Executive Summary

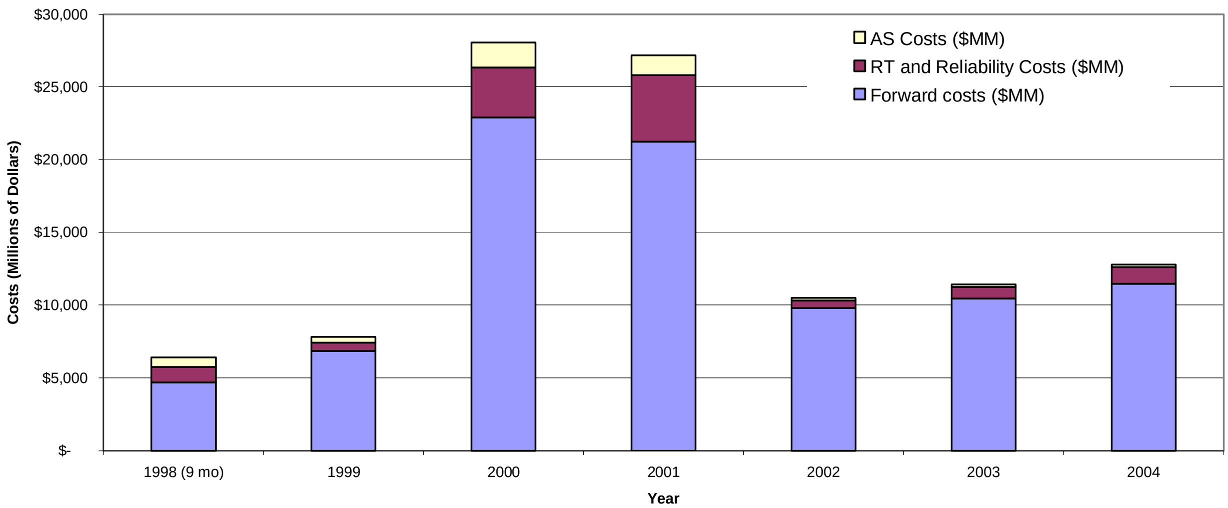
Calendar year 2004 was the third full year of stable market outcomes since the energy crisis that began in mid-2000. The wholesale energy market continued to perform well as a result of forward contracting by load serving entities that met a significant portion of their load requirements and the addition of new generation capacity in California and the southwest over the past three years. Abundant generation in the southwest, which increased by over 6,600 MW between January 2003 and January 2004,[1] resulted in an increase in California net imported energy by 5 percent over 2003 levels. The increase was achieved despite a weaker hydro season in the northwest, which limited imports from that area.

However, even with stable markets and increased imports, the CAISO faced significant challenges. Deliverability of forward scheduled energy into the SP15 load centers (southern California), which was a problem in 2003, became a chronic problem in 2004. It resulted in dramatically increased intra-zonal (within zone) congestion costs. Total intra-zonal congestion costs, which include the costs of committing units for local reliability reasons under the must-offer obligation, out-of-sequence and out-of-market real-time energy dispatches to mitigate congestion, and real-time dispatch of reliability must-run generating units to mitigate congestion, increased by 182 percent from 2003 levels. Congestion also caused operational difficulties as load serving entities scheduled significant amounts of low-cost power from the southwest to serve southern California load that was often not entirely deliverable to the load centers in the Los Angeles basin. Several transmission infrastructure enhancements have or will soon be completed which should help to mitigate some of the intra-zonal congestion problems. However, intra-zonal congestion will likely continue to be a problem in southern California until more new transmission infrastructure can be put into place to accommodate the migration of generation resources away from the load centers in the region and the new congestion management market design can be implemented, currently scheduled for early 2007.

Total wholesale energy and ancillary service costs increased 11.8 percent from 2003 levels as a result of increased natural gas fuel costs and significantly higher costs associated with mitigating real-time intra-zonal congestion. Continued stable energy market conditions and the expiration of some expensive long-term contracts signed during the 2000-2001 energy crisis helped to somewhat offset a 12 percent increase in natural gas fuel costs (the fuel almost exclusively used to run marginal generators in California). Figure E.1 compares the annual wholesale energy and ancillary service costs from 1998 through 2004. Comparing pre-energy crisis costs in 1999 to 2004 shows that when costs are normalized for natural gas, which averaged $2.39/MMBtu in 1999 and $5.62/MMbtu in 2004, costs have decreased considerably. Normalizing 2004 annual costs for natural gas results in a total cost reduction of 30 percent in 2004 from 1999 levels. This is a direct result of the addition of significant amounts of new efficient combined cycle natural gas generation facilities in California and throughout the west over the past four years, which has significantly improved the marginal heat rate for serving California load.

[1] 2003 and 2004 Western Systems Coordinating Council Information Summaries.

Figure E.1 1998 – 2004 Wholesale Energy Cost Components



Market Rule Changes in 2004

Both the CAISO's real-time imbalance energy market and ancillary service markets underwent substantial changes in 2004. The CAISO implemented Phase 1B of its Market Redesign and Technology Upgrade (MRTU) on October 1, effectively overhauling the entire CAISO real-time balancing market and dispatching system. Phase 1B consisted of the installation of Real-Time Market Application (RTMA), software developed for control room operators and market participants to automate the routine generation procurement and dispatch activities of the real-time market using an economic dispatch methodology. Phase 1B also was to include uninstructed deviation penalties (UDP), a system of fines to ensure that generators adhere to CAISO dispatch instructions, except under extraordinary circumstances. However, the CAISO postponed UDP implementation until mid-2005. RTMA software replaced the previous Balancing Energy Ex-Post Price (BEEP) auction system used to balance generation with load in real-time. It is the software that selects generators to ramp up or down based upon the imbalance between actual system load and forward-scheduled energy.

The RTMA software automatically balances electricity requirements in every dispatch interval. It will dispatch units for ramping up to two hours in advance if it estimates that would result in minimum cost to load. Previously, the CAISO manually dispatched resources according to lists of offer prices to increment (INC) and decrement (DEC) energy output every ten minutes. Operator systems have been expanded to collect detailed information about generation units and their production capabilities so that CAISO dispatch instructions can be more specific and generator response more dependable.

The implementation of the new real-time market systems provides several reliability and cost benefits to CAISO customers. RTMA uses sophisticated procedures to dispatch generation and intertie resources to meet imbalance energy needs based on operating constraints. The new systems encompass more feasible dispatch instructions for generation resources by incorporating a look-ahead function and physical operating constraints. This, combined with the uninstructed deviation penalties set to be incorporated in mid 2005, should result in significant improvements in following dispatch instructions, thereby increasing system reliability and reducing operating costs. See Chapter 1 for a more complete explanation of the new RTMA systems and their function and Chapter 3 for a review of RTMA performance during the fourth quarter of the year.

The CAISO's ancillary services (A/S) markets also went through substantial changes in 2004. There were a number of reasons for these changes but the two most immediate were the heightened sensitivity to reserve requirements in the aftermath of the August 14, 2003, blackout in the northeast and the reduced amount of reserve capacity bids in the A/S bid stack in SP15. The primary changes implemented to address these concerns were the zonal procurement of A/S during periods of limited transfer capability between northern and southern California and adjusting market rules to allow units that were constrained under the provisions of the must-offer obligation to bid into the day-ahead A/S markets without losing their minimum load cost compensation and uninstructed energy payments.

Supply and Demand Conditions

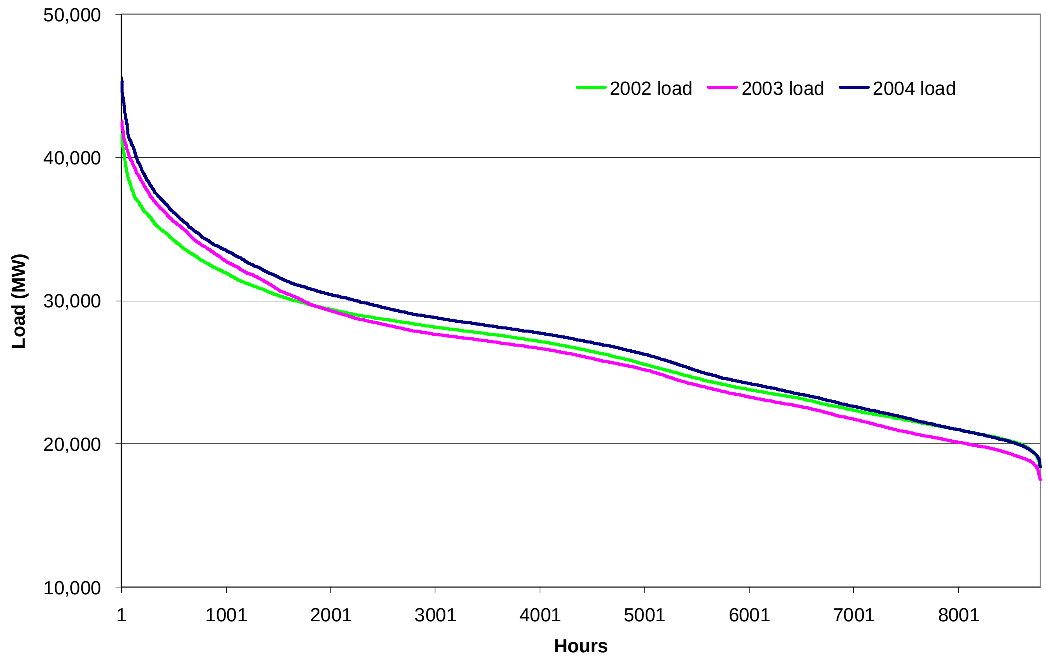
On average, loads increased approximately 4 percent from 2003 to 2004 due largely to economic growth. The Department of Market Analysis (DMA) calculates four load growth metrics. These are year-to-year comparisons of monthly average load, average daily peak load, average daily trough (minimum) load, and peak load for the entire period. All showed increases of between 3.5 and 4.9 percent on an annual basis. When comparing same months in 2003 and 2004 (e.g., January 2003 vs. January 2004), nearly all metrics showed increases (11 out of 12 months). This indicates that the load growth is not attributable to variations in weather. The CAISO set a new system peak load on September 8, 2004 as high temperatures in both northern and southern California increased loads to 45,597 MW, 7 percent higher than the 2003 peak. Fortunately, milder weather throughout the rest of the west allowed 9,116 MW of power to be imported into California to help meet the peak load. Table E.1 shows load statistics for 2001 through 2004 and Figure E.2 provides hourly load duration curves for 2002 through 2004.

Table E.1 2001 – 2004 Load Statistics

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	% Chg.	Annual Peak Load (MW)[2]	% Chg.
2001	25,372		222,816		38,975	
2002	26,063	2.7%	228,908	2.7%	42,352	8.7%
2003	26,328	1.0%	231,241	1.0%	42,581	0.5%
2004	27,299	3.7%	239,769	3.7%	45,562	7.0%

[2] Peak load numbers represent hourly integrated average load numbers which are slightly less than instantaneous peak loads. The 2004 instantaneous peak load was 45,597 MW.

Figure E.2 Hourly Load Duration Curves, 2002 – 2004



Available supply continued to be sufficient to meet growing load requirements. However, there were frequently significant deliverability challenges in southern California. The rate of new generation additions in California slowed considerably in 2004. Only 748 MW of additional generation capacity was added to the CAISO control area during the year, significantly less than the 4,830 MW added in 2003. Only 108 MW of new generation began commercial operation within the CAISO control area in 2004, of which 98 MW signed participating generator agreements with the CAISO. The majority of generation additions (640 MW) resulted from the return to service of previously mothballed generation owned by Reliant Energy Services. Fortunately, the rate of generation removed from the CAISO control area also decreased from 2,152 MW in 2003 to approximately 180 MW in 2004. Most of that capacity was located in the SP15 congestion zone in southern California. Dynegy determined that it was not economically feasible to repair its Long Beach Unit 8 generation facility, and retired it on March 22, 2004. It appears that the rate of new generation additions will pick up again in 2005 as the CAISO projects that 2,231 MW of new generation capacity will be added to the control area and only 450 MW will be lost to retirements. Table E.2 shows the generation additions and retirements by congestion region from 2001 through 2005.

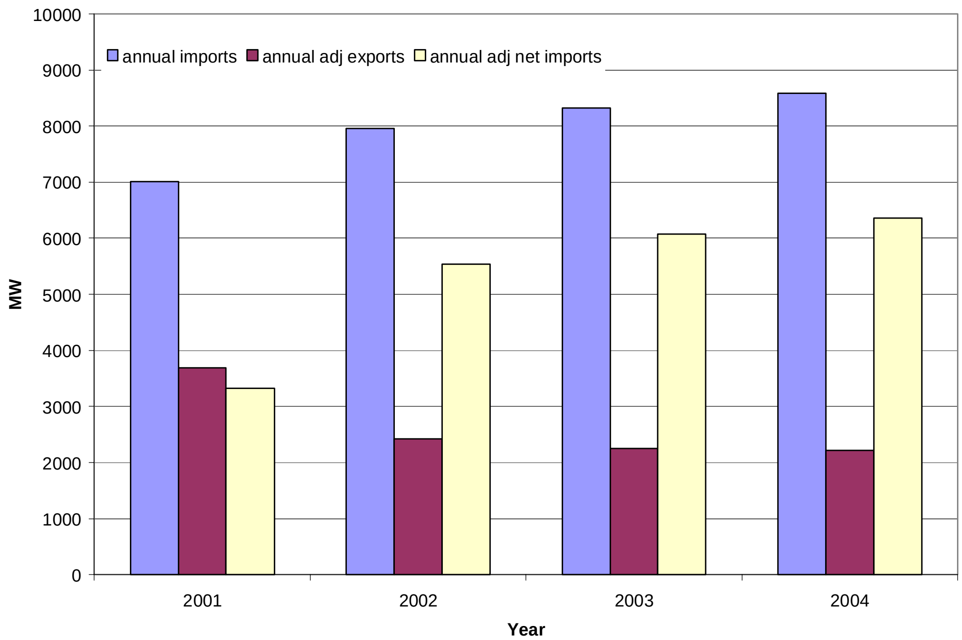
Table E.2 2001 through 2005 California Generation Additions and Retirements[3]

		2001	2002	2003	2004	2005	Total Through August 2005	Net NP26	Net SP26
New Generating Units by Sub-Regions									
	NP26	1,328	2,400	2,583	3	939	7,253	7,253	
	SP26	639	478	2,247	745	1,292	5,401		5,401
Total New Generating Units		***1,967***	***2,878***	***4,830***	***748***	***2,231***	***12,654***		
Retirements by Sug-Regions									
	NP26	(28)	(8)	(980)	(4)		(1,020)	(1,020)	
	SP26		(1,162)	(1,172)	(176)	(450)	(2,960)		(2,960)
Total Retirements		***(28)***	***(1,170)***	***(2,152)***	***(180)***	***(450)***	***(3,980)***		
Net Change in Capacity		**1,939**	**1,708**	**2,678**	**568**	**1,781**	**8,674**	6,233	2,441

Imports played an important role in meeting the growing load requirements in 2004. Net imported energy increased for the fourth year in a row as 2004 net imported energy increased by 5 percent over 2003 levels. This was primarily due to an increase in energy imports from the southwest where mild weather and abundant new efficient generation resources allowed for significant imports to California. Import levels from that region were 20 percent higher than last year due to significant generation additions and excess generation capacity in the region. Below normal hydro conditions and the outage of the Pacific DC Intertie for the last quarter of the year limited imports from the northwest. Import levels were 3 percent less than last year's levels. Figure E.3 shows the average import, export, and net import levels during peak hours for the years 2001 through 2004.

3 See the California ISO Summer Assessment and Chapter 1 for more detailed information on generation additions and retirements. NP26 refers to northern California or the region north of Path 26. Likewise SP26 refers to southern California for the region South of Path 26.

Figure E.3 2001 – 2004 Average Annual Imports, Exports, and Net Imports



Generation Outages

Generation availability was again high in 2004. As shown in Figure E.4, 2004 monthly combined forced and planned outages were similar to 2003 levels with the exception of October and November when two nuclear units were out for refueling in 2004. The forced outage rate, the annual average percentage of generation out due to unplanned reasons, dropped slightly in 2004 from 2003 levels remaining near 4 percent as shown in Figure E.5. Outages in 2004 displayed their usual seasonal pattern with planned maintenance and must-offer waiver approvals rising in the off-peak periods, and declining during the peak-load summer season.

Figure E.4 2002 – 2004 Monthly Average Planned and Forced Outages

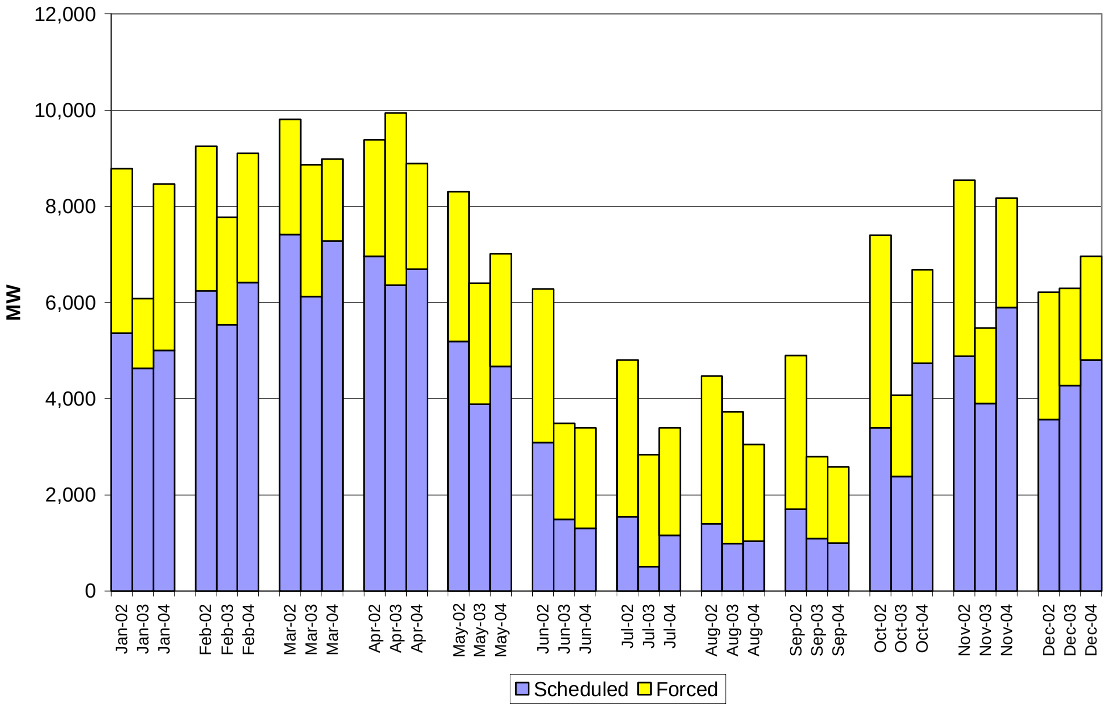
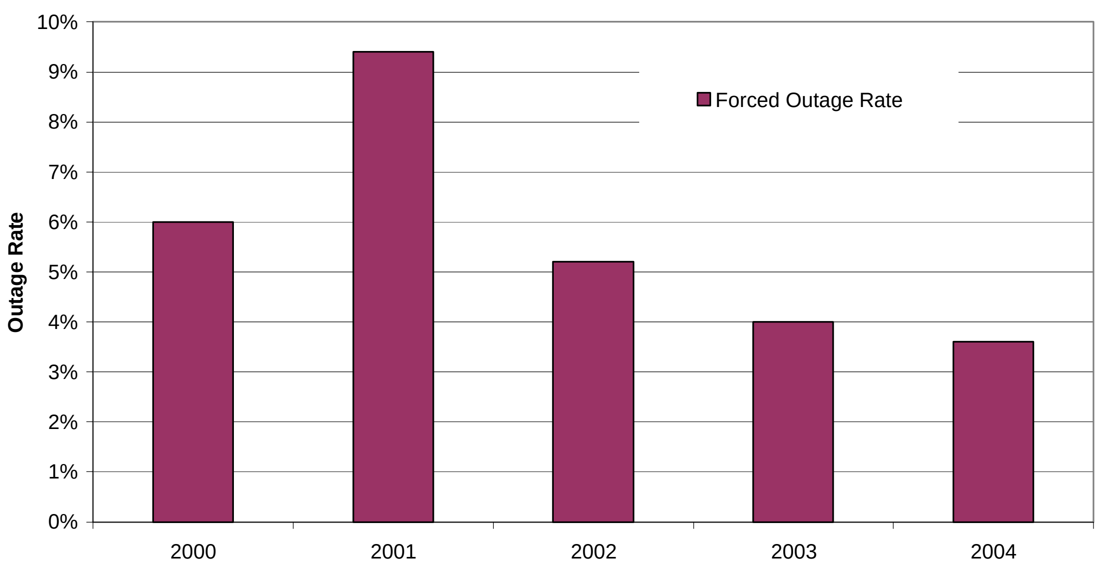


Figure E.5 2000 – 2004 Forced Outage Rates



Reserve Margin[4]

The reserve margin, the ratio of available generation over and above actual load to actual load during the peak load hour dropped for the first time in three years between 2003 and 2004. For the first time in three years peak load grew faster than new generation additions plus net imported energy. As shown in Figure E.6, the peak hour reserve margin in 2004 was 15.3 percent, compared to 22.8 percent in 2003. The overall reserve margin in 2004 was achieved largely due to a high level of net imported energy during the peak hour of 9,116 MW due to mild weather outside of California that enabled importers to supply large quantities of excess energy to meet the high California loads. 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. More generation has been constructed and has come on line in northern California compared to southern California during the last several years while 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.7 shows the SP15 and NP15 reserve margins for the southern California peak load day that occurred on September 10, 2004. Here the SP15 reserve margin was only 5 percent while the NP15 margin was a more comfortable 21 percent due to transmission constraints into southern California.

[4] 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. We consider capacity out on must-offer waivers available for this analysis. This is not the same as an operating reserve margin where units must be synchronized with the grid.

Figure E.6 1999 – 2004 Reserve Margins During Annual Peak Load Hour

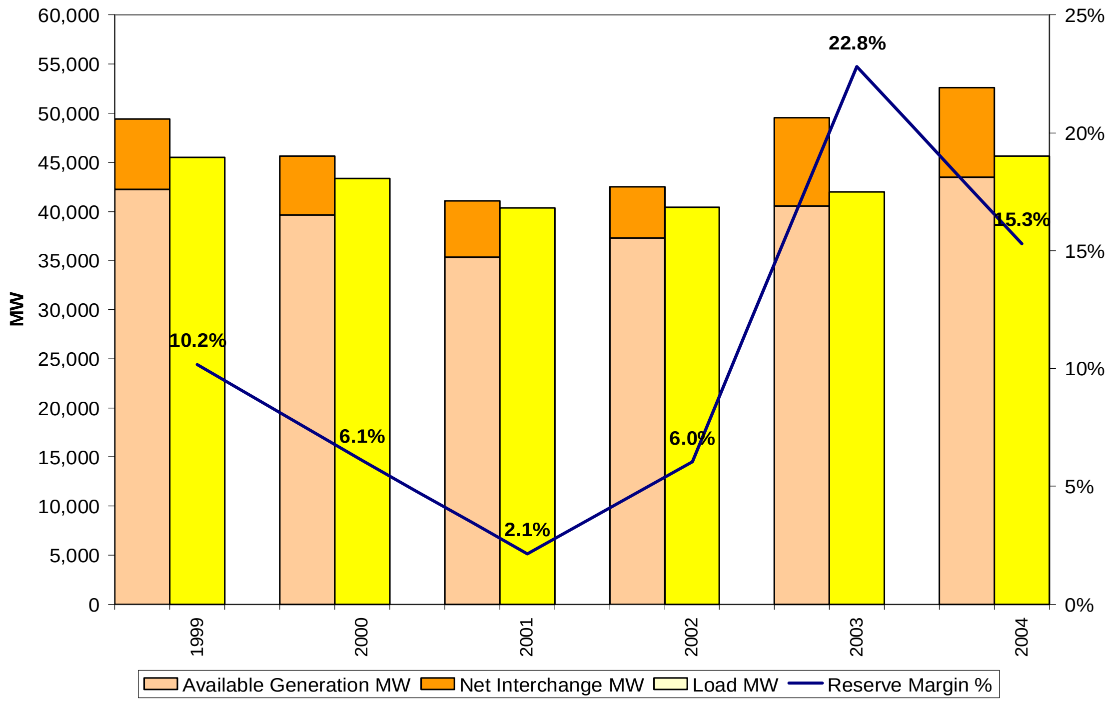
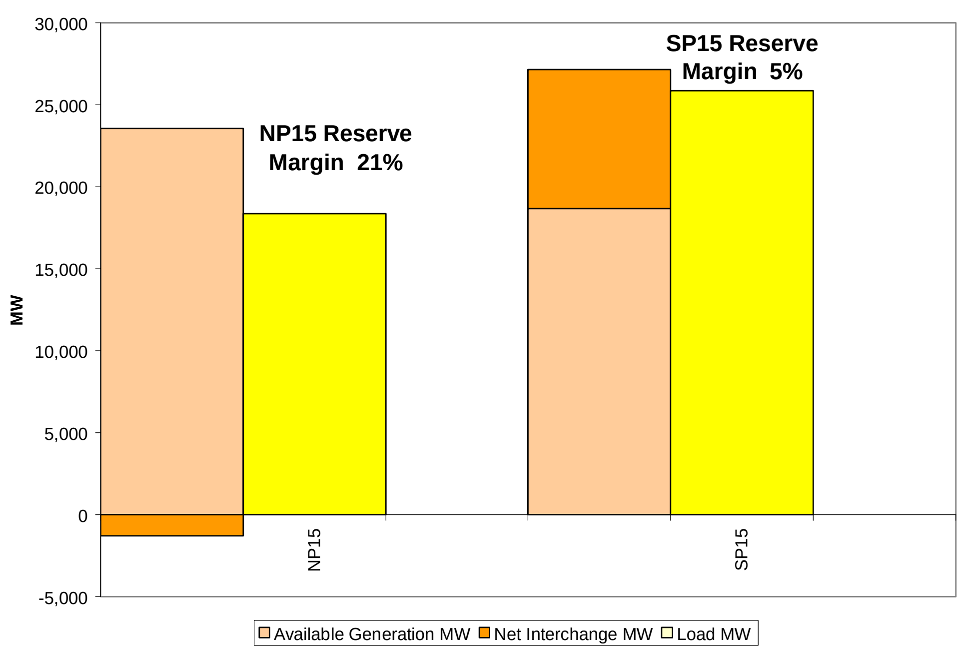


Figure E.7 Zonal Reserve Margins During SP15 Peak Hour, September 10, 2004, HE17



Short-term Energy Market Performance

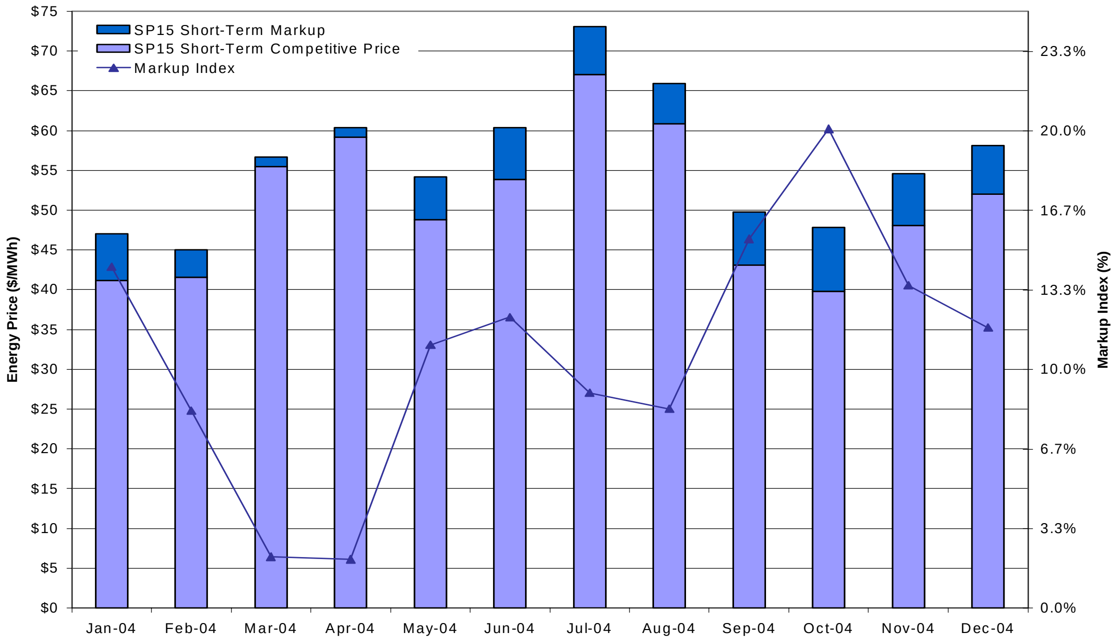
The significant number of long-term contracts entered into by the State of California in 2001 and by load serving entities since then combined with the large amount of new generation added to the western energy markets provided effective market power mitigation in the 2003 and 2004 short-term energy markets. When load serving entities are adequately supplied though longer-term arrangements, precise market power mitigation rules become less crucial because the smaller exposure of consumers to spot price volatility will not subject them to large cost impacts. 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 Hour-Ahead 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. DMA has estimated the hour-ahead mark-ups based on data collected from Powerdex, Inc.,[5] 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.8 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 2 and 20 percent, indicating competitive market conditions in the short-term wholesale energy markets in California. The highest monthly average mark-ups occurred in October. The higher October mark-up is a result of the tighter supply conditions in the market resulting from planned outages of many resources, including the San Onofre Nuclear Generation Station Unit #3 and the Pacific DC Intertie. Overall, the index indicates that short-term wholesale energy markets produced competitive outcomes in 2004 with mark-up averaging around 5 percent.

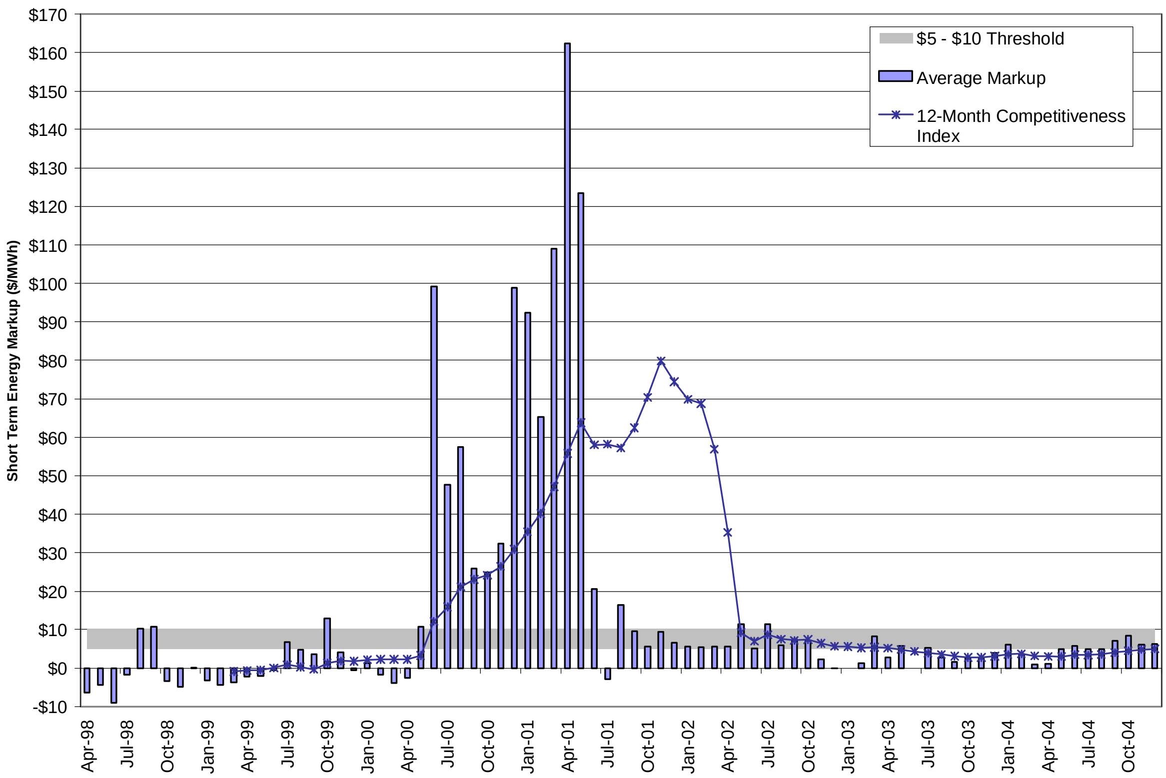
[5] www.hourlyindexes.com.

Figure E.8 2004 Short-term Forward Market Index – SP15



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 2004. This indicates that the short-term energy market in California that stabilized in late 2001 has produced fairly competitive results aver the past three years. Figure E.9 below shows the index from April 1998 through December 2004.

Figure E.9 Twelve-Month Competitiveness Index Through December 2004



Structural Measure of Whether Suppliers are Pivotal in Setting Prices: Residual Supplier Index

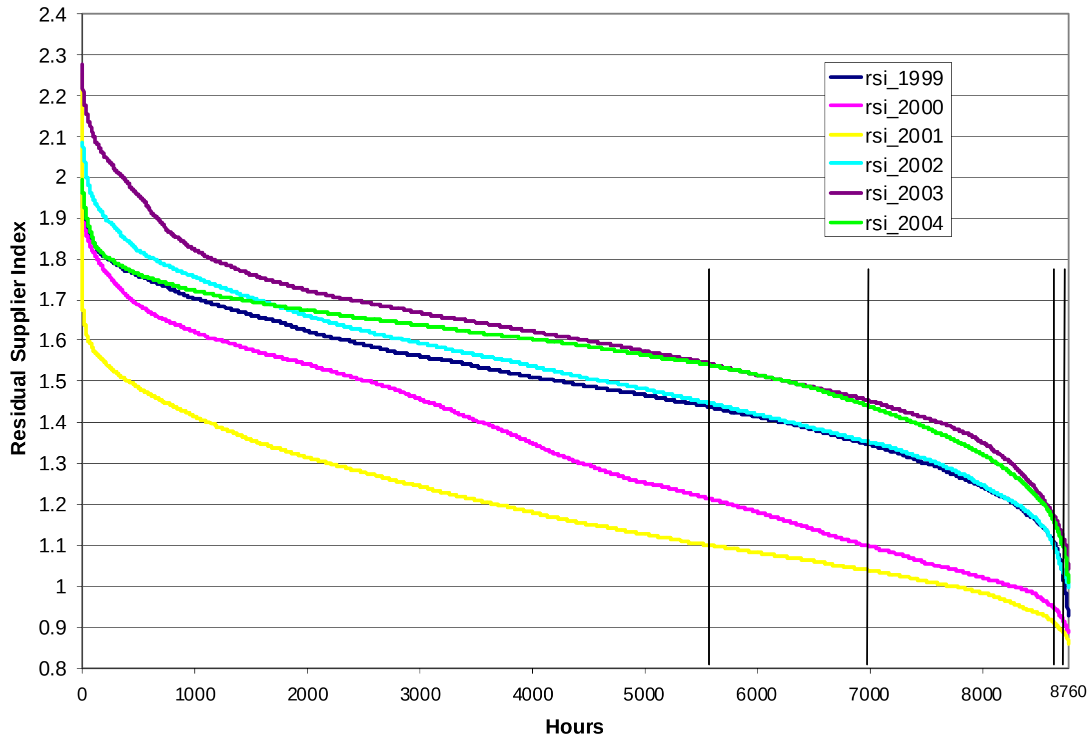
The residual supplier index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in a RSI value less than 1.0. When the largest suppliers are pivotal (an RSI value less than 1.0), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2004 were nearly as high as in 2003, which were the highest of the past five years. Using an RSI level of 1.1 to compare between years,[6] in 2004 the RSI levels were less than 1.1 in less than 0.55 percent of the hours (only 48 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 2004 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 2004. The significant amount of long-term contracts

[6] The 1.1 RSI level was chosen simply as it is close to 1.0 that would indicate a situation in which the potential to exercise market power is high.

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 2004 than 2001 as reflected by the higher RSI levels. Figure E.10 compares RSI duration curves for the past five years.

Figure E.10 Hourly Residual Supplier Index 1999 – 2004



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 extend to which CAISO markets contributed to the economics of investment in new supply capacity given observed prices in the CAISO's imbalance energy and ancillary service markets over the last two 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 in its discussion of market performance.

For this analysis, we obtained generation unit costs and operation information from a 2003 California Energy Commission Study (CEC).[7] The CEC estimated that over a 20 year period, a new combined cycle unit would need to recover, on average, $90/kW-year or $90,000/MW-year in fixed costs to be profitable. Similarly, the CEC estimated the fixed cost recovery requirement for a new combustion turbine unit to be $78/kW-year or $78,000/MW-year. We ran a net revenue analysis for both the 2003 and 2004 calendar years. To establish a baseline we assumed the generator was located in an unconstrained area and would self-commit when it was profitable to do so. Next, we estimated the additional revenue a combined cycle generator would have received under the must-offer commitment process had the generator been located in a transmission constrained area within SP15. This additional CAISO commitment revenue is shown as MLCC (minimum load cost compensation) in table E.3, below.[8]

Our results show that, in 2003, in the unconstrained area analysis, a combined cycle unit selling solely into the CAISO imbalance energy and ancillary service spinning reserve markets would have received net revenue in the range of approximately $47 to $58/kW-year for NP15 and SP15, respectively. In 2004, the largely decremental imbalance energy market combined with higher operating costs resulted in lower net revenues of $32 to $55/kW-year for NP15 and SP15, significantly less than the $90/kW-year net revenue requirement required to signal new investment. However, under the constrained area analysis, the addition of MLCC revenue could have potentially increased net revenue for a combined cycle unit in SP15 by nearly $17/kW-year, resulting in a net revenue of $72/kW-year. Although these revenues do not necessarily constitute a stable revenue stream and would be unlikely to provide an incentive for new generation to locate in a specific area, it does demonstrate that there was significant additional revenue provided from CAISO markets in constrained areas in southern California.

We also conducted the analysis for a hypothetical combustion turbine. A new combustion turbine unit selling solely into the CAISO imbalance energy and non-spinning reserve markets in 2003 would have received net revenue in the range of approximately $32 to $36/kW-year for NP15 and SP15, respectively. In 2004, the net revenue for the combustion turbine unit was lower than 2003 levels in NP15 at $21/kW-year but significantly higher in SP15 at $45/kW-year. Net revenue in both zones was much lower than the $78/kW-year cost estimate to support new generation entry of a combustion turbine. Again, this was primarily a result of the small volumes transacted in the real-time imbalance energy market. We attribute the increase in revenues in SP15 to the significant increase in the frequency of real-time market splits in 2004 from 2003 levels. This also contributed to the much lower net revenues in NP15 as prices tended to be suppressed during periods of market split.

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

[8] Under the must-offer obligation rules, generators that are denied must-offer waiver obligations by the CAISO are compensated for their start-up and minimum load operation costs as well as the uninstructed energy price for the minimum load energy. This construct results in a double payment for the minimum load energy and significantly increases the net revenue a unit could earn in a constrained area.

The unconstrained net revenue results for both a new combined cycle unit and a new combustion turbine are well below the estimated range of revenue needed to stimulate investment in new supply relying only on spot market revenues. These results serve to highlight the key role that forward contracts and/or capacity markets must play in stimulating investment in new supply with the current structure of California's wholesale market and the importance of effective resource adequacy rules to facilitate new generation infrastructure. The constrained area results that include MLCC illustrate the significant impact this compensation has on revenue adequacy in today's market. In 2004, the CAISO paid out $274 million in MLCC to generators located in constrained areas for local reliability reasons.

Table E.3 2003 and 2004 Financial Analysis of New Combined Cycle Unit

	2003		2004	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	57.6%	60.1%	58.0%	63.4%
Energy Revenue ($/kW-yr)	$ 263.9	$ 280.3	$ 265.8	$ 301.6 + MLCC $ 16.9
Ancillary Service Capacity Revenue ($/kW-yr)	$ 3.2	$ 2.8	$ 3.1	$ 2.9
Operating Cost ($/kW-yr)	$ 220.6	$ 225.6	$ 237.3	$ 249.4
Net Revenue ($/kW-yr)	$ 46.5	$ 57.5	$ 31.7	$ 55.1 + MLCC $ 72.0

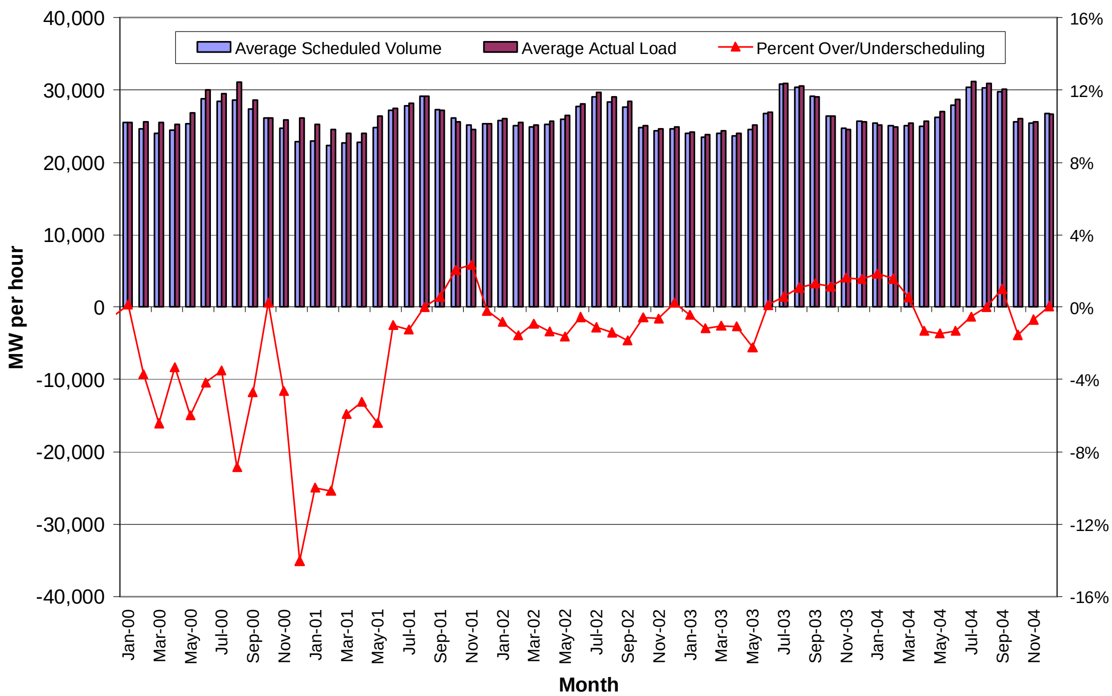
Table E.4 2003 and 2004 Financial Analysis of New Combustion Turbine Unit

	2003		2004	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	16.0%	20.2%	11.9%	16.6%
Energy Revenue ($/kW-yr)	$ 103.7	$ 130.8	$ 81.1	$ 114.6
Ancillary Service Capacity Revenue ($/kW-yr)	$ 20.6	$ 19.2	$ 13.5	$ 27.8
Operating Cost ($/kW-yr)	$ 91.9	$ 113.6	$ 73.6	$ 97.3
Net Revenue ($/kW-yr)	$ 32.4	$ 36.4	$ 21.0	$ 45.1

2004 Imbalance Energy Market

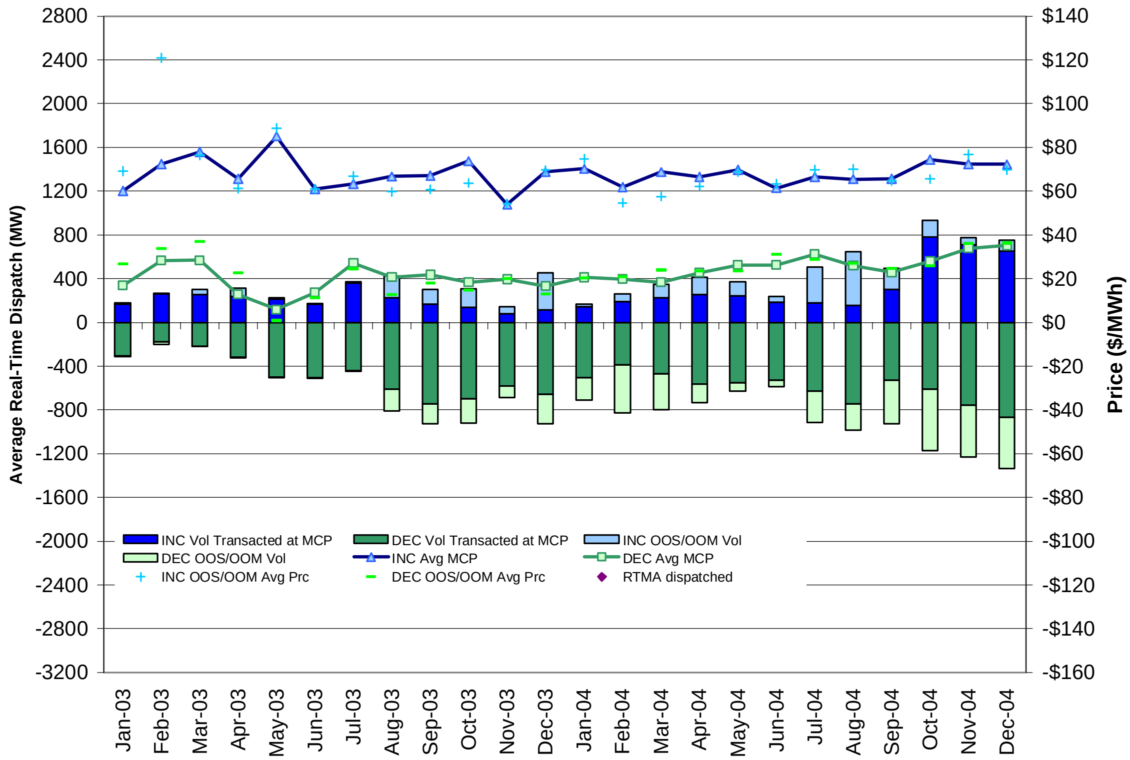
For the third year in a row, significant forward scheduling by load serving entities resulted in low imbalance energy volumes throughout 2004. Monthly average forward energy schedules were within 2 percent of actual load as shown in Figure E.11. Real-time balancing energy was again overwhelmingly in 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. Decremental energy dispatch volumes exceeded incremental energy dispatch volumes by a 1.85 to 1 margin. 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.11 Monthly Average Loads and Scheduling Deviations, 2000 – 2004



Monthly average prices for incremental energy in 2004 were stable, averaging between \$60 and \$80/MWh in every month of the year. Average prices for decremental energy were also stable, ranging between \$20 and \$30/MWh until the deployment of RTMA and then increasing to approximately \$40/MWh for the last few months of the year. Prices also became considerably more volatile after the new RTMA systems were implemented on October 1. Figure E.12 shows imbalance energy volumes and prices for 2003 and 2004.

Figure E.12 2003 and 2004 Monthly Average Imbalance Energy Volumes and Prices



Competitiveness of Real-time Energy Market

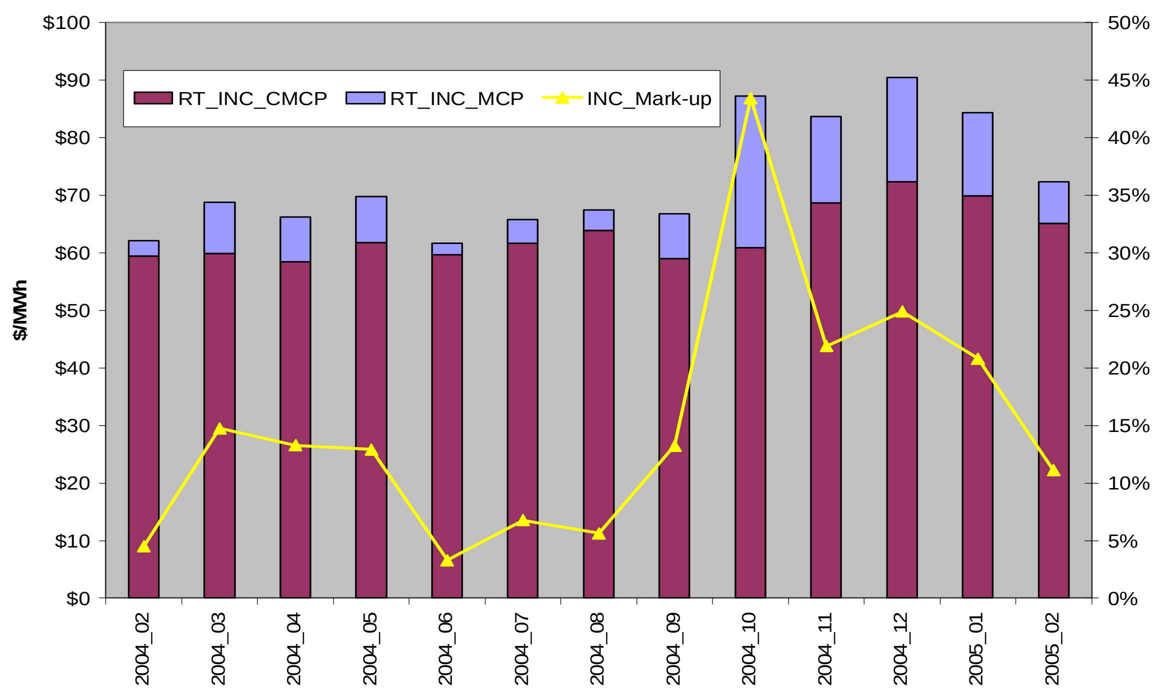
The CAISO has developed a real-time price to cost mark-up index designed to measure market performance in the real-time market. This index compares real-time market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[9] While an index based upon the small volume of transactions in the real-time market is not the preferred method of calculating mark-up, it provides a profile of general real-time market performance. For more than two years, monthly mark-ups have averaged less than 20 percent, indicating a reasonably healthy real-time energy market.

The trend of monthly average mark-ups below 20 percent ended in October 2004 with the implementation of the new real-time market application software (RTMA). RTMA was implemented as part of the CAISO's market redesign and technology upgrade (MRTU). The higher mark-up over competitive baseline prices was the result of several factors. First, under RTMA, the software takes into account generation unit operating constraints in determining real-time market dispatches. While this change is expected

[9] 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.

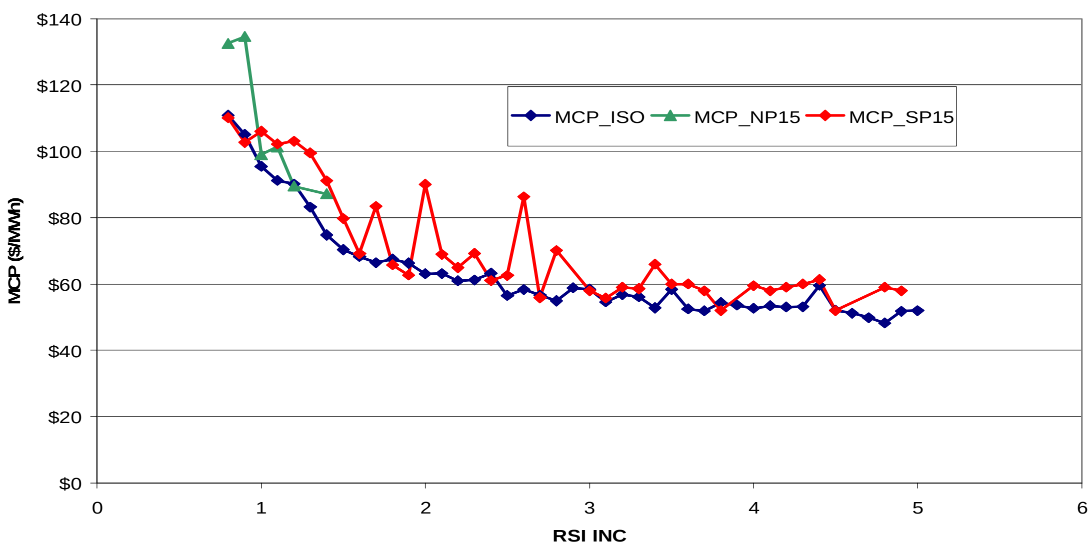
to make the market more efficient over time, it initially caused some problems because some generation unit operating data was not accurately input into the RTMA. For example, several units had default ramp rates set at minimum ramping levels. This caused the RTMA software to dispatch deep into the bid stack to meet imbalance energy requirements, resulting in actual prices that were significantly higher than competitive baseline prices. Similarly, certain reliability must run units (RMR) had the same maximum and minimum ramp rates stored in the CAISO's database, restricting these units from bidding in variable ramp rates with their supplemental real-time energy bids. To compensate, these units used pricing as a proxy for their ramping restrictions, which resulted in inefficient pricing. The CAISO has made significant progress in addressing RTMA issues. This has resulted in significant improvements to real-time market performance. Figure E.13 shows the monthly average mark-up above competitive baseline prices for 2004. As the figure shows, the low mark-up trend ended in October 2004 with the implementation of the new RTMA systems. Real-time price to cost mark-ups have since decreased as issues associated with the new real-time software have been addressed. Software tuning continues on the RTMA and we expect mark-ups to continue their downward trend as real-time markets continue to be competitive due to forward scheduling of energy that is near actual load levels. This has resulted in low demand for real-time energy outside of the morning and evening load ramping periods.

Figure E.13 Monthly Estimated Mark-up for Real-time Incremental Imbalance Energy Market



The CAISO also uses a residual supplier index (RSI), described earlier, to measure real-time market competitiveness. Figure E.14 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 2004 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. Real-time imbalance energy market ramping capability has declined significantly since 1999 as fewer fast ramping resources participate in the market. See Chapter 2 for more discussion on the competitiveness of the real-time imbalance energy market.

Figure E.14 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 and stems primarily from a combination of economic factors and the CAISO's current system for managing congestion on a day-ahead and hour-ahead basis.

The CAISO's current method for dealing with intra-zonal congestion involves a combination of steps and operating procedures. These steps and operating procedures are explained in Chapter 6.

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.

A variety of factors have contributed to an increase in intra-zonal congestion in 2004, primarily within southern California (SP15). First, while no major new generation capacity has been added within southern California over the last two years, significant new efficient generation resources continue to be added outside of the CAISO system in the southwest and within the CAISO system on the border with Mexico. Given daily spot market gas and electric prices in 2004, it was typically uneconomic to commit older generating units in southern California (with heat rates of 10,000 MMBtu/MWh or above), and economic to operate new generation units (with heat rates of 8,000 MMBtu/MWh or below). As a result, the amount of thermal capacity within southern California committed through the market in 2004 dropped significantly, while imports increased, thereby increasing intra-zonal congestion within SP15. This caused the CAISO to rely more heavily on the must-offer waiver denial process to commit additional thermal generation capacity within SP15 to maintain voltage and deal with generation and transmission outages.

While a number of transmission issues contributed to the need to utilize these mechanisms to manage intra-zonal congestion, the majority of costs incurred can be attributed to four specific points of intra-zonal congestion: Miguel, South of Lugo, Sylmar Substation, and the Southern California Import Transmission Nomogram.

The costs associated with mitigating intra-zonal congestion fall into three categories. The first is RMR costs resulting from real-time incremental dispatches to manage intra-zonal congestion. These costs totaled $49 million in 2004. The second cost category is the minimum load cost compensation (MLCC) resulting from committing non-RMR units at minimum load through the must-offer mechanism. The MLCC costs associated with managing congestion totaled $274 million for 2004. And finally, the costs resulting from real-time dispatch of non-RMR units (OOS and OOM) to manage congestion was approximately $103 million for 2004. This brings the total intra-zonal congestion management costs for 2004 to $426 million, 182 percent higher than the 2003 costs of $151 million.[10] The dramatic increase in intra-zonal congestion costs is due to many factors including higher natural gas costs, major facility outages, load growth within the Los Angeles basin, and the scheduling of lower cost southwestern energy into California. A detailed discussion of intra-zonal congestion costs can be found in Chapter 6.

[10] The CAISO does not have detailed intra-zonal MLCC cost data for the first five months of 2004. The annualized figure used in the total reported here is calculated by applying the proportion of total MLCC for June-December that resulted from congestion management to the total MLCC for the first five months of 2004.

Table E.5 Comparison of 2003 and 2004 Monthly Intra-zonal Congestion Costs by Category

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

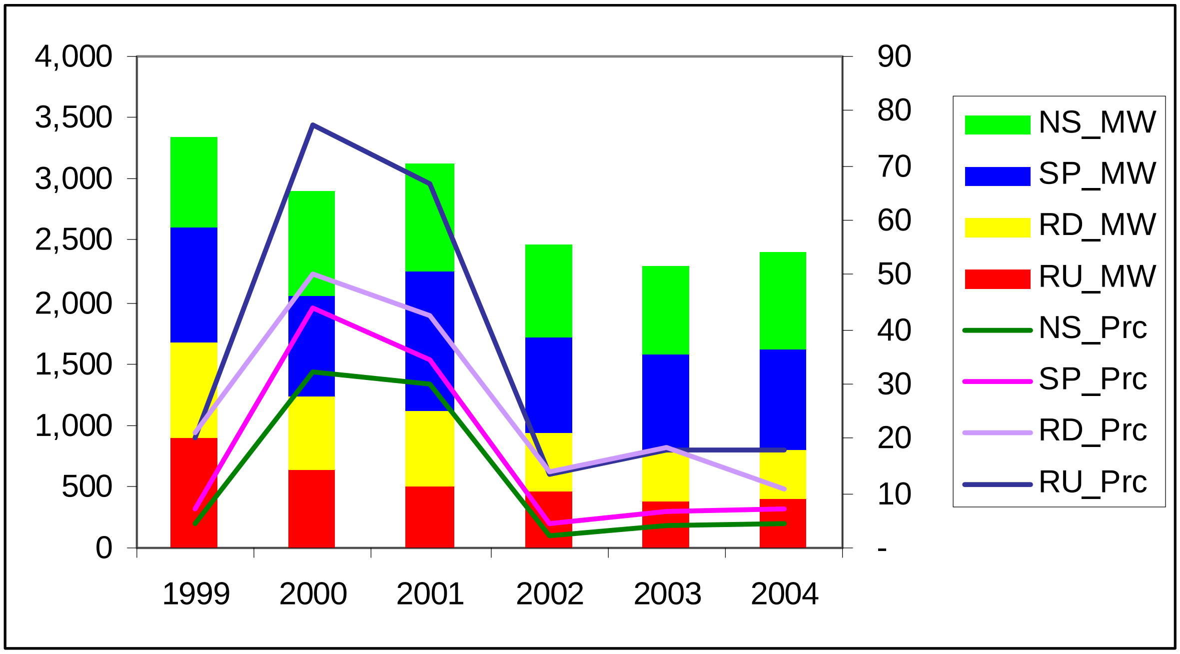
Ancillary Services Market

The implementation of zonal procurement during the summer of 2004 led to an increase in the frequency of the number of times when insufficient bids were offered to the ancillary service markets to meet SP15 reserve requirements. The tight SP15 markets led to frequent price spikes in the spinning and non-spinning reserve markets.

Despite increased instances of insufficient bids being offered to the ancillary services markets, the cost of ancillary services to load fell by 11 percent from an average of $0.856/MWh in 2003 to $0.763/MWh in 2004. The cost reduction was due to a large reduction in regulation down procurement costs. They dropped 40 percent from 2003 levels due to increased supply that became available due, in part, to load growth during off-peak hours. Overall A/S prices decreased slightly from a weighted average price of $9.81/MW in 2003 to $8.63/MW in 2004, a 12 percent decrease overall.

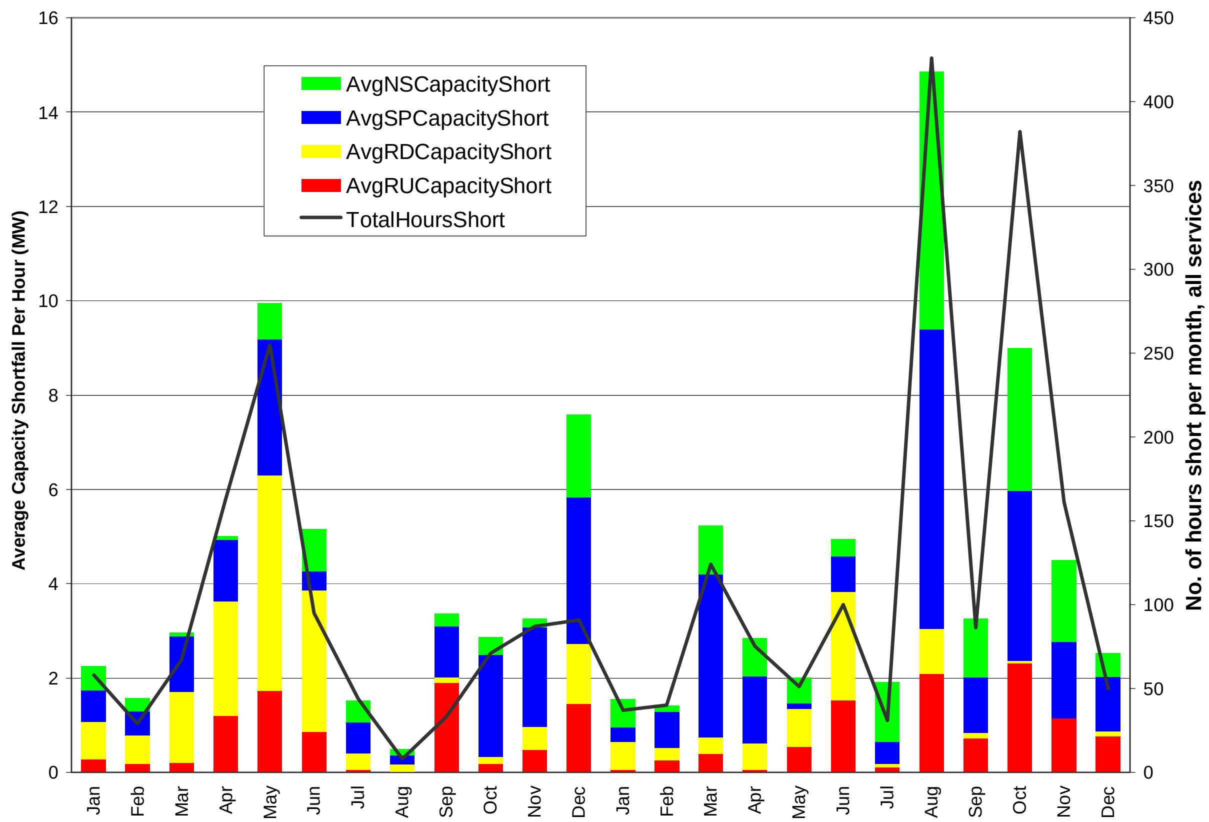
Self-provision of A/S continued to be a major component in the A/S markets in 2004 with average self-provision rates of between 50 and 80 percent. Offers of physical capacity to the A/S markets increased by 18 percent from 2003 to 2004. This was below 2002 levels as a result of the increase in control area generation units under RMR condition 2 contracts. We attribute some of the increase from 2003 to 2004 to the removal on July 11, 2004, of the disincentive to bid into the A/S markets by units constrained under the provisions of the must-offer obligation. Figure E.15 below shows the average annual A/S prices and volumes from 1999 through 2004.

Figure E.15 Annual A/S Prices and Volumes, 1999 – 2004



Bid sufficiency, having sufficient available capacity bid into the markets to meet minimum requirements, deteriorated in 2004 compared to 2003. Examining August and December of 2004 for example, we found the capacity shortage was much greater in August even though there were more shortage hours in December. The total capacity shortage increased by 18 percent from 2003. There was a significant increase in shortages of non-spin capacity and a corresponding decrease in the shortage of regulation down capacity. Overall, 2004 suffered from greater bid insufficiency than 2003. The same pattern was evident in the number of hours in which shortages were present. Bid sufficiency improved in regulation down but deteriorated in the other three services, especially in non-spin. Figure E.16 shows the monthly levels of bid insufficiency in 2003 and 2004.

Figure E.16 Bid Insufficiency by Capacity and Hour



Inter-zonal Transmission

Several major modifications to the inter-zonal transmission infrastructure took place during 2004. The long-awaited Path 15 upgrade was completed and turned over to the CAISO's operation on December 7, 2004. The upgraded Path 15 began commercial operation on December 22 in the hour-ahead market and on December 23 in the day-ahead market. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The average flows on the path increased 40 percent shortly after the upgrade was put into commercial operation.

The Pacific DC Intertie (also know as Nevada-Oregon Border or NOB), which runs from the Celilo substation in the northwest to the Sylmar substation in southern California also was significantly enhanced during the latter part of the year. This project replaced the last of the original vacuum-tube mercury-arc converters at the Celilo Converter Substation with solid-state silicon-based thyristors. These upgrades allowed the DC Intertie's transfer capacity to remain at 3,100 MW rather than being derated to 1,100 MW if improvements were not made.

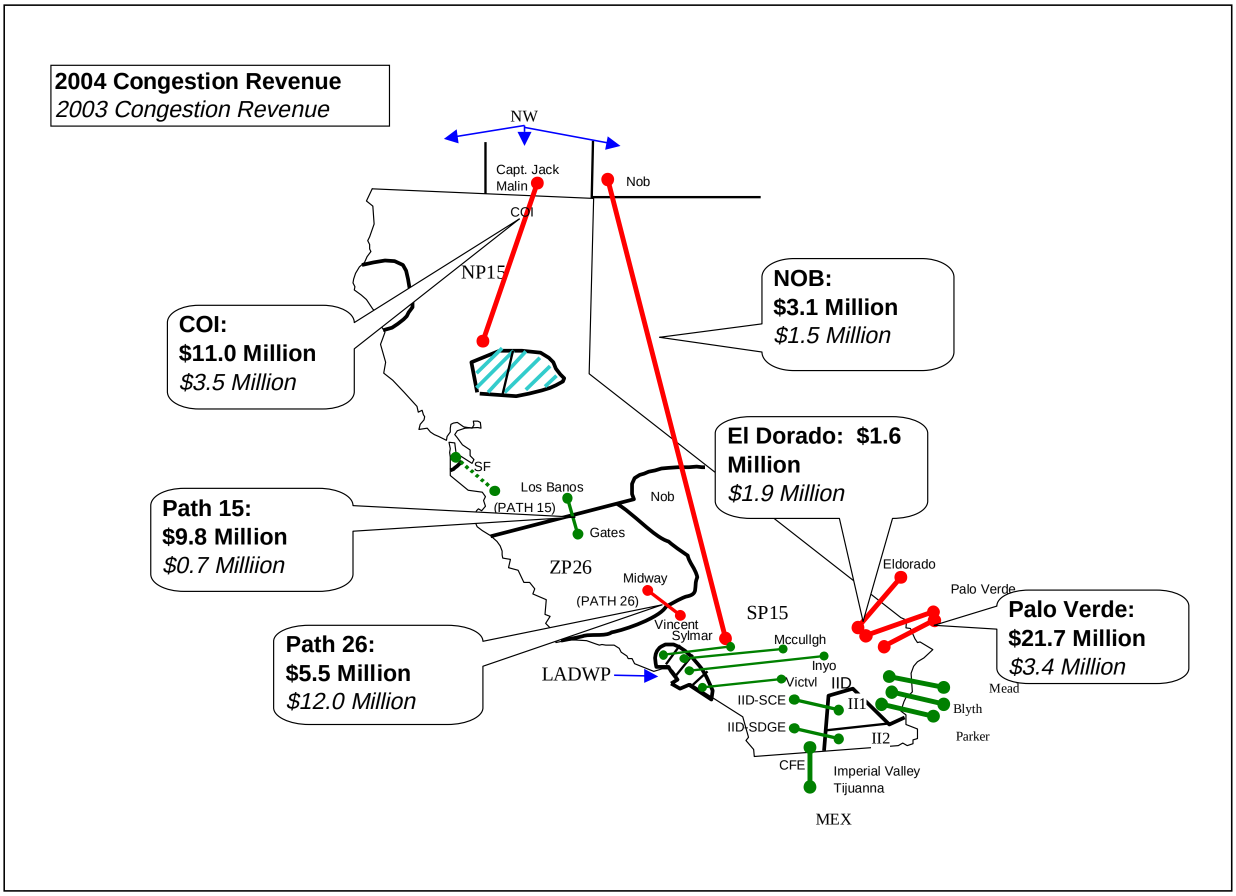
On December 31, 2004, three existing long-term contracts between WAPA and PG&E expired. On July 13, 2004, WAPA announced its decision to leave the CAISO control area and to join the Sacramento Municipal Utility District (SMUD) as a sub-control area effective January 1, 2005. WAPA intends to schedule power deliveries for its project use loads and customers that are directly connected to its transmission system. WAPA will also manage net power flows at sub-control area interconnection points.

As a result of the WAPA/SMUD transition, the CAISO defined new inter-connection points and new branch groups and placed a new network model in service on December 31, 2004, incorporating several market and system changes. The WAPA transmission system and USBR's northern California hydro generation were incorporated into the SMUD control area. As the result of the WAPA transition to the SMUD control area, the CAISO created eight new branch groups in its SA network model B5 to replace the two expiring branch groups.

Finally, the City of Pasadena became a PTO beginning on January 1, 2005. It turned over its transmission facilities to the CAISO to operate. The City of Pasadena owns about 200 MW of capacity on transmission paths into California.

Total inter-zonal congestion costs in 2004 were $55.8 million, significantly higher than the $26.1 million in 2003 and $41.8 in 2002. The higher congestion cost in 2004 was mainly due to congestion cost increases on Palo Verde, COI and Path 15. Congestion was primarily caused by high levels of imported energy scheduled into California combined with frequent scheduled line and substation work on a number of lines and substations related to these three interties as well as the work on PDCI. Chapter 5 provides a detailed discussion of the performance of the inter-zonal congestion market in 2004. Figure E.17 contains a map of the major interties into and between the CAISO congestion zones and the respective inter-zonal transmission costs in 2003 and 2004.

Figure E.17 2003 and 2004 California ISO Major Congested Interties and Congestion Costs



Resource Adequacy

Resource adequacy has been addressed by the eastern ISOs by putting explicit responsibility on the load serving entities (LSEs) to procure sufficient generation capacity ("steel in ground") to serve their annual peak load plus a margin. Since the majority of California load is currently served by the three investor owned utility distribution companies (UDCs), the California Public Utilities Commission (CPUC) is spearheading the development of a resource adequacy (RA) obligation for the LSEs under its jurisdiction.[11] This effort is ongoing. Its salient elements, at present, are embodied in CPUC's October 28, 2004, Resource Adequacy Decision.

The CPUC's October 28, 2004, Order establishes a year-round obligation on LSEs to procure sufficient capacity to serve their load plus a planning reserve margin. The level (MW) of the LSE's obligation varies by month and is based on the LSE's coincident monthly peak load plus a 15-17 percent planning reserve margin.

The CAISO has long held the position that all resources procured by load serving entities to satisfy their resource adequacy obligations must be deliverable, both on a

[11] It is anticipated that the CPUC RA will be adopted by local regulatory agencies in conjunction with other (non-CPUC jurisdictional) LSEs in California.

system-wide as well as local level. The CAISO has proposed three deliverability screens: (1) aggregate to load for evaluating control area resources, (2) imports, and (3) load pocket. The CPUC's October 28th Order supports the CAISO's proposals to implement the first two screens described above. Chapter 1 provides a summary of the provisions of the current status of the resource adequacy proceedings in California.

Transmission Economic Assessment Methodology (TEAM)

The CAISO is responsible for evaluating the need for all potential transmission upgrades that California ratepayers may be asked to fund.[12] This includes construction of transmission projects needed either to promote economic efficiency or to maintain system reliability. The CAISO has clear standards to use in evaluating reliability-based projects. To fulfill its responsibility for identifying economic projects that promote efficient utilization of the grid, the CAISO developed a methodology called the Transmission Economic Assessment Methodology (TEAM).

The goal of TEAM is to significantly streamline the evaluation process for economic projects, improve the accuracy of the evaluation, and add greater predictability to the evaluations of transmission need conducted at the various agencies. The methodology is intended to be a tool that will provide market participants, policy-makers, and permitting authorities with the information necessary to make informed decisions when planning and constructing a transmission upgrade for reliable and efficient delivery of electric power to California consumers.

This methodology was filed with the CPUC in June 2004 in a report. The report demonstrates the methodology by applying it to a proposed transmission expansion of Path 26 between central and southern California.

From Sept 2004 through Feb 2005, TEAM was used to evaluate a proposal by Southern California Edison (SCE) to expand the Palo Verde intertie by adding a new line, Palo Verde Devers Line #2 (PVD2).

The proposed PVD2 project is a 500 kV transmission line from the Palo Verde area (near Phoenix, Arizona) to SCE's Devers substation near Palm Springs in southern California. If approved, it is expected to come online by year 2009, increasing California's import capability from the southwest by at least 1,200 MW.

After a comprehensive analysis, it was projected that the PVD2 project would provide a significant amount of reliability and economic benefits to CAISO ratepayers, would improve reliability by increasing voltage support in southern California, and would enhance system operational flexibility by providing CAISO operators with more options in responding to transmission and generation outages.

The total capital cost of the project is estimated to be $680 million at the 2009 online date. The following table summarizes the expected benefits and costs over the 50-year economic life of the PVD2 project for various perspectives.

[12] The Legislature, pursuant to Public Utilities Code § 345, assigned the CAISO the responsibility of "ensur[ing] [the] efficient use and reliable operation of the transmission grid." To achieve this goal, the CAISO can compel Participating Transmission Owners to pursue construction of transmission projects deemed needed either to "promote economic efficiency" or to "maintain system reliability" (CAISO Tariff § 3.2.1.).

Table E.6 Summary of PVD2 Lifecycle Benefits, Costs, and Benefit-Cost Ratios for the Four Primary Perspectives (millions of 2008 dollars)

	WECC Or Societal	Enhanced WECC Competition or Modified Societal	CAISO Ratepayer (LMP Only)	CAISO Ratepayer (LMP+ Contract Path)
Energy	$56	$84	$57	$198
Operational	$20	$20	$20	$20
Capacity	$12	$12	$6	$6
System Loss reduction	$2	$2	$1	$1
Emissions reduction	$1	$1	$1	$1
Total	**$91**	**$119**	**$84**	**$225**
Levelized Costs	$71	$71	$71	$71
Benefit-Cost Ratio	**1.3**	**1.7**	**1.2**	**3.2**

For more details on this analysis, visit: http://www1.caiso.com/docs/2005/01/19/2005011914572217739.html.

The CAISO Board approved the PVD2 project unanimously at the board meeting of February 24, 2005, based on the staff recommendation applying the TEAM. SCE is expected to file its own justification for the line in the Certificate of Public Convenience and Necessity (CPCN) process at the CPUC by the spring of 2005.