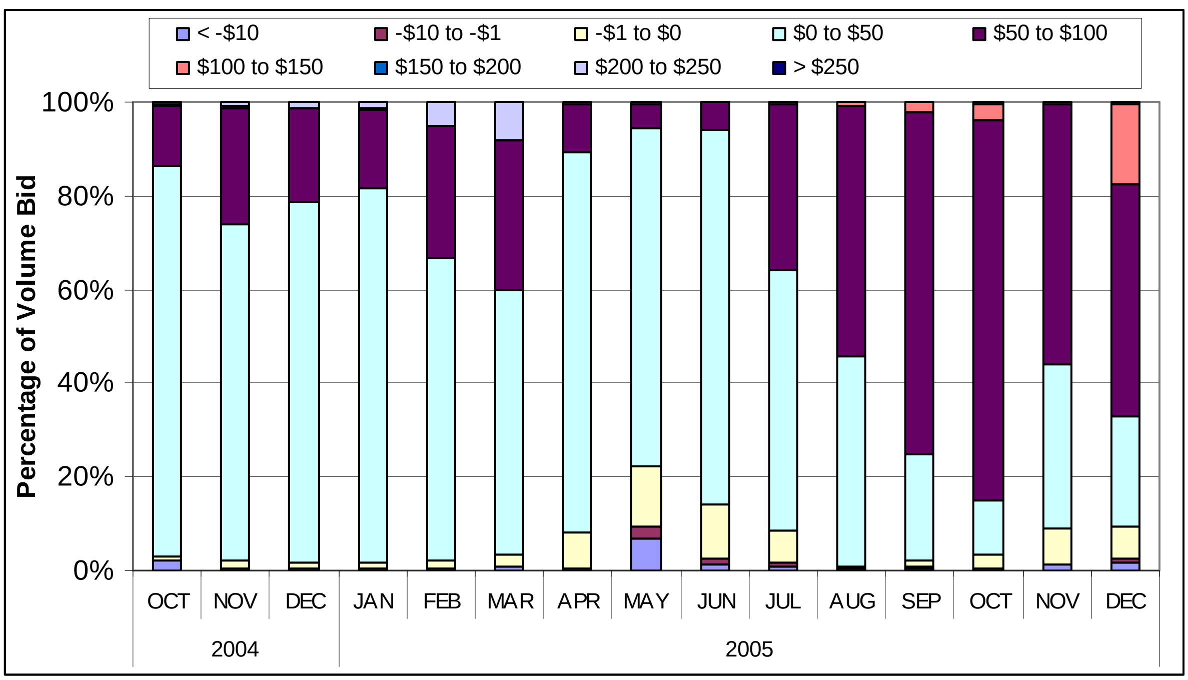


Figure 3.7 SP15 Decremental Energy Bids by Bid Price Bin: Oct-04 to Dec-05



Decremental bids below the price of $0/MWh were common, for a variety of reasons:

- Throughout the year, and particularly in the spring, certain hydroelectric resources faced spilling conditions due to high run-of-river water flows. Under these circumstances, reservoirs were full to capacity, and resource operators were admitting water into their generation turbines at the rate that water was flowing into the reservoir. In order to be decremented, resources would have had to divert water from their turbines over the spillway, effectively losing the potential energy for that volume of water.

- Certain gas-fired generators in California received operational flow orders requiring that generators face penalties if they fail to accept gas deliveries from pipelines. In the event that a generator does not have available gas storage, it may be required to run at its scheduled output, or incorporate these costs into its bids.
- Due largely to the binding SCIT Nomogram, a physical constraint on the instantaneous volume of imports into Southern California, Path 26 was congested in the north-to-south direction in real-time, resulting in divergent zonal prices. When the SCIT constraint is breached, it can be managed through out-of-sequence dispatches or real-time zonal congestion. In the latter case, the CAISO increments energy within SP15 and decrements within NP26, causing prices to diverge, and sending NP26 prices lower, sometimes below zero.
- During off-peak hours, particularly in the lowest-load hours of 1:00 to 5:00 am, few resources are on and generating above minimum operating capacity. As a result, few units are available to be decremented in these hours. This creates instances where competition is thin among the few providers of decremental energy during these hours.

3.3 Analysis of RTMA Performance

3.3.1 Relationship of Prices to Loads and Dispatches

In 2005, there were several occasions when very high peak summer demand conditions did not result in high real-time prices. These occurrences raised a concern that real-time prices were not well correlated with overall system conditions. This section examines this issue focusing on SP15 Real Time Market prices as this zone tended to have the greatest demand for incremental energy in 2005. A simple regression analysis for the peak month of July 2005 indicates that the SP15 real-time price exhibits a statistically significant positive relationship to both actual system loads and SP15 RTMA dispatch volumes, as would be expected (Table 2.1). These two explanatory variables, SP15 Dispatch Volume and Actual Load, explain approximately 48 percent of the variation in the SP15 real-time price.

Table 2.1 Regression of SP15 Real-Time Prices as a Function of Actual ISO System Load and SP15 Real-Time Dispatch Volume[3]

	Coefficient	t-statistic
Intercept	-13.8702	-11.1035
SP15 Dispatch Volume	0.0229	55.7868
Actual Load	0.0021	54.5312
Model R-square	0.48	
Observations	8928	

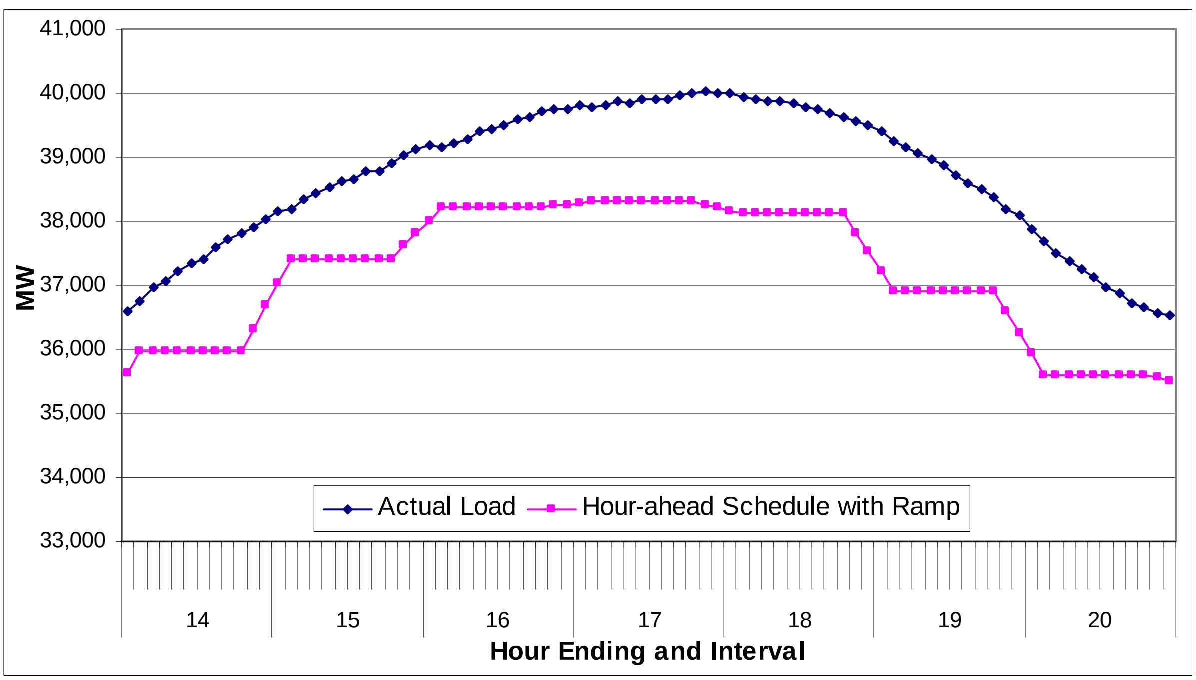
[3] Least-squares regression for all intervals, July 1-31, 2005.

While real-time prices are generally correlated with actual system loads, this is not always the case. In many instances in 2005, real-time prices were not always high during high-load periods. This tended to occur when the CAISO schedules were in excess of load, or when other types of energy were present. This can occur due either to inaccurate load forecasts, or to the following sources of energy, which Scheduling Coordinators cannot consistently account for when scheduling:

- Un-modeled and uninstructed energy;
- Minimum Load energy from resources retained under the Must-Offer Obligation; and
- Real-time RMR energy used to maintain reliability in the presence of transmission outages and other adverse grid events.

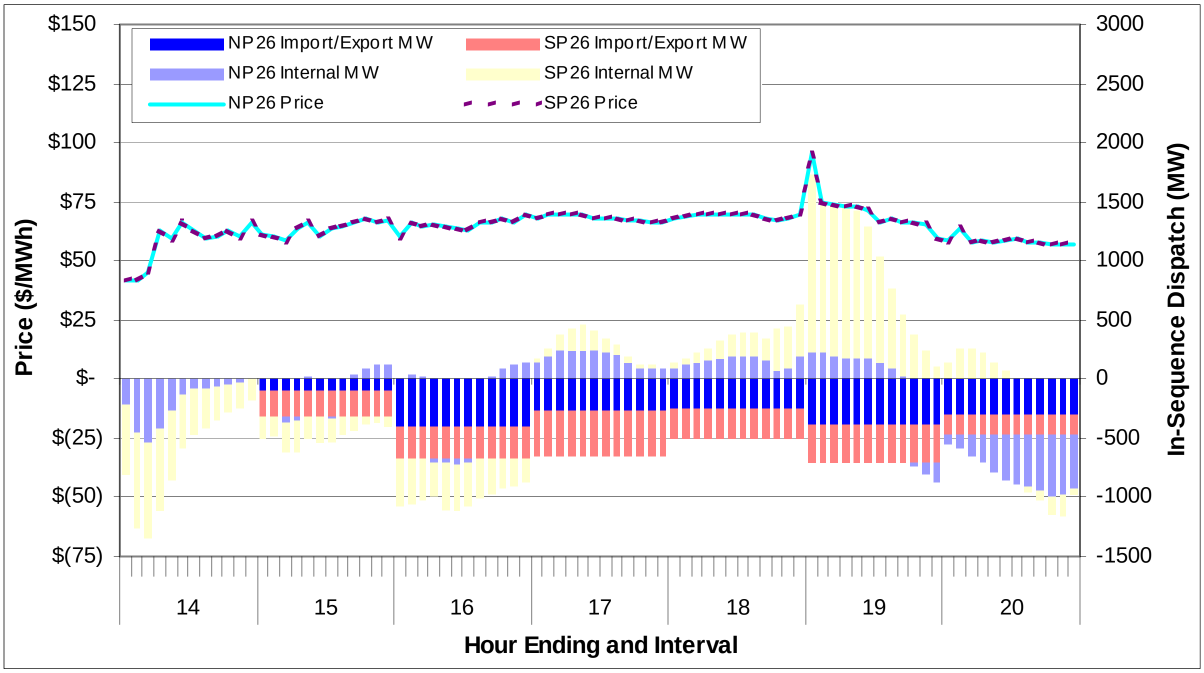
One example of such a day was Sunday, July 31, 2005, when CAISO system load ranged between 39,781 and 40,019 MW in Hour Ending 17:00 (between 4:00 and 5:00 pm). This hour represented one of the highest peak loads for Sundays in 2005, and was one of only three Sundays in 2005 that had a peak load above 40,000 MW. During this hour, Scheduling Coordinators had scheduled 38,309 MW, approximately 1,700 MW short of actual load. Figure 3.8 compares schedules and loads on the afternoon of July 31, 2005.

Figure 3.8 Hour-Ahead Schedule vs. Actual Load on the Afternoon of July 31, 2005



In this same hour, the system-wide real-time price ranged between $66.43 and $69.96/MWh. RTMA pre-dispatched approximately 656 MW of exports at the beginning of the hour, and then incremented between 97 and 458 MW of internal generation throughout the hour. Thus, the total net dispatch was actually negative. Figure 3.9 shows CAISO real-time in-sequence dispatch by zone on this same afternoon.

Figure 3.9 Real-Time Dispatch and Price on the Afternoon of July 31, 2005



Real-time energy prices were relatively low during this high-load period (Hour 17) due to unscheduled energy from a variety of sources. The total actual load as measured at the end of the hour ending 17 on July 31, 2005, was 40,019 MW. The approximate energy (average MW for the hour) used to meet that load is itemized in Table 3.1. The average net in-sequence dispatch (including pre-dispatched exports) was negative 385 MW. The CAISO also dispatched RMR capacity in this hour that provided approximately 1,174 MW of real-time energy. There was also an extra 175 MW of unscheduled resources at minimum load pursuant to the MOO, (which could have provided up to 3,954 MW of energy) and 40 MW of out-of-sequence energy dispatched. The remaining shortfall (703 MW) was met from regulation and uninstructed energy from small QF resources.

Table 3.1 Energy Generation Contribution by Type: July 31, 2005 - Hour Ending 17:00

Energy Type	Contribution (MW)
Hour-Ahead Scheduled	38,309
Net In-Sequence Dispatch (Avg.)	(382)
Real-Time RMR Dispatch	1,174
Minimum-Load (Must-Offer)	175
Out-of-Sequence Dispatch	40
Regulation and Uninstructed (Avg.)	703
Total Generation	**40,019**
Actual Load	**40,019**

This example demonstrates that unscheduled energy from RMR, must-offer waivers, and other sources can result in relatively low real-time prices despite large schedule shortfalls and high system loads.

3.3.2 Price and Dispatch Volatility

As previously discussed, RTMA was designed to address significant shortcomings in the prior real-time dispatch and pricing application (BEEP).[4] One of the major concerns raised about RTMA since its implementation is a perceived high degree of price and dispatch volatility. It should be noted that a real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on nearly an instantaneous basis. A high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids.

In October 2005, DMM conducted an in-depth market performance assessment of RTMA.[5] One of the key findings of this assessment is that the volatility of 5-minute prices in the CAISO's Real Time Market (from one interval to another within each operating hour) has increased significantly since implementation of the RTMA software. In addition, the volatility of individual generating unit dispatches in the CAISO's Real Time Market has also increased significantly since implementation of RTMA. The detailed analyses of that report and some additional analyses of RTMA performance are provided below.

Figure 3.10 compares the average and range of RTMA interval prices for 2005 with the average and range of interval prices for the last 12-months of BEEP operation (October 2003 – September 2004). The range of prices for each hour shown in Figure 3.10 represents the average interval price for that hour, plus and minus the average standard deviation of interval prices within each operating hour.[6] As shown in Figure 3.10, overall prices have dropped slightly for most hours since RTMA was implemented, but the range of interval prices within each hour has increased significantly.

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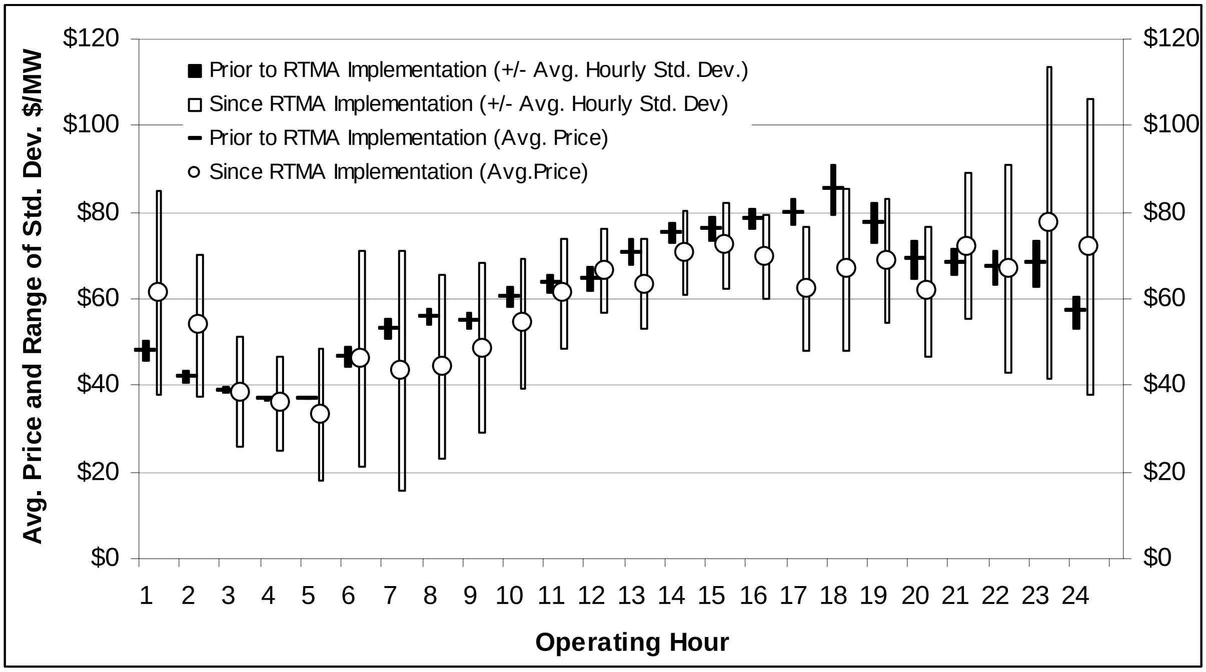
[4] Balancing Energy and Ex-Post Pricing (BEEP) software.

[5] Assessment of Real-time Market Application (RTMA) Performance, DMM Report, October 12, 2005 (http://www.caiso.com/docs/09003a6080/37/8c/09003a6080378c2c.pdf)

[6] The measure is designed to measure volatility of the prices for the pricing intervals in each hour (six 10-minute intervals in pre-RTMA and twelve 5-minute intervals under RTMA), rather than volatility in prices from day to day. Therefore, the standard deviation was first calculated for the interval prices within each hour. These individual hourly results were then averaged across the time period for each operating hour, 1-24.

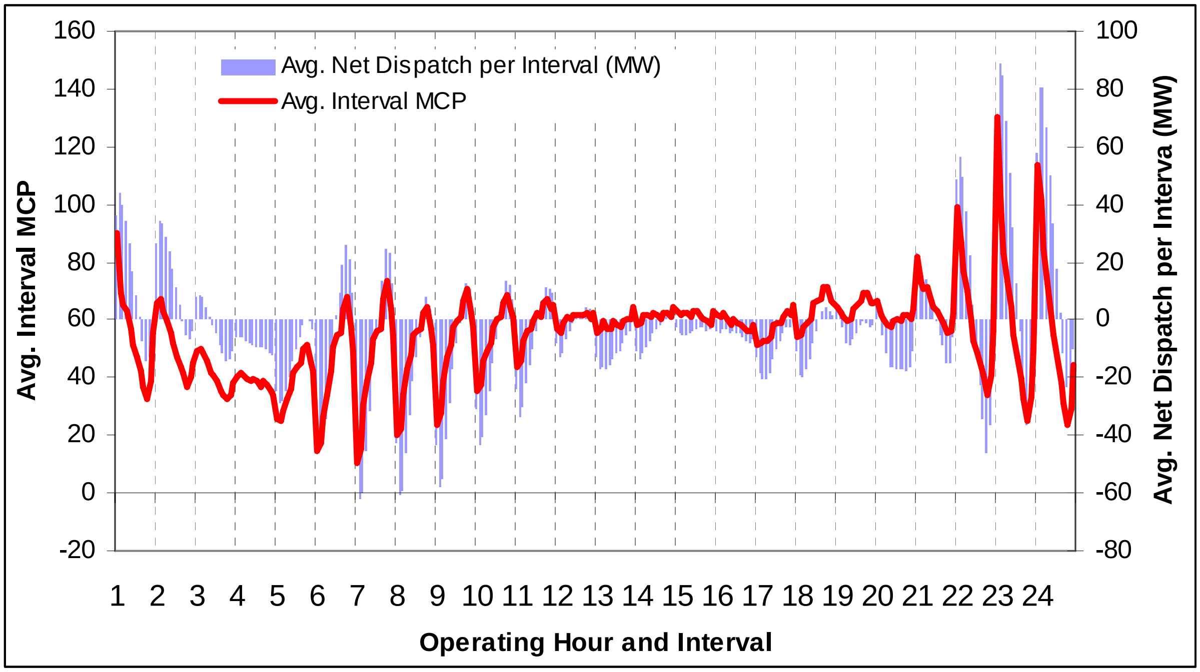
Figure 3.10 Average SP15 Hourly Prices and Standard Deviation Before (Oct 2003 – Sep 2004) and After (2005) RTMA Implementation



Analysis of price and dispatch data on a 5-minute interval basis shows that much of the intra-hour deviation of real-time prices under RTMA can be attributed to intra-hour fluctuations in demand for imbalance energy. As shown in Figure 3.11, there is a very close correlation between the intra-hour price deviations and net quantity of real-time energy dispatched each 5-minute interval since implementation of RTMA. Within each hour, prices are significantly higher when the CAISO is incrementing generation, and lower when the CAISO is decrementing generation. This pattern is especially noticeable during the morning and evening ramping hours, when the volatility of prices and imbalances within each hour are highest, as shown in more detail in Figure 3.13 and Figure 3.14, respectively.

During the morning ramp hours, prices tend to be lower during the first 15-minutes of each hour as the CAISO typically needs to decrement generation. During these intervals, the need to decrement generation stems from the fact that supply is ramping up to its new hourly schedule faster than the actual increase in loads during the first portion of each hour. Conversely, during evening ramp hours, the prices tend to be significantly higher during the first 15-minutes of each hour as the CAISO typically needs to increment generation. The need to increment generation during these intervals stems from the fact that supply is ramping down to its new hourly schedule faster than the actual decrease in loads during the first portion of each hour.

Figure 3.11 Intra-Hour Price Volatility Under RTMA in 2005



Not surprisingly, extreme RTMA interval prices (price spikes) tended to occur during the hours and intervals of the day that demand for imbalance energy was greatest. Most notably, prices spiked frequently in the first interval of the hour, as changes in supply output in response to hourly schedule changes fell out of synch with changes in actual load, and RTMA dispatched energy to correct for the difference. Another trend was regular spikes during the late-night ramp, particularly between 10:00 pm and midnight (hours ending 23:00 and 24:00). At 10:00 pm, peak-period bulk power contract deliveries end relatively abruptly in all seasons of the year, decreasing by several thousand megawatts in the course of one hour. Meanwhile, load ramps down more smoothly, and varies by season. As a result, RTMA tends to dispatch most or all resources to smooth the generation ramp change and more closely match it to load. Figure 3.12 shows the number of days in each hour and interval in which real-time prices exceeded $200/MWh. Note that in interval 1 of hour ending 23:00 (between 10:00 and 11:00 pm), the price spiked on 70 of 365 days, or approximately 19 percent of the time, in 2005.

Figure 3.12 SP15 Incremental Price Spikes by Hour of Day and Interval in 2005

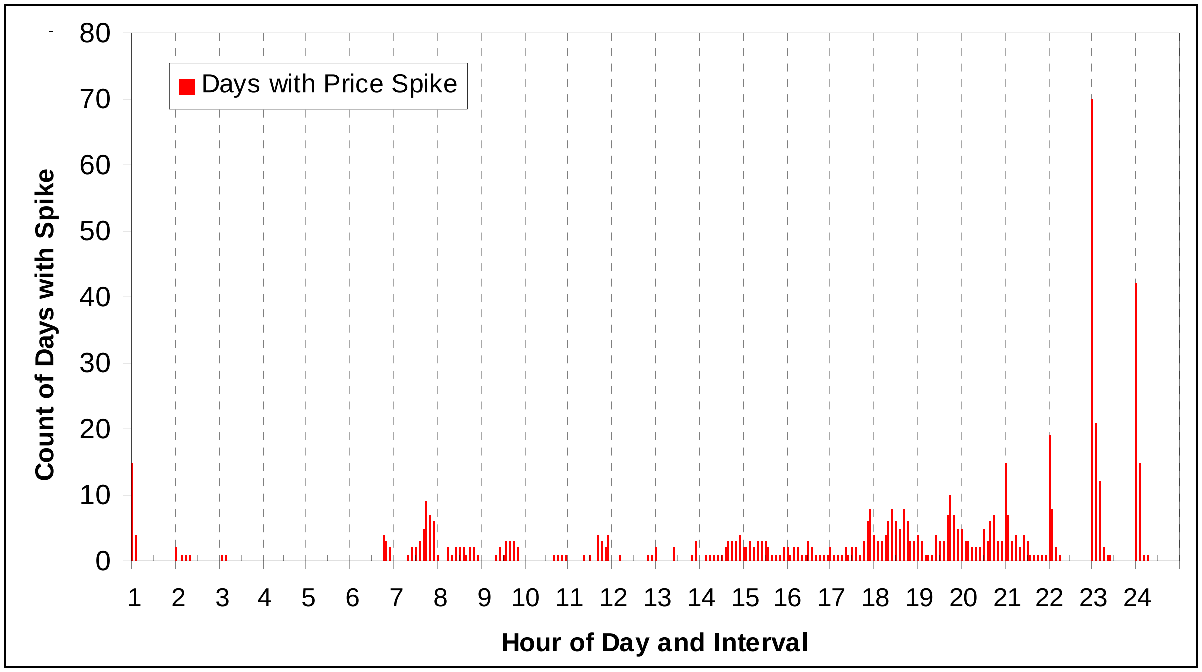


Figure 3.13 and Figure 3.14 below show average dispatch volumes and deviations of interval prices from the hourly average price for morning and late evening ramping hours in 2005.

Figure 3.13 Intra-Hour Price Volatility during Morning Ramping Hours (2005)

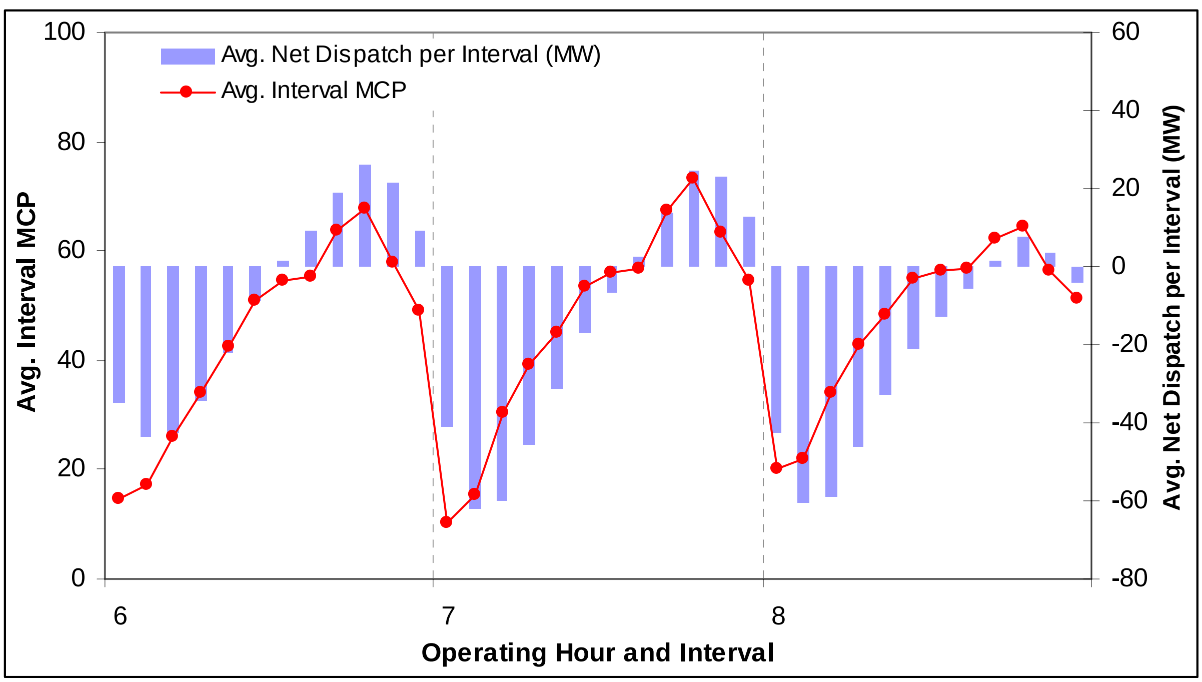
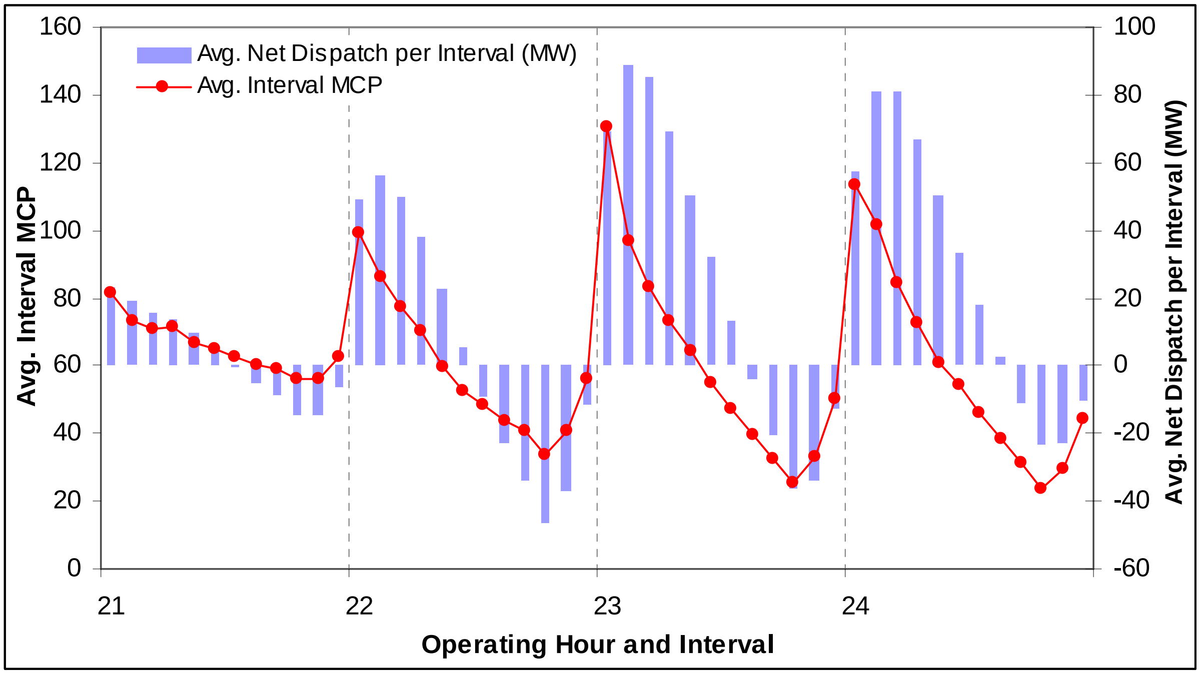
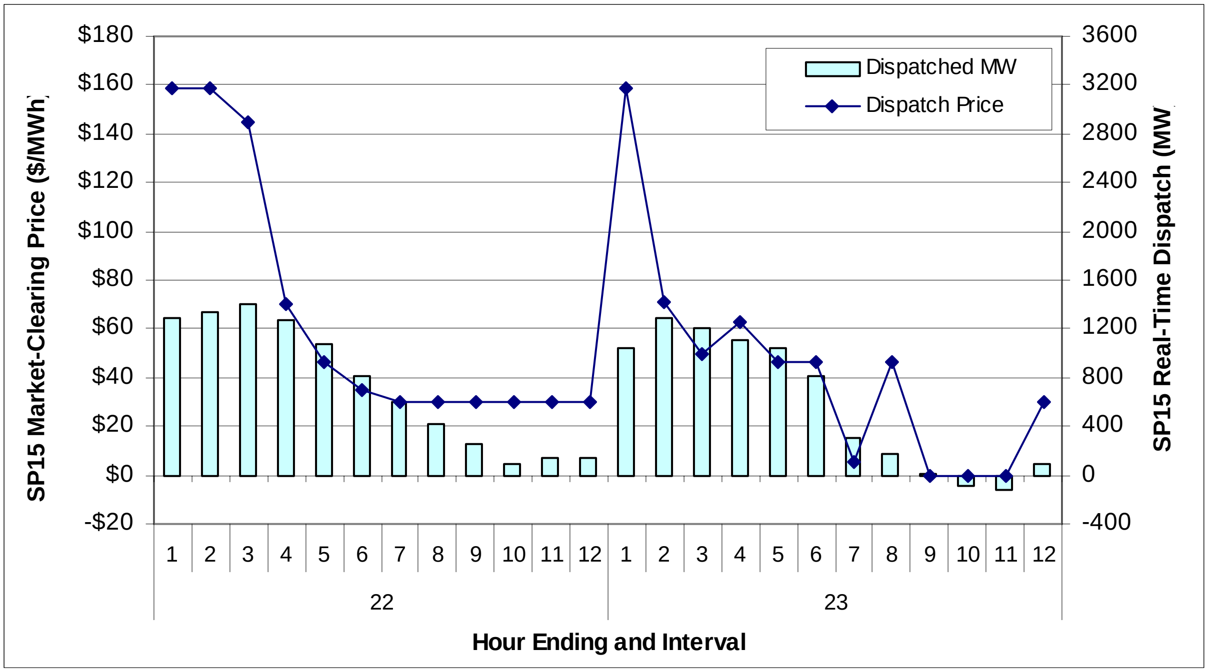


Figure 3.14 Intra-Hour Price Volatility during Evening Ramping Hours (2005)



Although demand for imbalance energy tends to peak in the second or third intervals of the evening hours (as shown in Figure 3.14 above), 5-minute prices tend to peak in the first interval and then drop in subsequent intervals through the hour. This trend can be attributed to changes in the available supply during each of these 5-minute intervals due to ramp limitations of lower priced resources. Figure 3.15 and Figure 3.16 below show an example of this using actual bid and dispatch data for an hour ending 23 in June 2005.

Figure 3.15 Dispatch and Pricing Example for Typical Evening Ramping Hours



As shown in Figure 3.15, the amount of imbalance energy dispatched during hour ending 23 rose sharply during the first interval with the price spiking to $159/MWh. While demand continues to rise in interval 2, the price dropped to $71/MWh. The cause of this pattern is illustrated in Figure 3.16 and Figure 3.17. As shown in Figure 3.16, the actual available supply of bids during the first 5-minute interval of an hour is often dramatically lower than the total amount of supply bids available over the entire operating hour. As shown in Figure 3.17, the supply of real-time energy bids during interval 2 is significantly higher than in interval 1 after taking into account ramp rates of each resource. During the first interval in this example hour, the price was set at $169/MWh by a fast-ramping resource dispatched to meet demand. During the second interval, however, additional energy was available from the lower cost resources, so that the higher cost bids are no longer needed to meet demand. As a result of this shift in the 5-minute supply curve, the price cleared at only $71/MWh during the second interval, despite the fact that demand for imbalance energy actually rose. This example also illustrates why some units may be receiving changes in dispatch direction, and why the number of units receiving a change in dispatch direction tends to be highest during the second interval of each hour.

Figure 3.16 Total Hourly Incremental Energy Supply vs. Ramp-Constrained Supply

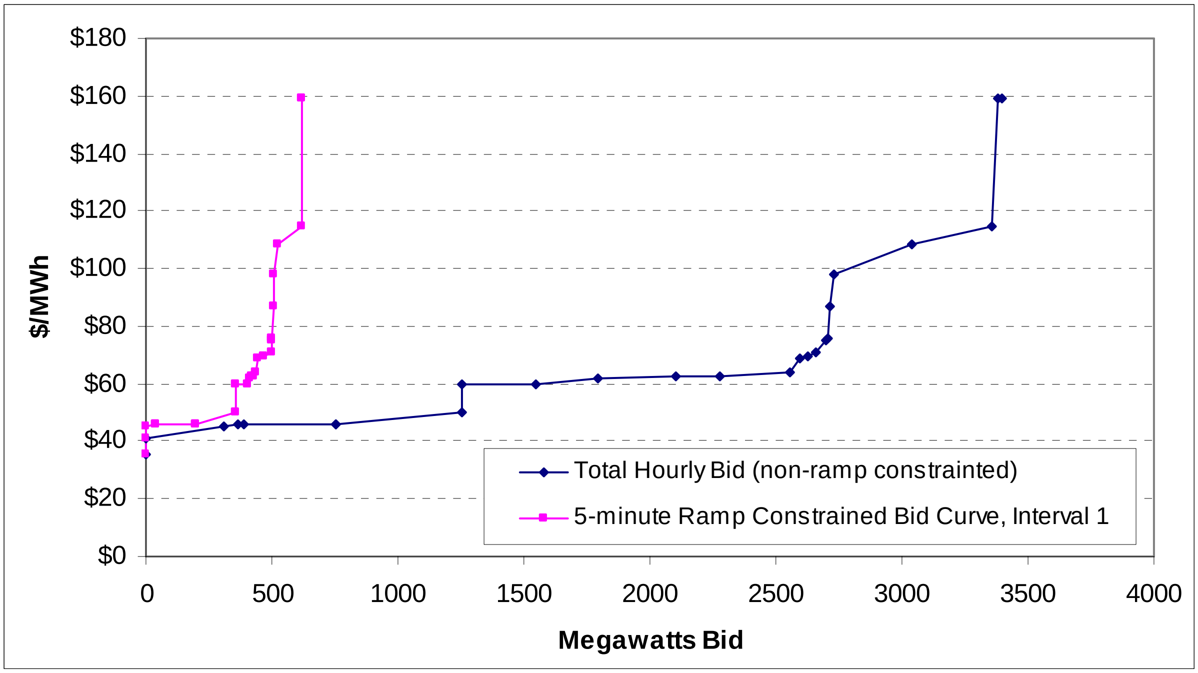
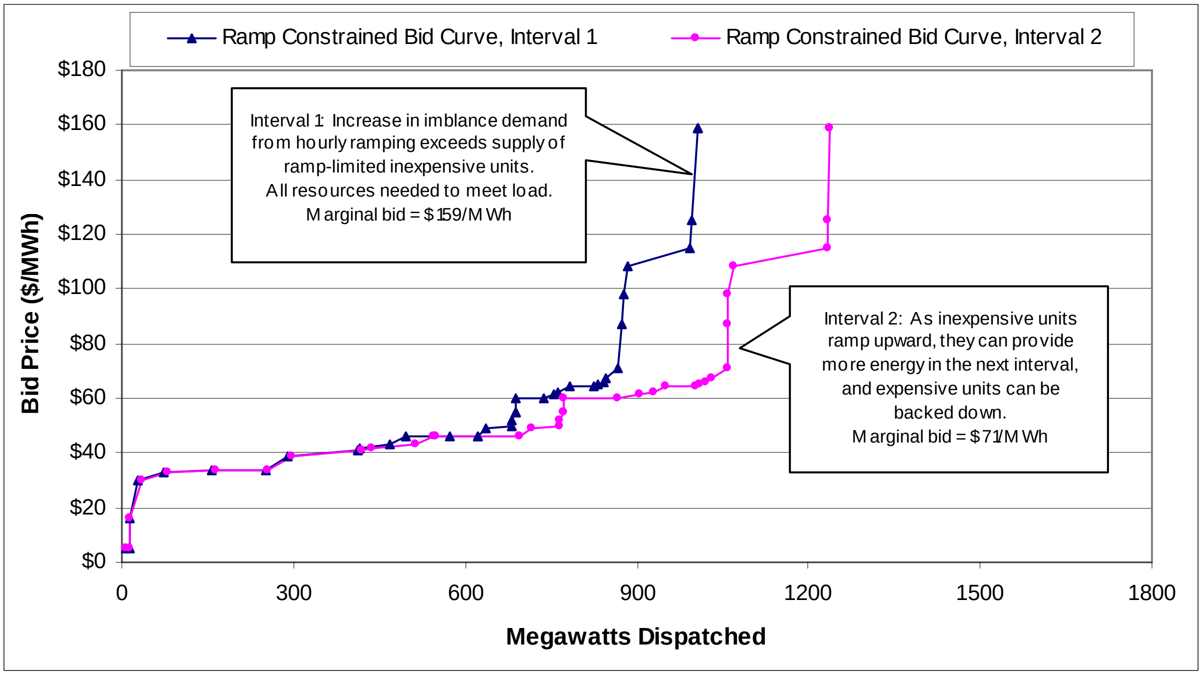


Figure 3.17 Ramp-Constrained Supply Available During Intervals 1 and 2



One of the major market design changes incorporated into the RTMA software was the economic dispatch or market clearing of all incremental and decremental bids for supplemental energy. Rather than simply dispatching the bids necessary to meet the projected imbalance of the CAISO system, RTMA dispatches all remaining incremental and decremental bids for supplemental energy with "overlapping" prices (i.e., incremental bids offered at a price lower than the price of decremental energy bids submitted by other participants). Analysis of RTMA dispatch data indicates that a large portion of energy dispatched in RTMA has been dispatched as part of the process of clearing real-time market bids, rather than to simply meet CAISO system imbalance needs. This indicates that this market design change may also be a significant cause of the increased volatility of prices and unit dispatches since implementation of RTMA.

In order to quantitatively assess the volatility of dispatches within each hour before and after RTMA, a measure of dispatch volatility was developed that counts the number of times each unit is dispatched by RTMA in a different direction than the previous RTMA dispatch within the same hour.[7] Under normal operating conditions, units may receive one or two switches in dispatch direction each hour. However, three or more switches in dispatch direction during any hour may indicate excessive volatility.

Based on this measure of dispatch volatility, the volatility of unit dispatches in the CAISO's Real Time Market does appears to have increased since implementation of RTMA. Figure 3.18 and Figure 3.19 show the average number of units that received a change in dispatch direction in each 5- or 10-minute interval of each operating hour before and after RTMA was implemented, respectively. As shown in these figures, there is a similar hourly and daily pattern in dispatches both before and after implementation of RTMA. At the beginning of each operating hour, a

[7] For example, if a unit is dispatched up in the first interval, and is then dispatched down in a subsequent interval within the same hour, the unit has received one "dispatch direction switch." If the same unit was then dispatched back up in yet another interval within the same hour, this would count as a second switch in dispatch direction that hour.

significant number of units are dispatched in a different direction, as new hourly schedules take effect. In addition, the number of units dispatched in a different direction increases significantly during the morning and evening ramping hours, during which the change in schedules and loads that must be met by imbalance energy is especially high. While these same patterns existed prior to implementation of RTMA, the overall number of units dispatched in different directions under RTMA has increased significantly across all intervals and hours of the day.

Figure 3.18 Average Number of Units Receiving Change in Dispatch Direction by Operating Hour and Interval (Pre-RTMA, October 2003- August 2004)

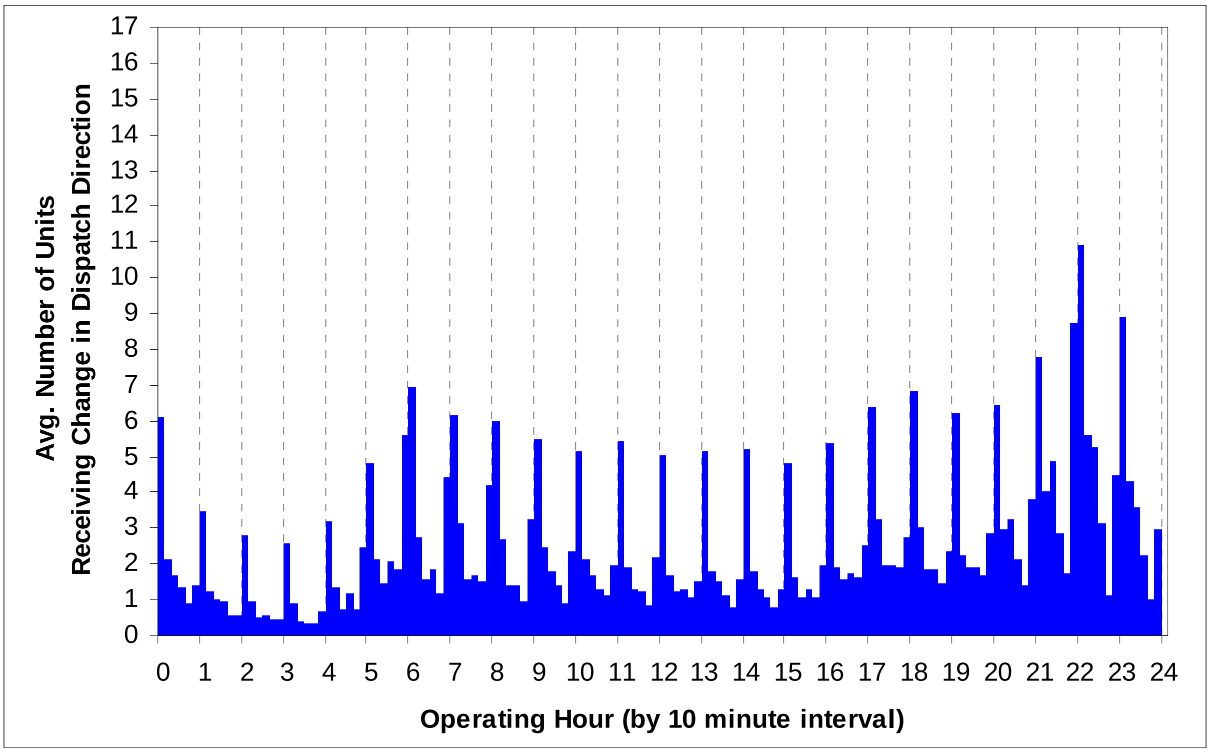


Figure 3.19 Average Number of Units Receiving Change in Dispatch Direction by Operating Hour and Interval (Post-RTMA, October 2004- August 2005)

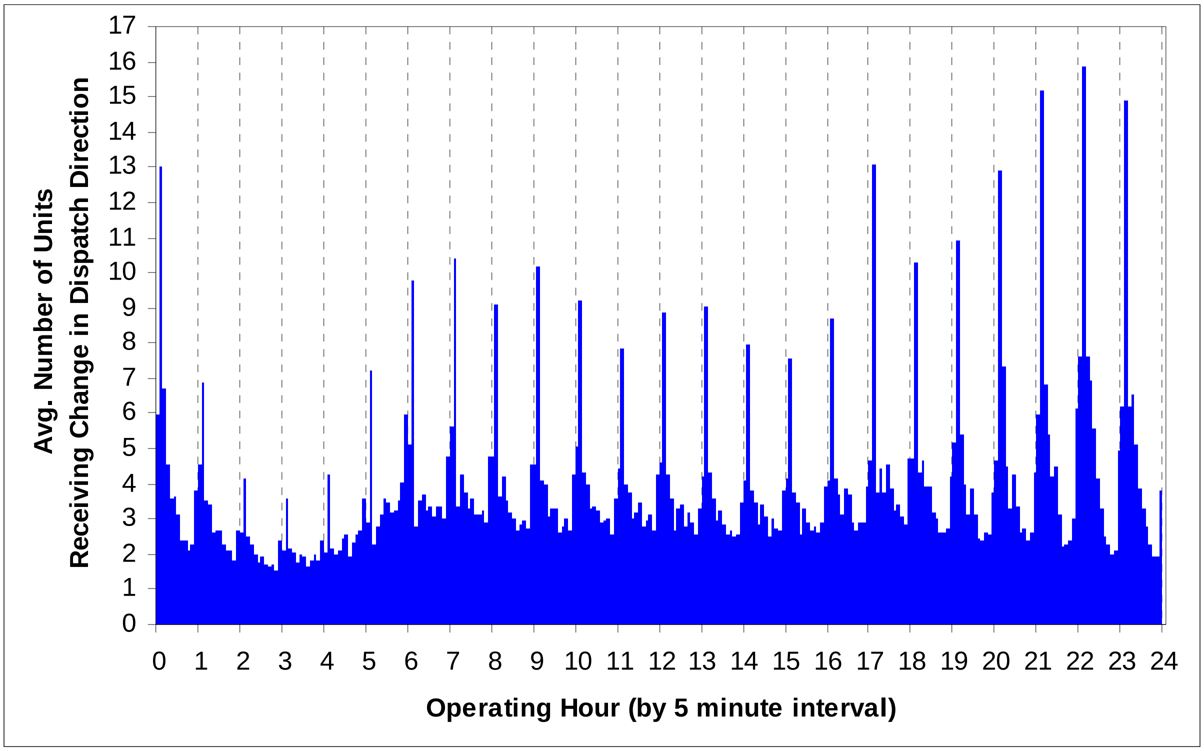


Figure 3.20 and Figure 3.21 show the average percent of units in each operating hour that experienced a change in dispatch direction for the period from October - August, before and after implementation of RTMA.

Figure 3.20 Percentage of Units Dispatched by BEEP with One or More Switches in Dispatch Direction each Hour (October 2003-August 2004)

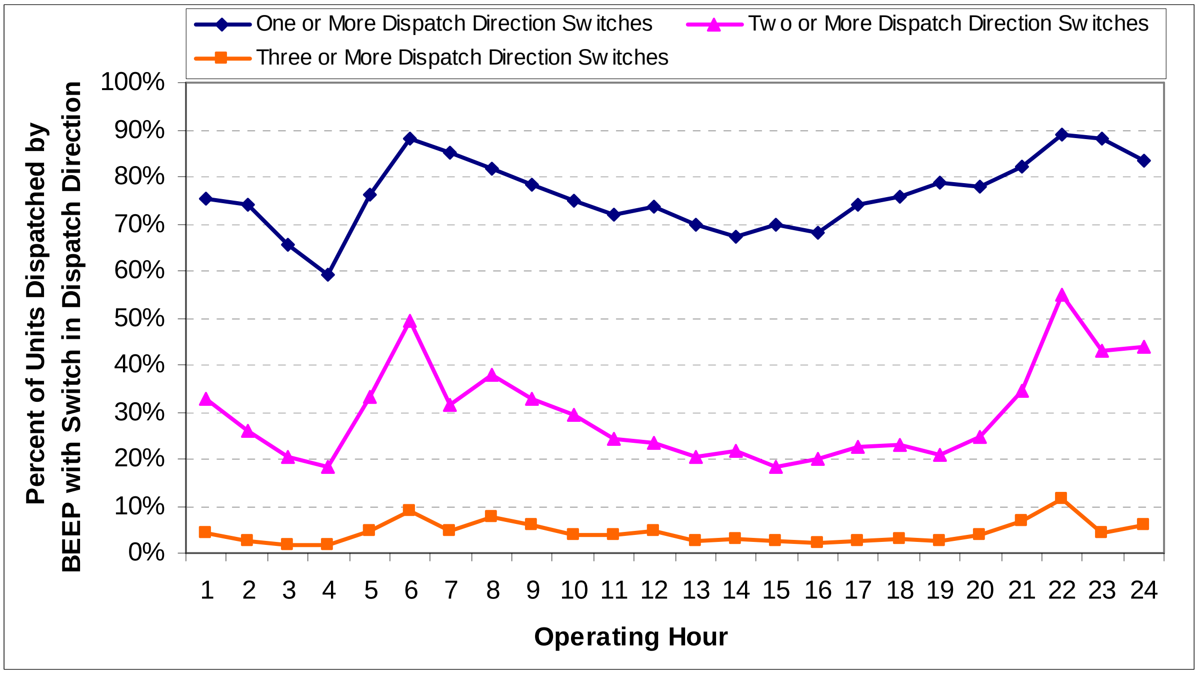
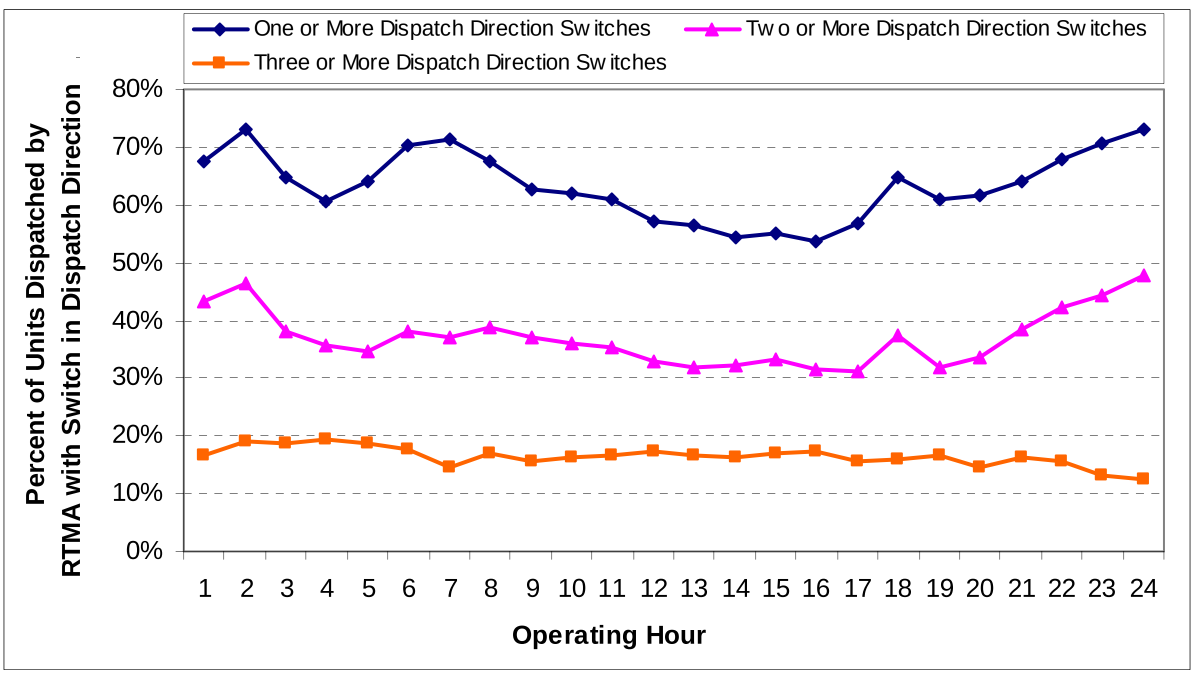


Figure 3.21 Percentage of Units Dispatched by RTMA with One or More Switches in Dispatch Direction each Hour (October 2004-August 2005)



3.3.3 Settlement of Pre-Dispatched Inter-tie Bids (Amendment 66)

As discussed in Chapter 1, the RTMA design included two significant modifications relating to the dispatch and settlement of import/export bids over inter-ties with neighboring control areas.

- **Market Clearing of Import/Export Bids**. One of the central features of RTMA was the establishment of a market clearing mechanism, under which bids for incremental energy to provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or "cleared" against each other. The RTMA software applies this market-clearing algorithm to all remaining bids after bids needed to meet projected CAISO imbalance energy demand are accepted. This market clearing mechanism, which is incorporated in all other major ISO market designs, was incorporated into the RTMA software to promote greater economic efficiency, encourage participation in the CAISO Real Time Market, and avoid problems with the alternative "Target Price" mechanism previously employed to resolve incremental and decremental bids with such price overlap.
- **Bid or Better Settlement Rule for Import/Export Bids.** A second key feature of RTMA as initially implemented was settlement of pre-dispatched import/export bids on a "bid or better" basis. Under the "bid or better" settlement rule, hourly import bids pre-dispatched by the CAISO were paid the higher of their bid price or the ex-post MCP subsequently set during the operating hour by resources within the CAISO system dispatched on a 5-minute basis. Conversely, pre-dispatched export bids were charged the lower of their bid price or the ex-post MCP. This settlement rule was adopted to encourage participation in the Real Time Market by imports and exports, which are prohibited from setting the real-time market price under market rules established by the Federal Energy Regulatory Commission (FERC). Although RTMA pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In cases when MCPs were lower/higher than bid prices of pre-dispatched import/export bids, additional payments or decreased charges applied to pre-dispatched import/export bids were recovered through uplift charges assessed to other CAISO participants based on uninstructed deviations and gross load.

In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the "bid or better" settlement rule. Under the "bid or better" settlement rule, the CAISO incurred uplift charges whenever actual ex-post MCPs were either higher or lower than the projected prices used to clear import/export bids. For example, when ex-post MCPs were higher than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched imports bid at prices in excess, but export bids cleared against these import bids were only charged the ex-post MCP. Conversely, when ex-post MCPs were lower than the project prices used to clear import/export bids, uplifts were paid to pre-dispatched exports bid at prices lower than the ex-post MCP, but import bids cleared against these export bids were paid the full ex-post MCP.

In spring 2005, this basic market design flaw was exacerbated by significant divergences between the projected prices used to clear import/export bids and the actual ex-post MCPs, which are based on an average of the actual 5-minute interval prices. One of the primary causes of this divergence was the way that the RTMA software accounted for uninstructed deviations by resources within the CAISO. Specifically, the initial RTMA software projected uninstructed deviations in future dispatch intervals by assuming that generation internal to the CAISO that was deviating from its schedule would seek to return to its scheduled operating level. This approach tended to underestimate positive uninstructed energy provided by many units, such as run-of-river hydro, Qualifying Facilities (QFs), and units operating at minimum load due to must-offer waiver denials. Since the RTMA software systematically underestimated uninstructed energy from these resources, ex-post MCPs tended to be significantly lower than projected prices used in pre-dispatching import/export bids. Combined with the basic design flaw of the “bid or better” settlement rule, this systematic price divergence created excessive uplift for export/import bids dispatched under the market-clearing feature of RTMA. This flaw in how uninstructed deviations were treated in RTMA was identified relatively quickly after RTMA implementation, but due to the lead-time for development and implementation of an enhanced algorithm this problem was not fixed until March 24, 2005.

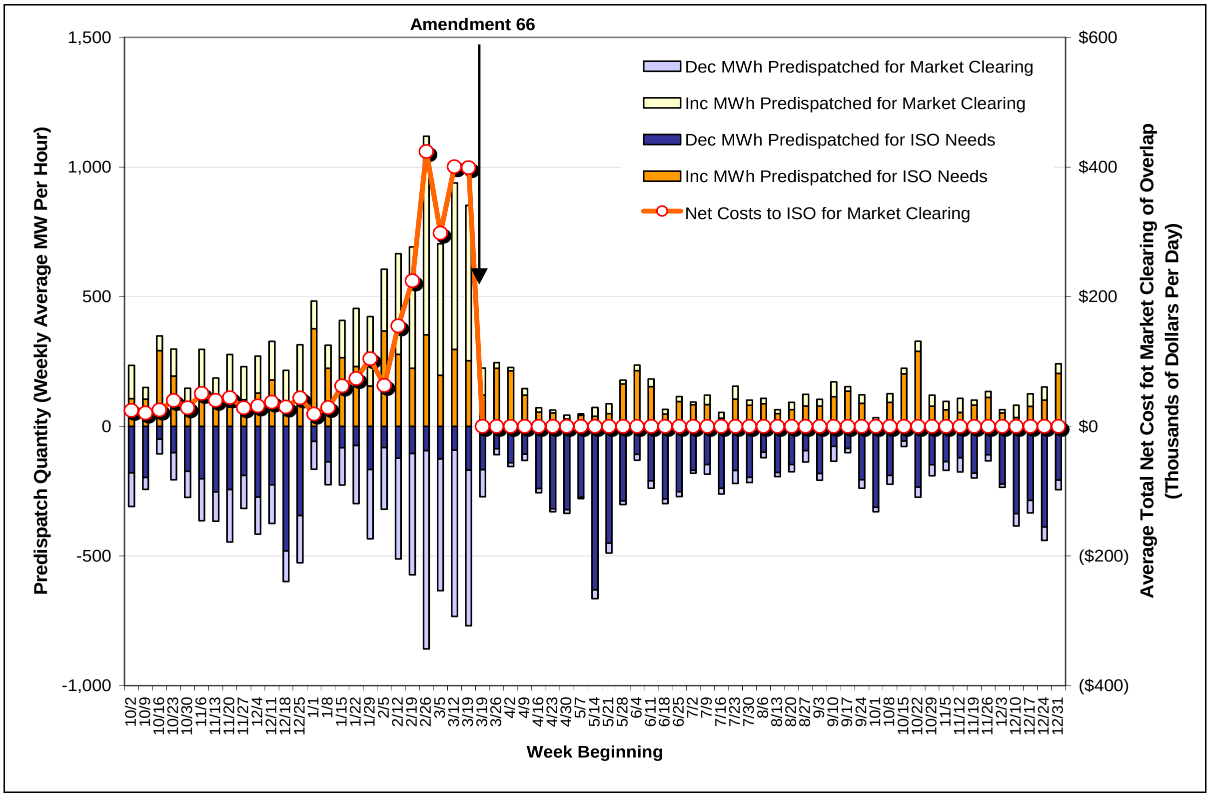
In addition, analysis of participant bidding behavior suggests that some market participants took advantage of these market design flaws and conditions by bidding imports and exports in a manner that increased the probability of having off-setting import and export bids accepted in the pre-dispatch, which resulted in uplift payments being made for the difference between bid prices and the ex-post MCP, despite the fact that no net energy was being delivered to the CAISO system as a result of these off-setting import and export bids.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the market clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the “bid or better” settlement rule for pre-dispatched import/export bids to an “as-bid” market design. Under an “as-bid” settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an “as-bid” settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

Once Amendment 66 was implemented, the volume of bids dispatched for market-clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically (Figure 3.22). Total uplift costs incurred prior to the CAISO’s March 23 filing were estimated at $33.6 million, with about $18.6 million of these uplift costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids under RTMA. Costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids averaged about $400,000 per day in the month prior to Amendment 66.

The volume of offsetting incremental and decremental energy bids pre-dispatched by the CAISO to clear the market has also been dramatically reduced under the “as-bid” settlement rule. Since the effective date of Amendment 66 through the end of 2005, an average of only about 30 MW of off-setting incremental and decremental bids have been pre-dispatched each hour, as opposed to an average of about 600 MW per hour in the month prior to implementation of Amendment 66.

Figure 3.22 Average Hourly Volume of Bids Pre-Dispatched by the CAISO and Average Daily Costs to CAISO of Market Clearing



Another indication that significant improvements have been made in RTMA since the change from the "bid or better" to an "as-bid" settlement rule is that prices for pre-dispatched energy from import/export bids have tracked much more closely with Real Time Market prices set by resources within the CAISO system subsequently dispatched within each operating hour. Figure 3.23 and Figure 3.24 show the trend in volumes and net prices of incremental and decremental energy pre-dispatched to balance CAISO system demand, and compare the net prices for pre-dispatched incremental and decremental energy with the value of this pre-dispatched energy calculated using the corresponding hourly ex-post MCP set by resources dispatched within the CAISO system. As shown in Figure 3.23, prior to implementation of Amendment 66, the cost of pre-dispatched incremental energy (including uplifts) was often significantly higher than the value of this incremental energy as reflected in the MCPs set in the CAISO real-time 5-minute imbalance market. Similarly, as shown in Figure 3.24, prior to implementation of Amendment 66, the cost of pre-dispatched decremental energy (including uplifts) tended to be systematically lower than the value of this decremental energy calculated at the ex-post MCPs set in the CAISO real-time 5-minute imbalance market.

Figure 3.23 Total Net Cost Paid for Incremental Energy Pre-dispatched to Balance CAISO System Demand

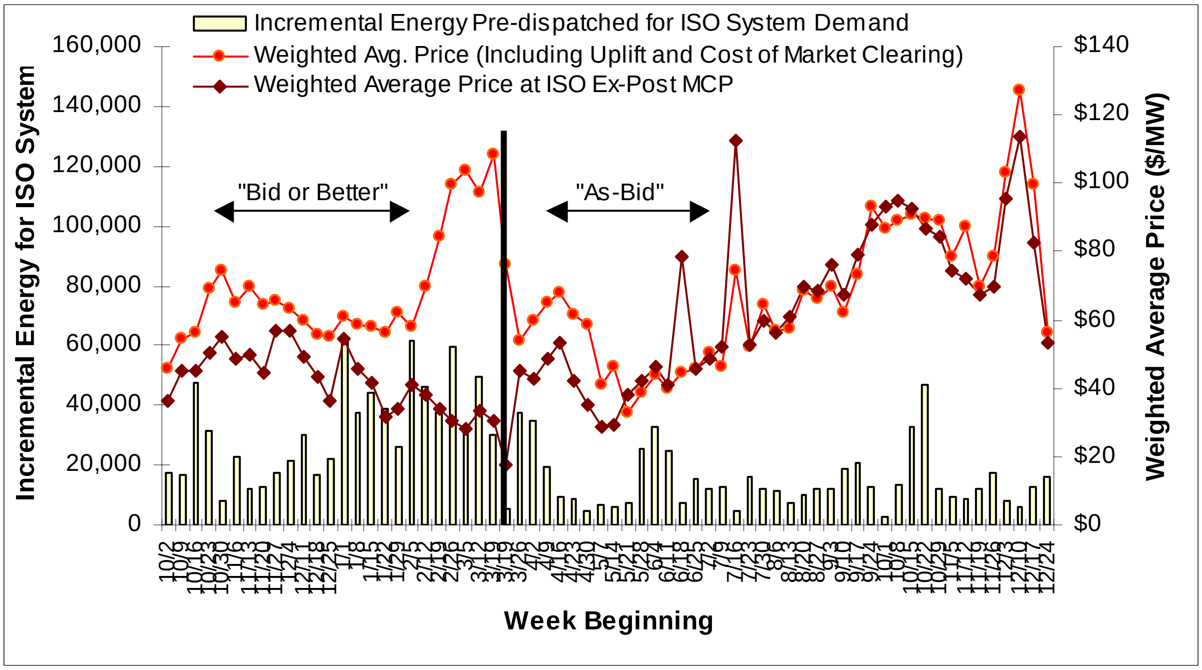
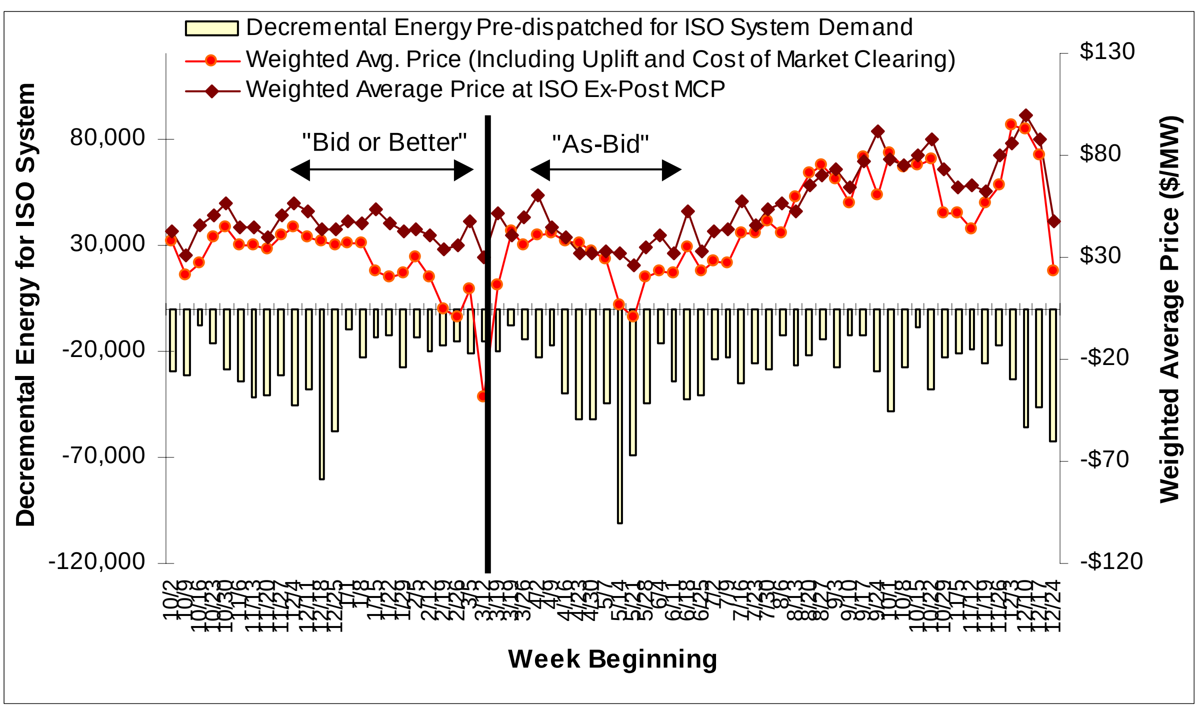


Figure 3.24 Total Net Price Received for Decremental Energy Pre-dispatched to Balance CAISO System Demand



The reduction in the difference between pre-dispatched energy costs and real-time MCPs is due to a combination of the elimination of uplift payments made under the “bid or better” settlement rule and the improved algorithm within RTMA used to account for uninstructed deviations by generating resources within the CAISO that was implemented at virtually the same time as the switch to an “as-bid” settlement rule on March 25, 2005. The divergence in pre-dispatch and real-time energy prices for incremental energy during mid-April to mid-June corresponds to a period when the CAISO needed to consistently decrement large volumes of resources to balance loads, due to a variety of seasonal conditions, such as low loads and inflexible output from hydro resources due to high spring runoff.

The replacement of the “bid or better” settlement rule with an “as-bid” settlement rule for imports/export created a concern among some market participants that this change would reduce the liquidity of import/export bids submitted to the CAISO market. To date, however, the CAISO has not experienced problems in terms of bid insufficiency or liquidity of incremental energy import bids since the switch to an “as-bid” market under Amendment 66. In fact, the volume of incremental energy bids has typically been higher this year than during the comparable period in 2004, and has consistently been well in excess of the quantity of bids actually pre-dispatched.

As shown in Figure 3.25, the volume of overall net imports scheduled or bid into the CAISO system remained comparable to pre-Amendment 66 levels throughout the summer months under the “as-bid” settlement rule. Net scheduled imports increased significantly, and the volume of incremental real-time energy bids remained far in excess of amounts of imports actually pre-dispatched. Similarly, as shown in Figure 3.26, the volume of decremental real-time energy export bids submitted to the CAISO Real Time Market increased and remained far in excess of amounts of imports actually pre-dispatched for most hours.

Bid prices for incremental energy from imports have increased and bid prices for decremental energy for export have decreased somewhat since implementation of Amendment 66 relative to bilateral market prices. However, this would be expected under an “as-bid” settlement rule, as participants adjust their bids to compensate for the expected value from uplift payments they previously received under the “bid-or-better” settlement rule. When the actual value of the additional benefits received under the “bid-or-better” settlement rule are incorporated into the analysis, bid prices for incremental energy imports and decremental energy exports both appear to have decreased moderately.

Figure 3.25 Net Scheduled Imports, Real-Time Energy Import Bid Volumes, and Pre-Dispatched Imports - Hourly Averages by Week (Peak Hours 13-20)

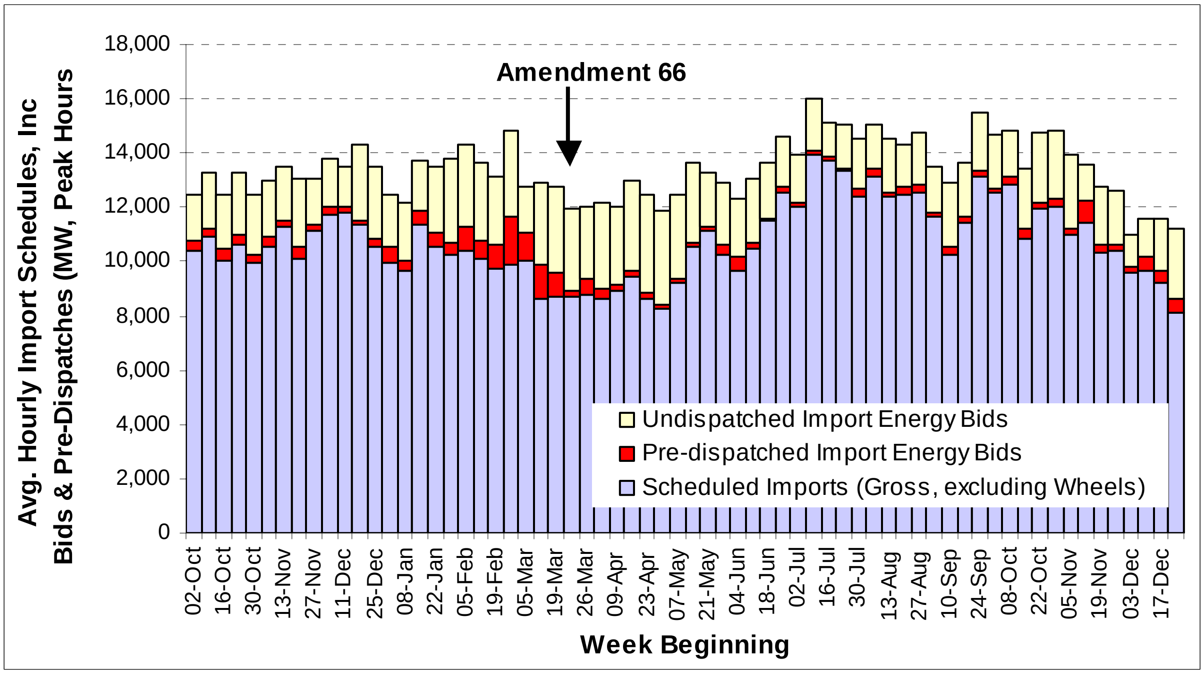
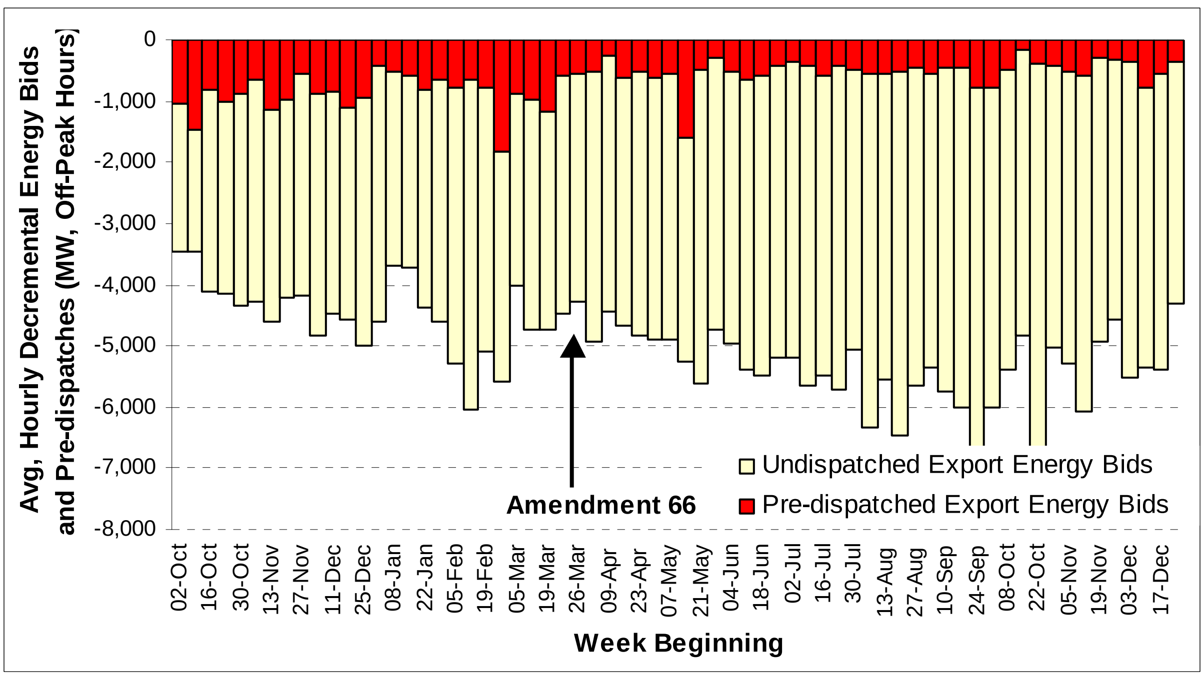


Figure 3.26 Real-Time Energy Export Bid Volumes And Pre-Dispatched Exports - Hourly Averages by Week (Off-Peak Hours 1-8)



3.3.4 RTMA Load Bias and Use of Regulation

The RTMA software has greatly reduced the frequency and degree of dispatcher judgment or intervention required to run the real-time imbalance market. For example, under the BEEP software, dispatchers calculated the imbalance requirement for the next 10-minute interval and communicated that requirement to the Grid Resource Coordinator who would then implement a specific dispatch solution to fulfill these requirements. Significant dispatcher knowledge and judgment was required to assess how to factor inputs such as: actual units start-up times, ramp rates, increased or decreased system load, known and anticipated imbalance energy needs, and conditions in future intervals. The RTMA software continues to allow for dispatcher adjustments, but focuses dispatcher input primarily on one single input: the *load bias*, which is an optional adjustment that can be entered by the dispatcher to RTMA's internally generated projection of imbalance energy requirements over the next one to two hour period.

Grid Operations has established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of all intervals. As shown in Figure 3.27, while the type of load bias has varied significantly from month-to-month in response to system conditions, dispatchers have utilized the load bias in no more than about 40 percent of the intervals within each month of 2005 except for January. This represents a dramatic reduction following the first four months under RTMA (October 2004 - January 2005).[8]

Dispatchers utilize the load bias function of RTMA to account for actual system conditions or anticipated conditions within the next few intervals, which include:

- Returning regulating units to their Dispatch Operating Points or Preferred Operating Point (POP). This basic reliability requirement is required under the CAISO Tariff, and may be the most frequent reason for the use of load bias.
- Mitigating congestion on transmission inter-ties by over-generating to help reduce inter-tie loading.
- Mitigating intra-zonal congestion. When dispatchers determine that resources must be incremented or decremented in real-time for intra-zonal congestion, the load bias may be used to increase the response time of RTMA in adjusting other resources as needed to balance overall system loads and resources.
- Managing sudden increases or decreases in imbalance energy conditions as relatively large blocks of pump loads are turned off or on.
- Compensating for load forecast error. Dispatchers may utilize the load bias to compensate for very short-term load forecast error if RTMA's load forecast appears to be lagging or systemically off.
- Managing uninstructed deviations. While RTMA does forecast uninstructed deviations on an ongoing basis based on an enhanced algorithm, dispatchers may utilize the load bias to account for uninstructed deviations if RTMA treatment of uninstructed energy appears to be lagging or is systemically off.
- Facilitating more rapid response to an unplanned loss of a generation or transmission facility. The load bias may be used to compensate for a sudden loss of resources or transmission outage that may be known to dispatchers, but has not yet been registered or fully incorporated into RTMA.

[8] Actual load bias data are not available for the first month of RTMA (October 2004).

- Compensating for differences in unit ramping characteristics not accurately modeled in RTMA. For example, combined cycle and other thermal units may have temporary operating constraints that are not modeled in RTMA. To the extent that dispatchers are aware of these constraints and how they limit the ramping ability of a unit, the load bias may be used to compensate for the difference between automated RTMA dispatch instructions and the dispatchers' estimate of actual unit responses to these dispatches.
- Restoring operating reserve. If resources providing operating reserve have been dispatched to provide real-time energy, the load bias may be used to more quickly dispatch supplemental energy bids in order to restore operating reserve margins.
- Adjusting for known telemetry error. In the event that telemetry from a resource fails or is determined to be significantly in error, the load bias may be used to adjust for this error.
- Compensating for manual and automatic time error correction. When the system frequency is modified (i.e., above or below 60 Hz) to correct time errors within the CAISO control area, the load bias may be utilized to help maintain this adjusted frequency.

Under all of the situations described above, the use of the load bias would help maintain system reliability by achieving a better balance between loads and resources, reducing use of regulation resources, and reserving regulation capacity for use in responding to sudden system imbalances.[9] As described later in this section of the report, analysis of load bias usage patterns by DMM also indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity.

In order to encourage operators to limit adjustments to RTMA on a minute-by-minute basis, Grid Operations has established an operational goal of utilizing a load bias in the RTMA software no more than 40 percent of all 5-munite intervals. As shown in Figure 3.27, while the type of load bias has varied significantly from month to month in response to system conditions, Operations staff have utilized the load bias in no more than about 40 percent of the intervals within each month of 2005 except for January. This represents a dramatic reduction following the first four months under RTMA (October 2004 - January 2005).[10]

Operations staff have indicated that the load bias is utilized primarily to decrease the usage of upward and downward regulation energy, or the deviation of units providing regulation from their Preferred Operating Point (POP). During ramping intervals when such sudden changes in system imbalances in a specific direction are anticipated, Operations staff have also indicated that the bias may be utilized to cause usage of regulation resources to deviate somewhat from POP in the opposite direction of the anticipated change in the system imbalance, so that the range of regulation capacity available to respond to the anticipated change is increased.

Under the approach described by Operations staff, the load bias is used to help preserve regulation capacity for use in responding to sudden system imbalances, rather than a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices. Analysis of load bias usage patterns by DMM also indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity.

[9] In many – if not most – of these situations, use of the load bias would be expected to reduce the overall system level deviation of regulation resources from their Preferred Operating Point (POP) during the same interval which the load bias was applied. However, in some cases, the load bias may be utilized to reduce anticipated regulation deviation in future intervals, rather than in the current interval.

[10] Actual load bias data are not available for the first month of RTMA (October 2004).

Figure 3.27 Utilization of Load Bias by Month (Percent of Intervals)

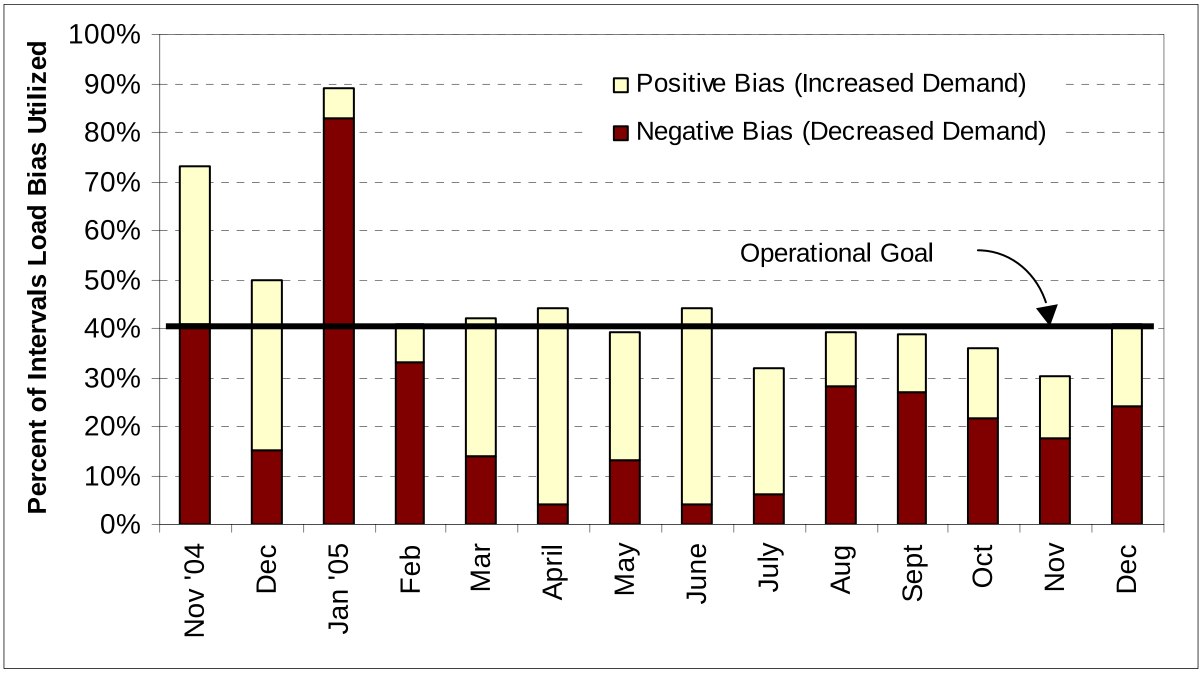
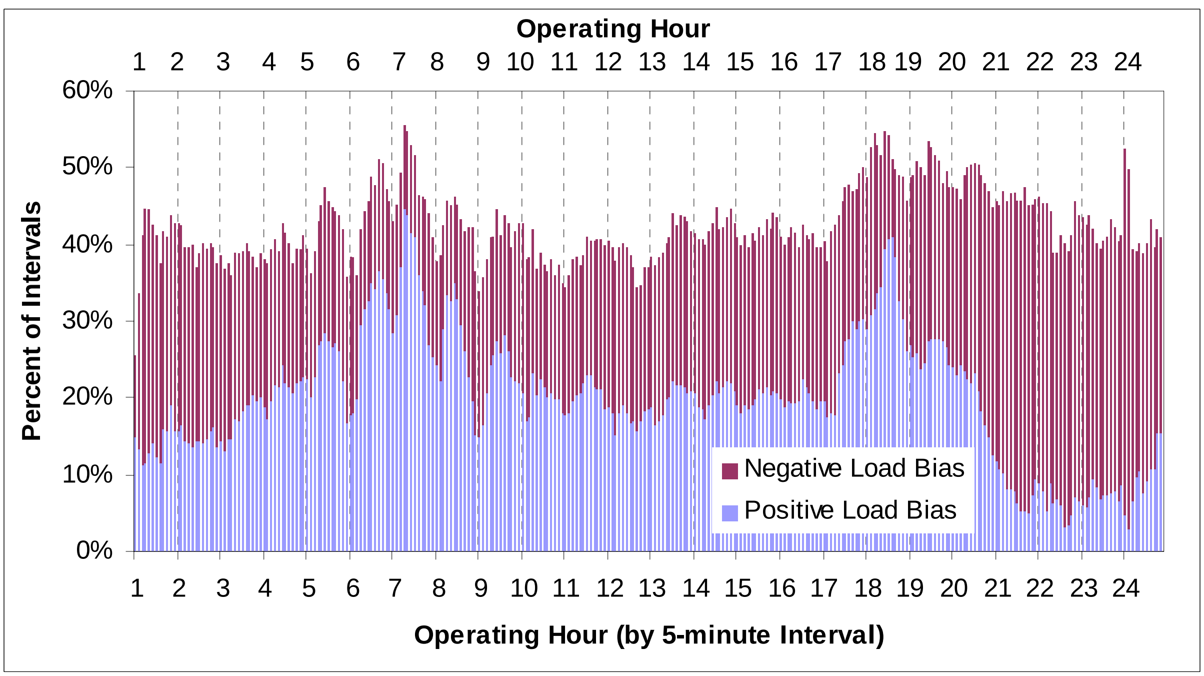


Figure 3.28 Utilization of Load Bias by Hour and Interval (2005)



Usage of the load bias is also relatively balanced across hours of the day, with usage reaching no more than about 50 percent during the morning and evening ramping hours, compared to no less than about 35 percent during other hours, as depicted in Figure 3.28. The load bias tends to be positive during the morning ramping hours (HE 6-8) and the peak evening hours (HE 17-18). During these hours, a positive load bias would tend to cause RTMA to increase dispatches of incremental energy, and thereby increase upward ramping capability of regulation resources by reducing usage of upward regulation or increasing usage of downward regulation. Conversely, as shown in Figure 3.28, load bias tends to be negative during the late evening ramping hours (HE 21-24). During these hours, a negative load bias would tend to cause RTMA to increase dispatches of decremental energy, and thereby increase downward ramping capability of regulation capacity by reducing usage of downward regulation or increasing usage of upward regulation.

More detailed analysis of the usage and impact of RTMA load bias was also performed by examining the load bias together with regulation usage on an interval-by-interval basis for the calendar year 2005. For this analysis, the impact of the load bias on regulation usage was approximated by calculating, for each interval, a counterfactual regulation deviation from POP that may have occurred if load bias had not been used. Specifically, it was assumed that each MW of load bias entered in an interval had a direct one-for-one impact on the amount of instructed energy dispatched through RTMA and, in turn, on regulation usage. For example, if a 100 MW positive load bias was entered during an interval when the actual regulation deviation was +150 MW, it is assumed that in the absence of the 100 MW positive load bias, 100 MW less of instructed energy would have been dispatched and the regulation deviation would have totaled +250 MW.[11] Summary results of this analysis are shown in Table 3.2, Figure 3.29, and Figure 3.30.

As shown in Table 3.2 and Figure 3.29, the actual average regulation deviation during the 44 percent of intervals when a positive or negative load bias was utilized (-16 and –51 MW, respectively) was relatively close to the actual average regulation deviation during the 58 percent of intervals when no load bias was utilized (-28 MW). However, if no load bias had been utilized during the 20 percent of intervals when a positive load bias was used, the average regulation deviation may have been as high as 229 MW. Similarly, if no load bias had been utilized during the 22 percent of intervals when a negative load bias was used, the average regulation deviation may have been as much as -255 MW.

[11] The general equation used to calculate the counterfactual regulation deviation each interval *t* is $Dev'_t = Dev_t + Bias_t$ The change in the absolute value of the regulation deviation from POP can then be calculated as Δ Abs (Dev_t) = $Abs(Dev_t) - Abs(Dev'_t)$.

Table 3.2 Estimated Impact of Load Bias on Regulation Energy Usage and Regulation Deviation from POP (2005)

	Type of Load Bias		
	Positive	Negative	None
Percent of 10-minute Intervals	20%	22%	58%
Average Load Bias (MW)	229	-255	0
Average Regulation Deviation (MW)	-16	-51	-28
Average Regulation Deviation (MW) Without Bias	212	-306	-28
Average Absolute Deviation (MW) from POP	126	127	120
Average Absolute Deviation (MW) from POP Without Bias	234	316	N/A
Average Decrease in Absolute Deviation (MW) from POP due to Bias	108	189	N/A
Instructed Energy Dispatches during Interval			
Incremental Only	5%	4%	5%
Decremental Only	12%	7%	9%
Both - Net Incremental	43%	38%	39%
Both - Net Decremental	38%	51%	46%
Average Instructed Incremental Energy (MW)	307	280	282
Average Instructed Decremental Energy (MW)	-297	-352	-324

Figure 3.29 Potential Impact of Load Bias on Regulation Energy Usage (2005)

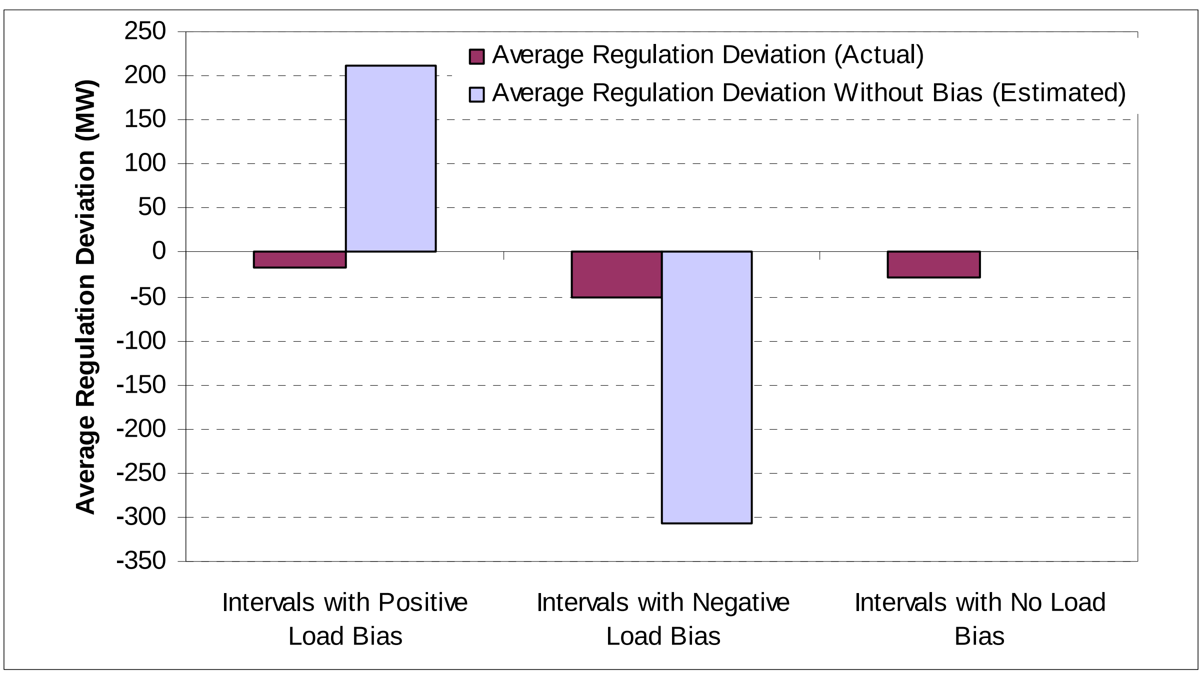


Figure 3.30 Potential Impact of Load Bias on Regulation Deviation from POP (January – December 2005)

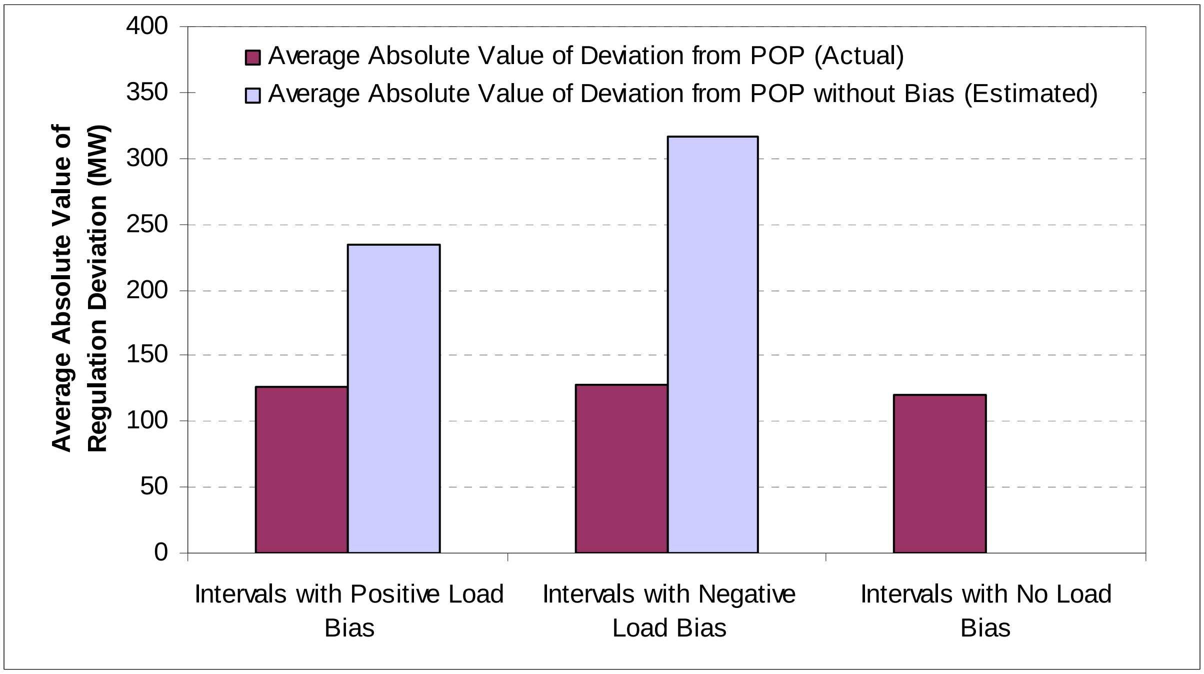


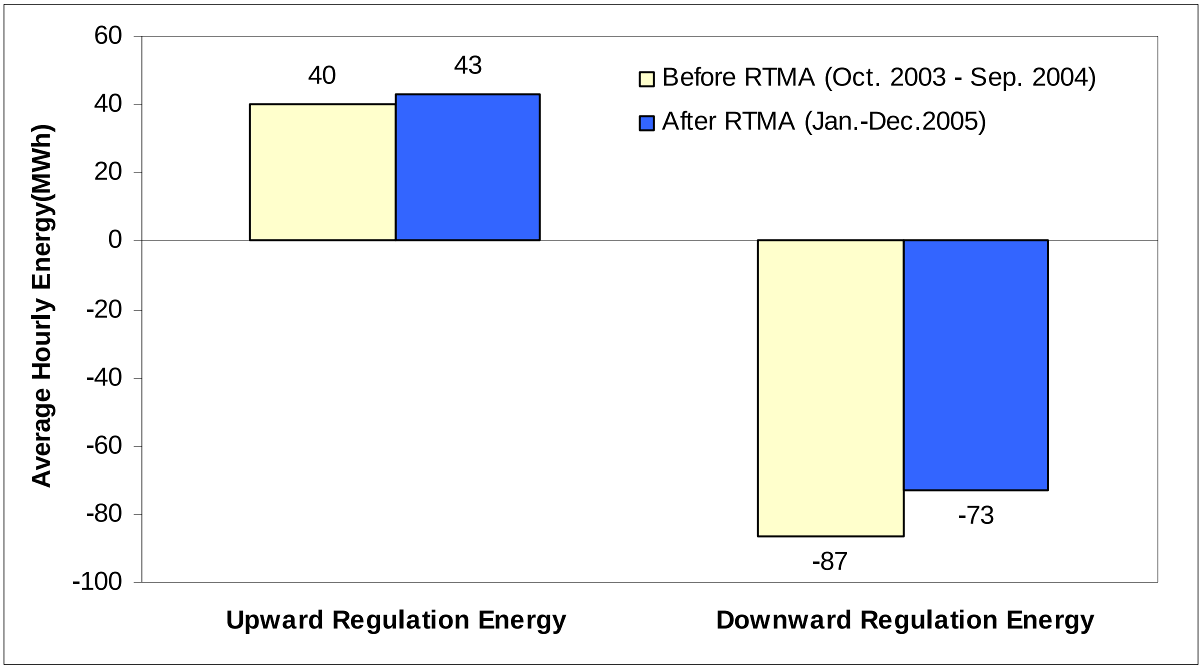
Table 3.2 and Figure 3.30 show a similar comparison of the absolute value of the actual regulation deviation from POP during these different intervals, along with the potential impact of the load bias in terms of decreasing the absolute regulation deviation from POP. Again, results suggest that the load bias was utilized in both the positive and negative direction to reduce the regulation deviation from POP during intervals when the average regulation deviation would have otherwise been relatively high as compared to intervals when no bias was used.

Examination of trends in instructed energy dispatches provides further indications that the load bias was used to manage regulation deviations, rather than as a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices. If the load bias has been utilized to smooth prices by reducing RTMA dispatches, a positive load bias would tend to be used in intervals when RTMA was primarily decrementing generation, while a negative load bias would tend to be used in intervals when RTMA was primarily incrementing.[12] However, as shown in the bottom section of Table 3.2, no significant difference appears in the pattern of incremental and decremental energy dispatches between intervals when a load bias was used and no load bias was used.

While the load bias appears to have been used to decrease the usage of regulation capacity relative to levels that would have occurred under RTMA absent any load adjustments by operators, the overall usage of regulation in 2005 has not changed significantly in 2005 relative to the twelve month period prior to implementation of RTMA (October 2003-September 2004). As shown in Figure 3.31, average usage of upward regulation increased from about 40 MWh to 43 MWh, while usage of downward regulation dropped from about -87 MWh to -73 MWh in 2005.

[12] For example, during intervals when RTMA was incrementing generation, a negative load bias would reduce incremental instructed energy dispatches (and thereby reduce real price increases), and increase use of upward regulation in place of instructed incremental generation.

Figure 3.31 Change in Regulation Usage Since Implementation of RTMA



3.3.5 Uninstructed Deviations

3.3.5.1 Background

The Uninstructed Deviation Penalty (UDP) was a feature incorporated into MRTU Phase 1b[13] market design that was designed to provide an incentive for resources to follow their schedules and CAISO dispatch instructions. For generating units in the CAISO control area, UDP was to only apply to generating units with Participating Generator agreements with the CAISO. Some participating generating units were to be exempt from UDP, such as generating units required to run by environmental constraints, certain intermittent renewable resources, certain Qualifying Facilities, Condition 2 Reliability Must Run units, and generating units that are part of a load-following Metered Subsystem. UDP was also to apply to dynamically scheduled generating units located outside of the CAISO Control Area, and to non-dynamically scheduled imports to the extent Supplemental Energy dispatches made 40 minutes prior to the operating hour were declined.

For units subject to UDP, penalties would only apply to generator deviations that were above or below a deadband equal to the greater of 5 MW or 3 percent of a unit's maximum output level. For generation in excess of a resource's dispatch instructions[14] plus the aforementioned deadband, the planned UDP charge was to be the level of the deviation multiplied by 100 percent of the corresponding applicable market clearing price. Thus, this charge was designed to essentially offset the revenues earned from this uninstructed energy, so that no net payment was received for excess generation. For resources generating less than their dispatch instruction less the aforementioned deadband, the planned UDP charge was to be equal to the energy quantity of the deviation multiplied by 50 percent of the corresponding applicable market clearing price for under-generation. In this situation, the charge was designed so that generators paid a total of about 150 percent of the real-time market price for any scheduled or dispatched energy that was not generated.

When MTRU Phase 1b was implemented on October 1, 2004, UDP was planned to be implemented as a component of Phase 1b after an initial two-month grace period, during which the CAISO would provide market participants with the results of its UDP calculations, but would not actually charge the penalty. Compliance with dispatch instructions was thought to be particularly important under Phase 1b, because, in addition to previously existing concerns about the effect of uninstructed deviations on control area operations, Phase 1b's RTMA system was anticipated to produce a greater quantity of dispatches than the previously existing BEEP system due to fact that RTMA clears all overlapping bids among suppliers (in addition to dispatching energy needed to meet CAISO imbalance energy needs).

The UDP grace period was extended past the initially planned two months while the CAISO resolved a variety of issues related to implementation of RTMA and UDP. In May 2005, the CAISO decided to indefinitely defer implementing UDP because experience gained during the UDP grace period showed that there was a reasonable potential that the existing design of UDP, coupled with the characteristics of the CAISO market systems, would make it impossible for market participants operating generating units to avoid UDP in certain situations despite their best efforts. These circumstances included the following:

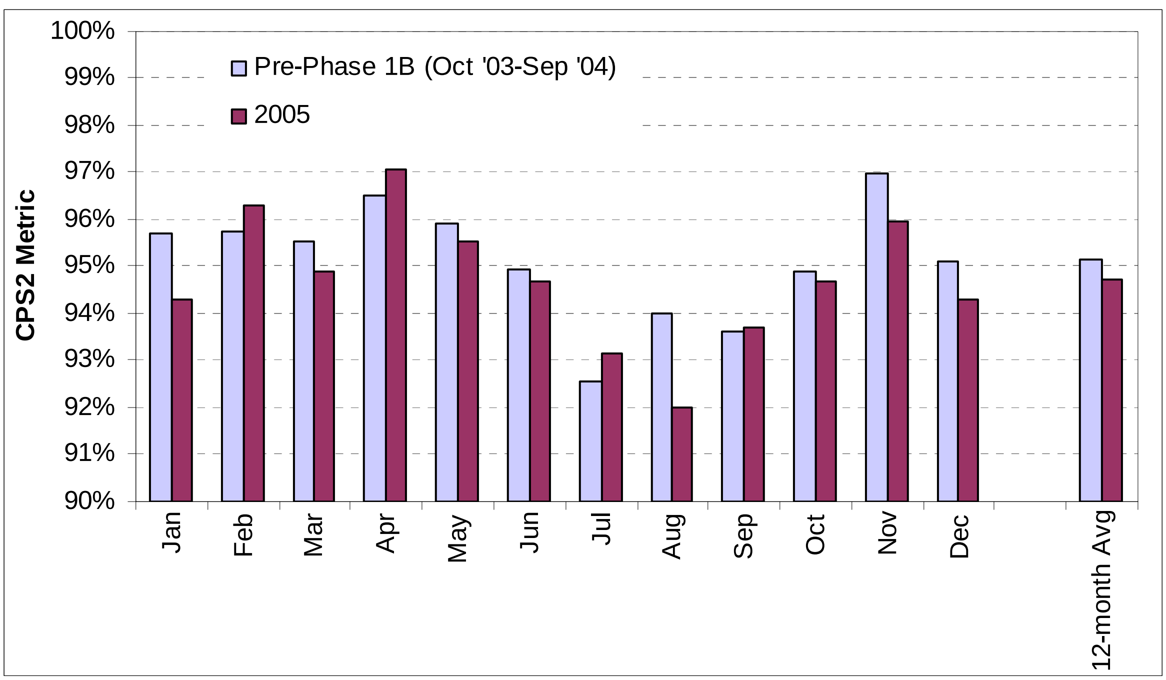
[13] "MRTU Phase 1b" refers to the October 1, 2004, implementation of RTMA and associated changes in market settlements, including UDP.

[14] CAISO dispatch instructions include dispatches to a resource's Final Hour-Ahead Schedule and dispatches for any Instructed Imbalance Energy.

- Many market participants maintained that dispatches generated by the RTMA system were difficult for generating units to follow because they were unpredictable and excessively volatile.
- RTMA dispatches do not accurately model the "steam inertia" characteristics of generating units when dispatch instructions reverse direction from the previous interval. This situation can result in generating units unavoidably deviating from dispatch instructions, often in excess of the UDP deadband.
- Many market participants maintained that reporting generating unit limitations in the CAISO outage reporting system was impractical to accomplish within a 30-minute timeframe that would be necessary to avoid UDP. These unit limitations include temporary changes to the unit's maximum or minimum output level, as well as other operating limitations such as the temporary inability of a combined cycle generating unit to begin ramping to greater output levels while the second stage of the unit is being brought into operation.

An additional factor considered in deferring implementation of UDP was that following implementation of Phase 1b, control area operations were reasonably stable without UDP, as indicated by control area performance metrics, including the CPS2 metric and the level of uninstructed deviation. For example, Figure 3.32 compares the CPS2 metric for Phase 1b operation in 2005 with the corresponding months from the 12-month period prior to Phase 1b. As shown in Figure 3.32, the monthly CPS2 metric shows no clear difference in CPS2 performance before and after Phase 1b's deployment.

Figure 3.32 Monthly CPS2 Metric



Another consideration in the decision to defer implementation of UDP was that the overall level and volatility of uninstructed deviations did not increase following implementation of Phase 1b and that implementing UDP would not significantly reduce any detrimental impacts that uninstructed deviation may have on system or market operations. The following sections of this report provide a quantitative analysis of actual trends and impacts of uninstructed deviations during 2005 – the first full calendar year since Phase 1b has been in effect – relative to a comparable time period immediately prior to implementation of Phase 1b in October 2004.

3.3.5.2 Methodology

This report examines trends in uninstructed deviations during 2005 based on three basic measures.

- *Volume of Uninstructed Deviations.* First, the total volume or magnitude of all uninstructed deviations on a system-wide level is important since this reflects the impact of uninstructed deviations on the overall quantity of incremental or decremental energy that the CAISO must dispatch to balance system loads and resources. For this analysis, the magnitude of system-level uninstructed deviations was measured by calculating the approximate net deviation in each 10-minute settlement interval of all generating units (including generating units not subject to UDP). For this analysis, the approximate deviation of each unit is first calculated for each interval. The net deviation on a system level of each interval is then calculated by summing up the approximate deviation of all generating units. This summation and netting of individual resource deviations reflects the fact that system and market operation are affected primarily by the net system-wide deviation, rather than deviations of individual resources. However, it is important to note that to the extent individual resource deviations create real-time congestion issues, individual resource deviations can be an operational concern as well.[15] Since the system level deviations can be either positive or negative each interval, the system level deviation each interval was converted to an absolute value for purposes of aggregating and comparing the magnitude of deviations over longer-term periods (e.g., by month).

- *Volatility of Uninstructed Deviations.* Second, the volatility of uninstructed deviations on a system-wide level from one interval to the next is also important since sudden and/or unpredictable changes in system level uninstructed deviations can have detrimental impacts on system and market operations. For this analysis, the volatility of uninstructed deviations was assessed based on the change in system level uninstructed deviations from each interval to the next. Again, since the system level deviations can be either positive or negative each interval, the change in system level deviation in each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month).

- *Potential Reduction in Uninstructed Deviations from Application of UDP Charges.* Finally, the potential reduction in the system level net deviation that may result if UDP charges were actually applied in the settlement process is examined. This analysis is based on the uninstructed energy quantities subject to UDP that are calculated by the CAISO as part of the participant advisory notices that continue to be made available to market participants as part of the advisory process developed for the initial UDP grace period. For this analysis, it is first assumed that during each interval each resource subject to UDP would reduce deviations to the deadband level at which no UDP charges would be

[15] This latter concern is one of the primary reasons the UDP design did not allow for netting of deviations across a market participant's entire portfolio and instead only allowed netting across generating units in very limited circumstances.

incurred. The system level net deviation was then recalculated each interval taking into account the assumed reduction in deviations by individual resources. It should be noted that this approach represents the upper bound of the potential reduction in the system level net deviation that result if UDP charges were applied, since it is not likely that all resources would be able to or would take action to modify their operations to eliminate UDP charges entirely.

For the first two analyses described above, uninstructed deviations is defined as the metered output of each generating unit, minus the unit's output due to scheduled generation and any instructed imbalance energy dispatches. This approach closely approximates how uninstructed energy is calculated for settlement purposes, but several adjustments were made in the calculation of instructed imbalance energy to account for differences and provide an equitable comparison between the Phase 1b and the pre-Phase 1b market designs and systems.[16] Units providing regulation were excluded from the analysis during the hours they were providing regulation since this energy is provided in response to CAISO operating instructions. As noted above, the analysis of the potential reduction in uninstructed deviations if the UDP were charged to participants is based on data calculated by the CAISO as part of the participant advisory notices sent as part of the advisory process developed for the initial UDP grace period.

The analysis includes only generating units located within the control area, which comprise more than 99 percent of the deviation subject to UDP. However, non-dynamically scheduled resources located outside the CAISO Control Area were not included because they are dispatched on an hourly basis and would not have deviations within the hour. Dynamically scheduled resources located outside the CAISO Control Area were not included because of difficulties reconciling naming conventions between the pre- and post-Phase 1b periods.

3.3.5.3 Results

Results of this analysis indicate that the volume and volatility of uninstructed deviations have not changed significantly in 2005 relative to the most recent comparable time period prior to implementation of Phase 1b, and that assessment of UDP charges may result in a relatively minor decrease in uninstructed deviations.

Figure 3.33 compares the magnitude of generating unit uninstructed deviations in January 2005 - December 2005 with the uninstructed deviations during the corresponding months from the 12-month period prior to Phase 1b (October 2003 - September 2004). Figure 3.33 also shows the percentage of settlement intervals in which the net system level deviation was positive (i.e., net generation exceeded the total amount of energy scheduled or dispatched from these units) during each of these months.

As shown Figure 3.33, the level of uninstructed deviation in 2005 has been relatively consistent with the level that existed prior to Phase 1b, with the net amount of uninstructed deviations averaging 384 MW in 2005 and averaging 368 MW in the 12 months prior to Phase 1b's implementation. These values were similar for both peak and off-peak periods in both 2005 and prior to Phase 1b. Both 2005 and the pre-Phase 1b period show a similar seasonal variation in

[16] The following items are dispatched as instructed imbalance energy by the Phase 1b systems but were <u>not</u> dispatched as instructed imbalance energy prior to Phase 1b: minimum load output during must-offer waiver denial periods; transmission loss self-provision; deviation from the standard 20-minute ramp during hourly schedule changes; and adjustments to output due to temporary limitations in a unit's minimum or maximum operating levels. These differences were accounted for by adding minimum load output to the instructed imbalance energy calculations for the pre-Phase 1b timeframe and subtracting transmission loss self-provision, ramping deviation, and adjustments to output due to temporary limitations from the instructed imbalance energy calculations for the Phase 1b timeframe.

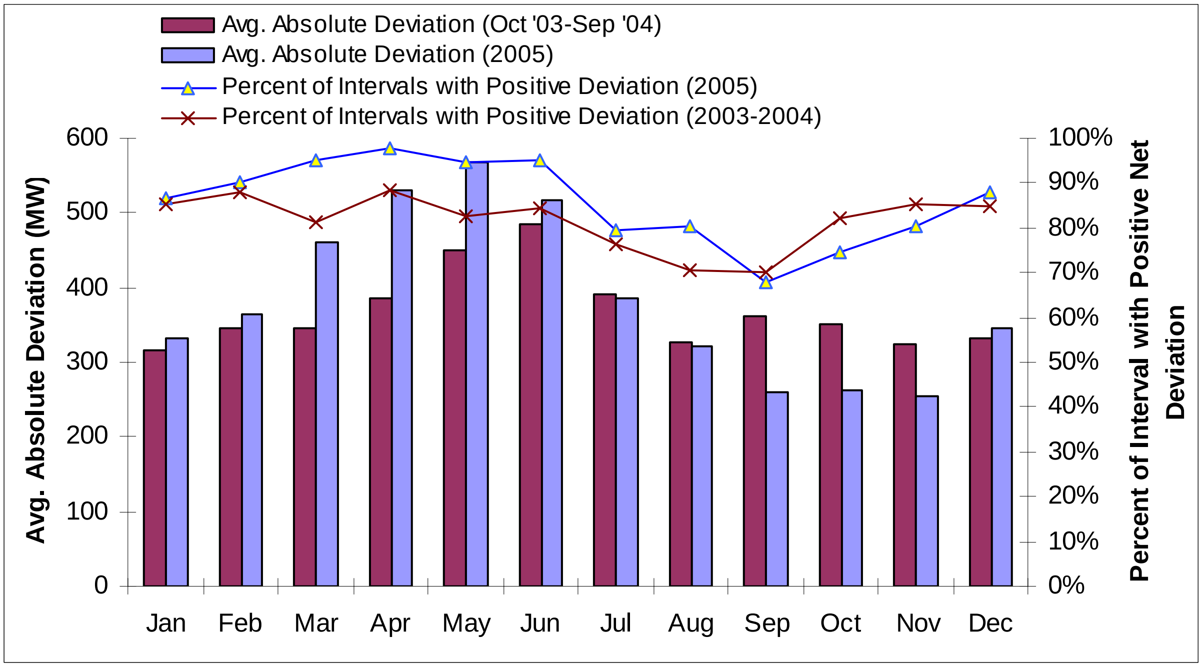
the magnitude of uninstructed deviation – relatively higher in the spring months and lower in the fall months. The higher deviation in the spring months is at least partially attributable to positive deviation of hydro units during the spring runoff period.

Figure 3.33 shows that in 2005, a relatively higher level of deviation existed in March - June, and a relatively lower level of deviation existed in September - November 2005, as compared to the corresponding months in the period before Phase 1b. These differences do not appear to represent any significant systematic deviations by any class of generating units, but rather appear to have resulted from the deviation of a limited number of generating units. For example, the relatively higher level of deviation seen in March - June 2005, compared to the corresponding pre-Phase 1b months, can be attributed to the deviation of a few large base-load non-gas-fired thermal and hydro generating units, as well as a number of Qualifying Facilities.

Figure 3.33 also shows that uninstructed deviations were predominately positive (i.e., generating more than schedule plus dispatch instructions) – the net deviation of generating units was positive in an average of 84 percent of settlement intervals throughout 2005 and the corresponding period prior to Phase 1b's implementation. This value was relatively consistent in the two periods. The prevalence of positive uninstructed deviation is likely explained by the fact that generating units are periodically operated without a schedule or dispatch instruction. This occurs when a generating unit owner does not shutdown a unit to avoid start-up/shutdown costs, if the operator anticipates the unit is to be needed again after a short period. Additionally, a number of units, such as hydro units and Qualifying Facilities must run unscheduled or above schedules due to environmental constraints or due to the nature of the energy source. This results in positive uninstructed deviation quantities that are relatively greater than the negative uninstructed deviation quantities resulting from units merely generating incrementally less than their scheduled or dispatched output level. Another contributor to net positive uninstructed deviation quantities is the generator output below a generator's minimum output level during start-up and shutdown periods, which is not dispatched as instructed imbalance energy.[17]

[17] Instructed imbalance energy is the incremental expected energy quantity corresponding to a CAISO dispatch to move a unit above or below its scheduled output level.

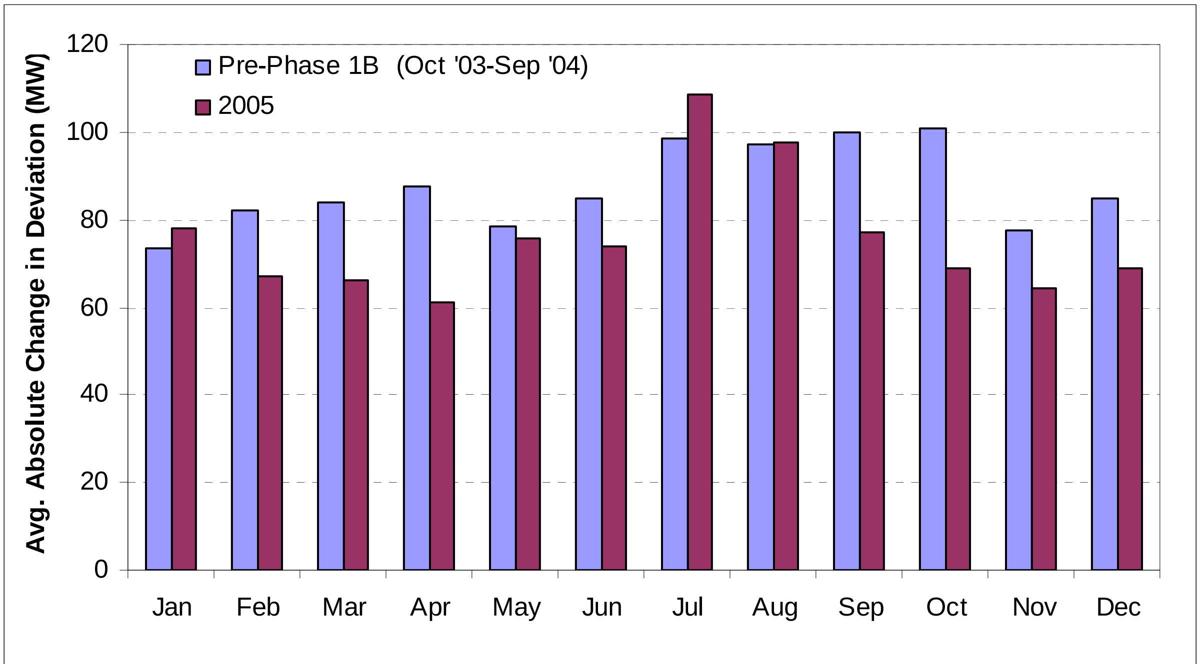
Figure 3.33 Average Absolute Value of Net Uninstructed Deviation (UD)



Market and control area operations are also affected by the settlement interval to settlement interval variation in the net amount of deviation. Figure 3.34 examines this variation, which is represented by the absolute value of the change in net generating unit deviations between 10-minute settlement intervals for January 2005 - December 2005 compared to the corresponding months from the 12-month period prior to Phase 1b (October 2003 - September 2004).

As Figure 3.34 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2005 has been relatively consistent with the level that existed prior to Phase 1b. The seasonal variation in the between-settlement interval net deviation change is similar in the two periods, as well as the average magnitude of the variation in the two periods, averaging 76 MW in 2005 and averaging 87 MW in the 12 months prior to Phase 1b implementation.

Figure 3.34 Average Change in Net Uninstructed Deviation between 5-Minute Dispatch Intervals



The degree to which uninstructed deviations could be reduced by assessment of UDP charges is limited by a variety of factors previously noted:

- Only deviations outside the UDP deadband (5 MW or 3 percent of a unit's maximum output level) are subject to UDP;
- A variety of generation resources and situations are exempt from UDP charges;[18] and
- Compliance with schedules and dispatch instructions may in some cases be infeasible for generators.

The upper range of the potential reduction in system level uninstructed deviations that might result from assessment of UDP charges was quantified for this report based on calculations done by the CAISO as part of the participant advisory process developed for the initial UDP grace period, as described above. Results of this analysis are provided in Figure 3.35, which shows the portion of aggregate net uninstructed deviations that might be reduced if each unit subject to UDP modified its operations to avoid all UDP charges.[19]

As Figure 3.35 shows, the reduction in net system level deviations due to such compliance by each unit subject to UDP averages only about 51 MW or about 16 percent of the average 313 MW net deviation in 2005.[20]

[18] UDP exemptions include deviation of individual units within generating units aggregated for UDP purposes as long as the net aggregate deviation is within the deadband, and exemptions for deviations during start-up/shutdown periods, outages, and other factors.

[19] Note that this calculation is an approximation that assumes that the direction (i.e., positive or negative) of the net deviation subject to UDP is in the same direction as the aggregate net system deviation.

[20] The 313 MW average net deviation is less than the 384 MW average net deviation presented in Figure 3.33 because the 313 MW value was calculated using the current Phase 1b definition of instructed imbalance energy.

Figure 3.35 Maximum Potential Reduction in Net Deviation if UDP Charges Were Assessed and Total Net Aggregate Deviation (2005)

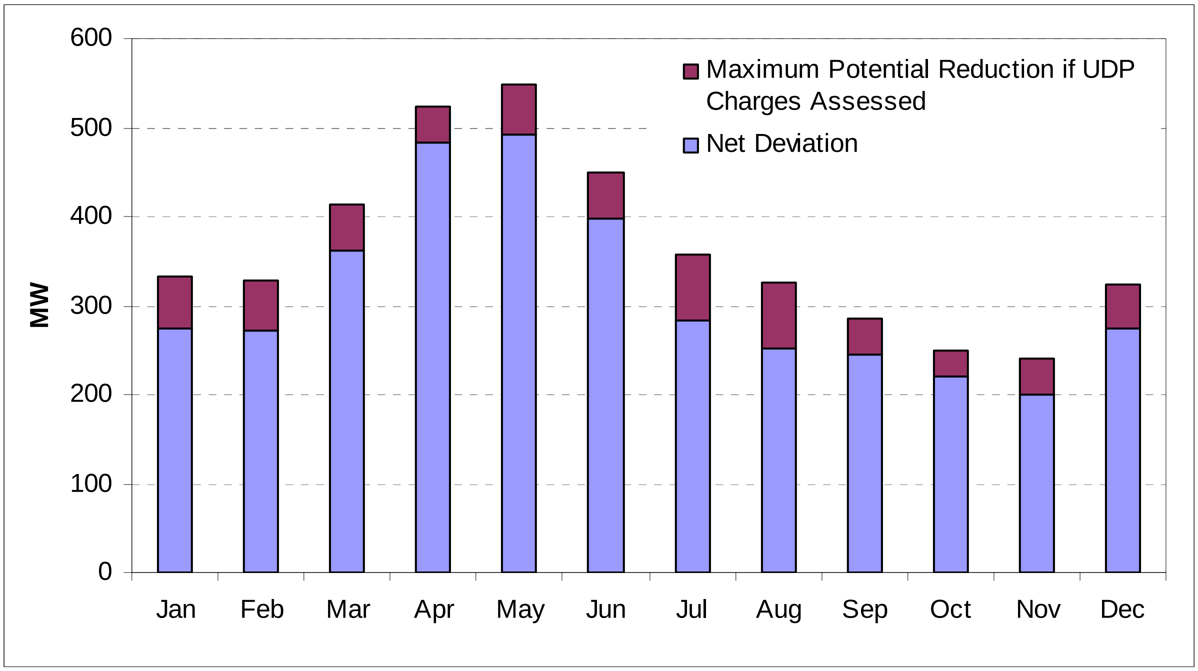
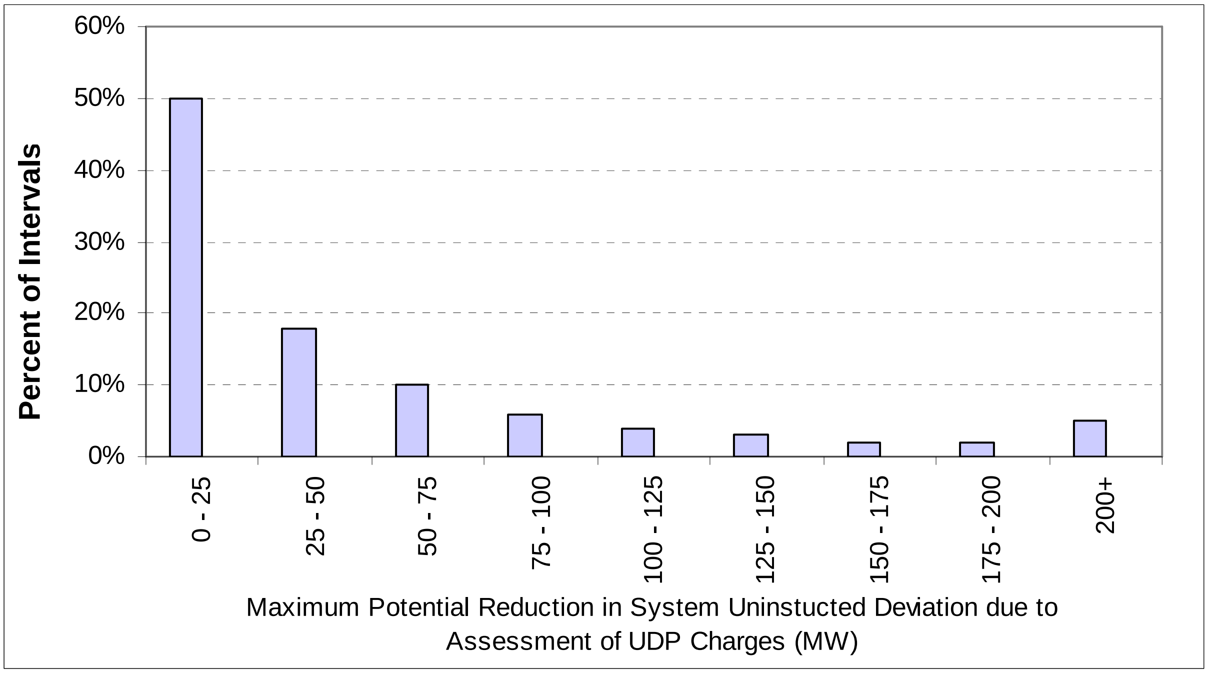


Figure 3.36 provides a histogram of the magnitude of the estimated maximum potential reduction in the net system deviation that might result from assessment of UDP charges on a 10-minute settlement interval basis. As Figure 3.36 shows, during about 50 percent of intervals this reduction would be 25 MW or less. The maximum potential reduction in net system deviation would be greater than 200 MW in only about 5 percent of intervals.

Figure 3.36 Maximum Potential Reduction in Net Aggregate Deviation if UDP Charges were Assessed (2005)



3.3.6 Summary and Conclusions

Much of the increase in price and dispatch volatility occurring since implementation of RTMA may be attributed to certain design features included in RTMA, which were developed to improve market efficiency. These include the following:

- **Real-Time Price Volatility and Fluctuations.** The volatility of 5-minute prices in the CAISO's Real Time Market (from one interval to another within each operating hour) has increased significantly since implementation of the RTMA software.
- **Volatility of Generating Unit Dispatches.** The volatility of individual generating unit dispatches in the CAISO's Real Time Market has also increased significantly since implementation of RTMA. This finding is consistent with feedback from several generation operators who have complained that their units are often "whipsawed", or dispatched in different directions excessively (i.e., dispatched up, then down and then back up, etc., within the same hour) under RTMA.
- **Regulation Capacity.** The overall amount of regulation capacity purchased and utilized by the CAISO does not appear to have been reduced since implementation of RTMA. While use of downward regulation capacity has decreased somewhat, use of upward regulation capacity has increased slightly. Thus, RTMA does not yet appear to have significantly reduced reliance on regulation energy to balance loads and resources.

- **Operator Bias of Load.** The performance of RTMA is also impacted by the frequency and magnitude of load bias that may be entered by Grid Operators (as an adjustment to RTMA's internally generated projections of imbalance energy requirements in subsequent intervals). The more the operator is able to rely on RTMA, the less manual bias may be needed. In order to encourage a balancing of the potential benefits of entering a load bias in RTMA with the goal of limiting reliance on this feature, Grid Operations has established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of dispatch intervals. The frequency with which a manual bias has been entered into RTMA (during an operating hour) has fluctuated just above or below the operational limit of 40 percent of the dispatch intervals. DMM analyses suggest that the load bias was utilized in both the positive and negative direction to reduce the regulation deviation from POP during intervals when the average regulation deviation would have otherwise been relatively high as compared to intervals when no bias was used. Furthermore, the load bias appears to be used to manage regulation deviations, rather than as a mechanism for "smoothing" out instructed energy dispatches issued through RTMA and the resulting market clearing prices.

- **System Reliability.** The primary metric used to measure CAISO system reliability – the Control Performance Standard 2 (CPS2) – shows no clear change in reliability performance since implementation of RTMA as compared to the period prior to RTMA. However, it should be noted that RTMA software includes a variety of features (such as 5-minute vs. 10-minute dispatch, increased automation, and forward-looking dispatch algorithms) that may facilitate and improve real-time operations in ways that may not be reflected in CPS2 metrics. Any operational benefits from these RTMA features may need to be assessed based on more qualitative input from Operations staff.

- **Prices for Pre-dispatched Imports/Exports and Real-Time Energy.** One indication that significant improvements have been made in RTMA since implementation of some enhancements to the software in late March 2005 is that prices for pre-dispatched energy from import/exports bids have tracked much more closely with Real Time Market prices set by internal resources dispatched within each operating hour.

- **Uplift Payments for Internal Resources.** One of the key features of RTMA not incorporated in the previous Real Time Market software is that RTMA dispatches units based on anticipated system conditions and resource ramping constraints over a two-hour "look-ahead" period. Bids from internal resources dispatched in one interval to meet expected needs in future intervals do not set the Market-Clearing Price (MCP) for that interval, but are paid the real-time MCP for each interval and are eligible for bid cost recovery over the entire operating day. Over the first 10-months of RTMA (October 2004 - July 2005), about 9.5 percent of total incremental energy and 5 percent of decremental energy from units within the CAISO system were eligible for uplift payments. Total uplift payments actually paid for both incremental and decremental energy, after netting of market revenues over the operating day, have been about $8.6 million over the ten-month period of October 2004 - July 2005, or only about 1.2 percent of total transactions costs for instructed incremental and decremental energy for units within the CAISO system.

Much of the increase in price and dispatch volatility occurring since implementation of RTMA may be attributed to certain design features included in RTMA, which were developed to improve market efficiency:

- **Increased Reliance on Market Energy Bids versus Regulation.** RTMA is specifically designed to increase reliance on Real Time Market energy bids to follow short-term fluctuations in demand, which may otherwise be met by the use of regulation energy. During many periods, however, the supply of highly flexible, fast-ramping resources offered into the real-time market has been limited, so that increased reliance on bids necessarily results in higher price volatility. This is particularly true during the morning and evening ramping periods, when prices have been most volatile.

- **Prices Set by Marginal Bids Dispatched to Meet Imbalance Each Interval.** A second major market design change incorporated into the RTMA software was that prices under RTMA are set based on the bid of the marginal resource dispatched to meet demand within each interval, and that prices are not set by bids that may have been dispatched to meet demand in future or previous intervals (but are "constrained on" in an interval due to ramping constraints or minimum operating times, etc.) Prior to RTMA, the real-time MCP could be "stuck" for multiple intervals by a high bid that was dispatched in a previous interval, but was no longer indicative of the marginal unit dispatched in subsequent intervals. RTMA was specifically designed to eliminate the "stuck price" issue that existed in the prior BEEP software. This feature of RTMA may tend to lower overall real-time prices, but would also tend to increase price volatility.

- **Market Clearing of Incremental and Decremental Bids.** A third major market design change incorporated into the RTMA software was the economic dispatch or market clearing of all incremental and decremental bids for supplemental energy. Rather than simply dispatching the bids necessary to meet the projected imbalance of the CAISO system, RTMA dispatches all remaining incremental and decremental bids for supplemental energy with "overlapping" prices (i.e., incremental bids offered at a price lower than the price of decremental energy bids submitted by other participants). This feature was incorporated into RTMA to allow greater overall market efficiency, and to encourage participants to submit increased volumes of incremental and decremental bids. However, this feature of RTMA may also contribute to the increased volatility of dispatches and prices relative to the previous BEEP software.

- **Elimination of Target Price Mechanism.** Some of the increase in price volatility may also be attributable to the fact that the volatility of real-time prices prior to RTMA were often muted by the "Target Price" mechanism incorporated in the previous BEEP software. The clearing of incremental and decremental energy bids eliminated the need to rely on the "Target Price" mechanism, which had the effect of "flattening out" prices over portions of the real-time energy bid stack, and was criticized for making market prices less responsive to actual bid prices. Prior to implementation of RTMA, 10-minute real prices cleared at the Target Price for each hour in about 18 percent of all intervals. Under RTMA, prices during intervals when the Target Price would have previously set the price are now set by bids for incremental and decremental energy.

A real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on nearly an instantaneous basis. Therefore, a high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids. Results from this analysis indicate that:

- Although RTMA has increased the volatility of prices and dispatches within each operating hour, this appears to be primarily the result of various features of RTMA designed to increase the responsiveness of prices and dispatches to system imbalance conditions in each 5-minute interval. Upon close examination, the fluctuations in prices and dispatches under RTMA closely mirror actual system imbalance conditions.
- Performance of RTMA seems to have improved since it was implemented on October 1, 2004, as numerous modifications have been made. For example, modification to the way RTMA projects uninstructed deviations dramatically improved convergence of prices for pre-dispatched bids on inter-ties and the Real Time Market price set by resources dispatched within the CAISO system during each hour.

4. Ancillary Service Markets

4.1 Summary of Performance in 2005

Overall, average Ancillary Service (A/S) prices increased by 23 percent in 2005 compared to prevailing prices in 2004. This price increase resulted in an increase to the total cost of A/S procurement of 24 percent. The increase in the aggregate A/S price resulted primarily from price increases in both the Regulation Reserve and Spinning Reserve markets, despite a drop in average price in the Non-Spinning Reserve market.

Two changes to the market structure that occurred in the latter half of 2004 that encouraged bidding from units committed under the Must-Offer Obligation (MOO) process and provided for zonal procurement of services, do not appear to have provided sustained benefits in terms of increased offers from units denied MOO waivers. While the CAISO does observe some bidding into the A/S markets by units in receipt of a MOO Waiver Denial, such volumes have not proved as large as initially anticipated.

Despite limited offers from MOO Waiver Denial units, the A/S markets experienced a significant decline in both the volume and hours of bid insufficiency in 2005 compared to 2004. The majority of the decline in bid insufficiency in 2005 can be attributed to the fact that there was no zonal procurement in 2005. The zonal procurement of A/S in 2004, which occurred in the August-December 2004 timeframe, resulted in increased bid insufficiency in SP15, especially in the Regulation markets.

4.2 Ancillary Service Markets Background

The CAISO procures Regulation Reserve, Spinning Reserve and Non-Spinning Reserve in the Day Ahead and Hour Ahead Markets such that the total procurement volumes plus self-provision volumes meet or exceed the Western Electricity Coordinating Council's (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electricity Reliability Council (NERC) Control Performance Standards (CPS). The CAISO procures A/S at the lowest overall cost while maintaining the reliability of the system and the competitiveness of the markets. The Rational Buyer algorithm facilitates this procurement approach. The definitions for the actively procured A/S follow:

1. **Regulation Reserves**: Reserved capacity provided by generating resources that are running and synchronized with the CAISO controlled grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control (AGC) to allow continuous balance between generating resources and demand. The CAISO operates two distinct capacity markets for this service, upward and downward Regulation Reserve.
2. **Spinning Reserves**: Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. The CAISO needs Spinning Reserve to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.

3. **Non-Spinning Reserves**: Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Curtailable demand can also supply Non-Spinning Reserve provided that it is telemetered and capable of receiving dispatch instructions and performing accordingly within 10 minutes. The CAISO needs Non-Spinning Reserve to maintain system frequency stability during emergency conditions.

CAISO market participants can self-provide any or all of these A/S products, bid them into the CAISO markets, or purchase them from the CAISO. The CAISO procures two other ancillary services on a long-term basis: voltage support and black start. Reliability Must Run (RMR) contracts serve as the primary procurement vehicle for these services. Through the remainder of this chapter, the term “ancillary services” (A/S) will be used only to refer to the three reserved capacity products defined above.

Scheduling Coordinators (SCs) simultaneously submit bids to supply any or all three products to the CAISO, in conjunction with their preferred day-ahead and hour-ahead schedules. Submitted A/S bids must be associated with specific resources (system generating units, import interchange location, load, or curtailable export) and must contain a capacity component and an energy component. The CAISO selects resources to provide A/S capacity based only on their capacity bid prices and deliverability. Thereafter, the CAISO uses the energy bid prices to dispatch units to provide real-time energy.

4.3 Changes in Ancillary Service Market Structures

The latter half of 2004 held two significant changes in A/S market structure that persisted through 2005. The first of these was a change in the eligibility rules for MOO units that had been denied a waiver and required to run. The second was a change to improve A/S procurement by procuring A/S by zone (as opposed to system-wide) during hours where transmission capacity on certain internal interfaces was projected to be insufficient, during contingencies, to deliver energy from A/S procured in the north to load in the south.

4.3.1 Ancillary Services from Units Constrained-On via the Must-Offer Obligation

Generating units that were constrained-on by the MOO waiver denial process (Constrained-On units), prior to Amendment 60, rendered themselves ineligible for Minimum Load Cost Compensation (MLCC) if they sold A/S to the CAISO. The CAISO sought to increase offers from these units by allowing them to keep the MLCC payment even if they sold A/S. Improvements to the transmission system in 2005 ultimately led to a significant decrease in volumes of Constrained-On capacity and a corresponding decrease in the capacity offered into the A/S markets from these units. Specifically, the market rule change allowing Constrained-On units to not forfeit their MLCC payments if they were awarded ancillary services only increased the capacity bid to Day Ahead and Hour Ahead Spinning and Non-Spinning Reserve markets by about 2 percent in 2005, compared to 12 percent in 2004. Figure 4.1 displays the average gross capacity bids from these resources for 2005.

Figure 4.1 Hourly Average Gross Capacity Bid into Day Ahead and Hour Ahead Markets by Constrained-On Units

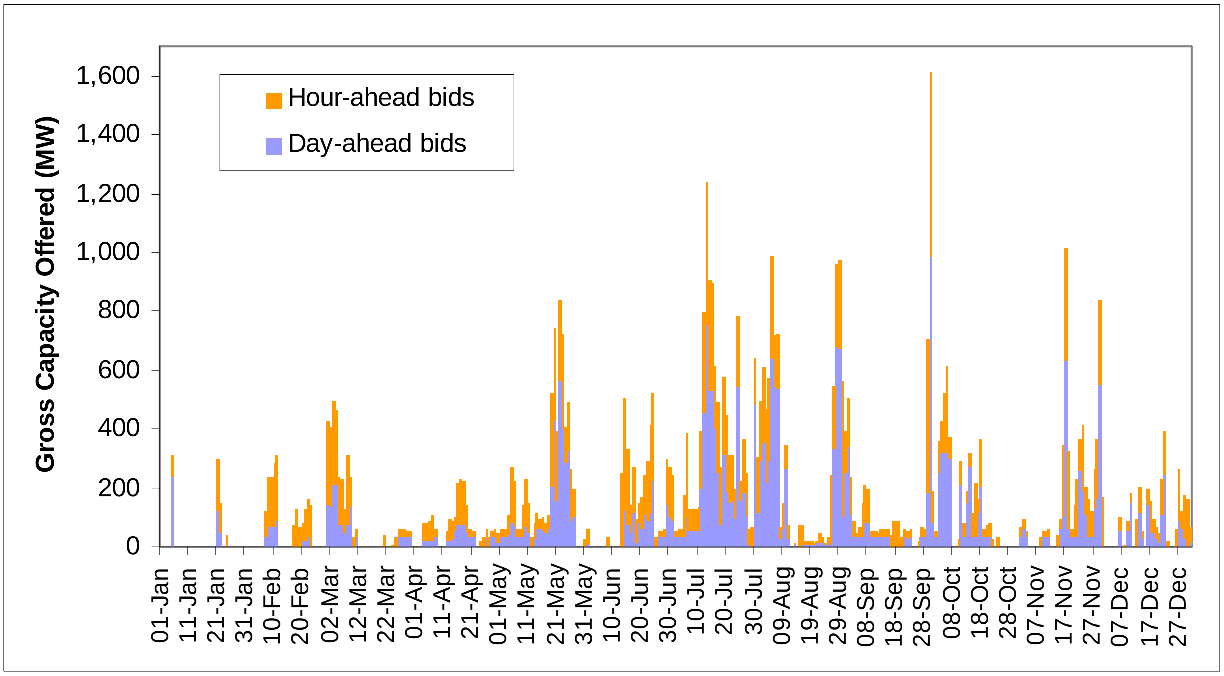
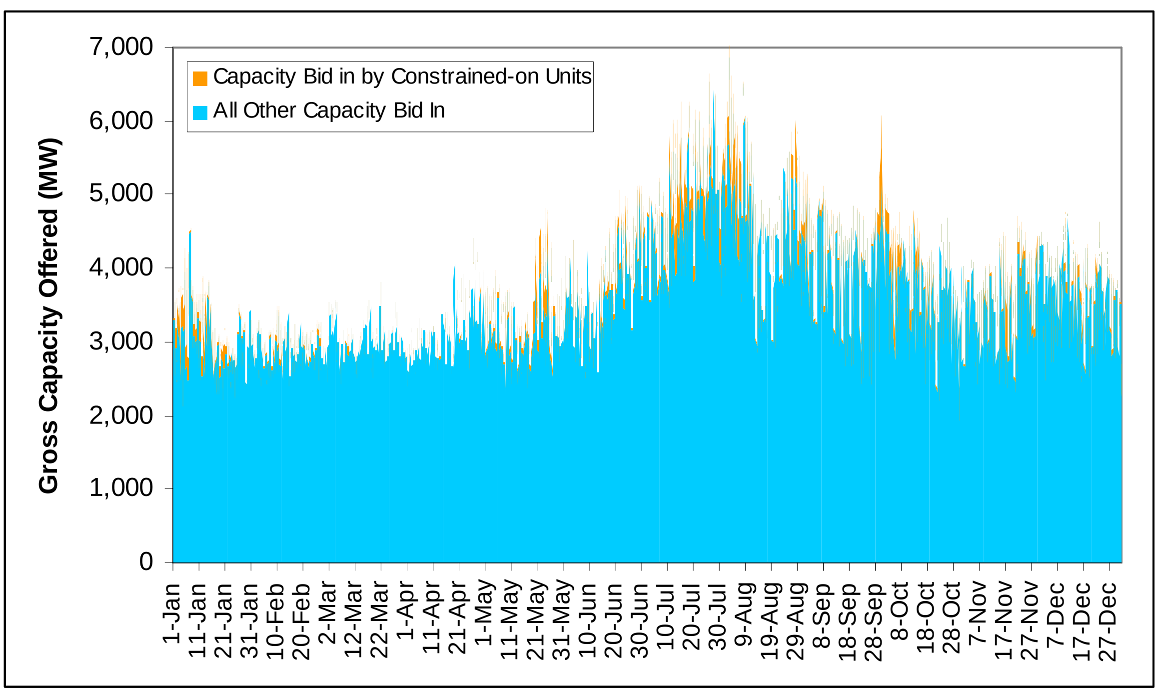


Figure 4.2 depicts the gross capacity bid from Constrained-On resources in relation to the remainder of the gross capacity bid into the day-ahead markets for 2005.

Figure 4.2 Incremental Ancillary Services Capacity Provided by Constrained-On Units in the Day Ahead Market



4.3.2 Assessment of Zonal Procurement

One major change in the ancillary services Markets in 2005 was the absence of any zonal procurement of A/S. During the period of August-December in 2004, the CAISO frequently procured A/S on a zonal basis and this practice resulted in a greater frequency of A/S bid insufficiency and higher prices in SP15. The absence of zonal procurement in 2005 resulted in much less bid insufficiency. This subsection briefly examines the effects of zonal procurement in 2004.

Traditionally, the CAISO procured A/S across the entire control area based on least cost. This approach was adequate when the availability of the services themselves was evenly distributed, and when there was sufficient reserve transfer capability between zones. In 2004, the CAISO began to notice that it procured most of its A/S from NP15 and less from SP15, the inverse of the load ratio between the two zones. There were a number of factors that contributed to this change:

- Increased energy imports from the southwest resulted in generators in SP15 staying off-line.
- In 2004, about 2,000 MW of additional RMR capacity was under Condition 2 of the contract, which limits participation in the A/S markets to only those hours that the unit is dispatched for RMR energy. This 2,000 MW of capacity represents about 300 MW of potential 10-minute reserve capacity that was often not bid into the A/S markets.
- More A/S capable units came online in NP15. This new A/S capability displaced the less efficient units in SP15, which had proportionally fewer A/S capable new units come online.
- Through the first half of 2004, market rules established that units Constrained-On under the Must-Offer Obligation were not able to bid into the A/S markets without jeopardizing their MLCC payments. This became a problem particularly in SP15. This was the zone with the most intra-zonal constraints (e.g., South-of-Lugo, Sylmar, SCIT). Generating units in the south were Constrained-On and prevented from bidding into the A/S markets, thereby thinning the A/S bid stack in that zone.

By the first quarter of 2004, the CAISO was procuring approximately 85 percent of A/S in NP15. The CAISO questioned the deliverability of these reserves and determined that such a least-cost procurement pattern was not giving enough emphasis to deliverability. Consequently, the CAISO embarked on a series of initiatives aimed at making the procured ancillary services inherently more deliverable by changing the procurement pattern, as well as trying to increase the volume of the bid stack, especially in the south. A more voluminous bid stack would, most likely, lower the overall cost of A/S, as well as ameliorate any market power concerns.

The CAISO had always retained the authority to split zones, but had ceased doing so in 2001. The CAISO began a dialogue with stakeholders in the spring of 2004 with the aim of explaining the issues to participants and seeking approval for its proposed zonal procurement solution. This solution allowed operators to forecast the flows on Path 26 to determine whether or not zonal procurement was necessary. The CAISO held stakeholder meetings, produced a white paper on zonal competitiveness, and solicited comments. The process resulted in a decision to go ahead with zonal procurement during times of insufficient transfer capability between Northern and Southern California and to dovetail the issue with the MLCC initiative mentioned below. On August 3, 2004 the CAISO reactivated the practice of splitting the procurement of ancillary services when necessary and procured reserves on a zonal basis during the period August-December 2004. Specifically, zonal procurement occurred on 45 days and in 422 hours between August 03, 2004 and December 02, 2004. The CAISO has not procured reserves on a zonal basis since that time.

The operating decision for splitting the A/S markets lay solely with the operating shift manager. This option for operating the A/S markets has always existed and continues as a critical option today with respect to reliability.[1]

Of the 45 days for which zonal procurement occurred, all but 7 days were weekdays and only 2 days were Sundays, i.e., entirely off-peak. On average, a split procurement day contained 9 split hours, which typically occurred between hours ending 11 and 20. Implementation of zonal procurement was split about evenly between the periods before and after Real-Time Market Application (RTMA) deployment. The pre-RTMA period had 24 A/S split days, while the post-RTMA period had 21.

A strong relationship exists between bid-insufficiency and zonal procurement of A/S. The number of shortage hours in a month corresponds well with the number of hours in a month having zonal procurement (Table 4.1).

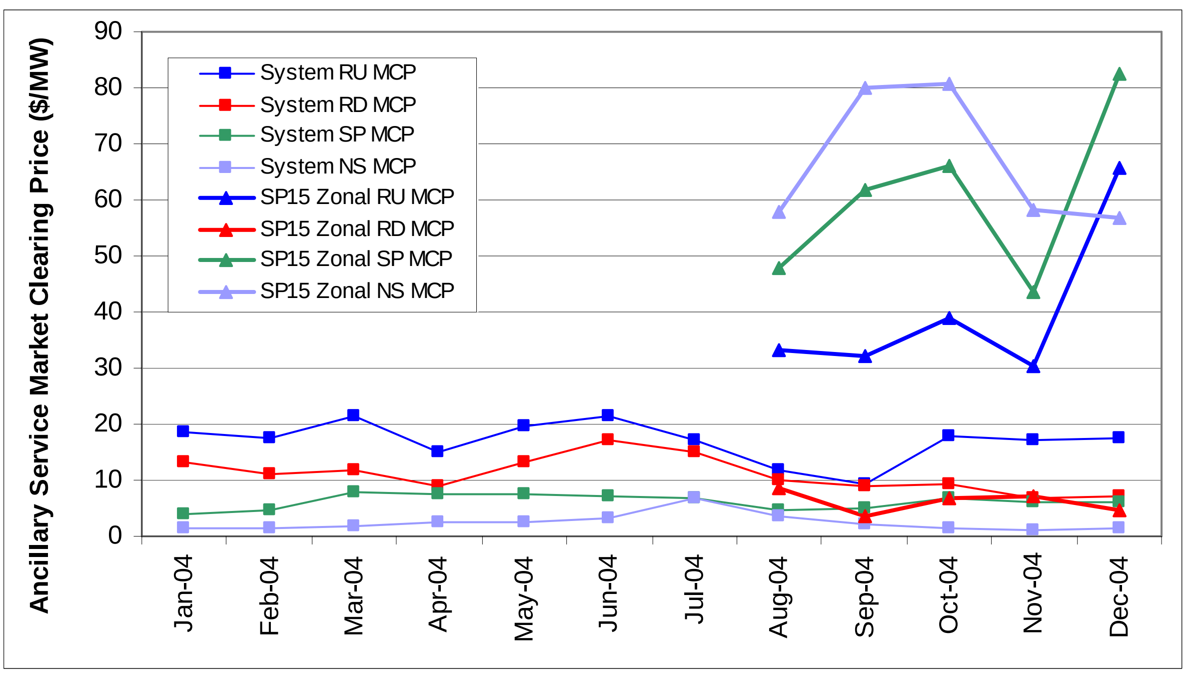
[1] The specific operating procedures used in determining the need for zonal A/S procurement are in Operating Procedure M-402, which can be found at http://www.caiso.com/docs/1998/12/02/1998120218202714536.pdf.

Table 4.1 Comparison of Split and Shortage Hours During the 2004 Zonal Procurement Period

Month	Number of Split Hours	Number of Hours Short
August	183	426
September	29	86
October	135	382
November	60	161
December	15	50

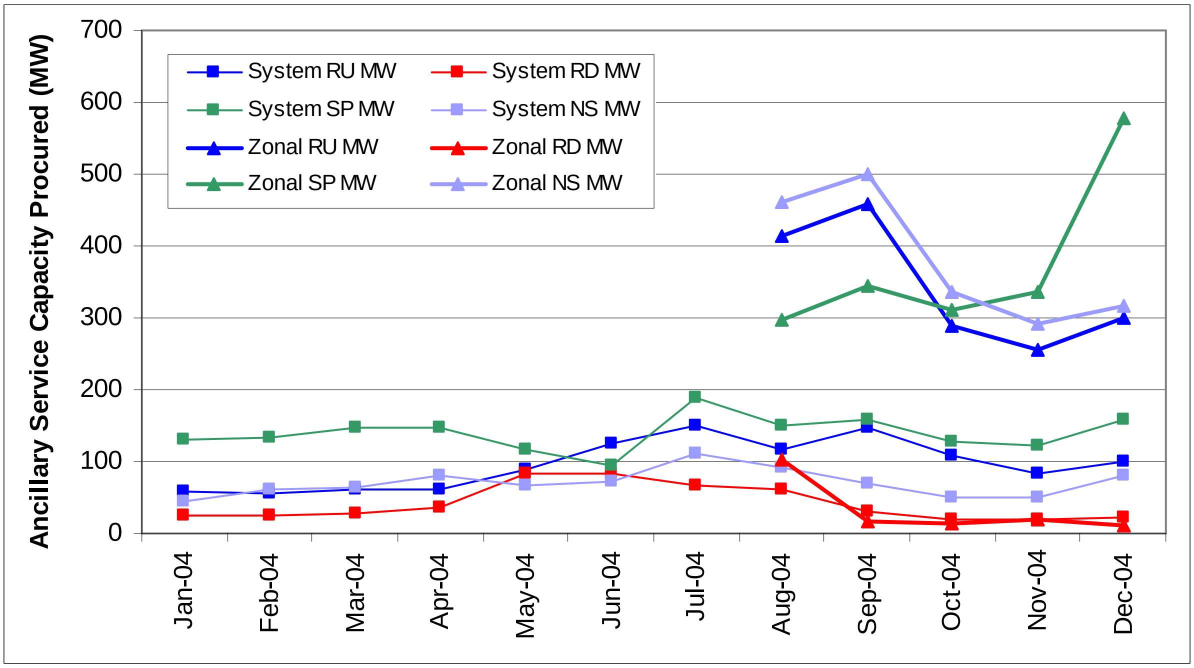
Figure 4.3 focuses on the price response to the zonal procurement practice. Comparing monthly average prices in SP15 across zonal and system procured hours during the August-December 2004 time frame shows that prices in SP15 for all the upward capacity products (Regulation-Up, Spinning and Non-Spinning Reserve) increased dramatically during hours where the markets were split. Regulation-Up increased about two-fold, while Spinning and Non-Spinning Reserves jumped up by factors of about 10 and 33, respectively. Interestingly, the average price of Regulation-Down moved slightly lower in hours of zonal procurement.

Figure 4.3 Comparison of 2004 DA A/S MCPs Under System and Zonal Procurement



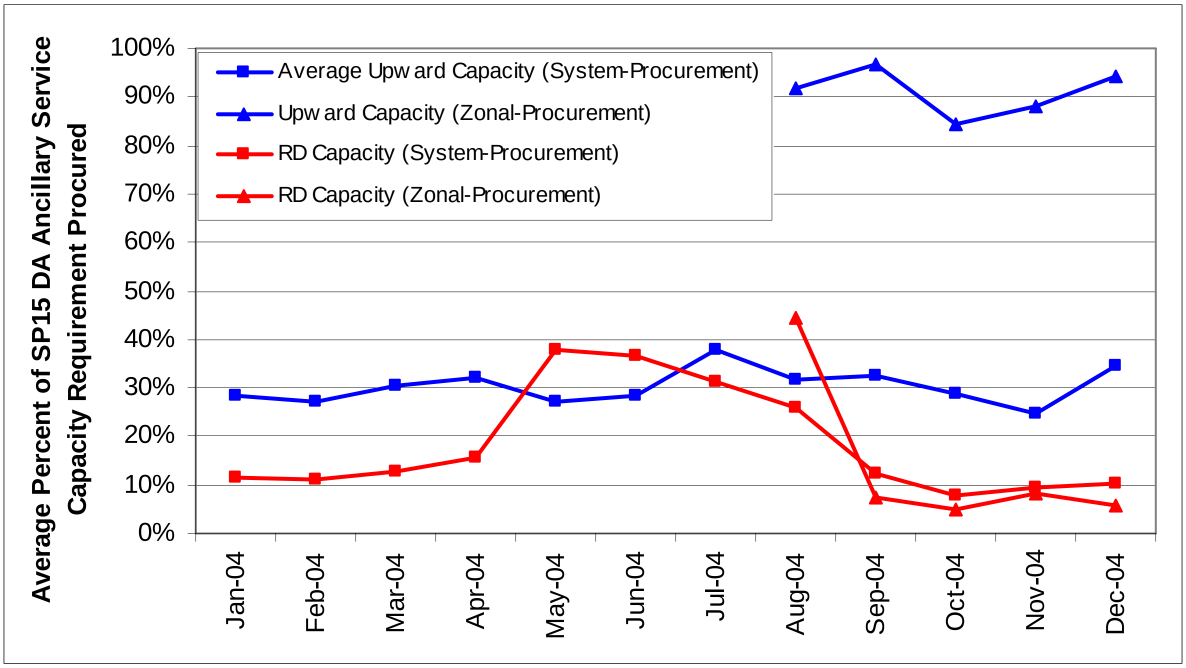
While these price increases under zonal procurement invoked some concern, procurement increases in SP15 accompanied the change. Regulation-Up procurement increased about two-fold, while Spinning and Non-Spinning Reserve procurement in SP15 increased by factors of about 1.5 and 4.5 respectively, as shown in Figure 4.4.

Figure 4.4 Comparison of 2004 Day-Ahead A/S Volumes in SP15 Under System and Zonal Procurement



Finally, an analysis of the Day Ahead Markets indicates that inter-temporal procurement patterns persist under zonal procurement. That is, operators require roughly the same levels of capacity in the Day Ahead Markets for both zonal and system procurement schemes. In fact, Regulation Reserve requirements remain virtually the same, while Operating Reserve requirements increase by less than 10 percent. Further, there was no shifting from day-ahead to hour-ahead procurement under zonal procurement. Figure 4.5 displays the ratios of procurement volumes to requirements for upward and downward capacity in SP15 on a system versus zonal basis. Here, the sum of Regulation-Up, Spinning and Non-Spinning Reserves comprise the measure of upward capacity procurement volumes and requirements. It is important to note that the comparison of system and zonal procurement shown in Figure 4.5 are not based on the same hours. Specifically, the average percent of requirement shown for the "system" procurement are for those hours that the CAISO was procuring A/S on a "system" basis. Similarly, the average percent of requirement shown for the "zonal" procurement are for those hours that the CAISO was procuring A/S on a "zonal" basis. During the August-December 2004 period, Figure 4.5 demonstrates that in hours of system A/S procurement the CAISO was only meeting, on average, 30 percent of its upward A/S requirements in SP15. In contrast, in hours when zonal procurement occurred, the CAISO was meeting approximately 90 percent of its upward A/S requirements in SP15. However, as seen in Figure 4.4 and Figure 4.5, while zonal procurement significantly increased the upward ancillary service procured in SP15 (i.e., Regulation-Up, Spinning and Non-Spinning Reserves) it did not increase Regulation-Down procurement, which had lowest percent of requirement value during the September through December period (Figure 4.5).

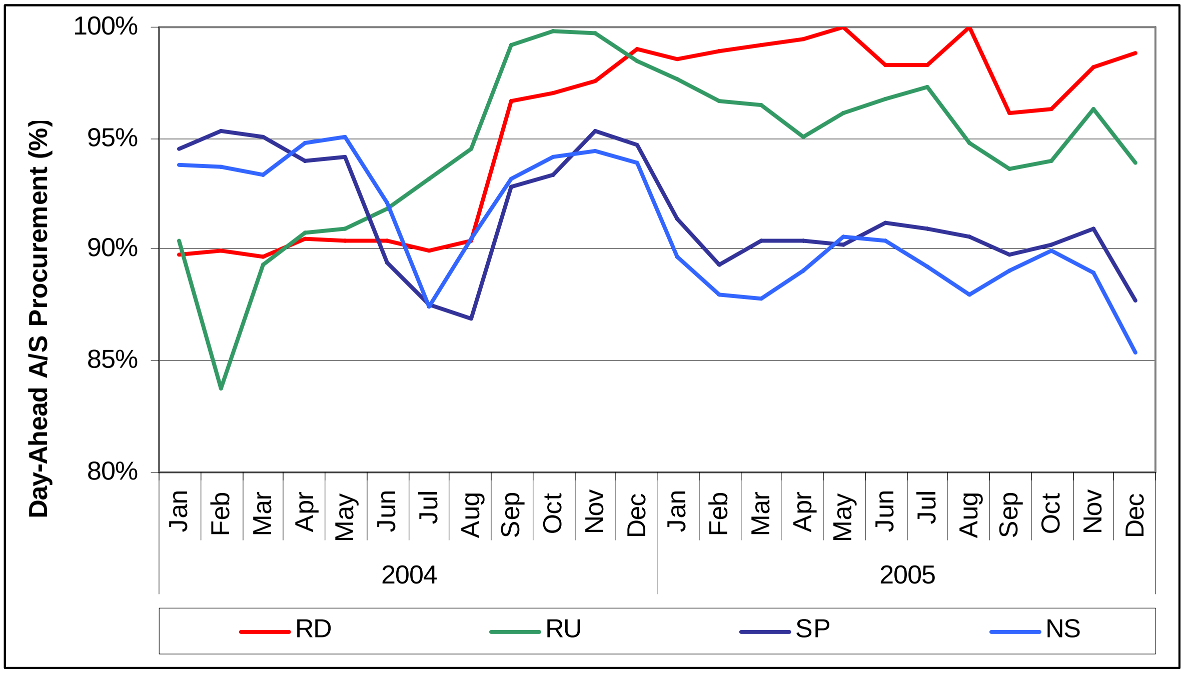
Figure 4.5 Comparison of 2004 DA Ancillary Service Capacity Volumes as Percent of Requirement for SP15: System versus Zonal Procurement



4.3.3 Day-Ahead versus Hour-Ahead Procurement

Historically, the CAISO has procured approximately 90 percent of capacity requirements in the Day Ahead Market. This practice allows operators to take advantage of better load forecasting as real-time approached and lower overall costs. Improvements to the transmission system between Northern and Southern California alleviated many of the reliability concerns that led to the practice of 100 percent day-ahead procurement in the 2004 operating year. While Regulation Reserve procurement patterns remain in the 95 to 100 percent range, Figure 4.6 depicts the general return to more traditional levels of day-ahead procurement.

Figure 4.6 Hourly Average Day-Ahead Procurement, 2004 - 2005



4.4 Prices and Volumes of Ancillary Services

4.4.1 Weighted Average Price Increase

Overall, A/S prices increased 23 percent from a weighted average price of $8.63 in 2004 to $10.72 in 2005. The overall price increase tracked increases of roughly 45 percent for both the Spinning Reserve and Downward Regulation components. Upward Regulation prices rose 17 percent, while Non-Spinning Reserve prices fell 10 percent.

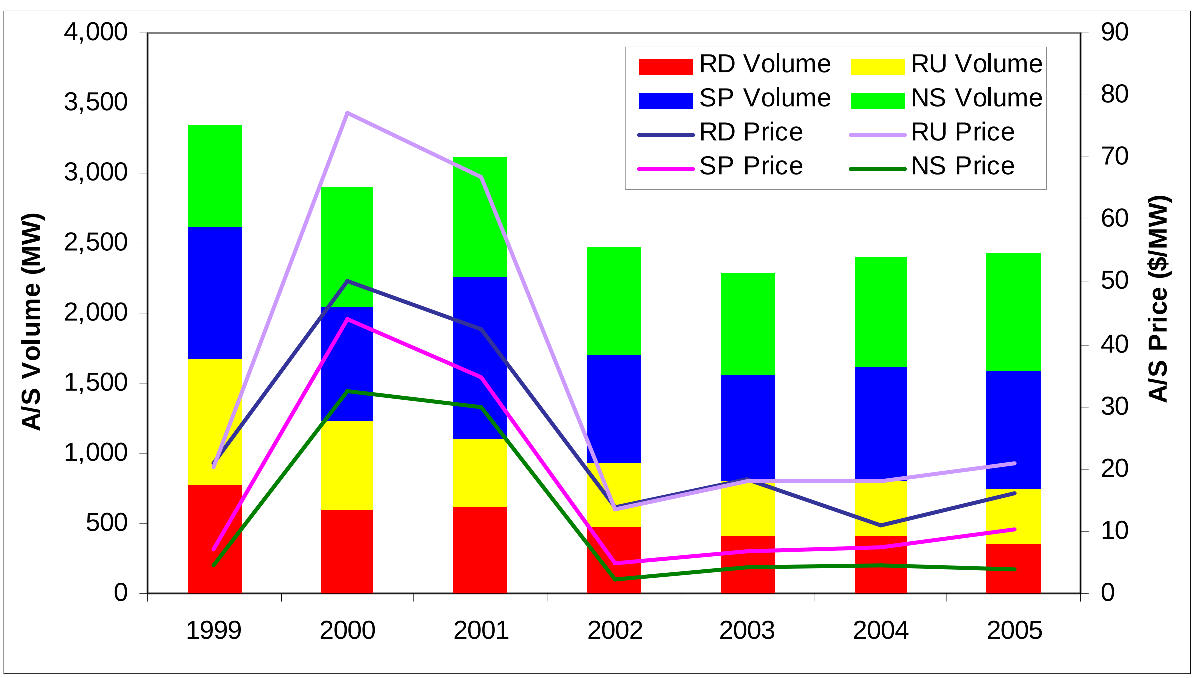
Procurement volumes, in total, were essentially unchanged from 2004. Changes to the mix of procured reserves were comprised of decreases to Regulation Reserve procurement and slight increases to Operating Reserve procurement. In particular, Upward and Downward Regulation procurement decreased by 2 and 11 percent, respectively, while Spinning Reserve and Non-Spinning Reserve rose 3 and 10 percent, respectively. Table 4.2 compares prices and volumes from past operating years.

Table 4.2 Annual A/S Prices and Volumes, 1999 – 2005

	Year	RD	RU	SP	NS	Average A/S Price
Price ($/MW)	1999	20.84	20.22	7.07	4.35	11.97
	2000	50.15	77.28	44.07	32.46	41.03
	2001	42.33	66.72	34.69	30.03	36.42
	2002	13.76	13.41	4.66	2.15	7.08
	2003	18.43	18.08	6.62	4.20	9.81
	2004	10.95	17.95	7.25	4.43	8.63
	2005	16.05	20.94	10.45	3.98	10.72
	Year	**RD**	**RU**	**SP**	**NS**	**Total Volume**
Volume (MW)	1999	769	903	942	735	3,687
	2000	594	633	818	861	3,479
	2001	614	492	1,148	862	3,420
	2002	469	460	775	763	2,524
	2003	416	381	767	722	2,309
	2004	408	395	817	782	2,427
	2005	363	386	841	839	2,428

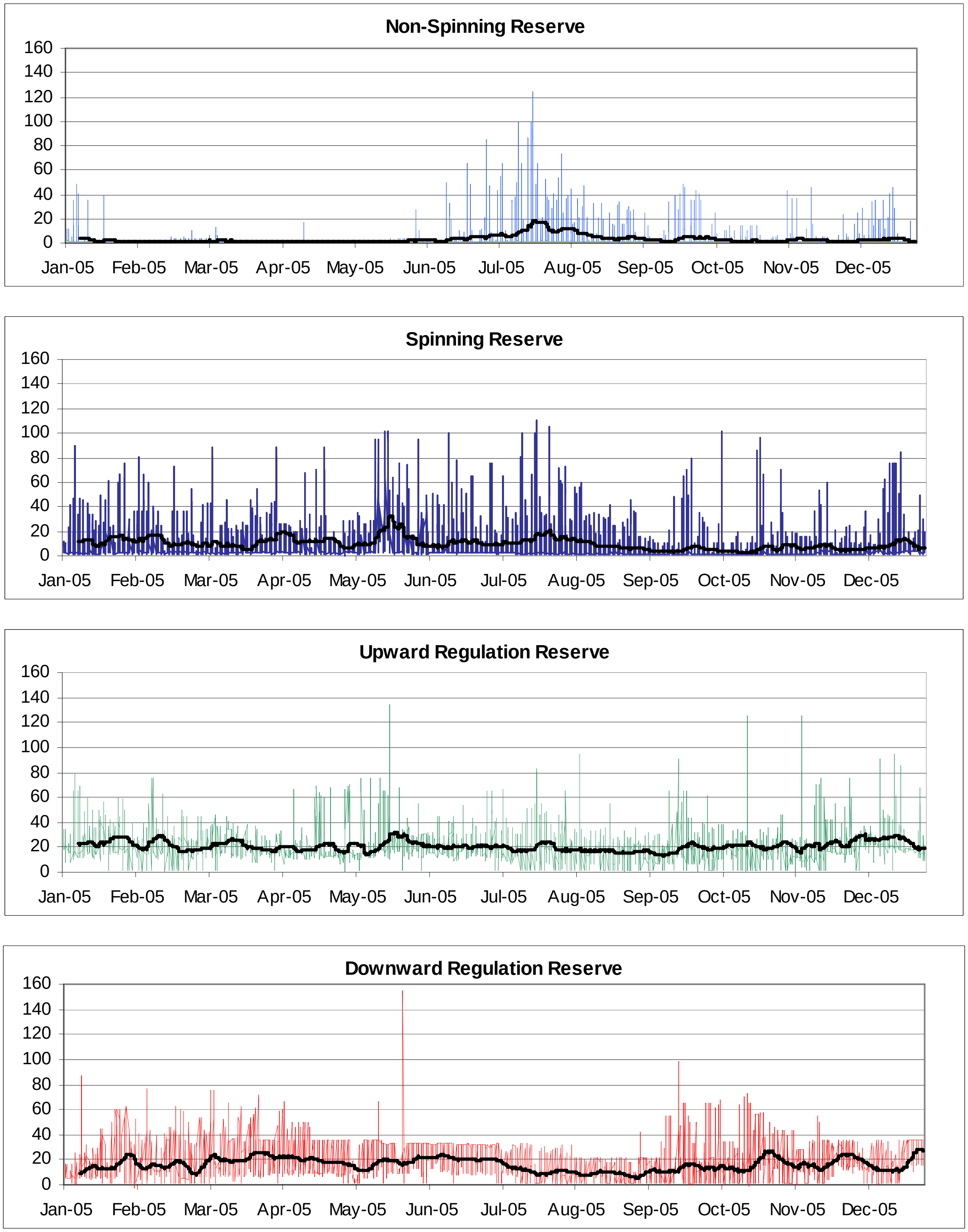
Figure 4.7 depicts the historic pattern of prices and volumes since 1999 and indicates that A/S prices and volumes have been relatively stable over the past four years (2002-2005) compared to the 1999-2001 period.

Figure 4.7 Annual A/S Prices and Volumes, 1999 - 2005



Hourly day-ahead reserve prices do tend to vary with system load levels and seasonal effects on generation. These prices appear in the composite charts, Figure 4.8. Excursions to high prices for Regulation Reserves occurred, though largely confined to the shoulder seasons of spring and fall. High price levels for Non-Spinning Reserves occurred through the peak months, while those for Spinning Reserves demonstrated a persistent tendency to reach high price levels throughout the year.

Figure 4.8 Day Ahead Ancillary Service Market Clearing Prices (A/S MCPs) with Weekly Moving Averages



The A/S price duration curves for the Day Ahead Markets, Figure 4.9 and Figure 4.10, reflect generally expected price behavior with the most valuable products exhibiting the highest sustained prices. Overall, Operating Reserve prices were at price levels above $25 in fewer than 10 percent of the operating hours. At the same time Regulation Reserve prices logged fewer than 25 percent of operating hours at prices over $25.

Figure 4.9 Price Duration: 2005 Operating Reserve Markets

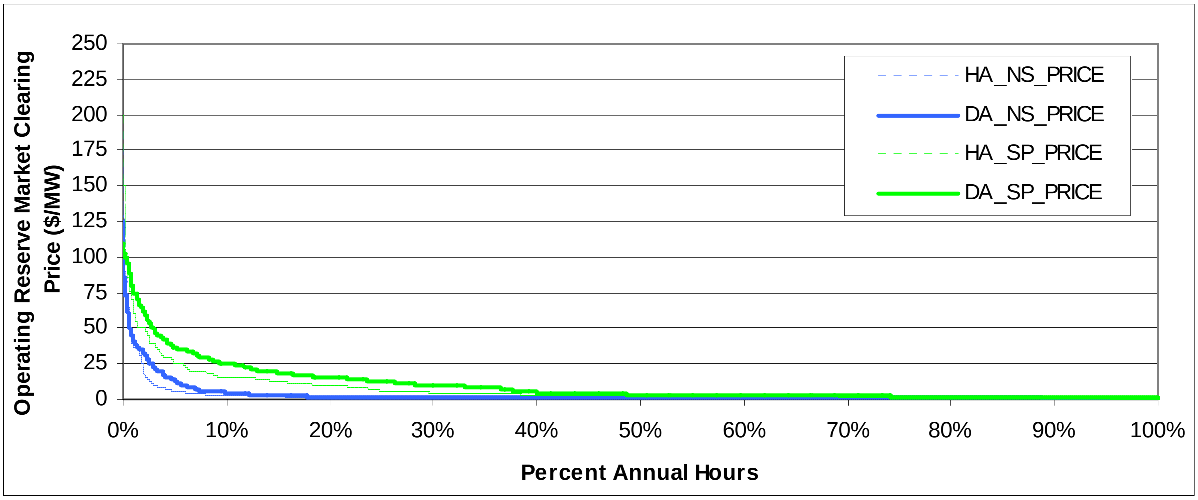
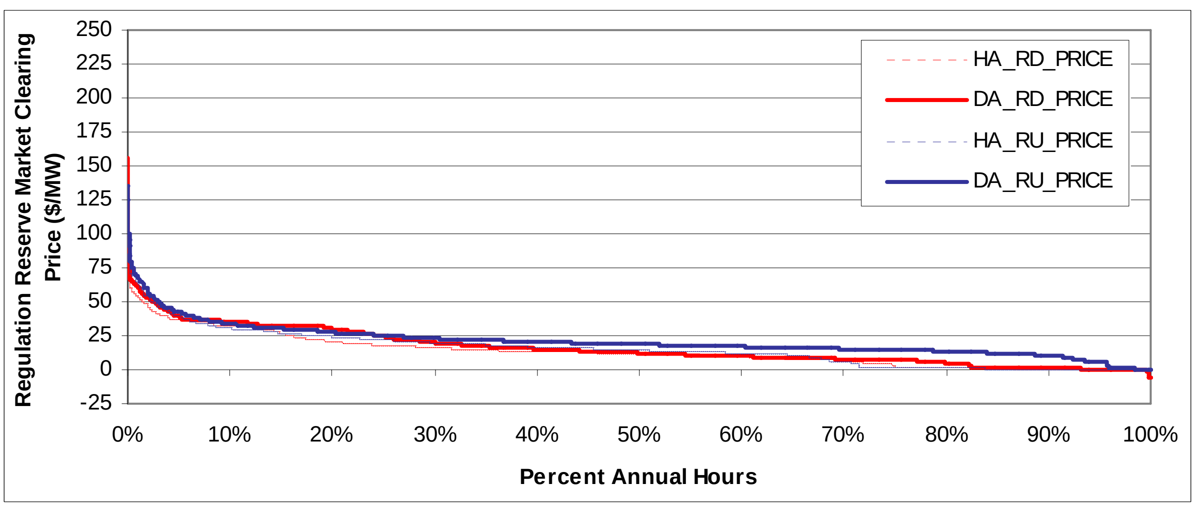


Figure 4.10 Price Duration: 2005 Regulation Reserve Markets

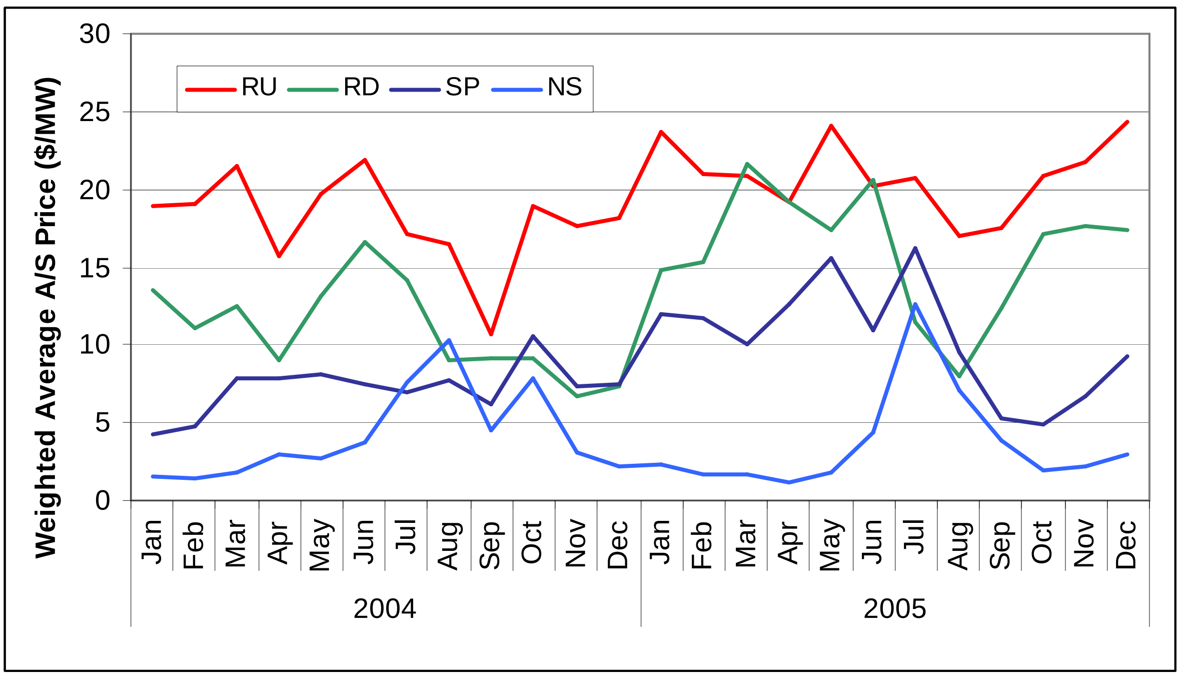


4.5 Monthly Prices of Ancillary Services

4.5.1 Price Patterns

Figure 4.11 charts the price pattern by month over the last two years. As expected, prices for Upward Regulation moved highest during seasons when loads were light and lowest during the peak load seasons as generating resources positioned themselves to be available to meet the energy needs of the system. Downward Regulation prices followed a similar trend, but deviated during times when heavy hydro flows accompanied light loads. The March 2005 and June 2005 price patterns characterize this effect. In contrast, high Operating Reserve prices generally accompany the heavy load periods, as higher energy demands reduced available capacity for reserves.

Figure 4.11 Monthly Weighted Average A/S Prices, 2004 - 2005

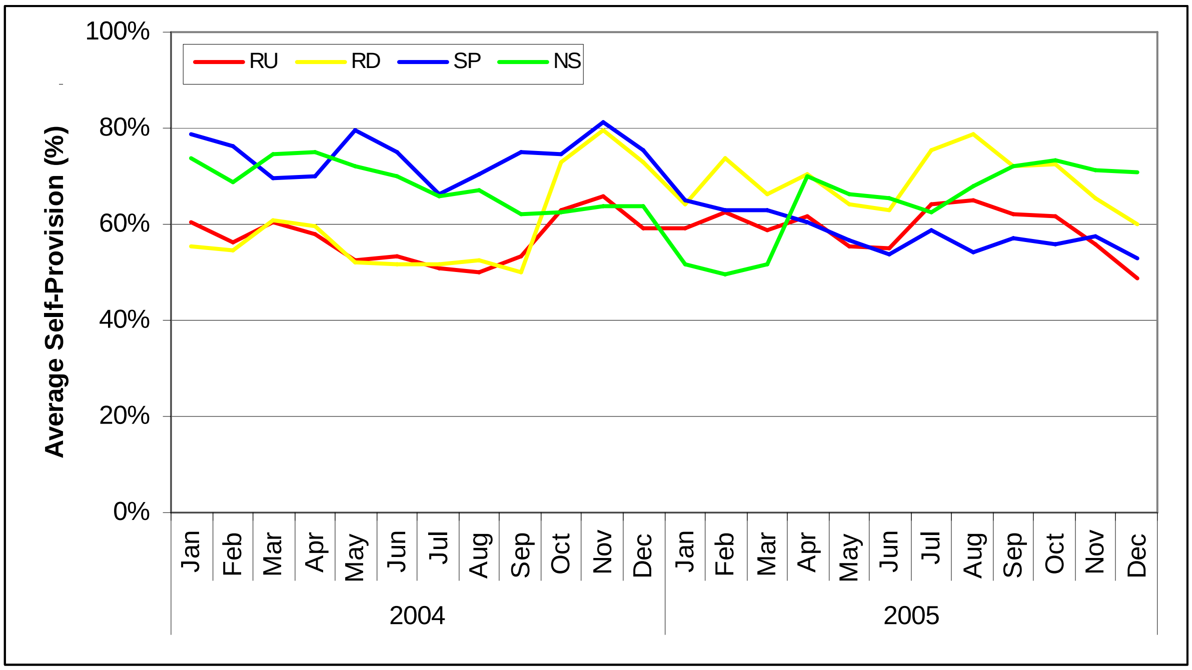


4.6 Ancillary Services Supply

4.6.1 Self Provision of Ancillary Services

Self-provided capacity reserves remain a core element of the A/S supply basis. Depending on the service and the season, self-provided capacity met from 50 to 80 percent of A/S requirements. Figure 4.12 captures this variation for the past two years.

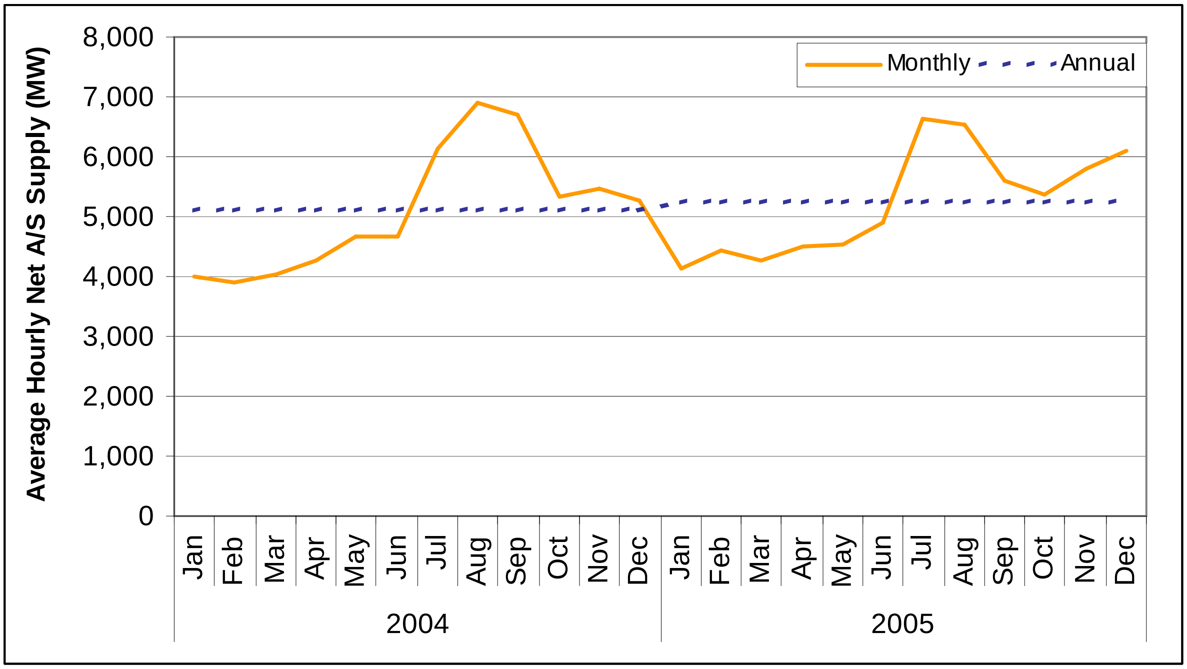
Figure 4.12 Hourly Average Self-Provision of A/S



4.6.2 Market Supply of Ancillary Services

Offers of physical capacity to the A/S markets went essentially unchanged from 2004 to 2005, increasing by just 2 percent. Net A/S supply measures the physical capacity offered to the market. Since physical capacity can be offered to several markets in the case of upward reserves, summing the capacity offers from a resource overstates the physical capacity offered to the markets. The net A/S supply accounts for market clearing mechanisms that only allocate distinct capacity portions to a single market. The monthly pattern in Figure 4.13 shows both the increase in supply as more units turn on in the summer and the sharp drop-off in supply from August to October, reflecting declining loads and the onset of the maintenance season.

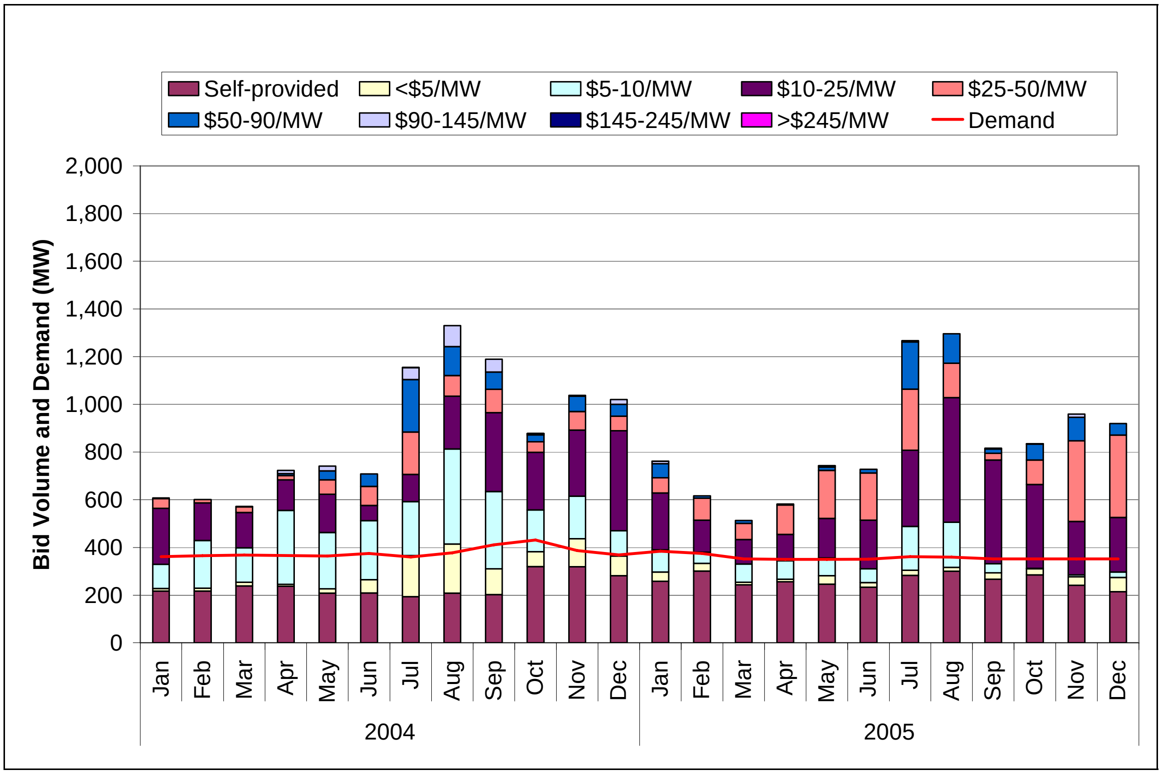
Figure 4.13 Average Hourly Net A/S Supply by Month, 2004 - 2005



Downward Regulation Reserve

A systemic decline in bid volumes at the $5-$10/MW level led to higher prices for Downward Regulation on average for the year. Figure 4.14 displays the Downward Regulation bid composition by month for the past two years.

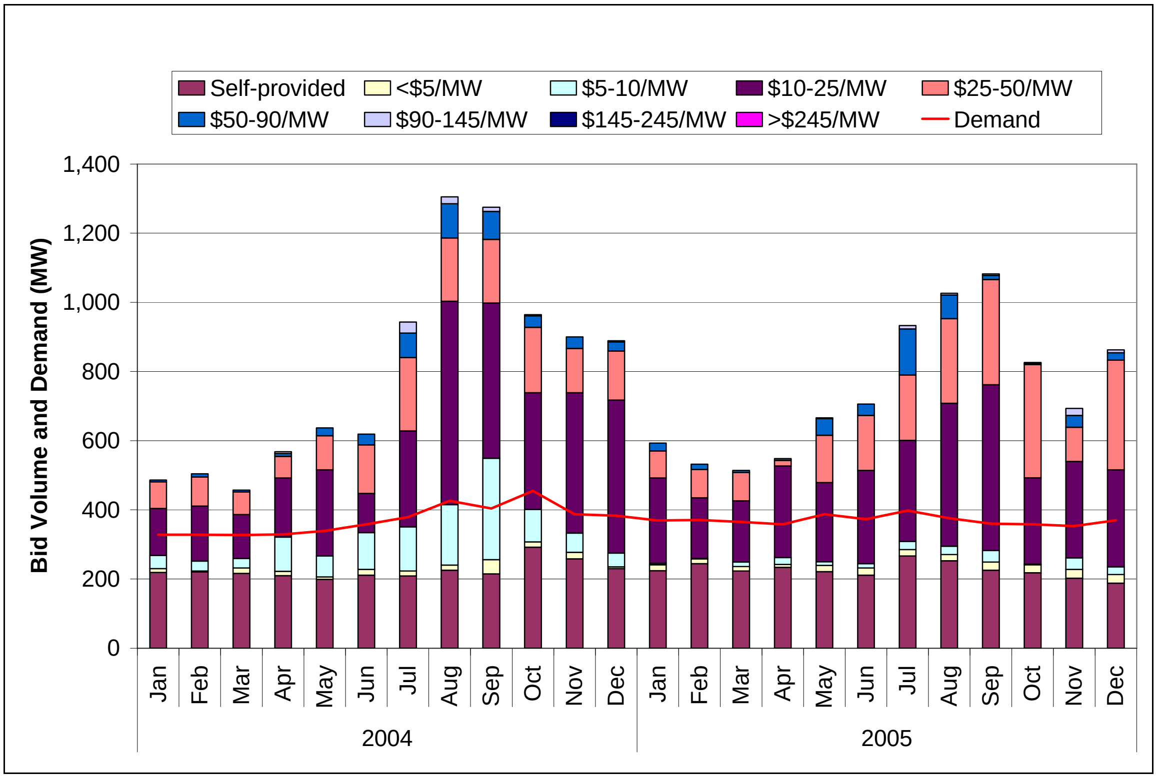
Figure 4.14 Day-Ahead Downward Regulation Reserve Bid Composition, 2004 – 2005 (Hourly Averages)



Upward Regulation Reserve

The same decline in bid volumes at the $5-$10/MW level led to higher prices for Upward Regulation on average for the year. The Upward Regulation bid composition by month for the past two years appears in Figure 4.15.

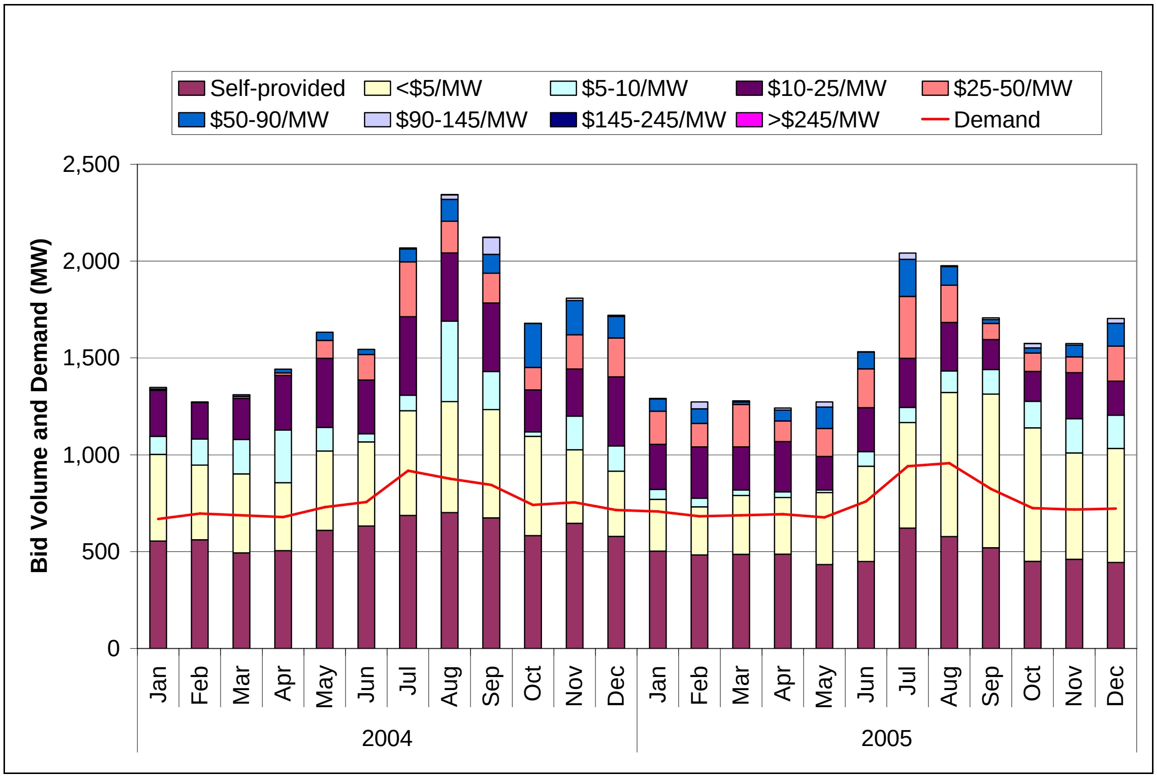
Figure 4.15 Day-Ahead Upward Regulation Reserve Bid Composition, 2004 – 2005 (Hourly Averages)



Spinning Reserve

Despite a significant supply of Spinning Reserve bids priced below $5/MW, thinner bid stacks at and above the $5-$10/MW level and lower self-provision volumes combined to push Spinning Reserve prices higher, on average, for 2005. Bid composition details for Spinning Reserves comprise Figure 4.16.

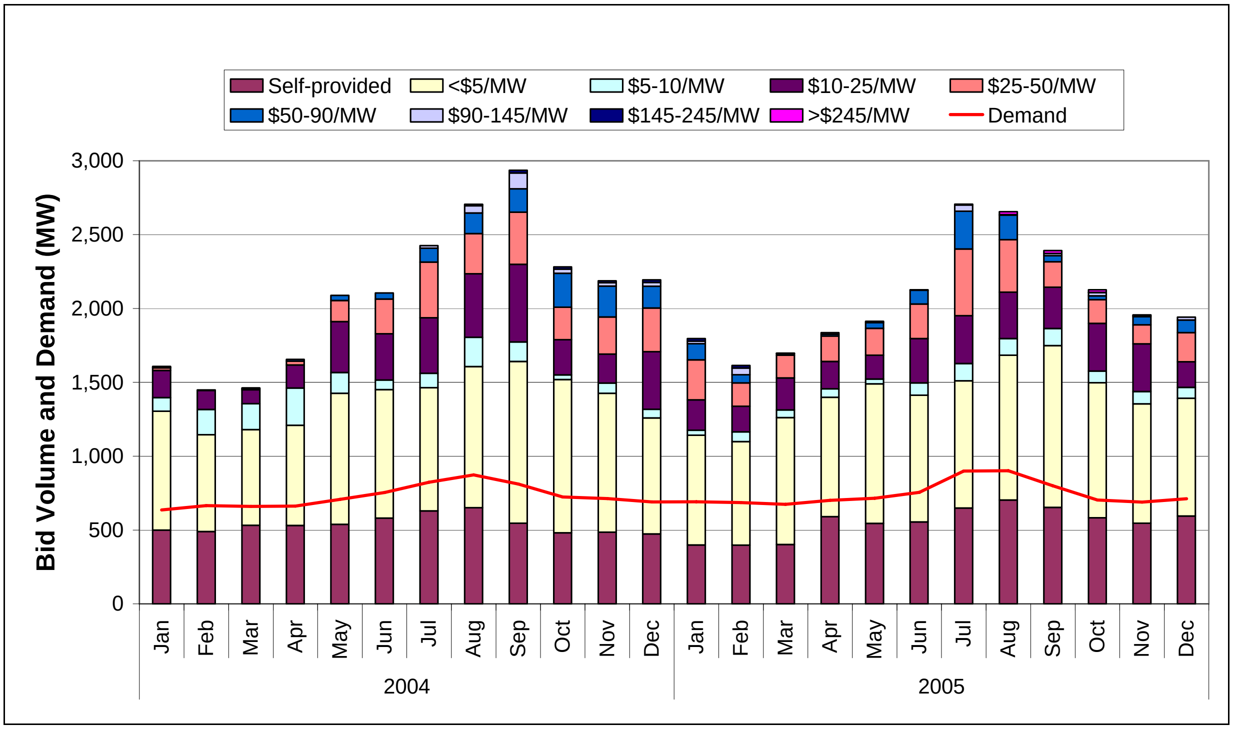
Figure 4.16 Day-Ahead Spinning Reserve Bid Composition, 2004 – 2005 (Hourly Averages)



Non-Spinning Reserve

Substantial bid volumes at the sub-$5/MW level drove the overall decline in the average price for Non-Spinning Reserves. Figure 4.17 depicts the Non-Spinning Reserve bid composition by month for the past two years.

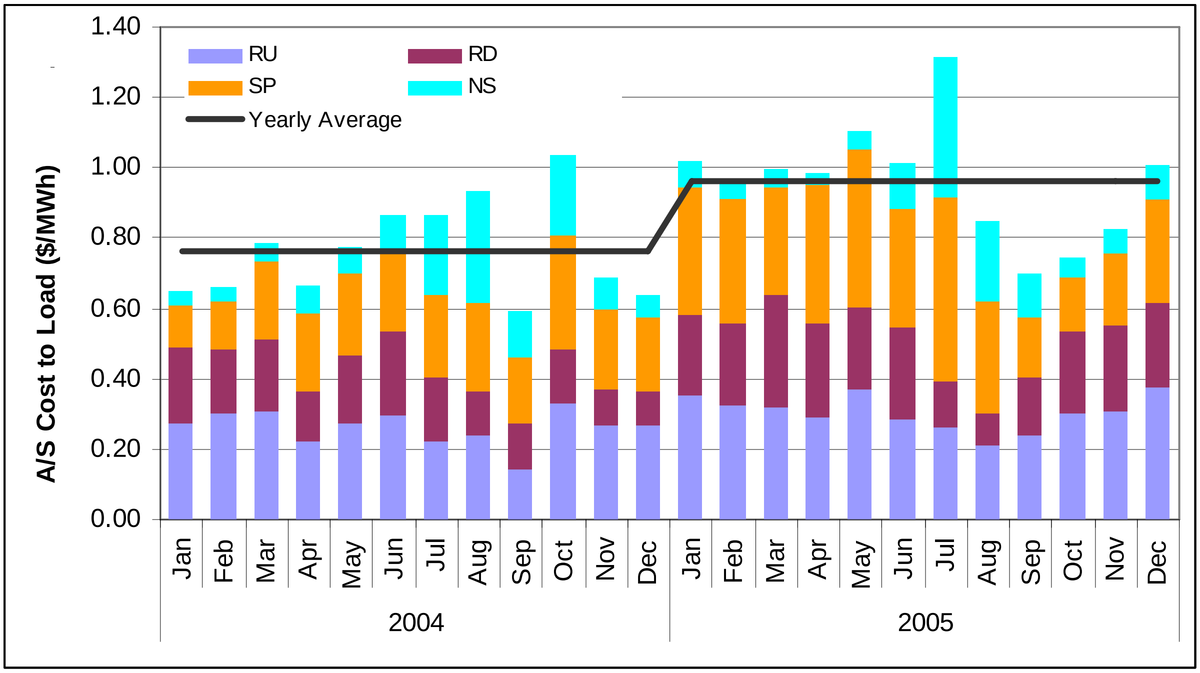
Figure 4.17 Day-Ahead Non-Spinning Reserve Bid Composition, 2004 – 2005 (Hourly Averages)



4.7 Cost to Load of Ancillary Services

The total cost of A/S capacity per unit of MWh load increased 26 percent from 2004 to 2005. The cost to load in 2005 averaged $0.96/MWh compared to a $0.76/MWh average the year prior. The 2005 operating year marks the fourth consecutive year resulting in an average cost to load under $1 (see Table 2.5). Figure 4.18 provides the monthly detail on these costs.

Figure 4.18 Monthly Cost of A/S per MWh of Load



4.8 Ancillary Service Bid Sufficiency

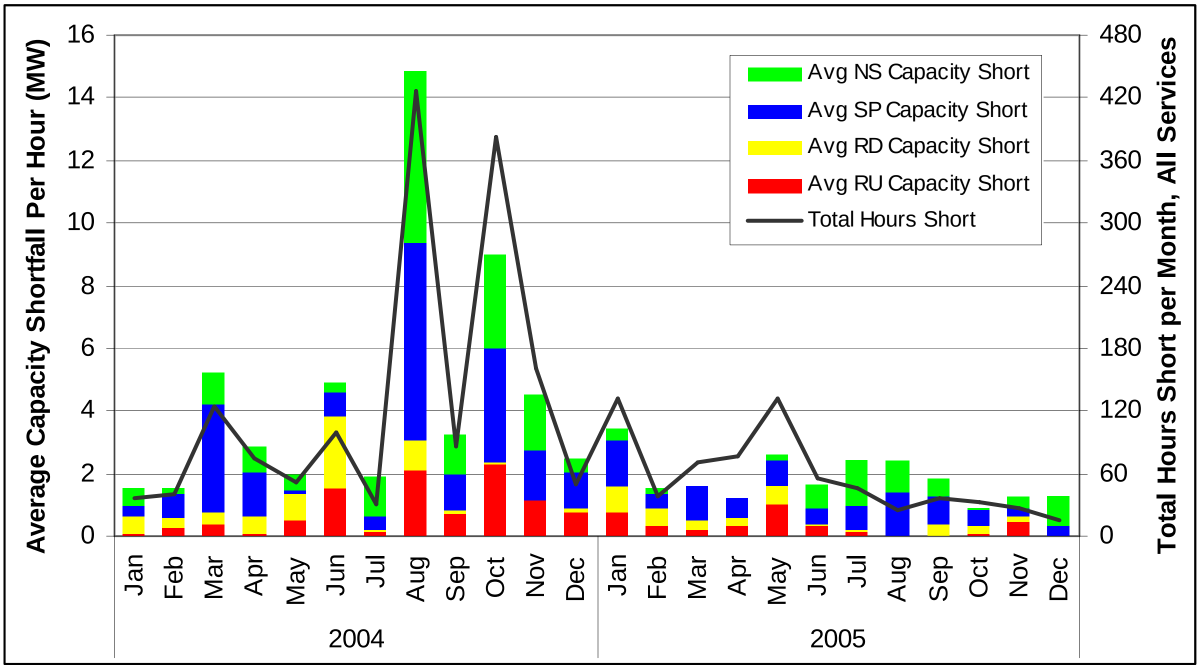
Bid insufficiency occurs when there is not enough available capacity bid into the markets to meet the procurement requirements. In addition to potentially creating reliability issues, bid insufficiency in the A/S markets can result in market power concerns as essentially any supplier to the A/S market in bid deficient hours is pivotal. Additionally, market power concerns can also arise if bid sufficiency exists but only marginally so. In these cases, certain suppliers may also be pivotal in the sense that the A/S requirements could not be met absent their supply. The CAISO employs several measures of bid sufficiency. Volumes of capacity shortages convey information about the magnitude of the deficiency events and the count of operating hours where bid-in capacity falls short of requirements represent commonly used metrics that provide insight into the frequency and severity of shortage events. Table 4.3 provides these two metrics for the past two operating years.

Table 4.3 Bid Insufficiency (2004 – 2005)

			Total Capacity Short (MW)		
Year	**RU**	**RD**	**SP**	**NS**	**Grand Total**
2004	7,310	4,519	15,641	12,338	39,809
2005	2,607	2,550	6,681	4,417	16,255
Percent	-64%	-44%	-57%	-64%	-59%
			Number of Hours Exhibiting a Shortage		
Year	**RU**	**RD**	**SP**	**NS**	**Grand Total**
2004	408	137	556	462	1,563
2005	135	163	279	107	684
Percent	-67%	19%	-50%	-77%	-56%

A/S markets experienced a significant decline in both volume and hours of bid insufficiency in 2005 compared to 2004, with a notable exception in the Downward Regulation market where the number of hours experiencing bid insufficiency increased by 19 percent. Figure 4.19 shows the average capacity shortfall per hour of bid insufficiency, by month and by service, for the past two years. The majority of the decline in bid insufficiency in 2005 can be explained by a comparison of the August-December timeframes across the two years. As previously discussed in Section 4.3.2, in August of 2004, the CAISO reinstated the practice of procuring A/S by zone and continued this practice into the first week of December 2004. During these months, the CAISO experienced levels of bid insufficiency that rose well above historical levels. Comparing these five months of 2004 to the same five months of 2005 shows that much of the decline in the annual bid insufficiency metrics can be attributed to discontinuation of the zonal procurement of A/S as the CAISO did not procure at the zonal level in 2005. While the total Downward Regulation capacity shortages decreased 44 percent, the number of shortage hours for Downward Regulation capacity increased by 26 on the year. Stronger hydrological conditions in the first half of 2005 drove the increase in bid insufficiency for Regulation-Down for this period, relative to the first half of 2004. During periods of heavy hydro flows, hydroelectric generators tend to sell large volumes of energy cheaply, which essentially creates a disincentive for would-be non-hydroelectric suppliers of Downward Regulation to be online.

Figure 4.19 Bid Insufficiency by Capacity and Hour



5. Inter-Zonal Congestion Management Market

5.1 Summary of 2005 Inter-Zonal Congestion Management Market

5.1.1 Overview

Under the current zonal model, the CAISO manages congestion in the forward market only on major inter-ties and two large internal paths (Path 15 and Path 26). It uses adjustment bids to mitigate the congestion while minimizing the cost of schedule adjustments and keeping each Scheduling Coordinator's (SC) schedule in balance. The marginal SC establishes the usage charge for the inter-zonal interface. All SCs pay this charge based on their accepted, scheduled flow on the interface. The CAISO pays the net amount of congestion charges it collects to the Transmission Owners (TOs) and the owners of Firm Transmission Rights (FTRs). Figure 5.1 shows the active congestion zones and major inter-zonal pathways (branch groups) in the CAISO grid that are active effective December 1, 2005. The new footprint of the CAISO grid reflects several operational changes that became effective on December 1, 2005, including:

- Transition of COTP and MID to the SMUD Control Area,
- TID becoming an independent control area,
- The new Plumas-Sierra Interconnection,
- The new and converted metered sub-systems, and
- A Pilot Pseudo Tie for Calpine's Sutter Plant.

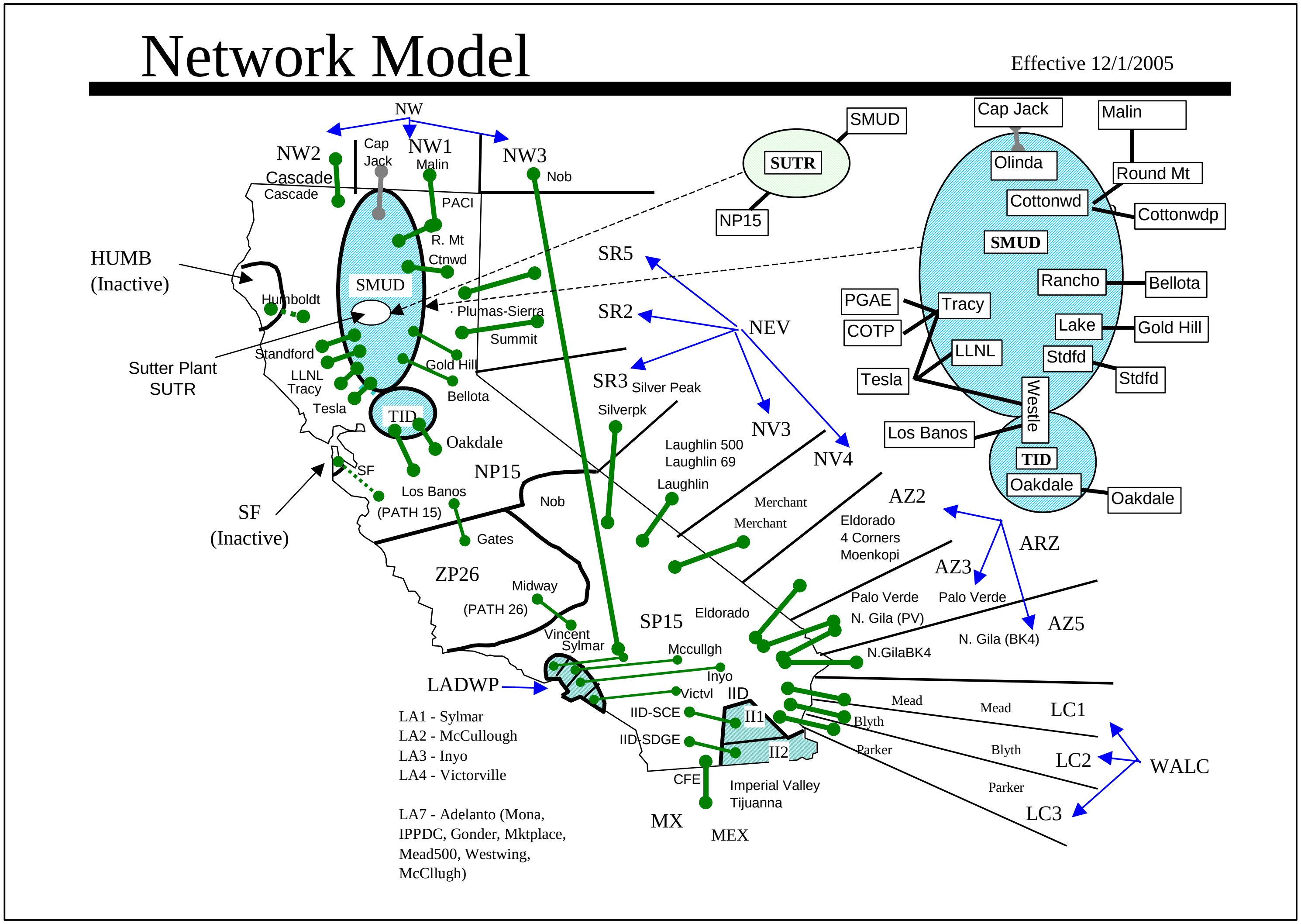
Total inter-zonal congestion cost for both the Day Ahead and Hour Ahead Markets in 2005 was $54.6 million, slightly lower than the $55.8 million in 2004, higher than the $ 26.1 million in 2003 and $41.8 in 2002, but significantly lower than $107.1 in 2001 and $391.4 in 2000. Table 5.1 shows the historical annual total inter-zonal congestion cost since the year 2000.

Table 5.1 Historical Inter-Zonal Congestion Cost

Year	Total Inter-Zonal Congestion Cost ($ Million)
2000	$ 391.4
2001	$ 107.1
2002	$ 41.8
2003	$ 26.1
2004	$ 55.8
2005	$ 54.6

The reduced inter-zonal congestion cost in 2005 was mainly due to upgrades of Path 26 that were effective during 2005, as well as upgrades of Path 15 that were effective December 2004. Compared to 2004, congestion costs in 2005 decreased on major branch groups such as Palo Verde, Path 15, Path 26, COI/PACI, NOB, and Mead, but increased on both Eldorado and Blythe. Higher congestion costs for Eldorado are mostly due to frequent and intensive scheduled work on lines and substations related to the two inter-ties that comprise the Eldorado Branch Group. Higher congestion costs for Blythe were caused by dynamic local load conditions in the Blythe area that resulted in frequent adjustments to the transmission limits on the Blythe Branch Group.

Figure 5.1 Active Congestion Zones and Branch Groups



5.1.2 Inter-Zonal Congestion Frequency and Magnitude

This section summarizes the frequency and average congestion price for the major inter-zonal interfaces (branch groups) in 2005. Table 5.2 lists all active inter-zonal interfaces (or branch groups) that the CAISO managed in its forward congestion management market in 2005.

Table 5.2 Summary of Active Branch Groups in the CAISO Market (2005)

BRANCH_GRP	Tie Point	FROM ZONE	TO ZONE	MAX OTC IN IMPORT DIRECTION (MW)	MAX OTC IN EXPORT DIRECTION (MW)	Note
ADLANTOSP_BG	ADELNT_2_SYLMAR, ADLNTO_5_LUGO	LA7	SP15	1036	162	new on 1/1/2005
BLYTHE _BG	BLYTHE_1_WALC	LC2	SP15	218	0	
CASCADE _BG	CASCAD_1_CRAGVW	NW2	NP15	100	0	
CFE _BG	IVALLY_2_23050	MX	SP15	800	0	
COI _BG	MALIN_5_RNDMTN, CAPJAK_5_OLINDA	NW1	NP15	4800	500	expired on 12/1/2005
CTNWDRDMT_BG	CTNWDW_2_RNDMTN	SMD3	NP15	370	0	new on 1/1/2005
CTNWDWAPA_BG	CTNWDW_2_CTTNWD	SMD2	NP15	1594	797	new on 1/1/2005
ELDORADO _BG	ELDORD_5_PSUDO, FCORNR_5_PSUED, MOENKO_5_PSUED	AZ2	SP15	1607	455	
GONDIPPDC_BG	GONDER_5_IPPDC	SR4	LA5	68	25	new on 1/1/2005
IID-SCE _BG	MORAGE_2_COCHLA, DEVERS_2_COCHLA	II1	SP15	600	-50	
IID-SDGE _BG	IVALLY_2_230S	II2	SP15	225	0	
INYO _BG	INYOS_2_LDWP	LA3	SP15	56	0	
IPPDCADLN_BG	IPPDC_5_ADLNTO	LA5	LA7	647	0	new on 1/1/2005
LAUGHLIN _BG	MOHAVE_6_69kV, MOHAVE_5_500kV	NV3	SP15	0	-222	
LLNLTESLA_BG	LLNL_1_TESLA	SMD8	NP15	256	0	new on 1/1/2005
MARBLESUB_BG	MBLSPP_6_MARBLE	SR5	NP15	0	0	new on 12/1/2005
MCCLMKTPC_BG	MCCLUG_5_MKTPLC	LA6	LC4	694	0	new on 1/1/2005
MCCULLGH _BG	ELDORD_5_MCLLGH	LA2	SP15	3600	0	
MEAD _BG	MEAD_2_WALC	LC1	SP15	1460	-1140	
MEADMKTPC_BG	MEAD_5_MKTPLC	LC5	LC4	263	263	new on 1/1/2005
MEADTMEAD_BG	MEADT_5_MEAD	LC6	LC5	182	182	new on 1/1/2005
MERCHANT _BG	MRCHNT_2_ELDORD	NV4	SP15	645	645	
MKTPCADLN_BG	MKTPLC_5_ADLNTO	LC4	LA7	423	0	new on 1/1/2005
MONAIPPDC_BG	MONA_5_IPPDC	PC1	LA5	564	545	new on 1/1/2005
N.GILABK4_BG	NGILA_5_NG4	AZ5	SP15	366	240	
NOB _BG	SYLMAR_2_NOB	NW3	SP15	2091	0	
OAKDALSUB_BG	OAKTID_1_OAKCSF	TDZ1	NP15	266	266	new on 12/1/2005
OLNDAWAPA_BG	OLNDWA_2_OLIND5	SMD1	NP15	1041	850	expired on 12/1/2005
PACI	MALIN_5_RNDMTN	NW1	NP15	2967	1633	new on 12/1/2005
PALOVRDE _BG	PVERDE_5_DEVERS, PVERDE_5_NG-PLV	AZ3	SP15	2823	973	
PARKER _BG	PARKR_2_GENE	LC3	SP15	220	0	
PATH15 _BG		ZP26	NP15	6390	9999	
PATH26 _BG		SP15	ZP26	9999	1034	
RNCHLAKE _BG	RANCHO_2_BELOTA	SMDE	NP15	2004	-797	
SILVERPK _BG	SLVRPK_7_SPP	SR3	SP15	17	0	
STNDFDSTN_BG	STNDFD_1_STNCSF	SMDK	NP15	446	446	new on 12/1/2005
SUMMIT _BG	SUMITM_1_SPP	SR2	NP15	120	0	
SUTTRLOFF_BG	SUTTER_2_LAYOFF	SMDM	SUTR			new on 12/1/2005
SUTTRNP15_BG		SUTR	NP15	1492	1366	new on 12/1/2005
SYLMAR-AC_BG	SYLMAR_2_LDWP	LA1	SP15	1600	-1200	
TRACYCOTP_BG	TRACY5_5_COTP	SMDH	NP15	143	79	new on 12/1/2005
TRACYPGAE_BG	TRACY5_5_PGAE	SMDL	NP15	4388	4352	new on 12/1/2005
TRACYWAPA_BG	TRCYPP_2_TRACY5	SMD4	NP15	1700	850	expired on 12/1/2005
TRCYTESLA_BG	TRCYPP_2_TESLA	SMD5	NP15	1366	0	new on 1/1/2005
TRCYWSTLY_BG	TRCYPP_2_WESTLY	SMD6	NP15	650	650	expired on 12/1/2005
VICTVL _BG	LUGO_5_VICTVL	LA4	SP15	1526	0	
WSLYTESLA_BG	WESTLY_2_TESLA	SMDJ	NP15	233	233	new on 12/1/2005
WSTLYLSBN_BG	WESTLY_2_LOSBNS	TDZ2	NP15	233	233	new on 12/1/2005
WSTWGMEAD_BG	WSTWNG_5_MEAD	AZ6	LC5	126	94	new on 1/1/2005

Table 5.3 shows annual congestion frequencies and average congestion prices by branch group, direction (import and export), and market type (Day Ahead and Hour Ahead). Congestion occurred primarily on five branch groups: Palo Verde (import), Blythe (import), COI/PACI (import), Eldorado (import), and Path 26 (north-to-south). The congestion patterns, categorized by congested branch groups, congestion frequencies, and direction of congestion, were similar to 2004. Most congestion on inter-ties occurred in the import direction. For instance, Palo Verde (import) was the most frequently congested path in 2005, having been congested in 23 percent of hours in the Day Ahead Market. Of the internal paths, Path 26 was frequently congested in the north-to-south direction before its rating was increased on June 27, 2005. Path 15 was much less congested in either direction compared to 2004 due to Path 15 upgrades that became effective on December 7, 2004. In addition, the average congestion prices were lower on COI/PACI and Path 26, higher on Blythe and Eldorado, and similar on Palo Verde as compared to figures from 2004. Consistent with previous years, the frequency of congestion was lower and congestion prices were higher in the hour-ahead markets than in the day-ahead markets primarily due to the fact that most schedules were cleared in the Day Ahead Market and consequently most congestion was managed in the Day Ahead Market. However, fewer available adjustment bids in the Hour Ahead Market often lead to higher congestion prices when congestion did occur in the Hour Ahead Market.

Table 5.3 Inter-Zonal Congestion Frequencies (2005)

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
Branch Group	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**
ADLANTOSP_BG	1	0	$17		0	0	$53	
BLYTHE _BG	5	0	$108		0	0	$96	
CASCADE _BG	4	0	$0		2	0	$0	
COI _BG	18	0	$3		13	0	$9	
ELDORADO _BG	6	0	$9		4	0	$13	
GONDIPPDC_BG	0	0		$20	0	0		
IID-SCE _BG	0	0	$49		0	0	$33	
IPPDCADLN_BG	2	0	$22		2	0	$41	
MEAD _BG	8	0	$2		4	0	$22	$30
MKTPCADLN_BG	0	0	$0		0	0	$0	
N.GILABK4_BG	0	1		$123	0	0		$100
NOB _BG	9	0	$1		6	0	$17	
OLNDAWAPA_BG	0	0		$250	0	0		$43
PACI _BG	0	0			1	1	$3	$0
PALOVRDE _BG	23	0	$6		8	0	$20	
PARKER _BG	1	0	$3		0	0	$0	
PATH15 _BG	1	0	$19		1	0	$10	
PATH26 _BG	0	2		$18	0	1	$65	$18
RNCHLAKE _BG	0	0			0	0		$50
SILVERPK _BG	0	0			0	0	$0	
SUMMIT _BG	0	0	$2		0	0	$0	$26
TRACYWAPA_BG	1	0	$22	$207	0	0	$50	$61
TRCYTESLA_BG	0	0	$1		0	0		
WSTLYLSBN_BG	0	1		$30	0	0		
WSTWGMEAD_BG	5	0	$2		2	0	$3	

* Average congestion price is the simple average price for hours in which the paths were congested.

5.1.3 Inter-Zonal Congestion Usage Charge and Revenues

Table 5.4 shows the annual congestion revenues for the major CAISO branch groups in 2005.[1] The total congestion revenue of $54.6 million in 2005 slightly decreased from $55.8 million in 2004. Of the total $54.6 million in congestion revenue, approximately 82 percent was attributable to five branch groups: $19.8 million to Palo Verde in the east-to-west (import) direction, $8.7 million to Blythe in the east-to-west (import) direction, $6.7 million to COI in the north-to-south direction (import), $4.7 million to Eldorado in the east-to-west (import) direction, and $4.9 million to Path 26 in the north-to-south direction.

Table 5.4 Inter-Zonal Congestion Revenue (2005)

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$730,982	$0	$13,385	$0	$744,367	$0	$730,982	$13,385	$744,367	1%
BLYTHE	$8,747,667	$0	$757	$0	$8,748,424	$0	$8,747,667	$757	$8,748,424	16%
CASCADE	$0	$0	$2	$0	$2	$0	$0	$2	$2	0%
COI	$6,644,439	$0	$104,791	$0	$6,749,230	$0	$6,644,439	$104,791	$6,749,230	12%
ELDORADO	$4,608,008	$0	$134,467	$0	$4,742,475	$0	$4,608,008	$134,467	$4,742,475	9%
GONDIPPDC	$0	$15,847	$0	-$2	$0	$15,845	$15,847	-$2	$15,845	0%
IID-SCE	$360,623	$0	$8,749	$0	$369,372	$0	$360,623	$8,749	$369,372	1%
IPPDCADLN	$1,704,061	$0	$169,999	$0	$1,874,060	$0	$1,704,061	$169,999	$1,874,060	3%
LAUGHLIN	$0	$0	$0	-$39	$0	-$39	$0	-$39	-$39	0%
MEAD	$1,046,698	$0	$102,866	$18,383	$1,149,564	$18,383	$1,046,698	$121,249	$1,167,947	2%
MKTPCADLN	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
N.GILABK4	$0	$1,117,802	$0	-$9,466	$0	$1,108,336	$1,117,802	-$9,466	$1,108,336	2%
NOB	$1,668,145	$0	$90,897	$290	$1,759,042	$290	$1,668,145	$91,187	$1,759,332	3%
OAKDALSU	$0	$0	$0	$1	$0	$1	$0	$1	$1	0%
OLNDAWAPA	$0	$20,060	$0	-$3,799	$0	$16,261	$20,060	-$3,799	$16,261	0%
PACI	$0	$0	$31,409	$2,359	$31,409	$2,359	$0	$33,768	$33,768	0%
PALOVRDE	$19,665,658	$0	$105,354	$0	$19,771,013	$0	$19,665,658	$105,354	$19,771,013	36%
PARKER	$28,397	$0	$2	$0	$28,399	$0	$28,397	$2	$28,399	0%
PATH15	$2,060,393	$0	$117,104	$0	$2,177,498	$0	$2,060,393	$117,104	$2,177,498	4%
PATH26	$0	$4,969,073	$28,205	-$133,170	$28,205	$4,835,903	$4,969,073	-$104,965	$4,864,108	9%
RNCHLAKE	$0	$0	$0	$13,003	$0	$13,003	$0	$13,003	$13,003	0%
SUMMIT	$5,930	$0	$1	$4,753	$5,932	$4,753	$5,930	$4,754	$10,685	0%
TRACYWAPA	$278,902	$157,378	$0	-$4,091	$278,902	$153,288	$436,280	-$4,091	$432,190	1%
TRCYTESLA	$2,792	$0	$0	$0	$2,792	$0	$2,792	$0	$2,792	0%
TRCYWSTLY	$0	$0	$17	$0	$17	$0	$0	$17	$17	0%
WSTLYLSBN	$0	$17,644	$0	-$1,084	$0	$16,560	$17,644	-$1,084	$16,560	0%
WSTWGMEAD	$104,749	$0	$7,290	$0	$112,039	$0	$104,749	$7,290	$112,039	0%
Total	**$47,552,695**	**$6,280,161**	**$908,005**	**-$111,778**	**$48,460,700**	**$6,168,383**	**$53,832,856**	**$796,228**	**$54,629,083**	**100%**

In 2005, the Hour Ahead Market generated approximately $0.8 million in congestion revenue. This congestion revenue was minimal compared to day-ahead revenues, mainly due to the fact that hour-ahead congestion typically occurs after SCs have adjusted their day-ahead schedule or if there was a change in line ratings from the Day Ahead Markets to the Hour Ahead Markets. Often, only those SCs who changed their schedules in the Hour Ahead Markets were required to pay the congestion charges in the Hour Ahead Markets. Therefore, the volume of transactions in the Hour Ahead Market was much smaller.

Figure 5.2 compares the congestion revenues between 2004 and 2005 for the selected major paths. For most paths, congestion revenue was significantly lower in 2005 than in 2004,

[1] All SCs who have accepted New Firm Use (NFU) schedules on the congested interfaces would pay the usage charge. The net account of congestion charge collected by the CAISO is paid to transmission owner or the FTR holders.

especially for COI/PACI, Path 15, and NOB. Congestion on Path 15 was down due to the Path 15 upgrade that became effective on December 7, 2004. Congestion on COI/PACI and NOB were down because of limited hydroelectric production in the Pacific Northwest in 2005, compared to 2004. The Pacific Northwest suffered a below-average snow pack in 2005 and had an unusually low supply of hydroelectric power.

Figure 5.2 Congestion Revenues on Selected Paths (2004 vs. 2005)

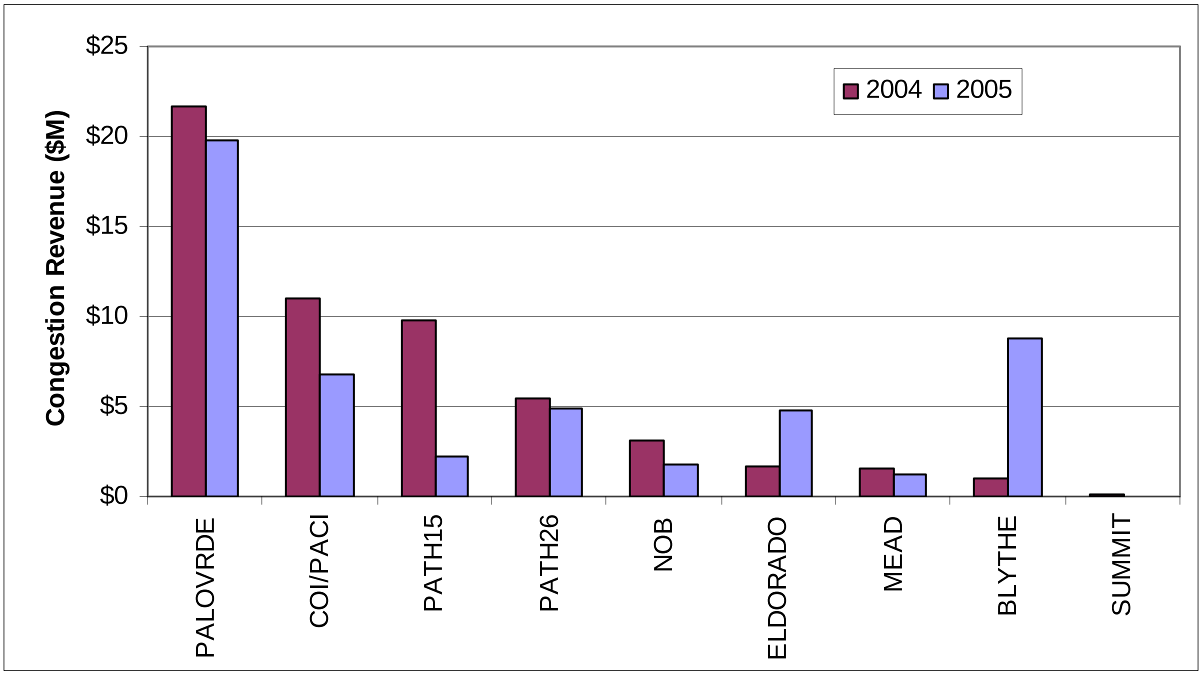
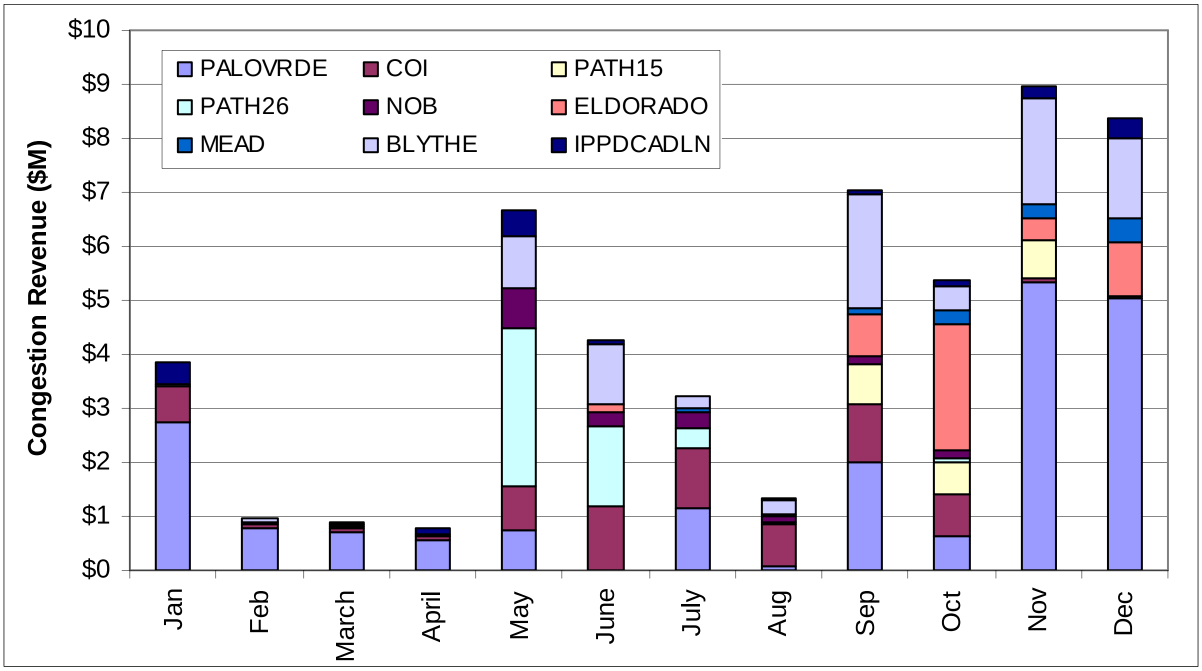


Figure 5.3 further demonstrates the seasonal pattern of congestion revenues on major paths. Similar to previous years' congestion patterns, congestion revenue in 2005 was higher in the second half of the year due to derates resulting from frequent scheduled transmission upgrades and line maintenance. The upgrades and line work caused many deratings on the major paths such as Palo Verde and Eldorado during the second half of the year, especially the last four months. During the first half of the year congestion revenue was moderate in the early months (January-April) but increased in the late spring and mid summer months (May-July). The increase was predominately due to the higher loads in the summer months, which resulted in significant amounts of energy imported into California from the Pacific Northwest in late spring and early summer when more hydro energy was available. Congestion was prevalent on Path 26 for the months of May and June due to this reason, and there was no congestion on Path 26 for the second half of the year due to the Path 26 enhancement that became effective on June 27, 2005. When hydro power was limited in the late summer, California relied more on imports from the Southwest. The higher demand for imports and various derates resulted in higher congestion costs on the major paths between the CAISO and the Southwest for September, October, November, and December (specifically Palo Verde, Blythe, and Eldorado). A more detailed discussion of the seasonal congestion patterns of each of these major paths is provided below.

Figure 5.3 Monthly Congestion Charges of Selected Major Paths (2005)



Palo Verde: The Palo Verde inter-tie had significant congestion costs in January, September, November, and December, all in the import direction and predominantly in the Day Ahead Market. In January, the Palo Verde branch group was congested in the import direction (east-to-west) for 36 percent of all hours in the Day Ahead Market at an average congestion price of $5/MWh, and 14 percent of all hours in the Hour Ahead Market, at an average congestion price of $7/MWh. Congestion on Palo Verde during this month was due in large part to wheeling energy from the Southwest to Northern California where day-ahead bilateral prices were higher. No significant derates were found in this month.

The Palo Verde – Devers 500kV line had a number of planned and forced outages/derates starting in July due to upgrades of series capacitors at Devers and related line/reactor work. For example, a line reactor at Devers was moved for replacement on July 21, and the outage continued through November 15, 2005. Also, since the middle of November 2005 both the Arizona and California series capacitors at Devers were scheduled to be removed from service until June 2006 due to work required for the Devers switching center 500kV revision. Theoretically the series capacitors could be by-passed, leaving the inter-tie transfer capability unaffected. However, in practice due to frequent work required for the capacitor upgrades, the Palo Verde transfer capability in the Day Ahead Market was periodically derated from 800 MW to 200 MW.

Blythe: In contrast to previous years, the Blythe branch group had significant day-ahead import congestion costs in 2005 beginning in April, and especially in the months of June, September, November, and December. The Blythe branch group (Path 59) is defined as the 161 kV tie between Blythe (WALC) in the WAPA lower Colorado region and Blythe (SCE) in the SP15 region. The normal rating of the inter-tie is 168 MW but the daily line limit on the Blythe branch group is based on Blythe area load. Most of the congestion on Blythe was related to Blythe area load fluctuation, which resulted in lower ratings for the Blythe branch group. During the second half of 2005 the CAISO required more imports from the Southeast than in 2004. As a result, the

Blythe tie limit was binding more often than in 2004, resulting in higher congestion costs on Blythe than in 2004. An initial assessment of the cost exposure resulting from a more dynamic line limit revealed a significant amount of hedging through FTRs for schedules across the Blythe branch group.

COI/PACI: The COI branch group had significant day-ahead import congestion throughout the year, especially in the months of June, July, and September. COI was congested for 23 percent of all hours in the day-ahead import direction (from Oregon to California) in June at an average congestion price of $5/MWh. However, comparing this figure to 2004, congestion on COI in June 2005 was much lower due to low hydro in the Northwest overall. The congestion on COI in June was mainly caused by frequent line derates resulting from various associated line and area resource limitations and scheduled maintenance outages. For instance, day-ahead congestion cost on June 8 was caused by derates on COI in the import direction from 4,340 MW to 3,000 MW for hours ending 7 to 19 due to limitations on the COI and PDCI 500kV caused by BPA's Grand Coulee-Hanford #1 line scheduled outage.

In July 2005, COI experienced continued derates due to various scheduled or forced line outages and line and area resource related limitations. For example, the COI import rating (north-to-south) was decreased from 4,550 MW to 3,850 MW on July 6 due to forced outages on the Malin shunt capacitors #3 and #4. During this period, COI was congested for 34 percent of all hours in the Day Ahead Market at an average congestion price of $2/MWh.

COI continued experiencing derates due to various scheduled or forced line outages and line and area resource related limitations in August and September. For example, on September 6, COI was derated by 700 MW due to a number of scheduled outages and line work, including the Grizzly-Sand Springs section of Grizzly-Captain Jack #1 500kV line connector work, and the Ashe-Marion #2 500kV scheduled outage. On September 7 and 8, COI was again derated due to the BPA scheduling limit. All day-ahead import congestion for September 7 and 8 occurred during the derating periods. Again on September 12, BPA reported a reduction in the COI OTC north-to-south to 1,600 MW due to lack of area generation resources. This scheduling limit continued until September 13, but gradually increased to 1,900 MW, and down to 1,750 MW on September 14, up to 2,090 MW on September 15, and 2,075 MW on September 16.

Eldorado: The Eldorado branch group had significant day-ahead import congestion cost in a number of months including September, October, and December due to various derates caused by various outages. For example, in October Eldorado was derated due to planned outages of series capacitors at Eldorado and Moenkopi and the planned outages of these series capacitors continued through November.

Path 26: Path 26 had significant day-ahead congestion costs in the north-to-south direction (from zones ZP26 to SP15) in the months of May and June before the Path 26 enhancements went into effect on June 27, 2005. The enhancements increased the north-to-south capacity on Path 26 from 3,400 MW to 3,700 MW. Congestion costs were very high in May due to derates of Path 26 for scheduled tests and line work. Path 26 was again derated from June 15 to June 18 for scheduled work on Midway-Vincent #3 500kV line. All Path 26 congestion occurred during this period. Congestion cost on Path 26 has been minimal since August 2005, indicating that the Path 26 enhancements were very effective in eliminating congestion.

5.1.4 Special Topics

5.1.4.1 Existing Transmission Contracts and Phantom Congestion

An Existing Transmission Contract (ETC) is an encumbrance, established prior to the start-up of the CAISO, in the form of contractual obligation of a CAISO Participating Transmission Owner (PTO) to provide transmission service to another party, in accordance with terms and conditions specified in the contract, utilizing transmission facilities owned by the PTO that have been turned over to the CAISO operation control. There are two main aspects of the CAISO's current treatment of ETCs – a scheduling aspect and a settlement aspect – whereby ETC's schedules are accorded different treatment than the treatment accorded other schedules. With respect to scheduling, since start-up the CAISO has accommodated ETCs by (1) "setting-aside" transmission capacity on inter-ties and inter-zonal interfaces (i.e., Path 15 and Path 26) on a day-ahead basis for the sole use of ETC rights holders, and (2) holding that capacity off the market, irrespective of whether or not it was fully scheduled by the ETC right holders, up until 20 minutes before the start of the operating hour in real-time. With respect to the settlement aspect, ETC schedules are exempt from all transmission Access Charges, the Congestion Management component of the Grid Management Charge (GMC), and any Usage Charges for congestion.

The CAISO's current treatment of ETCs in scheduling has created market inefficiencies. It was noted in the *2002, 2003,* and *2004 Annual Report* that the treatment of ETCs was an issue of concern from a market efficiency perspective. It remained a problem in the congestion market in 2005. Under the current market rules, ETC holders have the full amount of their ETC capacity reserved for them in the Day Ahead and Hour Ahead Markets whether they actually use it or not. The unused capacity is only released 20 minutes before the operating hour. Often this capacity cannot be fully utilized with such short notice due to factors such as ramping limits of generating facilities or that market participants have already made other arrangements to meet their load obligations.

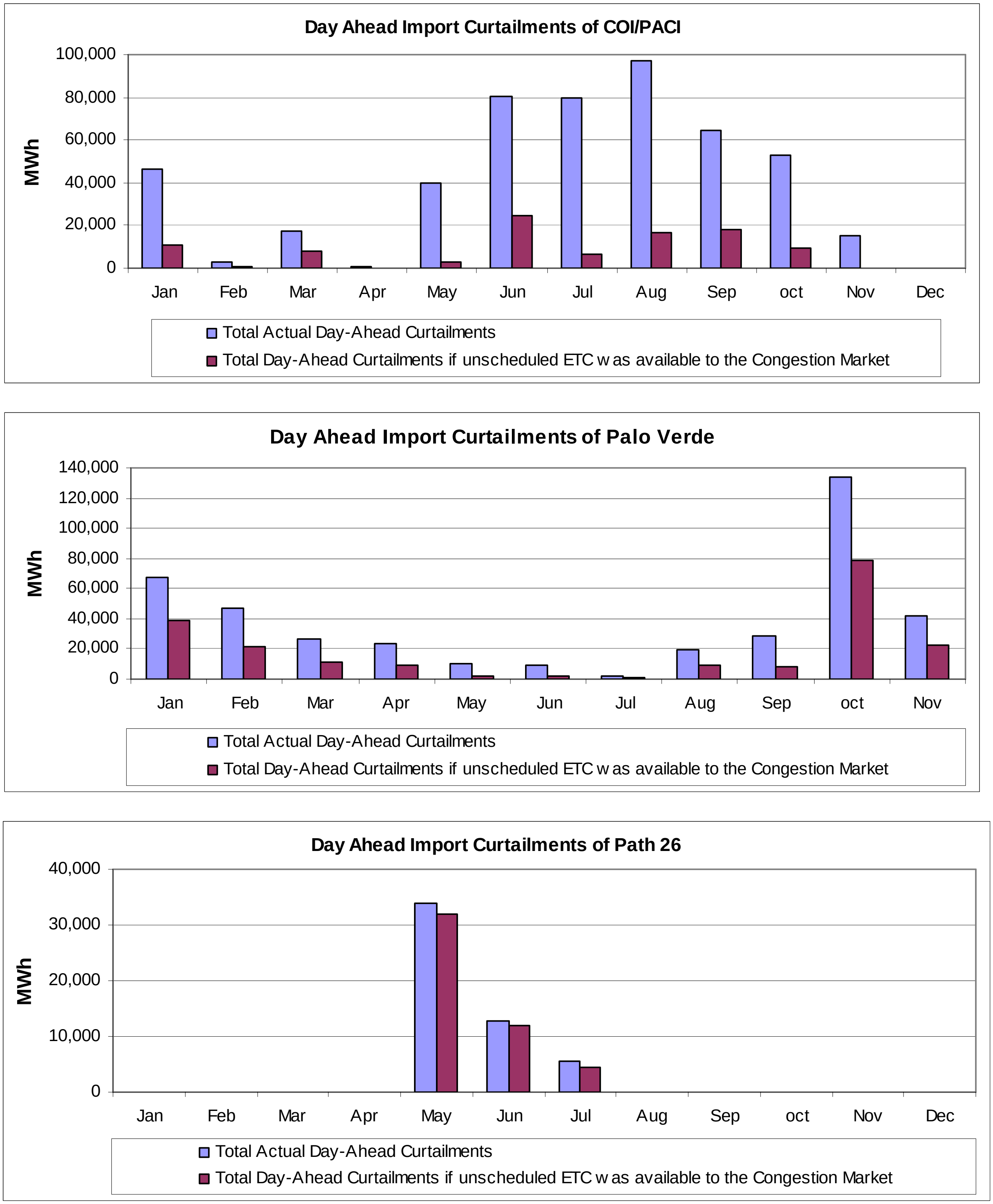
Figure 5.4 demonstrates, for the most congested paths in 2005, the extent to which the observed day-ahead congestion was due to phantom congestion, or the inability to make unscheduled ETC capacity available to the Day Ahead Market[2]. This analysis clearly indicates that releasing unscheduled ETC capacity can significantly reduce the congestion frequencies for all the major paths. For instance, the release of unscheduled ETC capacity and unscheduled capacity on the COTP portion of COI, which is not an ETC but a Transmission Ownership Right (TOR) that is functionally equivalent to an ETC in terms of its treatment and potential for creating phantom congestion, would have significantly reduced the congestion on COI in the import direction. In fact, the CAISO had to curtail about 1,088,984 MW of day-ahead schedules in 2005 (although much less than the 1,947,669 MW in 2004). These curtailments could have been significantly reduced to 421,205 MW if unscheduled ETC capacity would have been released to the market. Phantom congestion compromises market efficiency and can potentially increase the total costs to the final consumers.

Nevertheless, phantom congestion in 2005 was reduced from the 2004 level due to several ETCs that expired in 2005 and by the end of 2004. For instance, for SCE, 1,568 MW of ETC capacity expired on December 31, 2004, 900 MW expired on January 1, 2005, and 110 MW

[2] Note: For inter-ties, unscheduled ETC is based on the amount of ETC reserved in the Day Ahead Market that went unscheduled in the real-time market. For internal paths (Path 15 and Path 26), unscheduled ETC is based on the amount of ETC that was reserved in the Day Ahead but went unscheduled through the Hour Ahead Market (the CAISO does not have real-time schedule data for internal paths).

expired on May 14, 2005. PG&E has been involved in ETC matters pending at the FERC involving the termination of 200 MW of ETC.

Figure 5.4 Phantom Congestion on Major Paths (2005)



5.1.4.2 Remaining Issues with the CAISO's ETC Proposal Under MRTU

The CAISO has long recognized the phantom congestion problem created by unscheduled ETCs in the Day Ahead Market and has tried to address this issue in its market re-design effort. Treatment of ETCs under the CAISO's Market Redesign and Technology Upgrade (MRTU) is an especially important issue since ETCs may be in effect upon implementation of MRTU in November of 2007. In sum, these encumbrances represent transmission capacity of approximately 16,000 MW, or capacity sufficient to meet 35 percent of the CAISO's 2005 peak load of 45,431 MW. Following an extensive stakeholder process in 2004, the CAISO filed with the FERC on December 8, 2004, its Proposed Conceptual Treatment of Existing Transmission Contracts under the CAISO's Amended Comprehensive Market Design Proposal. The proposal resolved how ETCs would be scheduled, validated, and settled under LMP. Responding to the CAISO's proposal, the FERC issued a "Guidance Order on Conceptual Proposal for Honoring of Existing Transmission Contracts" on February 10, 2005. In this order, the FERC approved in principle certain elements of the ETC proposal, provided guidance and requested additional information and explanation of other elements. More specifically, the FERC accepted the CAISO's conceptual proposal to set aside capacity associated with an ETC within the CAISO's control area to the extent that it is scheduled in the Day Ahead Market and to fully honor all valid schedule changes in post-day-ahead markets. Also the FERC accepted the CAISO's proposal to continue to set aside unscheduled capacity over the inter-ties, but not for internal interfaces. The FERC agreed that this will make additional capacity available in the Day Ahead and subsequent markets for use by other users of the system, reduce the likelihood and magnitude of phantom congestion, and promote the convergence of day-ahead and real-time prices.

5.2 Overview of FTR Market Performance

A Firm Transmission Right (FTR) is a right that has the attributes of both financial and physical transmission rights. FTRs entitle their owners to share in the distribution of Usage Charge revenues received by the CAISO (in the Day Ahead and Hour Ahead Markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs also entitle registered FTR Holders to certain scheduling priorities (in the Day Ahead Market) for the transmission of energy across a congested inter-zonal interface.

The CAISO does not require that FTR owners be CAISO Scheduling Coordinators (SCs). FTRs may be purchased by any qualified bidder purely as an investment to enable the owner to receive a stream of income from the congestion usage revenues. In order to be used in scheduling, however, an FTR must be assigned to one of the SCs. In addition, an owner may resell the FTR or the scheduling rights may be unbundled from the revenue rights and sold or transferred to another party. All these sales, transfers or assignments are considered "secondary market transactions" and must be recorded in the CAISO Secondary Registration System (SRS).

5.2.1 Concentration of FTR Ownership and Control

The CAISO creates a primary market for FTRs by auctioning them each year for a 12-month period beginning in April and ending in March. However, due to some significant changes to the CAISO transmission grid in January 2005, an interim FTR auction was held in October 2004 for the effective period from January 1, 2005, through March 31, 2005. The primary FTR auction for the 2005/2006 FTR auction year (from April 1, 2005, to March 31, 2006) occurred in February 2005.

There were several reasons for holding an interim auction for the period from January 1 through March 31, 2005. First, in the 2004 primary FTR Auction held in February 2004 for the 2004/2005 FTR auction (from April 1, 2004, to March 31, 2005), the CAISO released FTRs on COI for only a nine-month duration due to the uncertainty associated with the December 31, 2004, termination of Contract 2947A between PG&E and WAPA. This contract directly impacts the CAISO's rights, through PG&E, for capacity on COI and the associated FTR release. Secondly, when the initial 2004 FTR Auction was held in February 2004, the CAISO was aware that several ETCs were set to terminate effective January 1, 2005. The expiration of these ETCs could free up additional capacity on COI, Path 26, and Path 15, which the CAISO could make available through an additional FTR Auction. Finally, the CAISO has been working with SCE to determine a rating methodology for the outbound direction of the Blythe Branch Group. When the final methodology was approved, the CAISO released incremental capacity in the interim 2004 FTR Auction. Table 5.5 shows the 2004 Interim FTR auction final results for the period from January 1, 2005, to March 31, 2005.

Table 5.5 Summary of 2004 Interim FTR Auction Results

(Effective January 1, 2005 – March 31, 2005)

Branch Group	Direction	Total FTRs Sold (MW)	Auction Clearing Price ($/MW)	Auction Revenue ($)
BLYTHE BG	Export	43	$28	$1,204
COI BG	Export	940	$28	$26,320
COI BG	Import	950	$2,978	$2,829,100
Path 15 BG	South-to-North (ZP26-NP15)	908	$1,826	$1,658,008
Path 26 BG	North-to-South (ZP26-SP15)	173	$995	$172,135
Total		**3,014**		**$4,686,767**

For the 2005/2006 FTR cycle, the primary auction was held and completed in February 2005. The FTR Auction is a simultaneous, multi-round clearing price auction conducted separately and independently across specified CAISO inter-zonal interfaces. Owners of FTRs can use their FTRs as a hedge against congestion costs. Their FTRs also entitle the owners to share in the distribution of Usage Charge revenues received by the CAISO (in the Day Ahead and Hour Ahead Markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs will also entitle the registered FTR Holder to certain priorities (in the Day Ahead Market) for the scheduling of energy across a congested inter-zonal interface. As noted above, the FTRs released in the primary auction are valid from April 1, 2005, through March 31, 2006. Total revenue earned was approximately $94 million, slightly lower than the 2004 primary auction revenue. The FTR Auction proceeds are distributed to Participating Transmission Owners (PTOs), based upon their respective ownership interest in each auctioned path.

In this primary auction, FTRs on 23 directional branch groups were auctioned. In total, the CAISO successfully auctioned 12,063 MW of FTRs, slightly higher than the 11,491 MW of FTRs auctioned in 2004 primary FTR auction. On the branch group level, the revenue on Palo Verde in the import direction increased slightly from $24 million in 2004 to $25 million in 2005. Revenues from FTRs on other frequently congested paths, such as COI (import), NOB (import), and Path 26 (north-to-south), all decreased in 2005. FTR revenue on Path 26 in the north-to-south direction decreased from $22 million in 2004 to $10 million in 2005. The changes in FTR auction revenues on different paths reflected the patterns of congestion in the past year.

As in the previous auction, one discernible pattern in the FTR auction results was that investor owned utilities acquired most FTRs on branch groups that are likely to be congested. For instance, Pacific Gas & Electric won 93 percent of FTRs on COI in the import direction, while Southern California Edison won 100, 84, 60, 100, and 68 percent of FTRs on El Dorado (import), Mead (import), Palo Verde (import), Silver Peak (import), and Path 26 (north-to-south), respectively. As the principal transmission owners of these paths, the utilities are also the recipients of the auction revenues. This allows them to bid very aggressively to ensure they acquire the quantity of FTRs they require to serve their retail customers without significant exposure to the spot congestion markets. This may have an inflationary effect on FTR auction clearing prices.

Table 5.6 Summary of 2005-2006 FTR Auction Results

Branch Group	Direction	Total FTRs Sold (MW)	Auction Clearing Price ($/MW)	Auction Revenue ($)
BLYTHE BG	Import (LC2-SP15)	177	$6,714	$1,188,452
BLYTHE BG	Export (SP15-LC2)	38	$100	$3,800
CFE BG	Import (MX-SP15)	200	$265	$53,000
COI BG	Import (NW1-NP15)	890	$18,609	$16,562,330
COI BG	Export (NP15-NW1)	573	$240	$137,520
ELDORADO BG	Import (AZ2-SP15)	743	$27,701	$20,581,962
ELDORADO BG	Export (SP15-AZ2)	445	$100	$44,500
IID - SCE BG	Import (II1-SP15)	600	$295	$177,000
IID - SDGE BG	Import (II2-SP15)	62	$190	$11,780
IID - SDGE BG	Export (SP15-II2)	62	$145	$8,990
MEAD BG	Import (LC1-SP15)	597	$18,174	$10,850,093
MEAD BG	Export (SP15-LC1)	637	$210	$133,770
NOB BG	Import (NW3-SP15)	169	$20,790	$3,513,483
NOB BG	Export (SP15-NW3)	173	$1,840	$318,320
PALOVRDE BG	Import (AZ3-SP15)	910	$27,425	$24,957,041
PALOVRDE BG	Export (SP15-AZ3)	683	$100	$68,300
PARKER BG	Import (LC3-SP15)	130	$705	$91,650
PATH 15 BG	Import (ZP26-NP15)	1807	$3,056	$5,522,626
PATH 26 BG	Export (ZP26-SP15)	1,464	$6,637	$9,716,641
SLVRPK BG	Import (SR3-SP15)	10	$540	$5,400
SLVRPK BG	Export (SP15-SR3)	10	$180	$1,800
VICTRVL BG	Export (SP15-LA4)	439	$100	$43,900
VICTRVL BG	Import (LA4-SP15)	1244	$100	$124,400
Total		**12,063**		**$94,116,759**

Table Column Definition:
Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed price > $100/MW per year, the comparison of the Auction Clearing Price and Seed Price* 5 indicates the extent to which the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.
Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.
Auction Revenue: This is equal to the product of Auction Clearing Price and Final MW Sold.

Table 5.7 FTR Concentration as of April 2005 *

Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
EXP	BLYTHE	MSCG	Morgan Stanley Capital Group, Inc.	100	38	38
EXP	COI	MSCG	Morgan Stanley Capital Group, Inc.	22	124	573
EXP	COI	BPEC	BP Energy Company	9	50	573
EXP	COI	CAL1	Cargill Power Markets	2	14	573
EXP	COI	CPSC	Constellation Energy Commodities	9	50	573
EXP	COI	NEI1	Constellation NewEnergy	2	10	573
EXP	COI	PCPM	PPM Energy Inc.	4	25	573
EXP	COI	PSCO	Public Service Company of Colorado	9	50	573
EXP	COI	PWRX	Powerex Corporation	35	200	573
EXP	COI	TEMU	TransAlta Energy Marketing	9	50	573
EXP	ELDORADO	MSCG	Morgan Stanley Capital Group, Inc.	55	245	445
EXP	ELDORADO	PSCO	Public Service Company of Colorado	34	150	445
EXP	ELDORADO	TEMU	TransAlta Energy Marketing	11	50	445
EXP	IID-SDGE	SETC	Sempra Energy Trading Corp.	81	50	62
EXP	IID-SDGE	MSCG	Morgan Stanley Capital Group, Inc.	19	12	62
EXP	MEAD	MSCG	Morgan Stanley Capital Group, Inc.	10	62	637
EXP	MEAD	PSCO	Public Service Company of Colorado	78	500	637
EXP	MEAD	SETC	Sempra Energy Trading Corp.	4	25	637
EXP	MEAD	TEMU	TransAlta Energy Marketing	8	50	637
EXP	NOB (PAC. DC INTER-TIE)	CPSC	Constellation Energy Commodities	29	50	173
EXP	NOB (PAC. DC INTER-TIE)	PSCO	Public Service Company of Colorado	55	96	173
EXP	NOB (PAC. DC INTER-TIE)	RVSD	City of Riverside	16	27	173
EXP	PALO VERDE	MSCG	Morgan Stanley Capital Group, Inc.	41	283	683
EXP	PALO VERDE	SETC	Sempra Energy Trading Corp.	22	150	683
EXP	PALO VERDE	TEMU	TransAlta Energy Marketing	7	50	683
EXP	PALO VERDE	WESC	Williams Power Company	29	200	683
EXP	PATH 26	MSCG	Morgan Stanley Capital Group, Inc.	3	41	1464
EXP	PATH 26	PCG2	Pacific Gas & Electric	7	108	1464
EXP	PATH 26	PWRX	Powerex Corporation	15	217	1464
EXP	PATH 26	SCE1	Southern California Edison	23	342	1464
EXP	PATH 26	SDG3	San Diego Gas & Electric	38	560	1464
EXP	PATH 26	SETC	Sempra Energy Trading Corp.	5	75	1464
EXP	PATH 26	TEMU	TransAlta Energy Marketing	8	121	1464
EXP	SILVER PEAK	MSCG	Morgan Stanley Capital Group, Inc.	20	2	10
EXP	SILVER PEAK	CEPL	Citadel Energy Products LLC	80	8	10
EXP	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	33	144	439
EXP	VICTORVILLE	WESC	Williams Power Company	45	196	439
EXP	VICTORVILLE	SETC	Sempra Energy Trading Corp.	23	99	439

* Only FTR ownership concentrations at or more than 25 percent are reported in this table.

Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
IMP	BLYTHE	FPPM	FPL Energy Power Marketing, Inc.	100	177	177
IMP	CFE	MSCG	Morgan Stanley Capital Group, Inc.	4	8	200
IMP	CFE	NEI1	Constellation NewEnergy	13	25	200
IMP	CFE	PWRX	Powerex Corporation	46	91	200
IMP	CFE	SETC	Sempra Energy Trading Corp.	38	76	200
IMP	COI	PCG2	Pacific Gas & Electric	28	252	890
IMP	COI	PWRX	Powerex Corporation	27	240	890
IMP	COI	SCE1	Southern California Edison	33	298	890
IMP	COI	TEMU	TransAlta Energy Marketing	11	100	890
IMP	ELDORADO	SCE1	Southern California Edison	100	743	743
IMP	IID-SCE	CAL1	Cargill Power Markets	4	25	600
IMP	IID-SCE	MSCG	Morgan Stanley Capital Group, Inc.	7	40	600
IMP	IID-SCE	RVSD	City of Riverside	3	20	600
IMP	IID-SCE	SCE1	Southern California Edison	77	460	600
IMP	IID-SCE	SETC	Sempra Energy Trading Corp.	3	19	600
IMP	IID-SCE	TEMU	TransAlta Energy Marketing	6	36	600
IMP	IID-SDGE	MSCG	Morgan Stanley Capital Group, Inc.	19	12	62
IMP	IID-SDGE	SETC	Sempra Energy Trading Corp.	81	50	62
IMP	MEAD	FPPM	FPL Energy Power Marketing, Inc.	10	57	597
IMP	MEAD	PSCO	Public Service Company of Colorado	61	365	597
IMP	MEAD	SCE1	Southern California Edison	29	175	597
IMP	NOB (PAC. DC INTER-TIE)	CPSC	Constellation Energy Commodities	15	25	169
IMP	NOB (PAC. DC INTER-TIE)	PSCO	Public Service Company of Colorado	51	86	169
IMP	NOB (PAC. DC INTER-TIE)	RVSD	City of Riverside	34	58	169
IMP	PALO VERDE	BAN1	City of Banning	0	4	910
IMP	PALO VERDE	CPSC	Constellation Energy Commodities	5	50	910
IMP	PALO VERDE	MSCG	Morgan Stanley Capital Group, Inc.	3	27	910
IMP	PALO VERDE	OPSI	Occidental Power Services, Inc.	8	71	910
IMP	PALO VERDE	PWRX	Powerex Corporation	5	45	910
IMP	PALO VERDE	SCE1	Southern California Edison	67	613	910
IMP	PALO VERDE	SETC	Sempra Energy Trading Corp.	11	100	910
IMP	PARKER	FPPM	FPL Energy Power Marketing, Inc.	100	130	130
IMP	PATH 15	PCG2	Pacific Gas & Electric	94	1700	1807
IMP	PATH 15	PWRX	Powerex Corporation	1	25	1807
IMP	PATH 15	SETC	Sempra Energy Trading Corp.	5	82	1807
IMP	SILVER PEAK	SCE1	Southern California Edison Company	100	10	10
IMP	VICTORVILLE	BPEC	BPEnergy Company	8	100	1244
IMP	VICTORVILLE	CAL1	Cargill Power Markets	4	50	1244
IMP	VICTORVILLE	MRNT	Mirant Americas Energy Marketing	5	60	1244
IMP	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	29	362	1244
IMP	VICTORVILLE	PWRX	Powerex Corporation	24	301	1244
IMP	VICTORVILLE	SETC	Sempra Energy Trading Corp.	16	200	1244
IMP	VICTORVILLE	TEMU	TransAlta Energy Marketing	4	50	1244
IMP	VICTORVILLE	WESC	Williams Power Company	10	121	1244

5.2.2 2005 FTR Market Performance

5.2.2.1 FTR Scheduling

FTRs can be used to hedge against high congestion prices and establish scheduling priority in the Day Ahead Market. As shown in Table 5.8, a high percentage of FTRs were scheduled on a few paths (83 percent on Eldorado, 73 percent on IID-SCE, 51 percent on Palo Verde, 80 percent on Silver Peak, 80 percent on IPPDCADLN, and 30 percent on Path 26). SCE and municipals primarily own the FTRs on these paths. In the 2005 FTR cycle, the average amount of FTRs scheduled was low. On average, only 24.3 percent of the total FTRs were scheduled in the Day Ahead Market, lower than the 38 percent in the 2004 FTR cycle. However, on some paths, FTR scheduling percentages were high and FTRs were used to establish the scheduling priority in the Day Ahead Market.

Table 5.8 FTR Scheduling Statistics, April 1 – December 31, 2005*

		MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE _BG	177	34	177	177	19%
IMP	COI _BG	890	142	252	252	16%
IMP	ELDORADO _BG	743	616	720	720	83%
IMP	IID-SCE _BG	600	439	469	449	73%
IMP	IPPDCADLN_BG	647	470	569	314	73%
IMP	MEAD _BG	667	52	451	350	8%
IMP	MEADTMEAD_BG	182	12	57	38	6%
IMP	MKTPCADLN_BG	423	13	105	90	3%
IMP	MONAIPPDC_BG	658	54	88	52	8%
IMP	NOB _BG	358	63	299	81	17%
IMP	PALOVRDE _BG	935	474	745	600	51%
IMP	PARKER _BG	130	26	130	130	20%
IMP	SILVERPK _BG	10	8	10	10	80%
IMP	VICTVL _BG	1244	27	100	100	2%
IMP	WSTWGMEAD_BG	126	37	61	28	29%
EXP	ELDORADO _BG	445	7	150	150	2%
EXP	GONDIPPDC_BG	21	6	15	15	27%
EXP	MEAD _BG	671	9	300	300	1%
EXP	MEADMKTPC_BG	263	0	60	60	0%
EXP	MEADTMEAD_BG	182	0	25	25	0%
EXP	MKTPCADLN_BG	423	2	28	25	1%
EXP	MONAIPPDC_BG	558	4	152	137	1%
EXP	NOB _BG	351	23	89	50	6%
N->S	PATH26 _BG	1464	443	662	560	30%

* Only those paths on which 1 percent or more of FTRs were attached are listed.

5.2.2.2 FTR Revenue Per MW

The current FTR market cycle begins on April 1, 2005, and ends on March 31, 2006. Table 5.9 summarizes the FTR revenues from April 1, 2005, to December 31, 2005.

During the current FTR cycle, only four paths (Blythe in the import direction, COI/PACI in the import direction, IID-SCE in the import direction, Palo Verde in the import direction) had total pro-rated FTR revenue greater than their auction prices. One straightforward conclusion is that some FTR holders did not financially benefit from their investment in the FTR market. This is not surprising. As mentioned earlier, the FTR holders of major paths are also transmission owners. The FTR auction revenues are used to reduce the transmission revenue requirement (TRR). As a result, the FTR purchase costs for these entities is to a large extent offset by a corresponding reduction in the TRR. Also, besides the FTR revenue, the FTR provides additional benefits to the holders. Schedules with FTR rights are entitled to scheduling priority in the Day Ahead Market and FTRs can serve as insurance to hedge against possible high congestion charges.

Finally, consistent with the congestion patterns, the FTR revenues were significant on a few of the most congested paths (see Table 5.9). FTR revenue on Blythe (import), COI (import), Palo Verde (import), and Path 26 (north-to-south) all exceeded $10,000 per MW as of December 31, 2005.

Table 5.9 FTR Revenue Statistics ($/MW) (April 2005 - December 2005)

		Net $/MW FTR Revenue											
Branch Group	Directn	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Cumm Net $/MW FTR Rev	Pro-Rated Net $/MW FTR Rev	Pa Auc Price ($/MW)
ADLANTOSP	IMPORT	$0	$0	$0	$0	$0	$3,516	$599	$190	$6	$4,311	$5,748	$0
BLYTHE	IMPORT	$0	$5,143	$5,957	$1,198	$1,381	$11,164	$2,366	$10,819	$8,202	$46,229	$61,639	$6,714
COI	IMPORT	$159	$2,081	$3,413	$2,199	$1,460	$3,664	$1,504	$251	$0	$14,730	$19,640	$18,609
ELDORADO	IMPORT	$61	$0	$187	$0	$4	$655	$2,412	$471	$1,159	$4,948	$6,598	$27,701
IID-SCE	IMPORT	$0	$0	$0	$823	$0	$0	$706	$1,960	$80	$3,568	$4,758	$295
IPPDCADLN	IMPORT	$399	$2,241	$263	$0	$258	$234	$588	$1,040	$1,706	$6,727	$8,970	$0
MEAD	IMPORT	$0	$0	$0	$491	$110	$903	$2,319	$2,156	$3,043	$9,022	$6,015	$18,174
NOB	IMPORT	$35	$3,674	$1,453	$1,318	$565	$1,019	$1,701	$40	$0	$9,805	$6,537	$20,790
PALOVRDE	IMPORT	$3,936	$3,963	$10	$6,770	$338	$8,721	$2,686	$29,869	$33,564	$89,856	$59,904	$27,425
PARKER	IMPORT	$0	$0	$0	$0	$0	$6	$14	$160	$0	$180	$240	$705
PATH15	IMPORT	$4	$0	$0	$0	$0	$906	$722	$906	$17	$2,555	$3,406	$3,056
WSTWGMEAD	IMPORT	$193	$47	$0	$1	$1,685	$832	$173	$1,324	$354	$4,607	$6,143	$0
GONDIPPDC	EXPORT	$0	$0	$0	$480	$0	$0	$0	$0	$0	$480	$640	$0
MEAD	EXPORT	$0	$0	$0	$138	$0	$0	$0	$0	$0	$138	$92	$210
PATH26	N->S	$0	$13,096	$5,288	$810	$50	$0	$119	$0	$0	$19,364	$25,819	$6,637

5.2.2.3 FTR Trades in the Secondary Markets

In California, the successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary markets. However, as shown in Table 5.10, the FTR transactions in the secondary markets have been minimal during the past FTR cycle. There were a total of 18 cases of changes in ownership of FTRs in the 2005 cycle (determined by different SC_ID association over time). However, all of these exchanges occurred between the four Southern

Participating Transmission Owners (SPTOs) (i.e., the City of Pasadena, the City of Anaheim, the City of Banning, and the City of Riverside) and the CAISO, due to either the transfer of FTRs owned by SPTOs to the CAISO, or the revision of the SPTOs' entitlements. For example, 14 cases of changes in ownership of FTRs were due to the transfer of FTRs owned by three of the SPTOs (i.e., City of Pasadena, City of Anaheim, City of Riverside) to the CAISO. For the most part, the secondary FTR market was rarely used during the three most recent FTR cycles. One possible explanation might be that FTR revenues only exceeded their prices in a few paths in 2005 and most of the investments in FTRs did not generate positive financial profits. Therefore, there was little incentive for market participants to purchase additional FTRs in the secondary market.

Table 5.10 FTR Trades in the Secondary Market (April 2005 - December 2005)

Branch Grp	Trade Day	Direction	Buyer	Seller	Quantity Sold (MW)	Operation Day Minimum	Operation Day Maximum	Minimum Operation Hour	Maximum Operation Hour
GONDIPPDC_BG	30-Mar-05	IMPORT	CISO	ANHM	2	1-Apr-05	31-Mar-06	1	25
GONDIPPDC_BG	31-Mar-05	IMPORT	CISO	RVSD	1	2-Apr-05	31-Mar-06	1	25
MONAIPPDC_BG	30-Mar-05	IMPORT	CISO	ANHM	17	1-Apr-05	31-Dec-05	1	25
MONAIPPDC_BG	30-Mar-05	IMPORT	CISO	ANHM	17	1-Jan-06	31-Mar-06	1	24
MONAIPPDC_BG	31-Mar-05	IMPORT	CISO	PASA	5	2-Apr-05	31-Mar-06	1	24
MONAIPPDC_BG	31-Mar-05	IMPORT	CISO	PASA	5	1-Apr-05	1-Apr-05	1	25
MONAIPPDC_BG	31-Mar-05	IMPORT	CISO	RVSD	10	1-Apr-05	31-Mar-06	1	25
NOB _BG	14-Mar-05	IMPORT	RVSD	CISO	23	1-Apr-05	31-Mar-06	1	25
PALOVRDE _BG	18-Mar-05	IMPORT	BAN1	CISO	15	1-Apr-05	31-Mar-06	1	25
GONDIPPDC_BG	30-Mar-05	EXPORT	CISO	ANHM	2	1-Apr-05	31-Mar-06	1	25
GONDIPPDC_BG	31-Mar-05	EXPORT	CISO	PASA	1	14-May-05	31-Mar-06	1	24
GONDIPPDC_BG	31-Mar-05	EXPORT	CISO	PASA	1	1-Apr-05	1-Apr-05	1	25
IPPDCADLN_BG	12-May-05	EXPORT	PASA	CISO	33	1-Apr-05	31-Mar-06	1	25
MONAIPPDC_BG	30-Mar-05	EXPORT	CISO	ANHM	10	1-Apr-05	31-Dec-05	1	25
MONAIPPDC_BG	30-Mar-05	EXPORT	CISO	ANHM	10	1-Jan-06	31-Mar-06	1	24
MONAIPPDC_BG	31-Mar-05	EXPORT	CISO	PASA	3	2-Apr-05	31-Mar-06	1	25
MONAIPPDC_BG	31-Mar-05	EXPORT	CISO	RVSD	6	1-Apr-05	31-Mar-06	1	25
NOB _BG	14-Mar-05	EXPORT	RVSD	CISO	23	1-Apr-05	31-Mar-06	1	25

6. Real-time (Intra-Zonal) Congestion

6.1 Introduction/Background

Real-time congestion occurs when scheduled power flows overload the transfer capability of grid facilities. The CAISO's day-ahead and hour-ahead congestion management system has established congestion zones that it models in order to measure and manage congestion. Real-time congestion results from a combination of economic factors and the fact that the CAISO only manages zonal congestion in the Day Ahead and Hour Ahead Markets.

Scheduling Coordinators (SCs) submit day-ahead/hour-ahead generation schedules to the CAISO. Due to differences in the price and availability of power in different locations, these schedules vary daily and, collectively, may exceed the transfer capability of grid facilities within the congestion zones. However, the CAISO's congestion management system measures and manages congestion only between zones, not within zones. This allows SCs, collectively, to submit day-ahead/hour-ahead schedules calling for transmission within a zone that is not physically feasible. This creates the need for CAISO operators to have to manage intra-zonal congestion in real-time. Managing large amounts of intra-zonal congestion in real-time creates operational and reliability challenges and can result in significant costs.

Intra-zonal congestion costs are comprised of three components:

1. Minimum Load Cost Compensation (MLCC).[1] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[2]
2. Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.
3. Costs of Out-of-Sequence (OOS) dispatches.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission to allow access to competitively priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together, with insufficient transmission to allow the energy to flow out of the pocket area. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Typically, there is very limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal congestion is closely intertwined with the issue of locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise locational market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often

[1] MLCC payments are cost-based and are calculated as variable cost for providing the minimum load energy plus a $6/MWh O&M adder.

[2] Pursuant to Amendment 60, MLCC costs are categorized into three categories (system, zonal and local), which reflect the primary reason the unit was denied a must-offer waiver. Both zonal and local MLCC costs are included as the MLCC component of intra-zonal costs.

constrains long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments. This is the means to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO real-time market.[3] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids OOS;[4]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-Of-Market (OOM).

Units incremented OOS to mitigate intra-zonal congestion are paid the higher of their bid price or the zonal market clearing price. They do not set the real-time market clearing price. Units decremented OOS to mitigate intra-zonal congestion are charged the lower of their decremental reference price or the zonal market-clearing price. They also do not set the real-time market clearing price. Inter-tie bids taken OOS are settled on an as-bid basis.

In addition, OOS bids are subject to local market power mitigation. Specifically, incremental OOS dispatches are subject to a conduct test where accepted OOS bids priced greater than the minimum of $50 or 200 percent above interval MCP are mitigated to their reference price for that OOS dispatch and are settled at the greater of mitigated bid price or the interval MCP. To the extent decremental bids are dispatched OOS for intra-zonal congestion, such dispatches will be based on decremental reference levels provided by an independent entity (Potomac Economics) rather than market bids.

6.2 Major Points of Intra-Zonal Congestion

Most of the major points of intra-zonal congestion in 2005 were located in the CAISO's southern congestion zone (SP15). Three new major points of intra-zonal congestion in 2005 were South of Pastoria, South of Magunden, and Cortina/North Geyser. Figure 6.1 shows the approximate location of each of these points in the CAISO Control Area.

[3] Available thermal units within the CAISO Control Area are subject to the Must-Offer-Obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids.

[4] The term "out-of-sequence" refers to the fact that such dispatches require the CAISO, when incrementing (or decrementing) generation, to bypass lower (or higher) priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

Figure 6.1 Major Points of Intra-Zonal Congestion in 2005

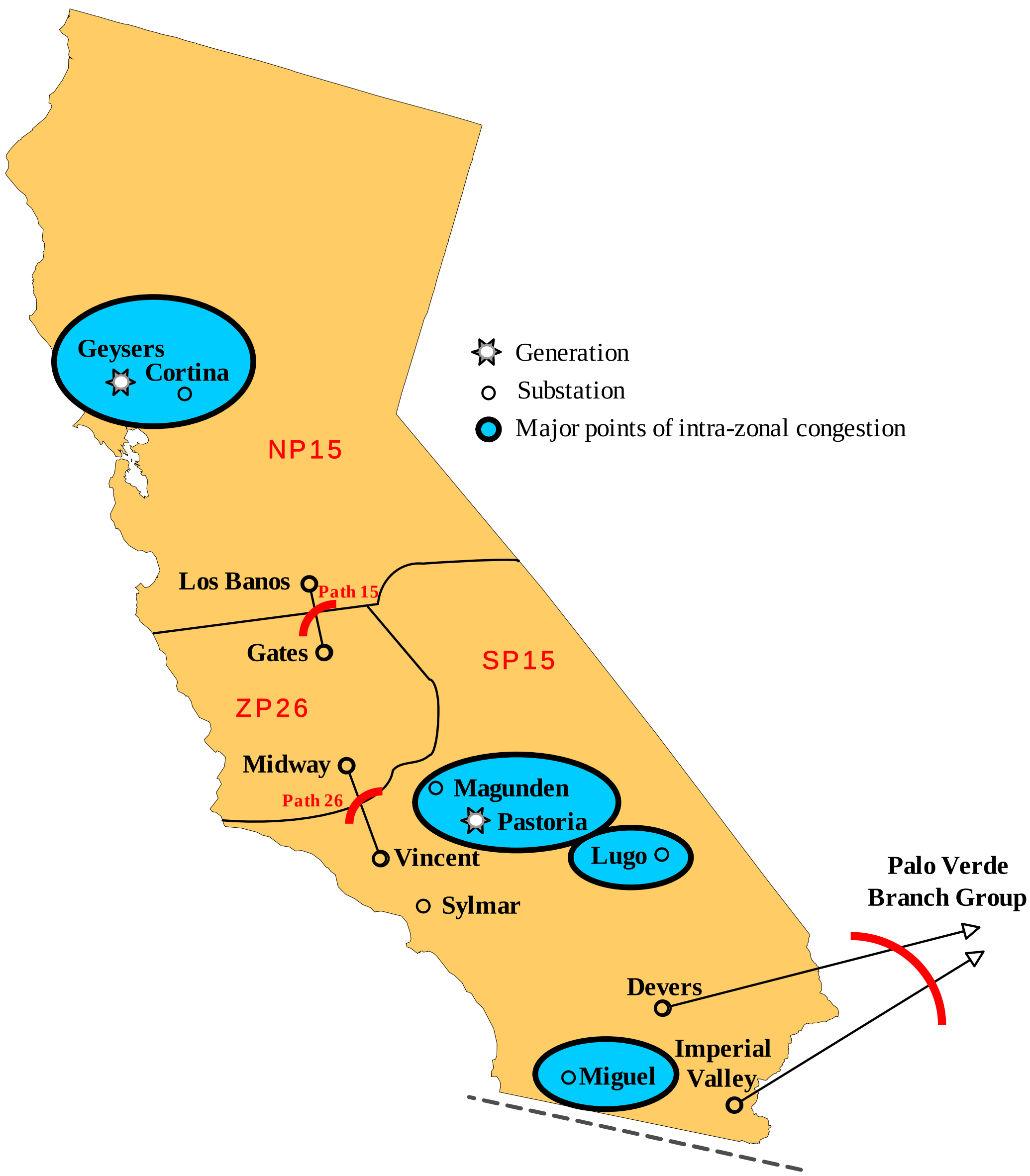
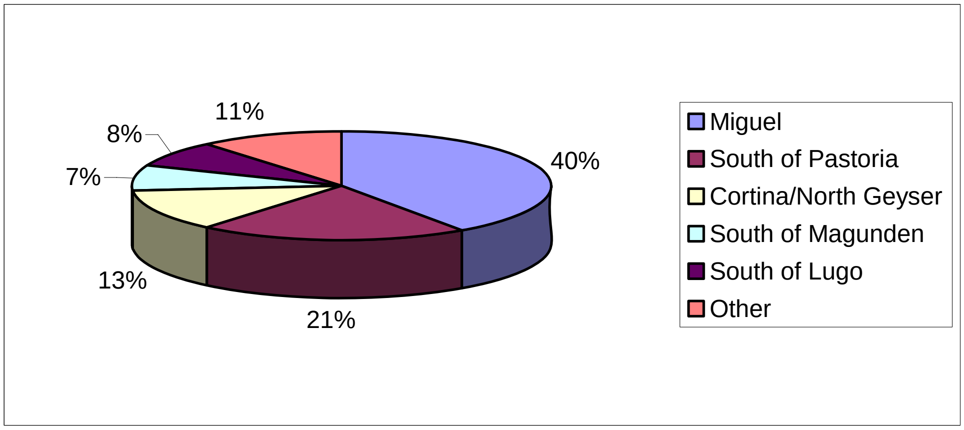


Figure 6.2 shows the percentages of total (OOS) redispatch cost[5] for each of the major intra-zonal congestion points. A description of each of these major intra-zonal constraints is provided below.

[5] The redispatch cost for units with incremented OOS dispatches that are not mitigated under the local market mitigation procedures is calculated as the higher of the unit's bid price minus the zonal market-clearing price or zero. For incremental OOS dispatches that are mitigated under the local market power mitigation procedures, the redispatch cost will be based on the same formula except that the unit's incremental reference price will be used in place of its market bid. The redispatch costs for decremental intra-zonal congestion is calculated as the higher of zero or the zonal market-clearing prices minus the unit's decremental reference level.

Figure 6.2 Real-time Intra-Zonal OOS Redispatch Costs by Reason



Miguel. Intra-zonal congestion costs associated with the Miguel area decreased in 2005 compared to 2004. The decrease in congestion cost on the Miguel substation close to San Diego is attributable largely to the upgrade of the new Miguel #2 230 kV line, which was on line in June 2005. The upgrade resulted in the congestion cost in this area steadily going down from Spring 2005 through Summer 2005. Prior to the upgrade, intra-zonal congestion was frequent and significant due to the addition of three new generation units in northern Mexico in 2003 comprising about 1,070 MW of capacity. These units are connected to the CAISO system at the Imperial Valley substation. When combined with imported energy on the Palo Verde Inter-tie, this additional generation has frequently created congestion at the Miguel substation. To mitigate congestion at Miguel, the CAISO must increment resources in the San Diego area, and must decrement generation in northern Mexico east of Miguel and/or decrement imports on the Palo Verde tie point with Arizona. The cost in January 2005 (prior to the upgrade) was $3.6 million, whereas in August 2005 intra-zonal congestion management costs were less than $0.2 million. However, the largest single component of OOS redispatch costs is attributable to intra-zonal congestion at Miguel, with 40 percent of total OOS redispatch cost. While the upgrades did appear to decrease redispatch costs resulting from real-time congestion management at Miguel in the first half of the year, those costs began increasing again during the second half of the year, peaking at $3 million in December.

South of Pastoria/South of Magunden. Since Pastoria Energy Facility's combined cycle unit started its operation in February 2005 with an initial maximum capacity of 255 MW that was gradually increased to a maximum capacity of 750 MW in July 2005, the transmission lines in South of Pastoria (Pastoria – Pardee 230 kV line, Pastoria – Bailey – Pardee 230 kV line, and Pastoria – Warne – Pardee 230 kV line) and two 230 kV lines from Magunden to Antelope are inadequate to handle the output from the new generator and output from the Big Creek hydroelectric facility. As a consequence, the CAISO has been mitigating the intra-zonal congestion in this area during the second half of 2005. Monthly redispatch costs to mitigate this intra-zonal congestion has varied from $1 million to $2 million dollars starting from September 2005. The recent projects by SCE to reconductor the Pastoria/Pardee line and the Pastoria/Bailey line will relieve the severity of congestion in future. The reconductoring work of these two lines is expected to be finished in March 2006 and June 2006, respectively.

Cortina/North Geysers. The Cortina/North Geysers area experienced significant congestion in Spring 2005, when a major upgrade in the transmission system was in full construction. The upgrades included: Cortina 420 MVA 230/60kV Transformer Bank #4, Cortina – Eagle Rock/

Eagle Rock – Red Bud 115 kV Line Swap, Mendocino 200 MVA 115/60kV Transformer Bank and Mendocino 75 MVAR 115kV Capacitor Bank. The area voltage stability margin and thermal overload were improved upon the completion of these upgrades in Fall 2005. The congestion cost was greatly reduced to insignificant numbers.

South of Lugo. The total OOS redispatch cost of mitigating South of Lugo congestion in 2005 was a little less than $3 million. SCE added equipment that allowed the CAISO to boost the rated capacity of the grid in the Victorville/Norco/Ontario area by 500 MW. The upgrade reduces congestion and supplies more electricity to the Los Angeles Basin. However, the South of Lugo area still remains one of the most constrained areas in the CAISO system. Mitigation costs approached $1 million in November 2005 due to line outages.

6.3 Intra-Zonal Congestion Costs

One notable change in CAISO costs for 2005 was the significant decrease in total intra-zonal congestion costs. While 2004 was a high-cost year for intra-zonal congestion management, coming in at $426 million, the total costs in 2005 were down 52 percent to $203 million with significant decreases in MLCC costs (down 58 percent) associated with fewer MOO waiver denials and real-time redispatch costs (down 65 percent). These costs are summarized in Table 6.1.

Table 6.1 Total Estimated Intra-Zonal Congestion Costs for 2003-2005 ($M)

	MLCC			RMR			R-T Redispatch			Total		
	2003	**2004**	**2005**	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**	**2003**	**2004**	**2005**
January	$6	$12	$8	$0	$3	$3	$1	$4	$6	$7	$19	$16
February	$6	$13	$4	$1	$4	$3	$0	$7	$3	$7	$23	$10
March	$6	$20	$3	$0	$4	$4	$1	$8	$3	$7	$31	$10
April	$4	$18	$6	$1	$4	$5	$2	$5	$3	$7	$27	$14
May	$1	$22	$14	$3	$3	$5	$0	$4	$2	$3	$28	$20
June	$2	$25	$7	$2	$3	$2	$0	$2	$0	$4	$30	$9
July	$3	$29	$13	$2	$6	$4	$0	$11	$1	$5	$47	$18
August	$13	$29	$14	$4	$5	$7	$9	$15	$1	$25	$50	$22
September	$10	$23	$8	$3	$4	$7	$6	$12	$3	$19	$39	$18
October	$11	$21	$13	$6	$4	$7	$8	$18	$4	$25	$43	$25
November	$9	$29	$12	$2	$5	$4	$2	$9	$6	$13	$44	$22
December	$9	$33	$11	$3	$4	$2	$17	$8	$5	$29	$45	$18
Totals	**$78**	**$274**	**$114**	**$27**	**$49**	**$53**	**$46**	**$103**	**$36**	**$151**	**$426**	**$203**

A detailed discussion of each of three cost components of intra-zonal congestion is provided below.

6.3.1 Minimum Load Cost Compensation

Minimum Load Cost Compensation (MLCC) pertains to the minimum load cost of generating units that are denied a waiver from the Must-Offer Obligation and are therefore required to be on-line at minimum load for the next operating day. In such cases, the CAISO is required to compensate the units for their minimum load costs. In addition, a generator with units under must-offer waiver denials is also paid the real-time energy price for the unit's minimum load energy.[6] Units subject to Must-Offer Obligations are also required to bid all unloaded capacity into the CAISO Real Time Market. In order to encourage units on must-offer waiver denials to bid into the ancillary service markets, the CAISO filed Amendment 60, which allows them to keep ancillary service revenues without having to forfeit MLCC.

Table 6.2 Must-Offer Waiver Denial Capacity and Costs ($M)

	2004			2005		
Month	**Average MW ***	**MLCC ($M)**	**Imbalance ML Energy Payments ($M)****	**Average MW ***	**MLCC ($M)**	**Imbalance ML Energy Payments ($M)****
January	1,626	$13	$5	840	$8	$4
February	1,719	$13	$5	723	$4	$1
March	2,792	$21	$8	474	$4	$1
April	2,542	$18	$7	524	$6	$2
May	2,524	$23	$10	2,142	$14	$4
June	2,729	$25	$9	1,348	$8	$3
July	3,568	$33	$14	2,050	$21	$10
August	3,151	$30	$11	1,461	$17	$7
September	3,153	$25	$10	890	$8	$3
October	2,383	$23	$10	940	$13	$5
November	2,646	$30	$15	1,098	$12	$6
December	2,704	$33	$15	865	$11	$4
Annual Total	**2,628**	**$287**	**$118**	**1,113**	**$126**	**$51**

* Average maximum daily capacity of units on must-offer waiver. Includes minimum operating level plus unloaded capacity.

** Uninstructed energy payment for minimum load energy received by generator. Since MLCC covers full operating costs, this represents net operating revenue for the generator, or contribution to fixed costs.

Table 6.2 tabulates the MLCC payments to units that were denied waivers for intra-zonal or other local reliability concerns during 2004-2005. As shown, overall capacity operating each day due to must-offer waiver denials and the MLCC costs associated with this capacity both decreased by nearly 60 percent in 2005, from an average of 2,628 MW per day in 2004 to 1,113 MW per day in 2005 and from a total cost of $287 million to $126 million in 2005. The imbalance energy payments received by generators (in addition to MLCC payments) for the minimum load energy associated with this capacity also decreased by about 57 percent, from $118 million to $51 million. Figure 6.3 and Figure 6.4 show the average daily capacity on must-offer waiver denial and total MLCC costs (both system and congestion related) by month for 2003 through 2005.

The overall reliance by the CAISO on the must-offer waiver denial process to commit units to provide reliability service (both system and congestion related) is depicted in Figure 6.3. Unit commitments (and total unit capacity committed) in 2005 declined significantly from the high levels seen in 2004 due in large part to resolution of transmission congestion issues frequently

[6] Since generators are paid twice for minimum load energy – once through the MLCC and again through payments for imbalance energy – the CAISO sought to net these imbalance energy payments against MLCC as part of its Amendment 60 filing. However, FERC ruled that generators should continue to receive imbalance energy payments for minimum load energy in order to provide a source of contribution to fixed costs.

experienced at Sylmar and an increase of 500 MW in the SCIT limit that was implemented in January 2005. Both of these factors resulted in a significant decrease in additional unit commitments in SP15. The congestion issue at Sylmar was resolved late in 2004, when the new 230/220 kV, 900 MVA bank was finished at the Sylmar station. This upgrade increased the Path 41 rating from 800 MVA to 1600 MVA, relieving the requirement to commit units out-of-market to provide reliability support in this area. Figure 6.3 also highlights the high non-market unit commitment requirements in 2003. These were driven in large part by several transmission outages (specifically, Sylmar bank, Lugo substation, and the PDCI line outages) and extended generation outages that contributed to inertia deficiencies on the SCIT.

Figure 6.3 Average Daily Capacity on Must-Offer Waiver Denial for All Reasons (Local, Zonal, and System) (2003-2005)

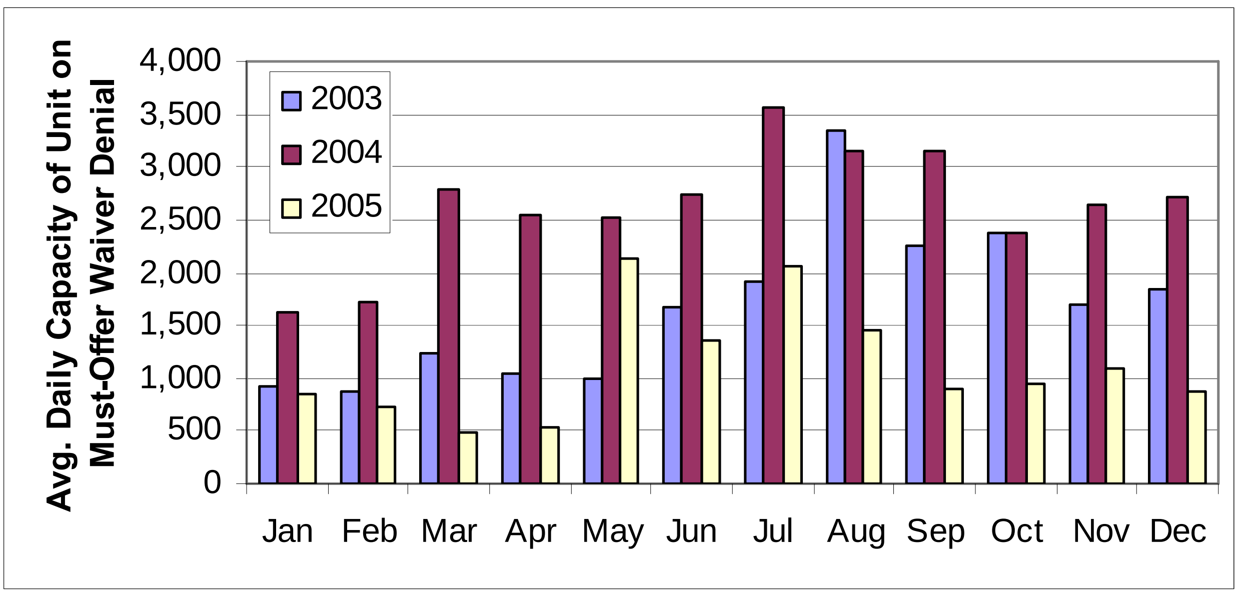


Figure 6.4 Total Monthly Minimum Load Compensation Costs for All Reasons (Local, Zonal, and System) (2003-2005)

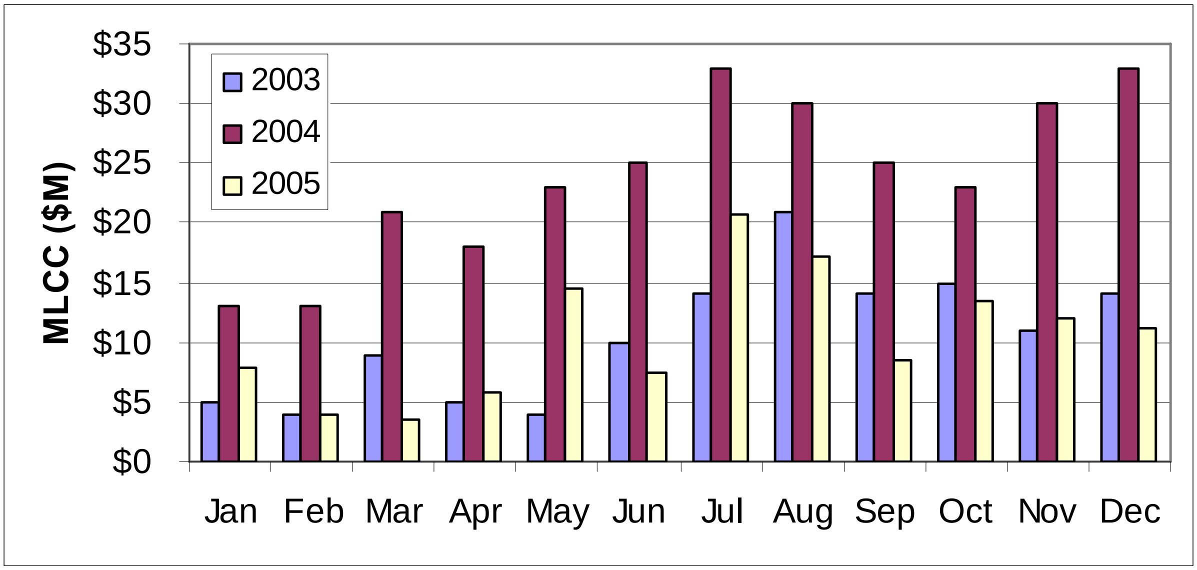


Table 6.3 Minimum Load Cost Compensation (MLCC) by Reason - 2004 (June-December) and 2005

Reason	Amendment 60 Cost Allocation Category	MLCC	% of Total	MLCC	% of Total
		2004 (June - Dec)*		2005	
South of Lugo	Local	$59.6	31%	$42.8	34%
SCIT	Zonal	$64.6	34%	$22.6	18%
Capacity – SP15	Zonal	$0.0	0%	$14.4	11%
Capacity - System	System	$16.0	8%	$13.6	11%
SONGS (OUTAGE)	Local	$0.0	0%	$8.9	7%
Devers-Palo Verde	Zonal	$0.0	0%	$3.7	3%
Sylmar	Local	$27.3	14%	$2.4	2%
Serrano (LA Basin)	Local	$8.1	4%	$0.0	0%
Path 26	Local	$0.0	0%	$2.3	2%
Victorville-Lugo	Zonal	$5.0	3%	$0.0	0%
Other	Local / Zonal	$10.0	5%	$16.0	13%
Total		**$190.6**	**100%**	**$126.7**	**100%**

* Data on specific reasons for must-offer waiver denials are not available prior to June, 2004.

Table 6.3 summarizes MLCC costs based on cost allocation categories under Amendment 60 and provides more detailed descriptions of the specific reasons. One significant reduction of MLCC from 2004 to 2005 is due to improvement of congestion in the vicinity of Sylmar substation, decreasing the MLCC cost from $27 million in 2004 (June-December) to $2 million in

2005. The improvement in the Sylmar substation also relieved transmission constraints in SCIT, which dramatically reduced MLCC costs in SCIT from $65 million in 2004 (June-December) to $23 million in 2005. Although South of Lugo was on top of the list in 2005 with $43 million, it still decreased by $13 million from 2004 (June-December).

6.3.2 Reliability Must Run Costs

To mitigate local market power and to ensure that local reliability requirements are met, California's current market design relies upon RMR contracts with units located at known congested locations on the transmission grid. Through an annual planning process, the CAISO designates specific generating units as RMR units, based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices. RMR units are either pre-dispatched for local reliability needs (prior to real-time), or incremented in real-time either for local reliability or for intra-zonal congestion. RMR units cannot be pre-dispatched for intra-zonal congestion.

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[7]

Table 6.4 shows total fixed and variable RMR costs by month in 2005, and further divides variable cost payments into costs associated with pre-dispatched RMR energy for local reliability and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[8] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy. Table 6.5 shows a breakdown of RMR costs between the three Investor-Owned Utilities' (IOU) service territories.

7 Units under Condition 1 of the RMR contract are free to select the "Market Option" when receiving an RMR dispatch on a day-ahead or hour-ahead basis, in which case they keep all revenues from sales of this energy and do not receive any re-imbursement for variable operating costs.

8 Since selection of RMR units and pre-dispatch of RMR units is based on local reliability requirements, these costs are not specifically associated with intra-zonal congestion. While annual designation RMR units and pre-dispatch of RMR units to meet local area reliability requirements may reduce intra-zonal congestion in real-time, these costs would be incurred even if intra-zonal congestion did not occur in real-time. Thus, it is more appropriate to exclude costs associated with the FOP and pre-dispatch of RMR units from intra-zonal congestion costs.

Table 6.4 RMR Contract Energy and Costs (2005)

Month	Pre-dispatch Energy (GWh)*	Real-time Energy (GWh)*	Fixed Option Payments ($M)	Net Pre-dispatch Costs ($M)	Net Real-time Costs ($M)	Total RMR Costs ($M)
January	703	96	$28	$12	$3	$42
February	601	91	$20	$14	$3	$38
March	562	106	$21	$14	$4	$40
April	593	110	$22	$18	$5	$45
May	576	80	$19	$17	$5	$42
June	464	46	$20	$13	$2	$35
July	408	157	$21	$9	$4	$35
August	358	195	$24	$13	$7	$44
September	263	111	$22	$15	$7	$44
October	280	126	$21	$16	$7	$45
November	240	128	$19	$9	$4	$32
December	113	63	$11	$6	$2	$20
2005 Total	**5,160**	**1,308**	**$250**	**$156**	**$53**	**$460**
% ∆ from 2004	**-65%**	**-51%**	**-31%**	**-34%**	**8%**	**-29%**

* Includes RMR energy provided under Contract Option only, excluding energy provided under Market Option of the contract.

Table 6.5 RMR Contract Energy and Costs for Major Transmission Owners (2005)

Owner	Pre-dispatch Energy (GWh)*		Real-time Energy* (GWh)		Fixed Option Payments ($M)		Net Pre-dispatch Costs ($M)		Net Real-time Costs ($M)		Total RMR Costs ($M)	
	2004	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**	**2004**	**2005**
PG&E	8,537	2,125	1,325	523	$264	$123	$125	$66	$29	$31	$418	$220
SDG&E	4,917	2,378	1,146	693	$80	$94	$75	$61	$18	$19	$173	$173
SCE	1,272	657	200	84	$15	$29	$36	$30	$2	$3	$53	$62
Total	**14,726**	**5,160**	**2,671**	**1,300**	**$359**	**$246**	**$236**	**$157**	**$49**	**$53**	**$644**	**$455**

* Includes RMR energy provided under Contract Option only, excluding energy provided under Market Option of the contract.

Total RMR costs decreased from about $644 million in 2004 to $455 million in 2005, as shown in Table 6.5 and Figure 6.5. The decrease in costs is due to a combination of three major factors:

- First, the portion of RMR capacity selecting Condition 2 of the pro forma RMR contract decreased significantly. As shown in Figure 6.6, the amount of thermal generation under Condition 2 ranged from about 3,000 to 4,000 MW in 2004, but dropped to about 2,000 MW in 2005. Since units receive higher fixed option payments when under Condition 2 compared to the fixed payments received if they select Condition 1, the reduction in capacity under Condition 2 created a significant decrease in fixed option payments. As shown in Figure 6.5, overall fixed option payments for RMR units dropped from about $359 million in 2004 to about $246 million in 2005. The drop in units selecting Condition 2 of the RMR contract may be attributed to increasing profitability for sales in bilateral and spot markets, which allows owners to earn market revenues from RMR units. RMR contract data indicate that the trend toward decreasing capacity under Condition 2 of the contract is continuing in 2006, which may provide further indications of increasing profitability for sales in bilateral and spot markets.

- Second, the amount of energy dispatched from RMR units – or the minimum reliability requirements at which RMR units are required to operate – dropped significantly in 2005. As shown in Figure 6.7, total RMR energy requirements issued to thermal units dropped from about 15,000 GWh in 2004 to about 9,500 GWh in 2005. As shown in Table 6.5, the decrease in RMR energy dispatches was due to a drop in reliability requirements issued on a forward (pre-dispatch) basis as well as real-time RMR energy dispatches. This resulted in a decline in Net Pre-dispatch Energy Costs from $236 million in 2004 to $157 million in 2005. However, the net real-time dispatch costs of RMR increased slightly in 2005 ($53 million versus $49 million in 2004). This increase is substantially attributable to the increase in natural gas prices during 2005.

- Finally, a significantly larger portion of RMR energy dispatches were provided under the Market Option of the contract rather than the Contract Option. Under the Market Option, the RMR unit owner keeps all market revenues from energy generated while meeting an RMR reliability requirement, and no additional variable cost payment is made in the event that market revenues are less than the unit's variable operating cost. As shown in Figure 6.7, about 29 percent of RMR energy dispatches issued to thermal units in 2005 were met through the Market Option, compared to only about 10 percent in 2004. As described above, the increase in the portion of RMR energy provided under the Market Option may be attributed to increasing profitability of sales in bilateral and spot markets.

Figure 6.5 Total RMR Costs (2004-2005)

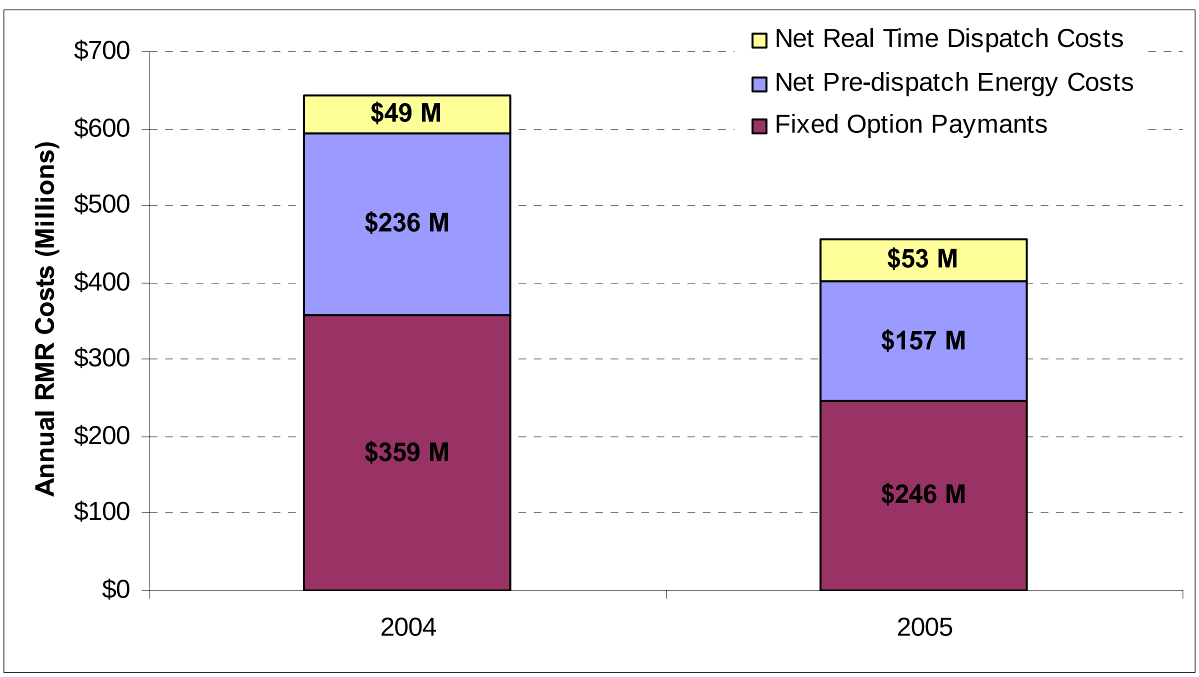


Figure 6.6 RMR Capacity by Resource and Contract Type (2004-2005)

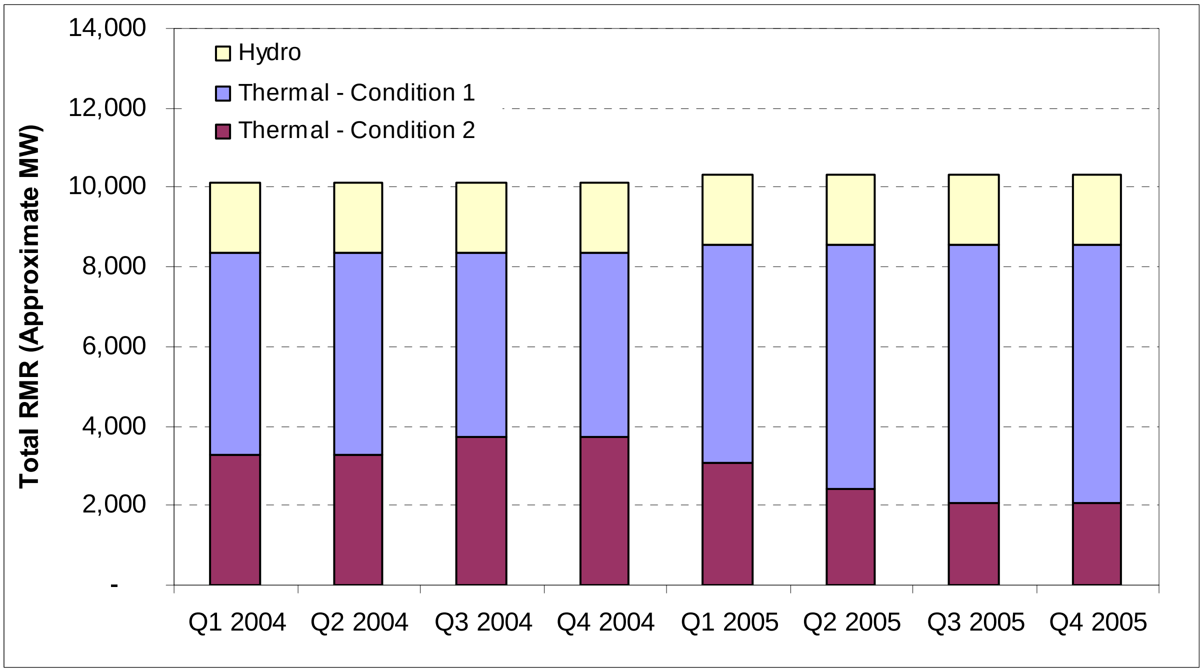
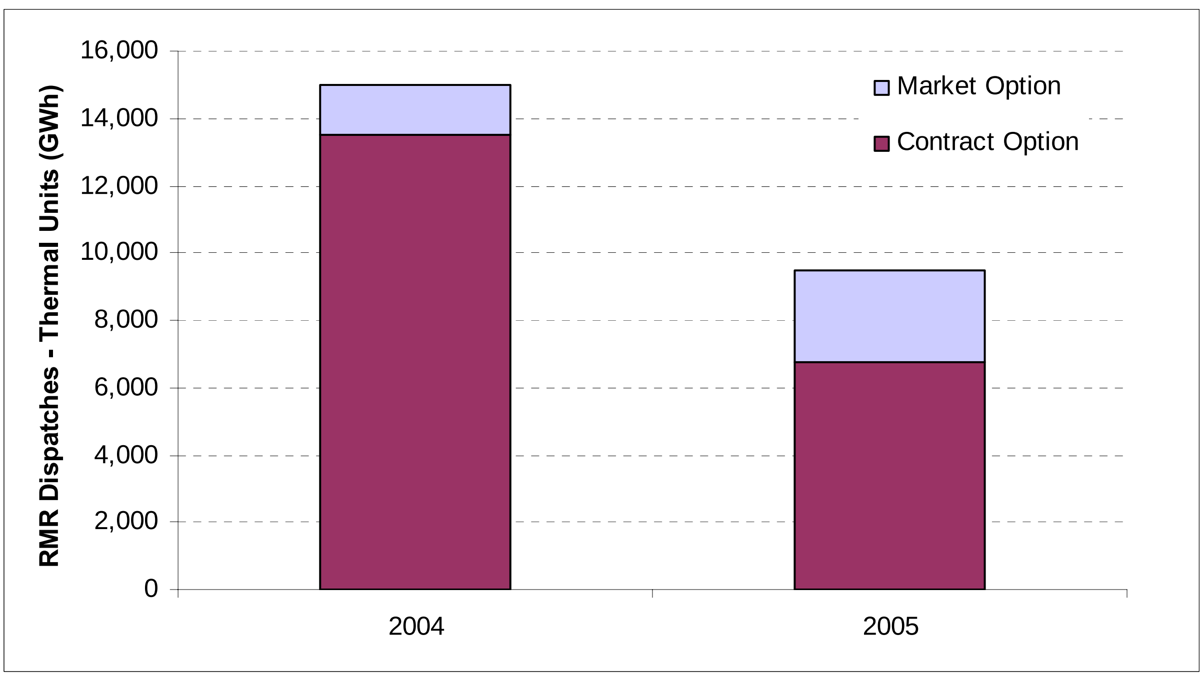


Figure 6.7 RMR Dispatch Volumes – Thermal Units (2004-2005)



The bulk of the decrease in RMR energy dispatches occurred in Pacific Gas and Electric's (PG&E) service territory, where annual pre-dispatched RMR energy provided under the Contract Option decreased from 8,537 GWh to 2,125 GWh and annual real-time RMR energy decreased from 1,325 GWh to 523 GWh (Table 6.5). Much of this decrease is attributable to substantial reductions in dispatches from various Bay Area RMR contract facilities in 2005. These facilities were dispatched for congestion at the PG&E Ravenswood substation and along the San Mateo – Ravenswood 230 kV transmission line. However, substantial transmission upgrades around the Bay Area have reduced local reliability energy requirements, and consequently energy dispatches under RMR contract, in the PG&E service territory.

Within the SCE service territory, annual RMR energy dispatches in SCE's service territory decreased from 4,917 GWh to 2,378 GWh in the pre-dispatch timeframe, and from 1,146 GWh to 693 GWh in real-time (Table 6.5), due to less mitigation for Orange County flows and compliance with the Southern California Import Nomogram.

Within the SDG&E service territory, annual RMR energy dispatches provided under the Contract Option declined from 4,917 GWh in 2004 to 2,378 GWh in 2005 in the pre-dispatch timeframe, and from 1,146 GWh in 2004 to 693 GWh in 2005 in real-time. This reduction in RMR energy dispatches may be substantially attributed to two conditions. First, substantial quantities of RMR energy were dispatched while San Onofre Nuclear Generating Station 3 was on refueling outage. Originally SONGS 3 was planned to be out from September 27 to November 11, 2004, but was subsequently extended through to December 29, 2004. The shutdown of SONGS 3 imposed substantial local constraints and exacerbated local congestion around Miguel, and its return decreased the need for RMR energy to compensate for the outage. Second, transmission upgrades went into place at Miguel, including an additional 230kV to 500kV transformer on October 31, 2004, and the Miguel-Mission #2 230kV line went into service on June 6, 2005. With these two transmission upgrades, the need for RMR energy within the San Diego area declined dramatically between 2004 and 2005.

6.3.3 Out-Of-Sequence (OOS) Costs[9]

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is based on the bid price paid for OOS energy less the market clearing price. For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental energy.

As shown in Table 6.6, gross payments for incremental OOS energy dispatches during 2005 totaled $9 million, which is a 90 percent reduction from the 2004 gross payment of $92 million. The net cost of these dispatches to Load Serving Entities (redispatch costs) was just above $3 million in 2005, compared to $40.6 million in 2004. In all, the CAISO procured 117,643 MWh of incremental OOS energy at an average price of $78/MWh. The average cost for 2004 was $67/MWh; the increase in price is mainly attributable to the increase in the price of gas from 2004 to 2005. The average net cost was $28.05, which was down from $29.44 for 2004. For incremental OOS dispatch, the largest drop in redispatch costs results from less mitigation

[9] Intra-zonal congestion has traditionally been resolved by OOS calls. However, due to the absence of an obligation to insert decremental bids, as well as the workings of the Amendment 50 reference levels, some of these dispatches are tagged out-of-market (OOM). Whether the dispatches are OOS or OOM, the salient feature is that they are all for intra-zonal congestion. Within this document, any references to OOS calls will always include some OOM calls where those OOM calls are for intra-zonal congestion.

occurring at the Sylmar substation. This is likely the result of the bank upgrade performed at Sylmar and completed in late 2004, where the new 230/220 kV, 900 MVA bank was completed which increased the Path 41 rating from 800 MVA to 1600 MVA. In addition, converters 1 & 2 were rebuilt in January 2005 increasing the capacity to 3100 MW. These redispatch costs dropped from $25 million in 2004 down to $0.1 million in 2005. Similarly, redispatch costs for real-time congestion management at SCIT dropped significantly in 2005. This is likely due to the 500 MW increase in the SCIT limit that went into effect in January 2005.

Table 6.7 indicates that the decremental OOS energy cost in 2005 was down to $31.4 million, or about half of the 2004 cost. The new line installed at Miguel alone created savings of $21 million in redispatch costs. The new Miguel #2 230 kV line went online in January 2005. The upgrade resulted in significantly reduced congestion cost at Miguel, while the same seasonal pattern of low congestion costs for April-September was observed. Prior to the upgrade, intra-zonal congestion was frequent and significant due to the addition of three new generation units in northern Mexico in 2003 comprising about 1,070 MW of capacity. For comparison, the average of cost for decremental energy was $38.24 per MWh in 2005, consistent with decremental energy price levels seen in 2004. The remainder of the decline in decremental OOS redispatch costs can be primarily attributed to less real-time intra-zonal congestion management at SCIT, South of Lugo, and Sylmar.

Table 6.6 Incremental OOS Congestion Costs 2005

	MWh	Gross Cost	Redispatch Premium	Mitigation Savings	Average Price	Average Net Cost
Jan	17,976	$1,172,257	$287,944	$1,079	$65.21	$16.02
Feb	8,954	$503,480	$227,984	$1,743	$56.23	$25.46
Mar	7,303	$433,774	$168,586	$4,871	$59.39	$23.08
Apr	749	$53,304	$8,837	$0	$71.20	$11.80
May	25,707	$1,615,580	$1,112,935	$61	$62.85	$43.29
Jun	3,511	$234,260	$32,953	$0	$66.71	$9.38
July	12,664	$1,068,629	$322,965	$42,795	$84.38	$25.50
Aug	7,232	$687,072	$142,363	$6,541	$95.01	$19.69
Sep	17,158	$1,859,198	$569,430	$450	$108.36	$33.19
Oct	937	$104,374	$22,752	$0	$111.43	$24.29
Nov	13,529	$1,282,651	$333,812	$0	$94.81	$24.67
Dec	1,924	$241,787	$69,103	$0	$125.66	$35.91
2005 Total	**117,643**	**9,256,365**	**3,299,664**	**57,540**	**$78.68**	**$28.05**
%∆ from 2004	**-91%**	**-90%**	**-92%**	**n/a**	**17%**	**-5%**

Table 6.7 Decremental OOS Congestion Costs 2005

	MWh	Gross Cost	Redispatch Premium	Average OOS Price	Average Net Cost
Jan	229,918	-$7,017,664	$5,281,048	$30.52	$22.97
Feb	215,504	-$5,834,760	$3,084,988	$27.07	$14.32
Mar	154,799	-$3,478,599	$2,861,021	$22.47	$18.48
Apr	137,077	-$3,820,274	$3,031,146	$27.87	$22.11
May	17,549	-$375,115	$341,108	$21.38	$19.44
Jun	3,279	-$113,640	$41,393	$34.66	$12.62
July	11,614	-$487,712	$251,089	$41.99	$21.62
Aug	52,801	-$2,434,458	$1,166,405	$46.11	$22.09
Sep	55,284	-$2,739,109	$2,637,278	$49.55	$47.70
Oct	105,896	-$6,311,372	$3,865,824	$59.60	$36.51
Nov	161,973	-$7,233,787	$4,817,115	$44.66	$29.74
Dec	145,431	-$9,529,564	$3,982,617	$65.53	$27.38
2005 Total	**1,291,124**	**-$49,376,054**	**$31,361,031**	**$38.24**	**$24.29**
%∆ from 2004	**-52%**	**-53%**	**-50%**	**-2%**	**4%**

7. Market Surveillance Committee

7.1 Market Surveillance Committee

Historically, the Market Surveillance Committee (MSC or Committee) has served as an impartial voice on market issues primarily for the CAISO as well as for state policymakers, the FERC and the media. CAISO management and the FERC have adopted a number of Committee recommendations since its inception. The MSC has been recognized consistently by the industry and the public as useful and effective, due in large part to the stature of its members as nationally recognized experts as well as their perceived independence. Both characteristics have led to the MSC being shown considerable deference by state and federal regulators.

7.1.1 The Current Members

In 2005, the Committee was comprised of the following members: Frank Wolak of Stanford University, Benjamin Hobbs of Johns Hopkins University, James Bushnell of University of California Energy Institute at Berkeley and Brad Barber of University of California, Davis Graduate School of Management. Frank Wolak served as the chairman of the Committee.[1] The following is a brief description of each member's background.

Dr. Frank A. Wolak, the chairman of the MSC since its inception in 1998, is a Professor of Economics at Stanford University. His fields of research are industrial organization, regulatory economics, energy economics and econometric theory. He specializes in the study of methods for introducing competition into infrastructure industries – telecommunications, electricity, water delivery and postal delivery services – and on assessing the impacts of these competition policies on consumer and producer welfare. Dr. Wolak is a visiting scholar at University of California Energy Institute and a Research Associate of the National Bureau of Economic Research (NBER).

Dr. Benjamin F. Hobbs, a member of the MSC since 2002, is a Professor of Geography and Environmental Engineering at the Johns Hopkins University with a joint appointment in the JHU Department of Applied Mathematics and Statistics. Dr. Hobbs has published widely on environmental and water resources systems and on electric power market economics, regulation, and systems analysis. This area of expertise includes use of engineering economic models to simulate imperfectly competitive energy markets, and decision analysis under uncertainty and multiple objectives. He also serves as Scientific Advisor to the Policy Studies Unit of the Netherlands Energy Research Centre (ECN) and on the Public Interest Advisory Committee of the Gas Technology Institute. Dr. Hobbs is on the editorial boards of the ASCE Journal of Infrastructure Systems; Energy, The International Journal; The Electricity Journal; and the IEEE Transactions on Power Systems. He is a Senior Member of IEEE and Member of ASCE.

Dr. James Bushnell, a member of the MSC since 2002, serves as the Research Director of the California Energy Institute at Berkeley. He also serves as Lecturer at the Haas School of Business, UC Berkeley on Policies and Strategies in the Energy Markets. He is a former member of the Market Monitoring Committee of the California Power Exchange (CALPX). His research interests include game theoretic optimization models, industrial organization and regulatory economics, energy policy, and environmental economics. He has published

[1] More information available at http://www.caiso.com/docs/2005/10/04/200510041131538087.html

numerous articles on the economics of electricity deregulation and has testified extensively on energy policy issues. Much of his research has focused on examining the market incentives in particular; market rules and structures created and in developing empirical methods for measuring the impact of market power on deregulated electricity markets.

Dr. Brad M. Barber, a member of the MSC since 2002, is a Professor of Finance at the UC Davis Graduate School of Management. His recent research focuses on analyst recommendations and investor psychology. He is a regular speaker at academic and practitioner conferences.

7.1.2 Accomplishments

During 2005, the MSC completed a significant amount of work in the areas of market design, market participant behavior, and market performance. Some of the accomplishments of the MSC are listed below:

- Issued six opinions on pertinent issues such as the economic analysis of the Palo Verde-Devers Line Number 2 transmission network upgrade, the California ISO's Market Redesign and Technology Upgrade (MRTU) conceptual filing, and raising the level of the bid cap on the real-time energy market in California;
- Produced several white papers that provided technical advice for MRTU policy decisions;
- Reviewed and commented upon a number of different transmission studies undertaken by the CAISO and participated in the stakeholder process;
- Provided expert advice to CAISO management on potential behavior harmful to system reliability and efficiency in the market design and made suggestions to improve CAISO protocols to reduce incentives or loopholes that may cause behavior harmful to system reliability and market efficiency and/or manipulation of the market;
- Attended numerous FERC technical conferences on market monitoring techniques, MRTU design issues, and market power mitigation mechanisms. They contributed significantly to the discussions with the stakeholders, and provided technical support in resolving pending issues;
- Visited FERC and state legislators on behalf of CAISO to discuss several MRTU issues; and
- Continued to provide expert advice to the CAISO's DMM in the development of tools used to assess the benefits of transmission expansion, the design of market power mitigation measures, and the development of economic indices for market monitoring.

7.1.3 MSC Opinions

Following is a list of opinions provided by the Committee during 2004 that were filed at FERC and with other regulators.[2]

1. *Assessment of An Economic Analysis of the Palo Verde-Devers Line Number 2 (PVD2) Transmission Network Upgrade - February 22, 2005*

[2] These opinions are available at http://www.caiso.com/docs/2000/09/14/200009141610025714.html.

In this opinion, the Committee discussed the CAISO's economic analysis of the Palo Verde-Devers Line No. 2 Transmission Network Upgrade. The Committee determined that the Market Analysis and Grid Planning Departments undertook, for the most part, a conservative economic analysis of the expected benefits of this proposed upgrade. The Committee indicated that the CAISO's modeling results implied a wide range of plausible scenarios for future system conditions that yield significant net benefits to California ISO ratepayers from the upgrade. Throughout the opinion, the Committee summarized the reasons why they believe that application of the TEAM methodology provides credible, yet conservative, estimates of the expected benefits of the PVD2 upgrade to California ISO ratepayers and they concluded by recommending that the CAISO Board approve the PVD2 transmission expansion.

2. *Opinion on the California ISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing - April 26, 2005*

In this opinion, the Committee commented on the CAISO's conceptual filing to the Federal Energy Regulatory Commission (FERC) on the Market Redesign and Technology Upgrade (MRTU). There were three main elements of the filing.

(1) The method used to translate Load Aggregation Point (LAP) demand bids into nodal prices in the day-ahead market.

- On this element, the Committee recommended that the CAISO explore adding more LAPs and eventually work toward implementing nodal-bidding and pricing of load and address the issue of higher locational prices to some LSEs though the CRR allocation process.

(2) The structure of the Hour-Ahead Scheduling Process (HASP).

- On this element, the Committee believed that it may be more cost-effective for the CAISO to formulate a long-term solution to the pre-dispatch of inter-tie bids before committing to a design for the HASP.

(3) The policies and mechanisms for managing system-wide and local market power in the CAISO's short-term energy, ancillary services, and residual unit commitment (RUC) markets.

- On this element, the Committee indicated that in order to be effective, an LMPM mechanism must be integrated with the design of the energy and ancillary services market. Although the Committee had a few reservations with some portions of the proposed LMPM mechanism, they believed overall that that proposed mechanism, integrated with the overall energy market design, constituted a major step forward for the California market. For this reason, they strongly advocated that FERC adopt this comprehensive package rather than pick and choose aspects of the proposed market design combined with features from other US ISOs.

3. *Addendum to the Opinion on the California ISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing - May 6, 2005*

In this addendum, the Committee clarified portions of the previous opinion that led to additional questions from stakeholders; specifically, they provided additional commentary regarding managing market power in wholesale electricity markets, and elaborated on features of an effective LMPM mechanism.

4. *Medium-Term Solution to Clearing Inter-tie Bids in the Real-Time Energy Market - June 24, 2005*

In this opinion, the Committee was asked to provide a recommendation for a medium term solution for settling inter-tie bids under the Real-Time Market Application (RTMA) market design until the Market Redesign and Technology Upgrade (MRTU) is implemented in February of 2007. The Committee strongly supported the current pay-as-bid mechanism as the preferred medium term solution until the MRTU is implemented. They also emphasized that this does not imply that they support a pay-as-bid mechanism for settling inter-ties under MRTU. In fact, a major factor in their preference for maintaining the pay-as-bid mechanism until MRTU is implemented has to do with any medium term solution only being in place for a short period of time, which implies the need to balance the relative expense of any proposed solution against the relative benefits of that solution over the period of time the solution will be in place.

5. *Raising the Level of the Bid Cap on the Real-Time Energy Market in California – November 9, 2005*

The CAISO management asked the Committee whether recent trends in natural gas prices justified raising the level of the bid cap on the real-time energy market in California. The MSC stated that the new level of the bid cap should be high enough to make it very unlikely that the CAISO will need to increase the cap again before the locational marginal pricing (LMP) market is scheduled to be implemented. If the current $250/MWh bid cap was appropriate for the natural gas prices that prevailed during 1998 and 1999, the bid cap should be increased to at least $400/MWh, considering the likely trajectory of natural gas prices in the winter of 2005.

6. *Opinion on Aspects of the California ISO's Market Redesign and Technology Upgrade (MRTU) Conceptual Filing - September 30, 2005*

In this opinion, the Committee comments on a number of aspects of the California ISO's Market Redesign and Technology Upgrade (MRTU). The specific issues addressed in this opinion are: (1) the use of bid adders for frequently mitigated units, (2) competitive path assessment to implement the CAISO's local market power mitigation (LMPM) mechanism, (3) the formulation of the Hour-Ahead Scheduling Process (HASP), (4) the formation of trading hubs, (5) the rules for allocating Congestion Revenue Rights (CRRs), (6) rules for allocating CRRs to loads located outside of the CAISO control area, and (7) rules for allocating CRRs to merchant transmission owners.

7.1.4 MSC Meetings

During the year, the MSC conducted several bi-monthly meetings. Most were at the CAISO offices in Folsom, while one was held at the California Public Utility Commission (CPUC) headquarters in San Francisco in March 2005. Generally, the Committee discussed current market issues and market design issues. The meetings provided a forum for stakeholders to take part in discussions with the MSC and allowed the MSC to understand the opinions and concerns of the stakeholders.

7.1.5 Other MSC Activities

In addition to providing opinions and participating in discussions at its bi-monthly meetings, the MSC was very active in providing independent expert advice on CAISO market issues at Capitol Hill and with other regulators during the year. Members of the Committee attended meetings with the CPUC and the legislative staff of senators to discuss various market design issues. They also collectively and individually attended several CAISO and FERC stakeholder meetings on MRTU market design and the transmission methodology and studies.