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

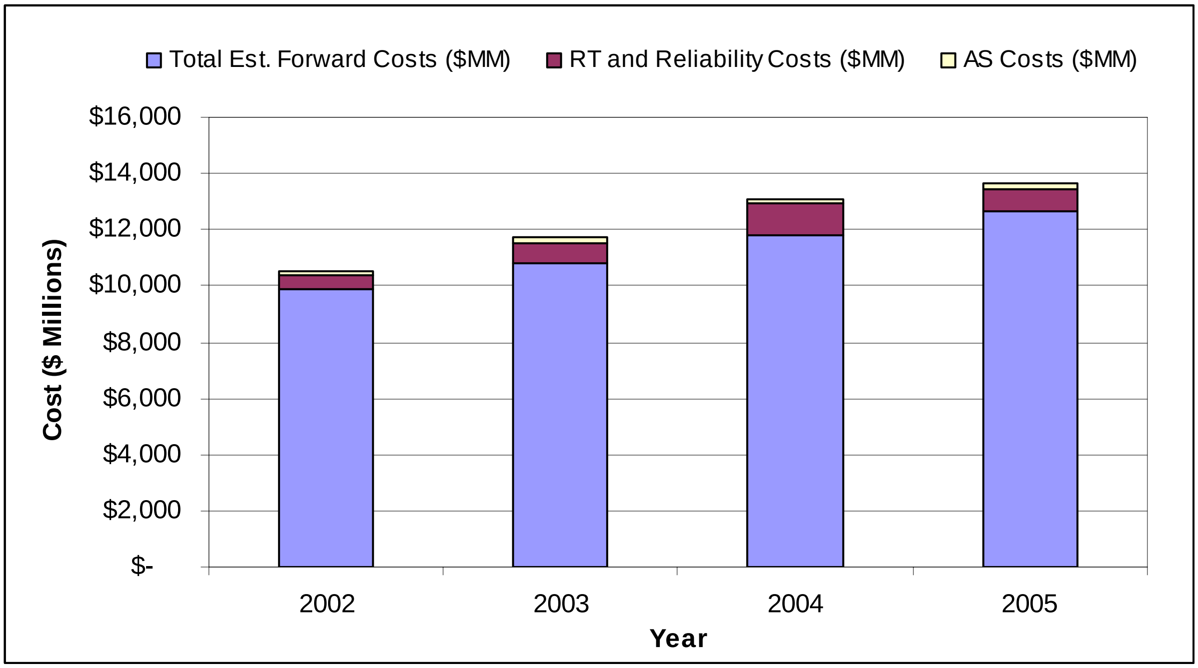
[2] FERC Winter 2005-2006 Energy Market Update, February 16, 2006 (http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf)
[3] 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.
[4] 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.
[5] 2005 Integrated 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.

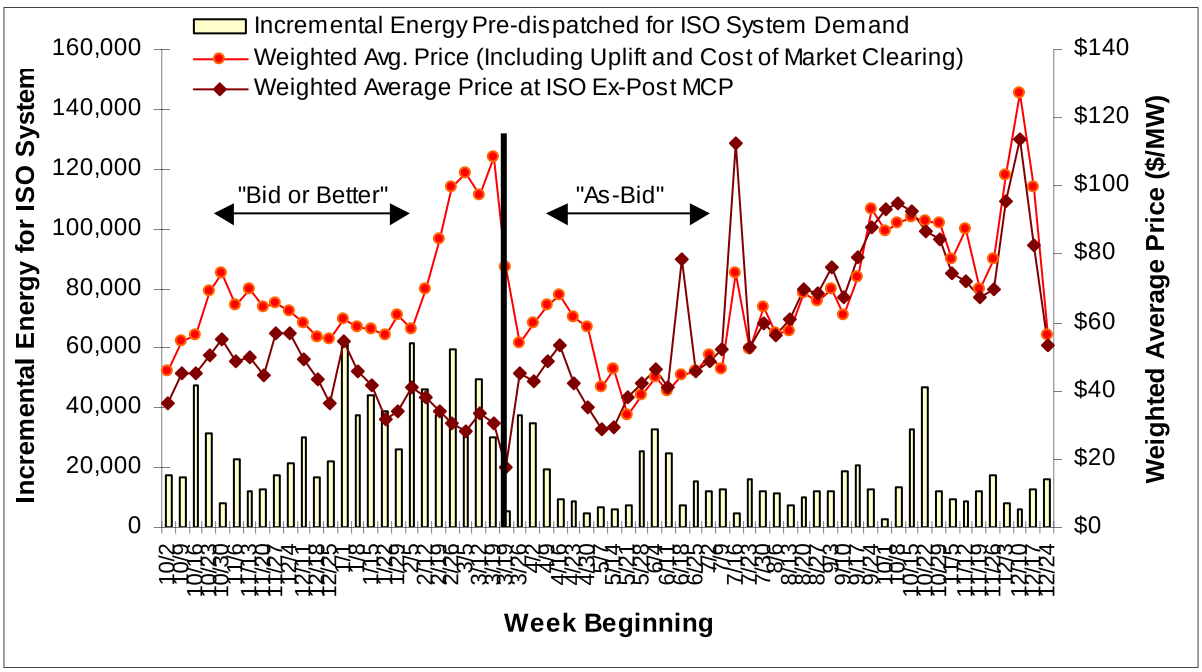
Although RTMA has increased the volatility of prices and dispatches within each operating hour, this appears to be primarily the result of various features of RTMA designed to increase the responsiveness of prices and dispatches to system imbalance conditions in each 5-minute interval. Upon close examination,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

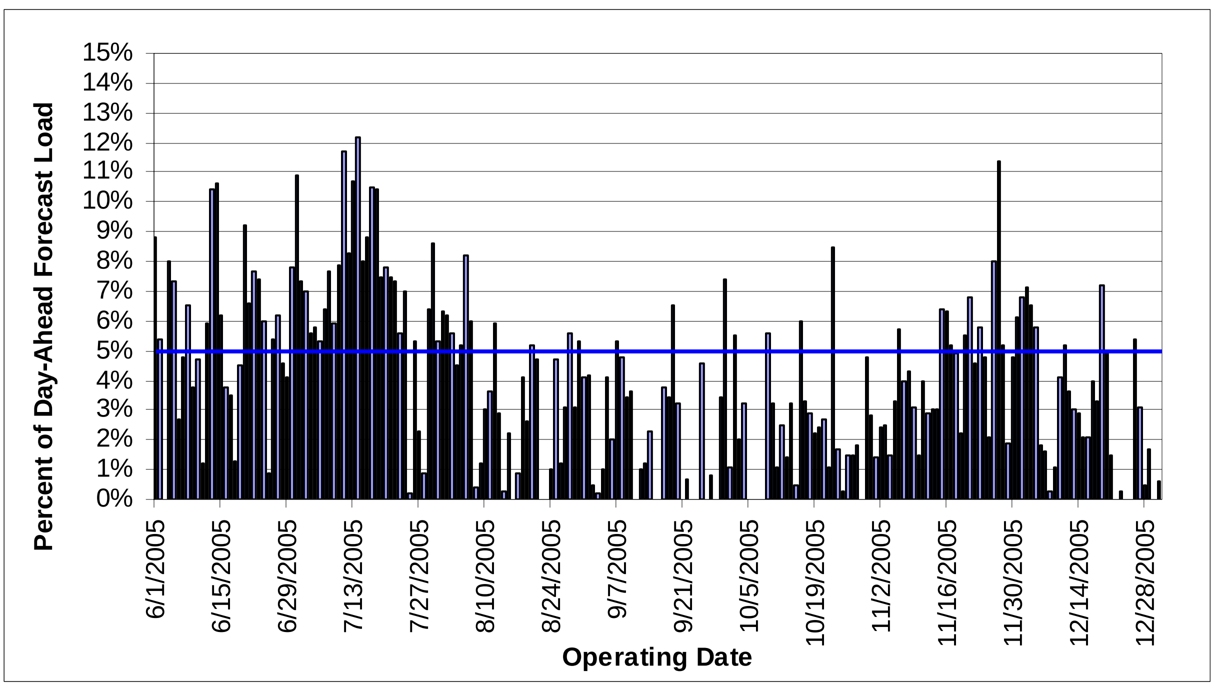


Load Scheduling Practices

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.

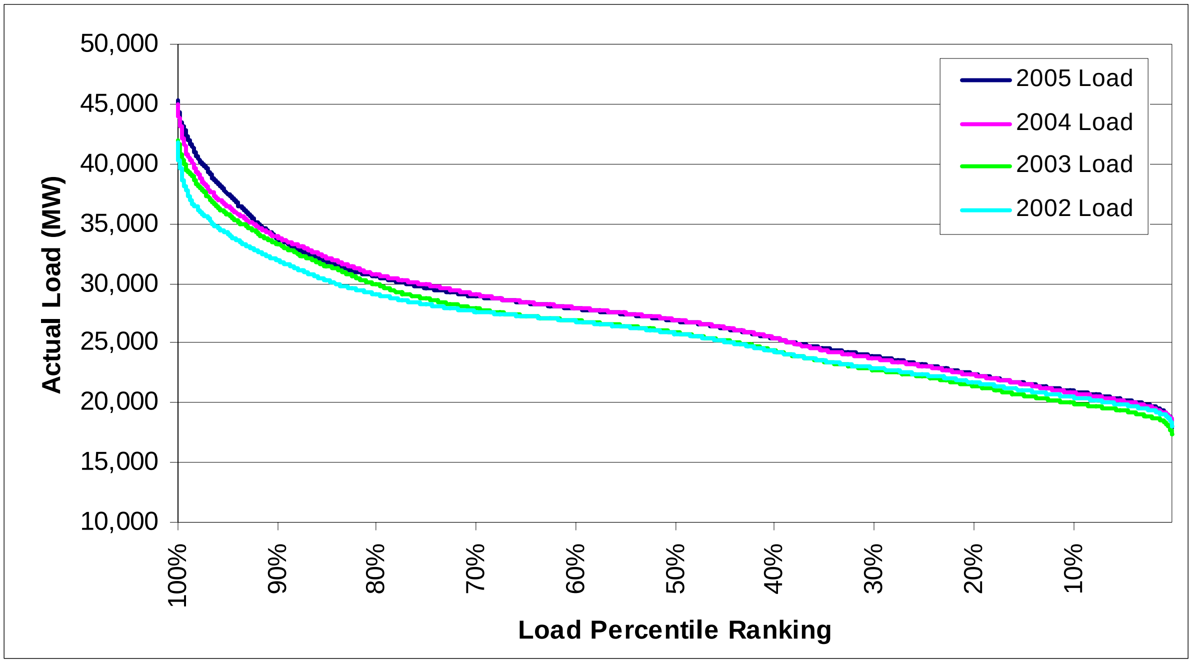
Table E.1 Load Statistics for 2001 – 2005*

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.

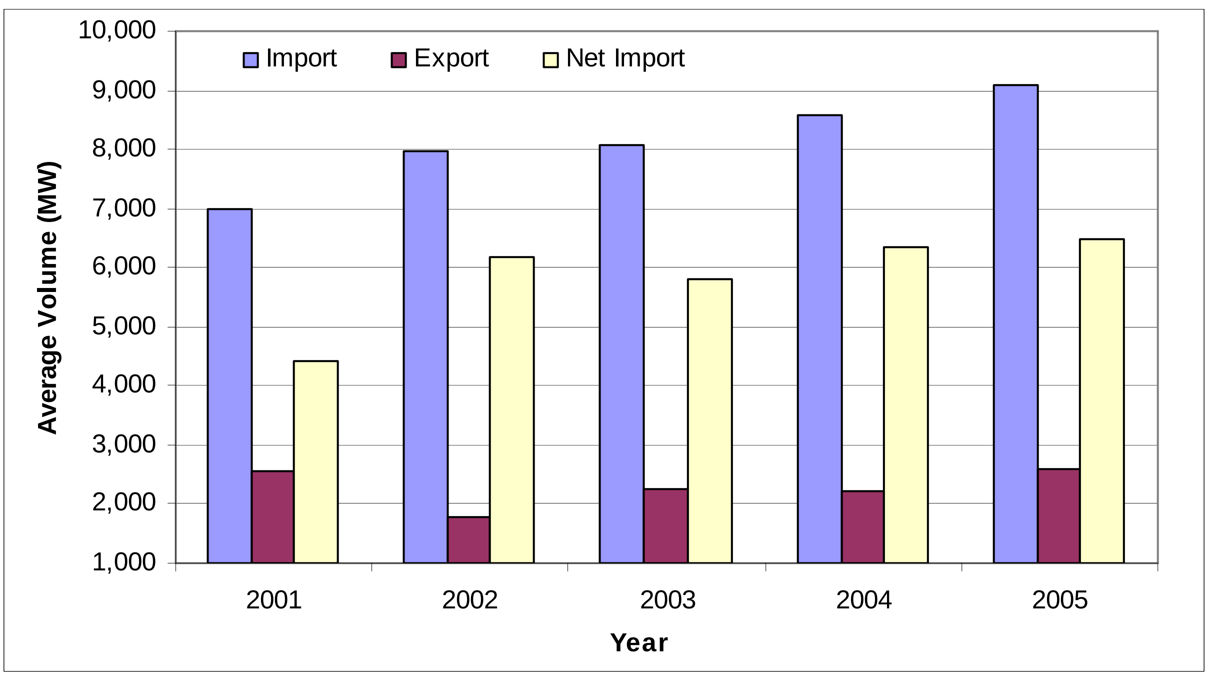
Table E.2 CAISO Generation Additions and Retirements

	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)

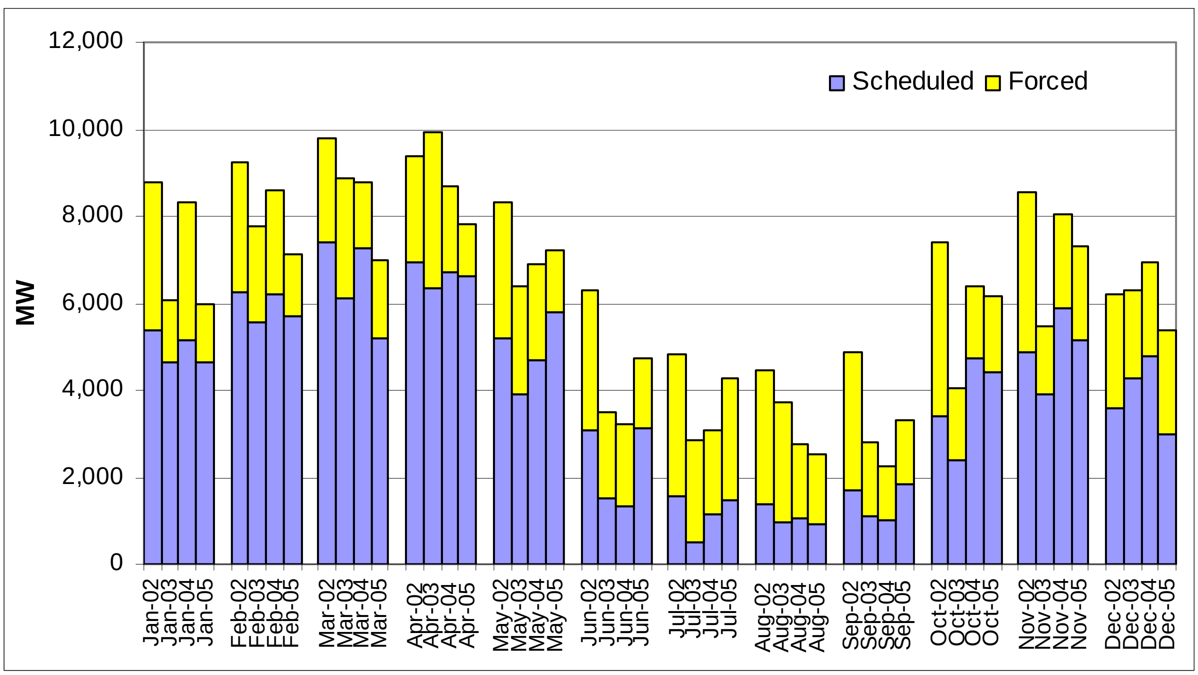
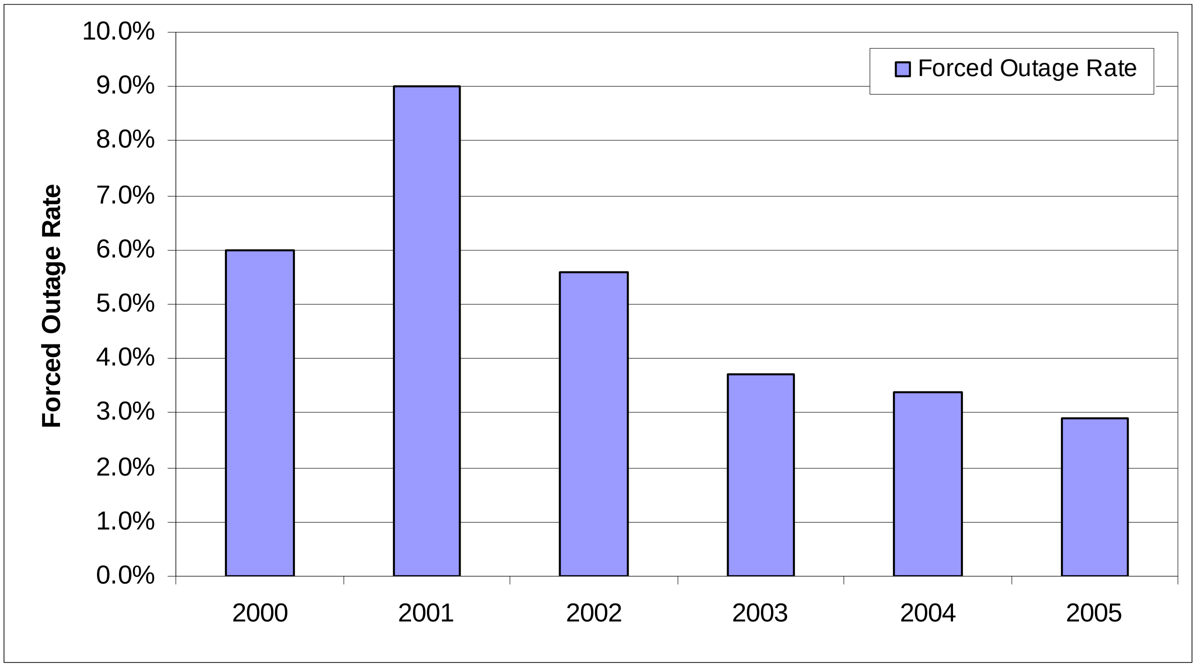


Figure E.7 Annual Forced Outage Rates (2000 – 2005)



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)

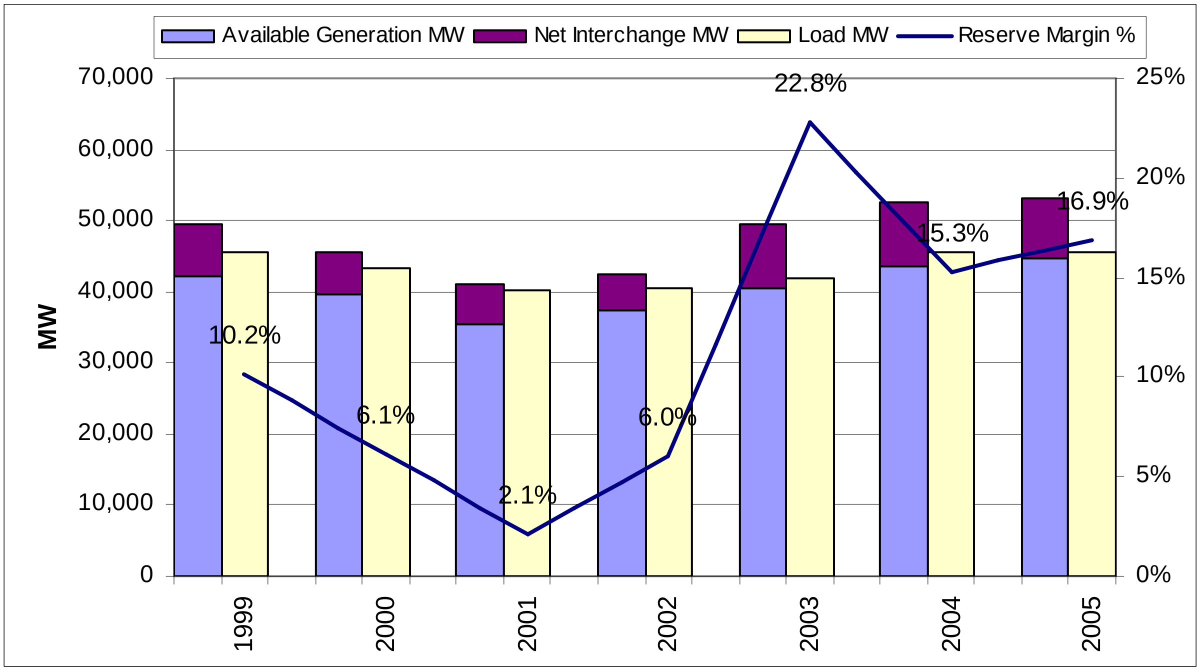
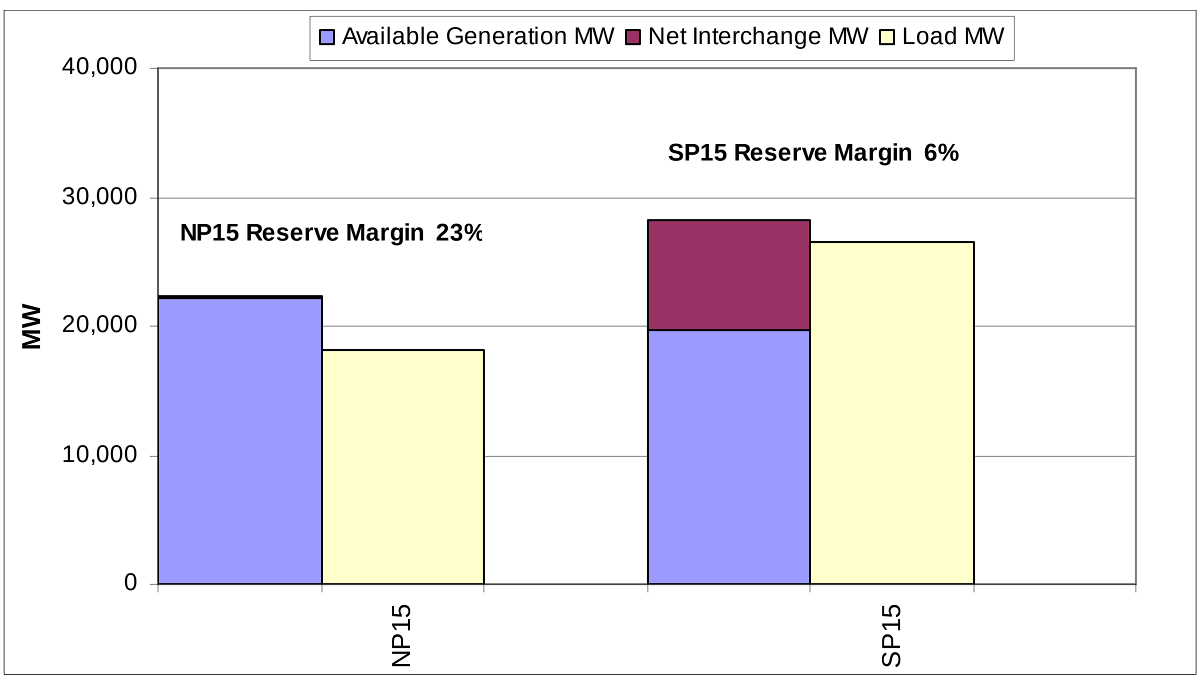


Figure E.9 Zonal Reserve Margins During SP15 Peak Load Hour (August 21, 2005)



Short-term Energy Market Performance

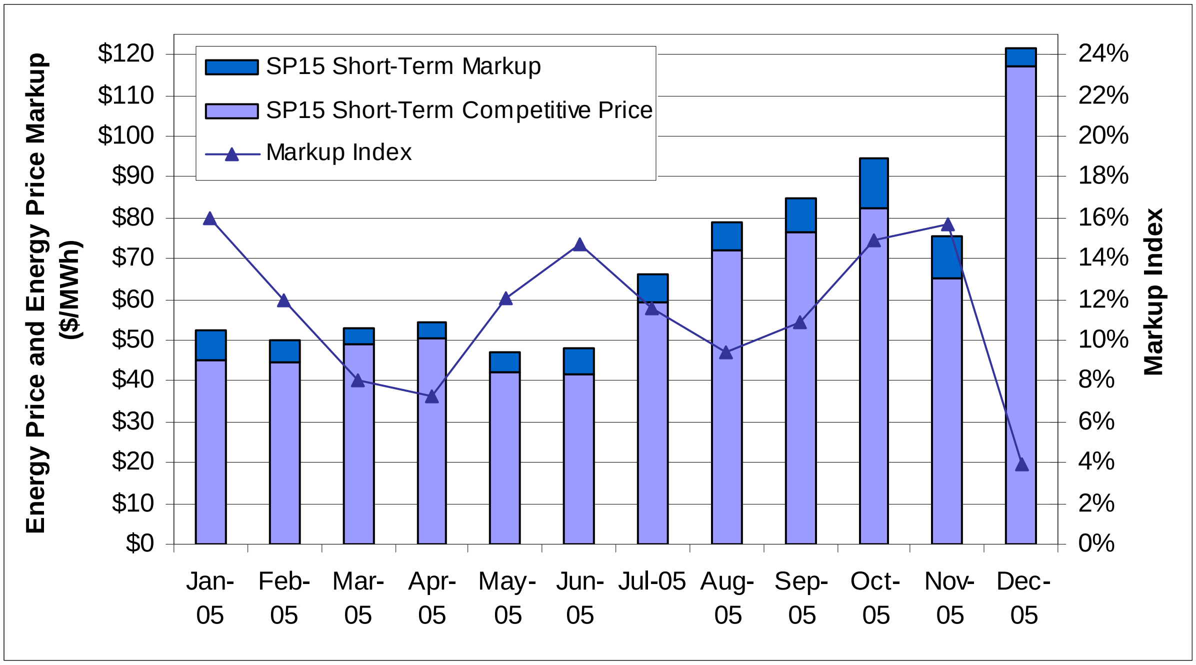
The significant number of long-term contracts entered into by the state of California in 2001 and by load serving entities since then combined with the large amount of new generation added to the western energy markets provided effective market power mitigation in the 2005 short-term energy markets. 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/.

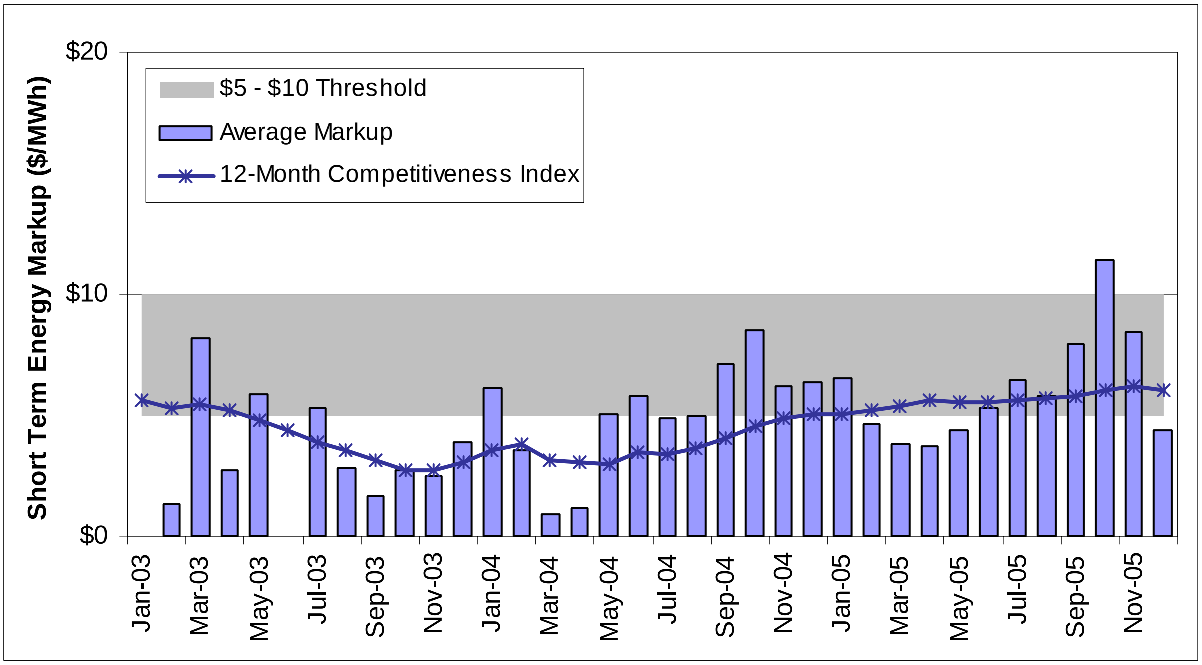
Figure E.10 Short-term Forward Index – SP15 (2005)



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

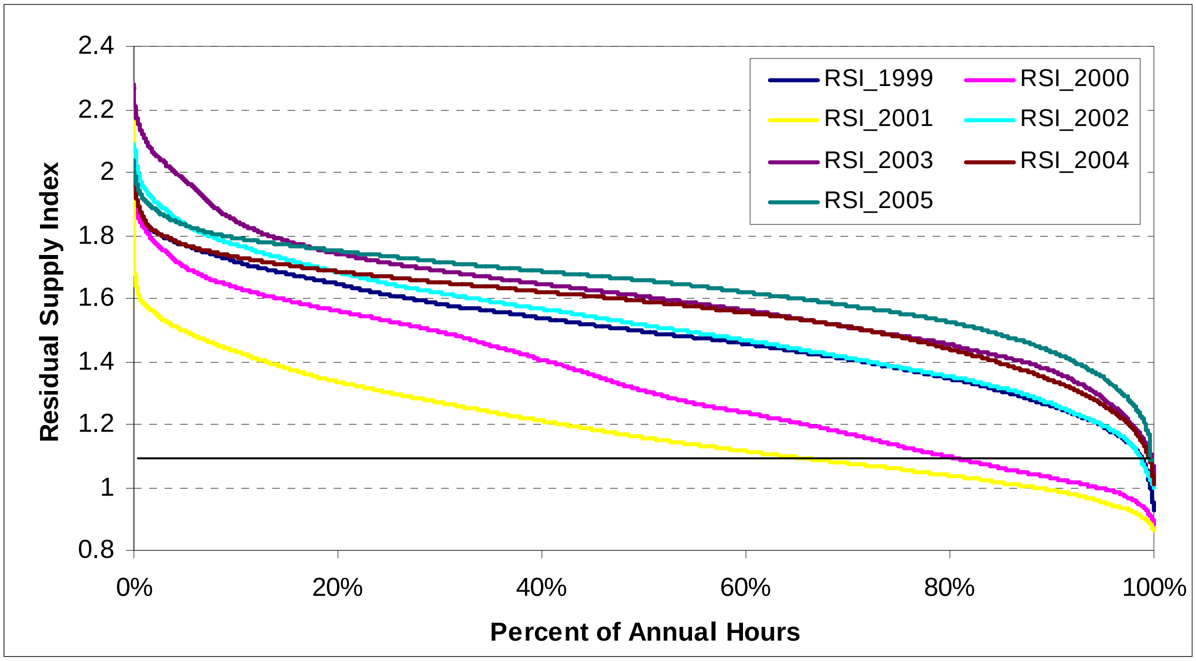
The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier 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)

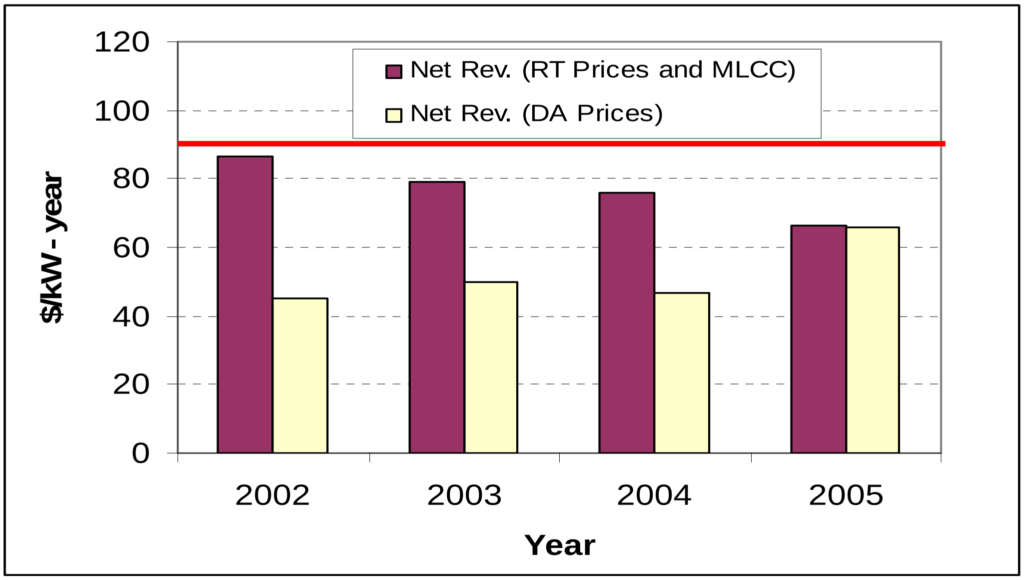
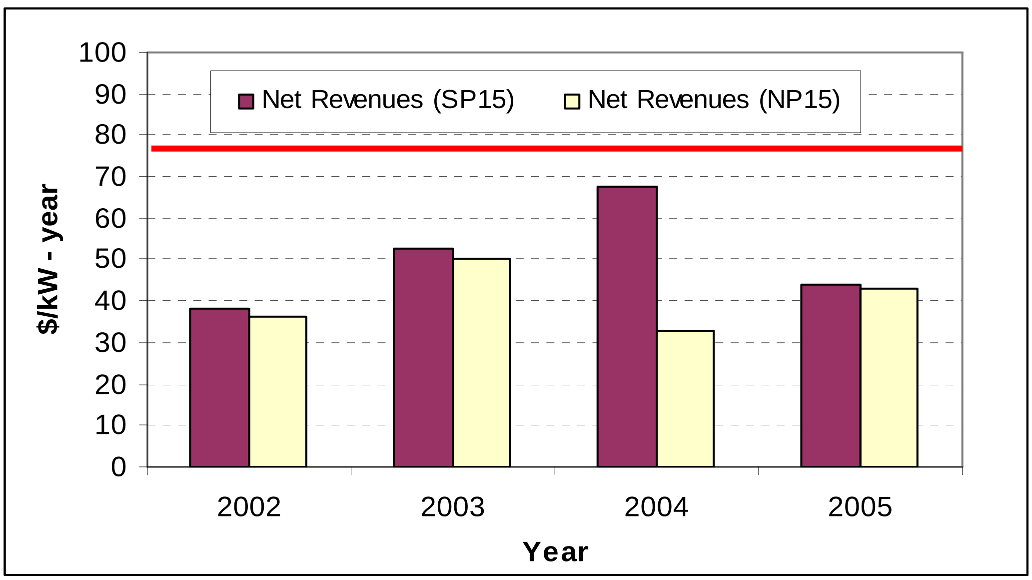


Figure E.14 Financial Analysis of New CT Unit (2002 – 2005)



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

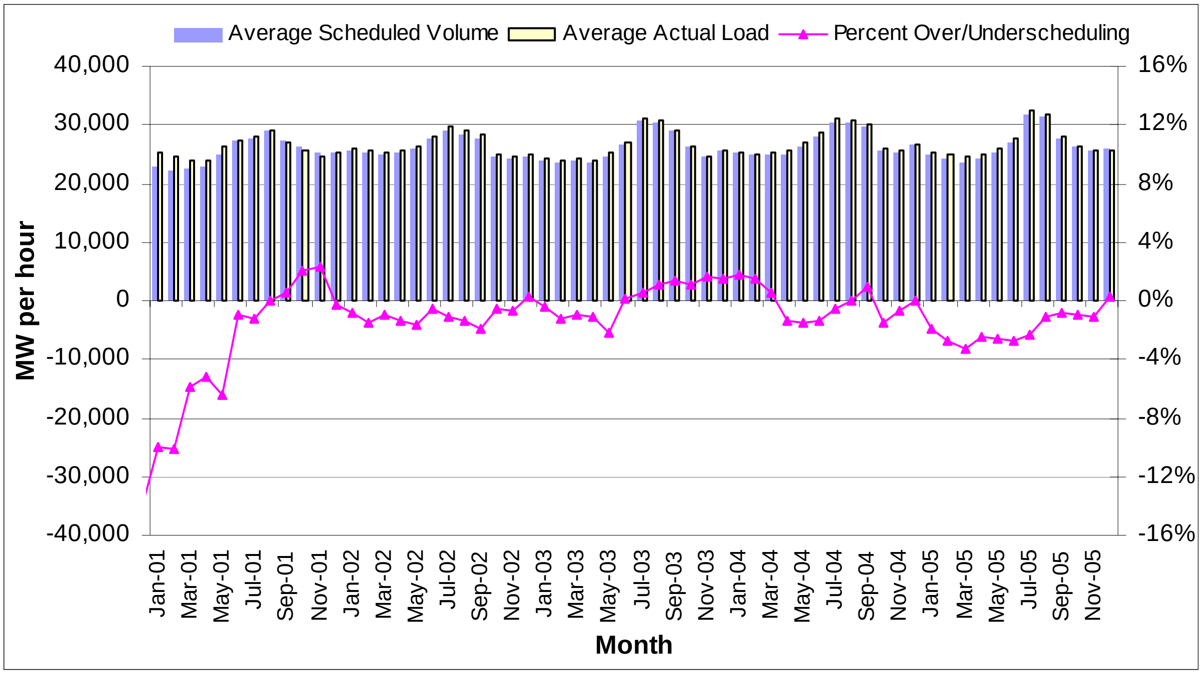
Although the MOO provides cost compensation plus a second market-based payment for minimum load as well as opportunity for market revenues from providing A/S and real-time energy, generation owners have argued that there is insufficient fixed cost recovery provided by the MOO provisions and that units 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

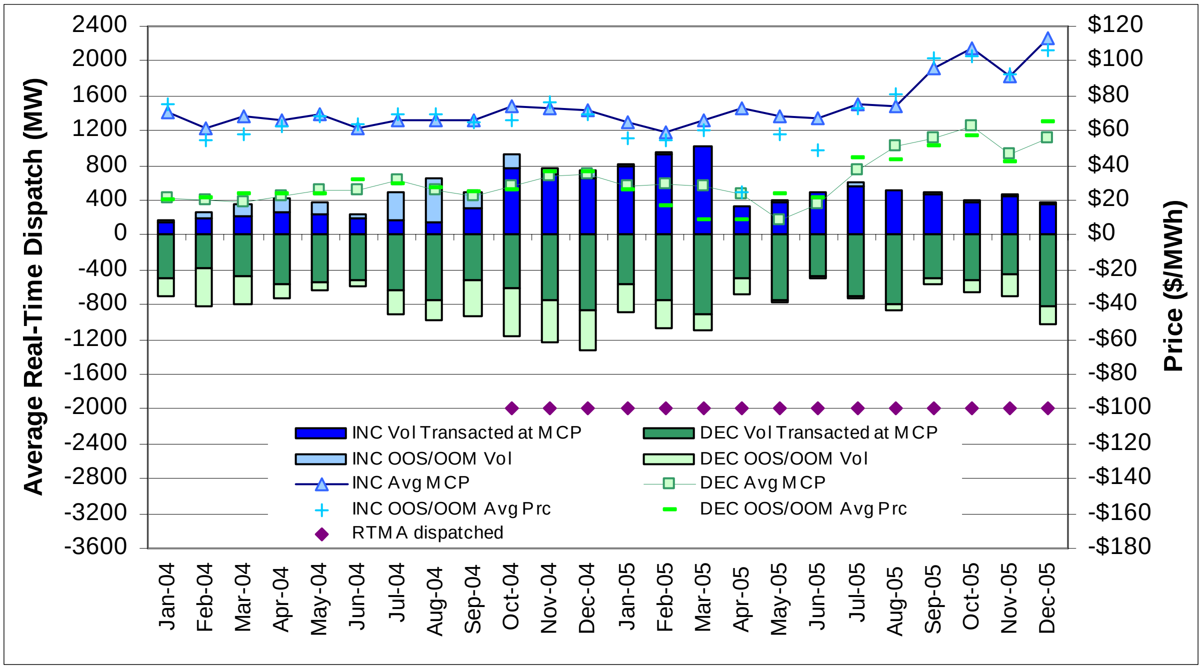
For the fourth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2005. Monthly average forward energy schedules were within 2 percent of actual load as shown in Figure E.15. Real-time balancing energy was again overwhelmingly in the decremental 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

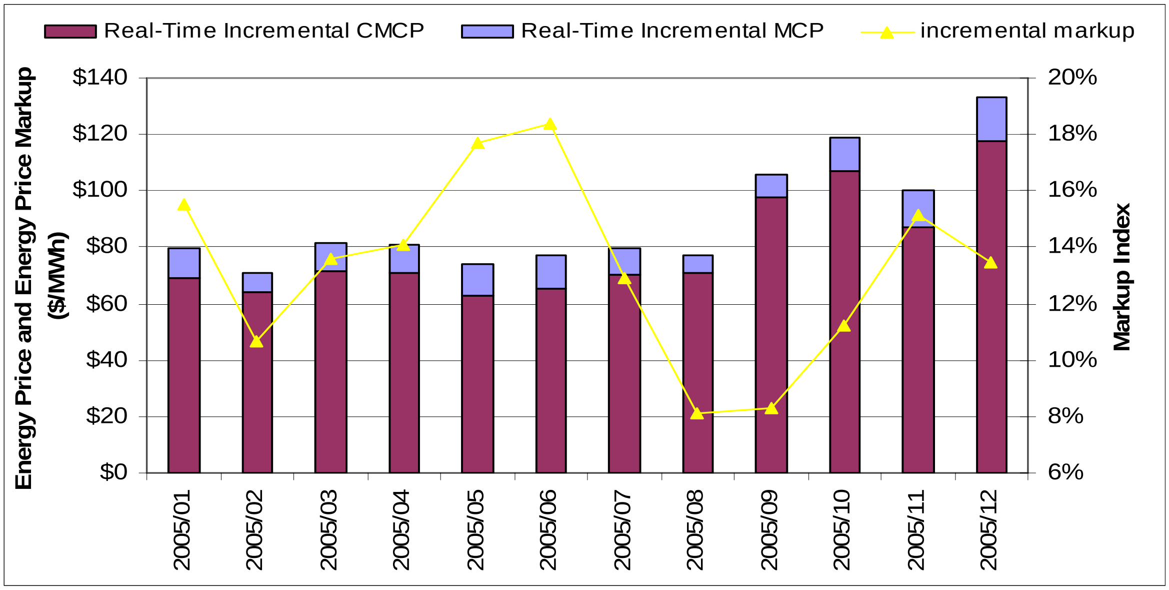
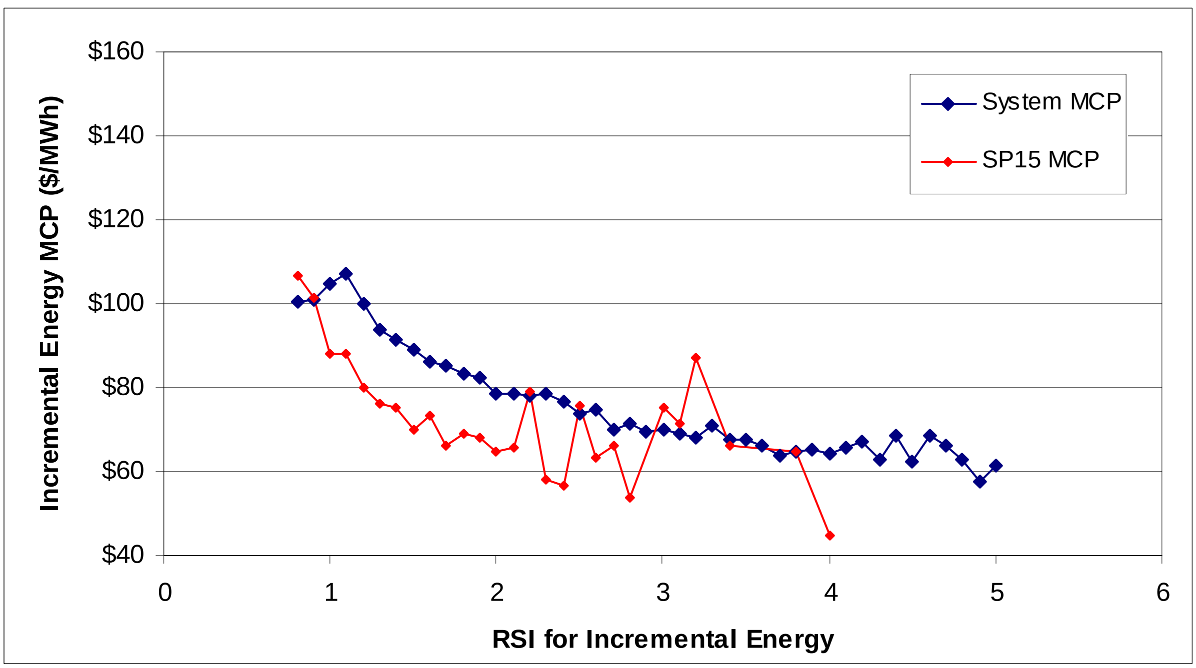


Figure E.18 RSI Relationship to Average Hourly Real Time Incremental Market Clearing Prices



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

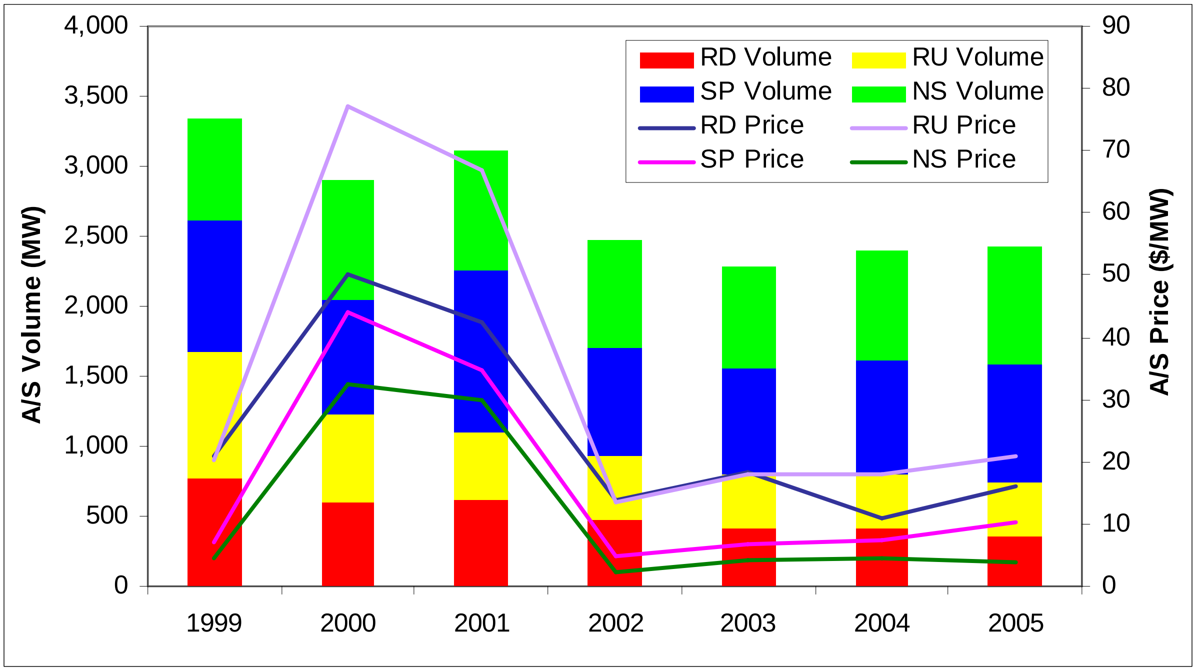
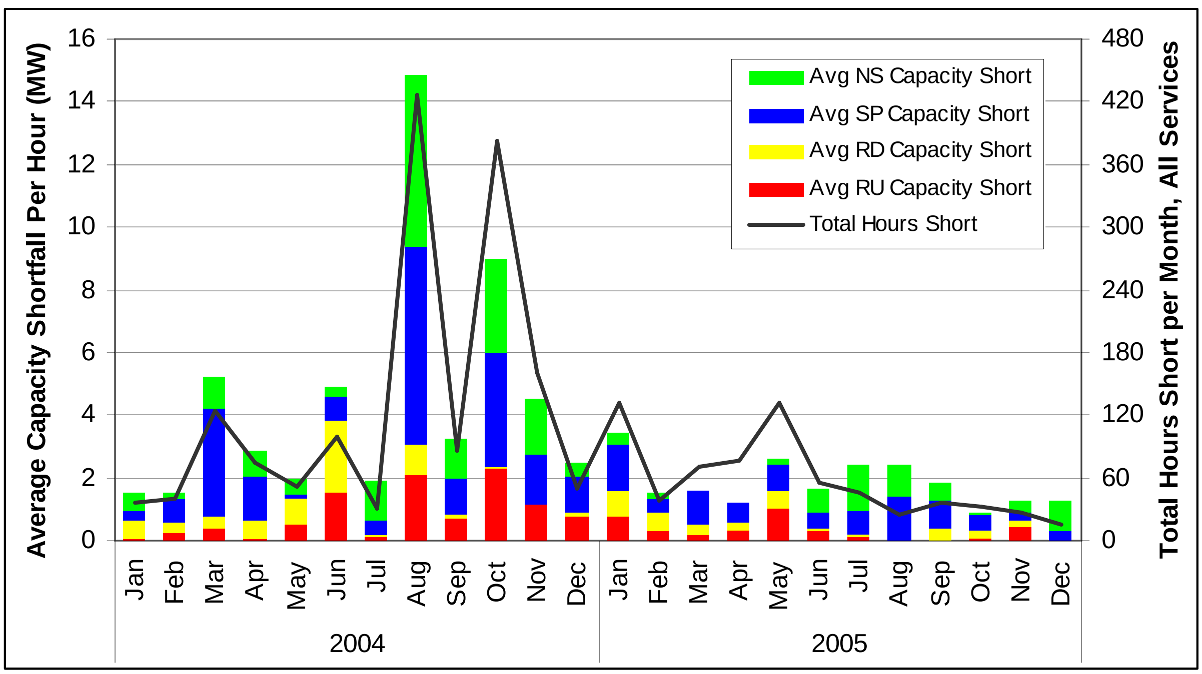


Figure E.20 Bid Insufficiency by Capacity and Hour

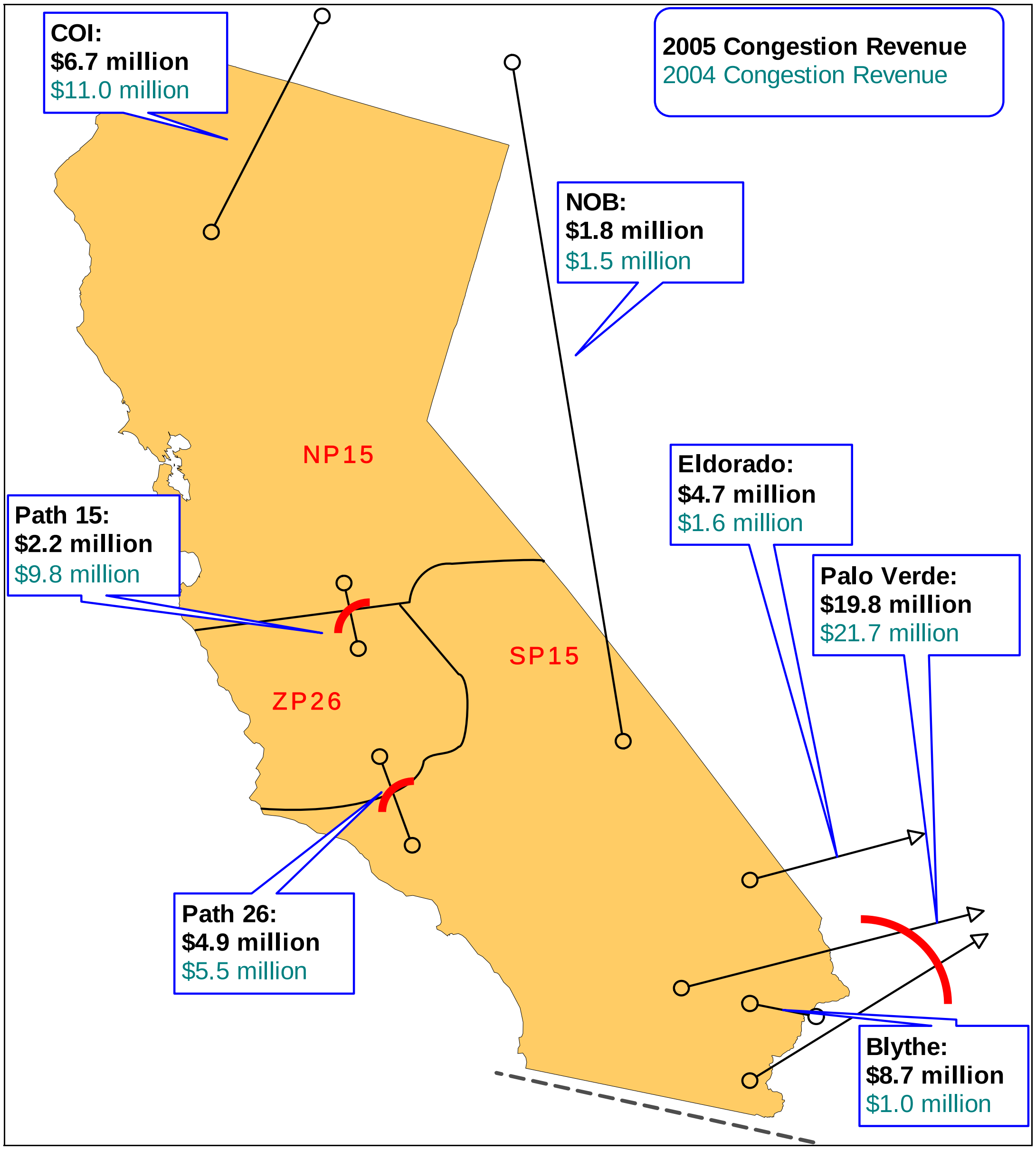


Inter-zonal Congestion Market

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.