California ISO
Your Link to Power

Annual Report
Market Issues and Performance

2006

Department of Market Monitoring

California Independent System Operator

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Overview

Each year the Department of Market Monitoring (DMM) 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, 2006 through December 31, 2006.

From an operational standpoint, 2006 was a year of extremes with operational challenges in the spring due to excessive hydroelectric generation and in the summer due to a record breaking heat wave. Through it all, grid reliability and the markets fared very well. A well above average snowpack throughout California and the Pacific Northwest resulted in an abundance of hydroelectric generation production in the first half of the year. High volumes of hydroelectric production caused persistent over-generation conditions and unscheduled loop flow issues that created real-time operational challenges and caused a high degree of price volatility in the Real Time Market. The abundance of hydroelectric power coupled with lower natural gas prices also had a significant impact of reducing day-ahead spot energy prices. In the first half of the year, day-ahead energy prices in Southern California averaged approximately $51/MWh, compared to $84/MWh for the same period last year.

However, in a matter of weeks, California and the rest of the West went from surplus generation to supply scarcity conditions as the entire region experienced an unprecedented heat wave lasting nearly three weeks in July. System operation and the market were pushed to their limits during this period and performed very well. From a reliability standpoint, the record setting July heat wave only resulted in one Stage 2 Emergency[1] and no Stage 3 Emergencies (involuntary load interruptions). On the market side, spot energy and ancillary service prices rose significantly during the heat wave with day-ahead prices frequently at the $400 soft bid cap. However, prices in the CAISO Real Time Market were much lower due to an extremely high level of forward scheduling, which resulted in minimal imbalance energy demand and in many cases caused the CAISO to dispatch generation down.

Overall, despite the extreme range of system conditions, California's spot wholesale energy markets in 2006 were generally stable and competitive, similar to the past several years (2002-2005). However, as discussed in prior reports, the slow pace of new generation investment in California remains a concern. One of the primary metrics that the CAISO 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 CAISO considers MCI values in the range of $5-$10/MWh to be reflective of a workably competitive market. The monthly MCI values estimated for 2006 were either below or within this range for all months of the year.

The average estimated cost of wholesale energy in 2006 was $47.55/MWh of load compared to $57.83/MWh in 2005. Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy

[1] Stage 2 Emergency Notice is declared by the CAISO any time it is clear that an Operating Reserve shortfall (less than 5 percent) is unavoidable.

redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The decrease in the costs in 2006 was primarily due to lower natural gas prices in 2006, particularly in the September-December period when there was a sharp increase in natural gas prices in 2005 due to the supply interruptions from the Gulf Coast hurricanes. An abundance of hydroelectric generation in 2006 also contributed to the decline.

One of the major success stories reported in the 2005 Annual Report on Market Issues and Performance was the sharp reduction in intra-zonal congestion costs. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. In 2005, intra-zonal congestion costs totaled $222 million, compared to $426 million in 2004, representing a 48 percent decrease. For 2006, total intra-zonal congestion costs declined further to $207 million. The relatively low levels of intra-zonal congestion costs over the past two years is the result of various transmission enhancements in 2005 and 2006 that were targeted to address frequently congested areas. Transmission enhancements also helped to reduce total RMR costs, which include annual fixed option payments and total dispatched energy costs. Total RMR costs declined substantially from approximately $505 million in 2005 to $428 million in 2006, a reduction of approximately $77 million. This reduction resulted from a decline in RMR dispatched energy costs from approximately $254 million in 2005 to $168 million in 2006, a 34 percent decrease. The fixed option RMR payments increased slightly in 2006 (3.7 percent), which partially offset the decline in RMR dispatch costs.

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2006, the moderate pace of new generation investment in Southern California coupled with the continued reliance on aged generation units and significant load growth remains a reliability concern for the peak summer season. Though a significant amount of new generation capacity was added to SP15 in 2005 (2,376 MW), less was added in 2006 (434 MW), and SP15 experienced approximately 1,770 MW of generation retirements during the past two years. As a consequence, new generation investment within Southern California is not keeping 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 more 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 one day during the 24 day period of July 5 to July 28. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California. The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid. Additionally, another 1,300 MW of new generation is projected to be on-line in SP15 by the end of 2008 with no unit retirements anticipated.

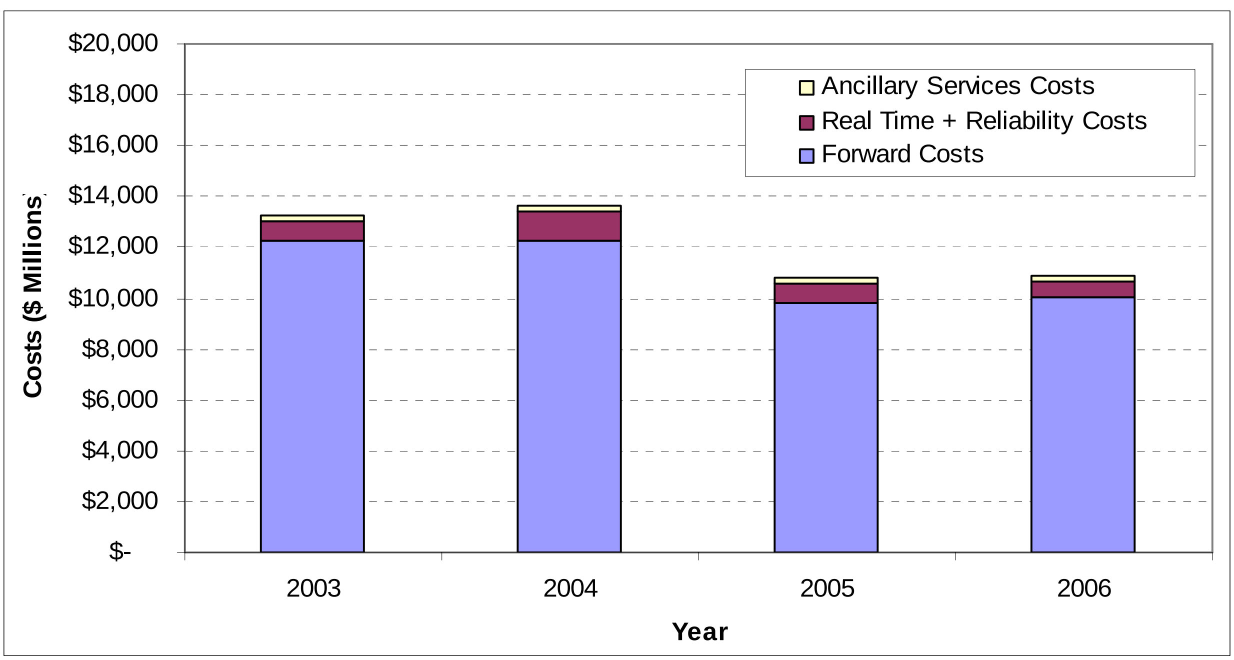
The DMM’s financial assessment of the potential revenues a new generation facility could have earned in California’s spot market in 2006 indicates estimated spot market revenues fell short of the unit’s annual fixed costs. This marks the fifth straight year that the DMM’s analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past three years (2004-2006) does show a positive trend of net revenues increasing for a new combined cycle unit with estimated net-market revenues in 2006 nearing the $90/kW-year break-even point for fixed recovery. In 2006, the net revenues for a new combined cycle unit were estimated at approximately $85/kW-year, compared to $69/kW-year and $51/kW-year in 2005 and 2004, respectively. The increase in 2006 can be primarily attributed to the combination of a higher bid cap in 2006 (from $250/MWh to $400/MWh) and the prolonged July heat wave, which resulted in day-ahead bilateral prices well above $250/MWh in numerous hours.

Despite the positive trend in spot market revenues, the fact that California's spot markets fail to provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. 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. The CPUC implementation of Local Resource Adequacy Requirements in January 2007, which are based on CAISO technical studies, should help in facilitating generation development in critical areas of the grid.

Total Wholesale Energy and Ancillary Service Costs

Total estimated wholesale energy and ancillary service costs declined by 16 percent in 2006 from $13.6 billion in 2005 to $11.4 billion in 2006.[2] The forward energy cost component declined in 2006 by 16 percent, mainly due to lower natural gas prices. In addition, the real-time and reliability costs component declined in 2006 by 24 percent from 2005.

Figure E.1 2003 – 2006 Wholesale Energy Cost Components



[2] 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 "Real Time + Reliability Costs."

Market Rule Changes

Increase in Bid Cap for Energy and Ancillary Services

On January 14, 2006, the energy bid cap in the CAISO Real Time Energy Market was raised from $250/MWh to $400/MWh, and on February 14, 2006, the bid cap for ancillary services was also raised from $250/MWh to $400/MWh. The DMM and the Market Surveillance Committee (MSC) spearheaded this increase in response to rising natural gas prices in late 2005, which were brought on by the gulf coast hurricanes. The DMM and the MSC expressed concern that if natural gas prices continued to escalate during the peak winter heating season, the marginal costs of some generation units could increase above the then current bid cap of $250/MWh. Though the energy bid cap is a “soft-cap” meaning that suppliers could bid above the cap and be paid their bid price provided they could cost justify the bid, both the DMM and MSC were concerned that suppliers, particularly importers, might elect not to offer into the CAISO Real Time Market rather than run the regulatory risk and burden of having their bids cost justified. DMM also pointed out a number of other advantages to having a higher bid cap such as providing increased incentives for forward contracting and greater incentives for generator availability during peak demand periods.

Though natural gas prices declined shortly after raising the bid cap, due to an unusually mild winter in the Eastern U.S. that reduced demand for gas, the $400 bid cap for energy and ancillary services has remained in place. It is not possible to precisely assess the impact the higher bid cap has had on the Western market as it would require knowing the counterfactual scenario of what market prices would have been had the bid cap remained at $250/MWh. However, overall it appears that the higher cap has had little impact on the market during most of 2006 and may have been very beneficial to the market and grid reliability during the July 2006 heat wave in the following respects:

- During the record heat wave in July 2006, generation forced outages remained at extraordinarily low levels given the extreme conditions. As the DMM pointed out in recommending the $400 bid cap, a higher bid cap coupled with a high level of forward contracting increases the incentive of suppliers to maintain generating units at a higher level of availability in order to cover their energy contract positions as well as to sell any excess capacity (beyond contract coverage) to the spot market.

- Spot market prices for energy and reserves increased to levels above $250/MWh in numerous hours during the July heat wave. The additional market revenues earned during this period increased the financial viability of new generation investment. Though the DMM’s net revenue analysis for 2006 still indicates that estimated net spot market revenues for new generation are below a unit’s going forward cost, the gap was much smaller in 2006.

- Though California’s major Load Serving Entities (LSEs) most likely incurred some additional costs during the heat wave, the fact that the vast majority of their energy demands were met with their own generation and forward contracts significantly mitigated the financial impact – underscoring the critical importance of hedging spot market exposure.

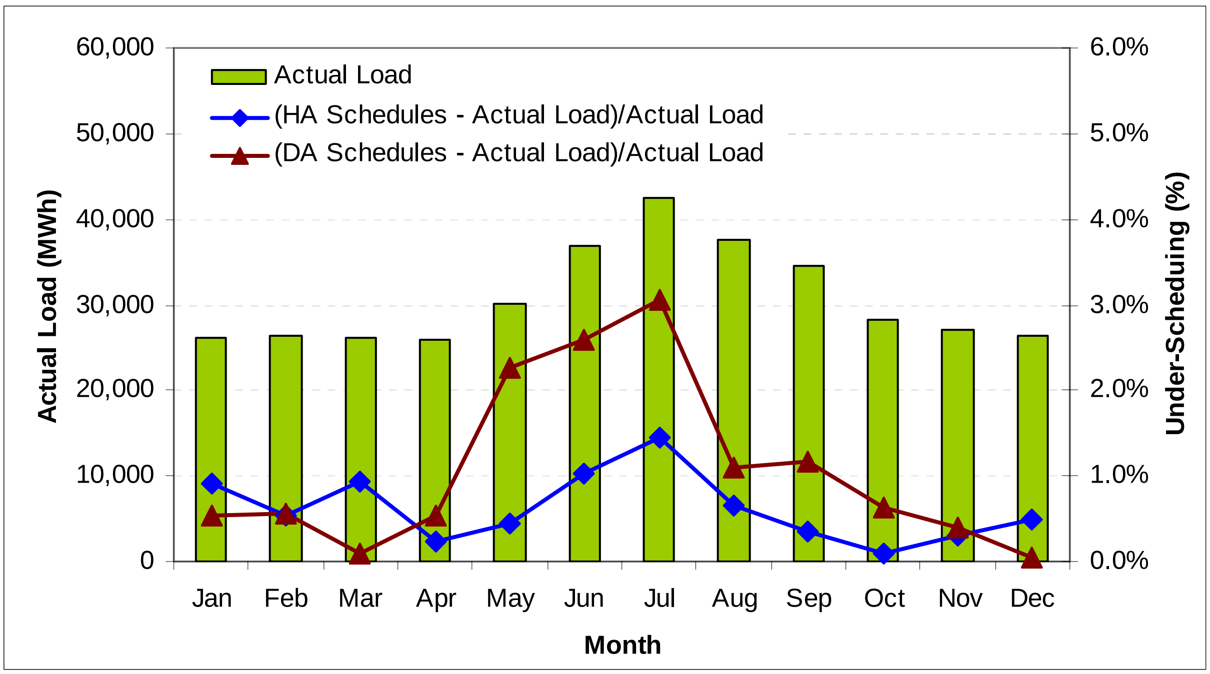
One persistent but relatively minor impact of the higher bid cap is that periodic price spikes in the CAISO Real Time Market that were previously at or near $250/MWh are now typically at or near $400/MWh. Such price spikes were more frequent during the first half of 2006 (occurring in approximately 1.2 percent of the 5-minute intervals), primarily because the over-generation conditions stemming from an abundance of hydroelectric energy reduced the supply of 5-minute dispatchable energy bids being offered to the Real Time Market, resulting in more frequent price spikes. However, the dispatch volumes in the Real Time Market were very minimal (2.6 percent of total load) and, therefore, the cost impact of these spikes were also minimal. Price spikes in the Real Time Market continued to occur in the second half of 2006 but were less frequent due to more thermal generation being on-line and offering into the market as well as a transition out of over-generation conditions.

Enforcement of Amendment 72 – Load Scheduling Requirement

In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecast demand for each hour of the next day. The 95 percent day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through must-offer waiver (MOW) denials and dispatching additional energy in the real time. Beginning in the spring of 2006, the DMM phased in enforcement of the LSEs' reporting requirements under Amendment 72.

Figure E.2 shows, by month, average actual load together with day-ahead and hour-ahead under-scheduling for peak hours in 2006. Even in July when average load peaked, the percent of under-scheduled load in the peak hour was, on average, under four percent in the day-ahead and under 2 percent in the hour-ahead.

Figure E.2 Summary of Load Scheduling Practices (Hour 16)



The fact that, on average, day-ahead load scheduling exceeded 95 percent suggests that there may be other factors influencing scheduling behavior. For example, the amount of forward scheduling in 2006 may be affected by a variety of California Public Utilities Commission

(CPUC) procurement guidelines which have had the effect of encouraging the state's major Investor Owned Utilities (IOUs) to forward contract for most or all of their projected energy needs. Additionally, while Resource Adequacy (RA) requirements in effect for 2006 only require that available RA capacity be made available to the CAISO, it is likely that many RA capacity contracts are coupled with energy contracts – such as energy tolling agreements – which allow the LSE to schedule energy from RA resources on a day-ahead basis.

System Resource Adequacy Requirements

In 2006, Resource Adequacy programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs, developed pursuant to Assembly Bill 380, require that LSEs procure sufficient resources to meet their peak load along with appropriate reserves. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecast load for each month, plus a 15 percent reserve margin. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs. The procurement requirements for 2006 were entirely on a system-wide basis. There was no requirement in 2006 to procure resources based on capacity needs determined on a local basis. For 2007, LSEs under CPUC jurisdiction are required to obtain resources located within defined local areas based on their share of the forecast load within each CAISO Transmission Access Area, which equate to the old service territories of the investor owned utilities. Both the system and local requirements are important to reliability, short-term revenue adequacy, and to provide a framework for investment in infrastructure.

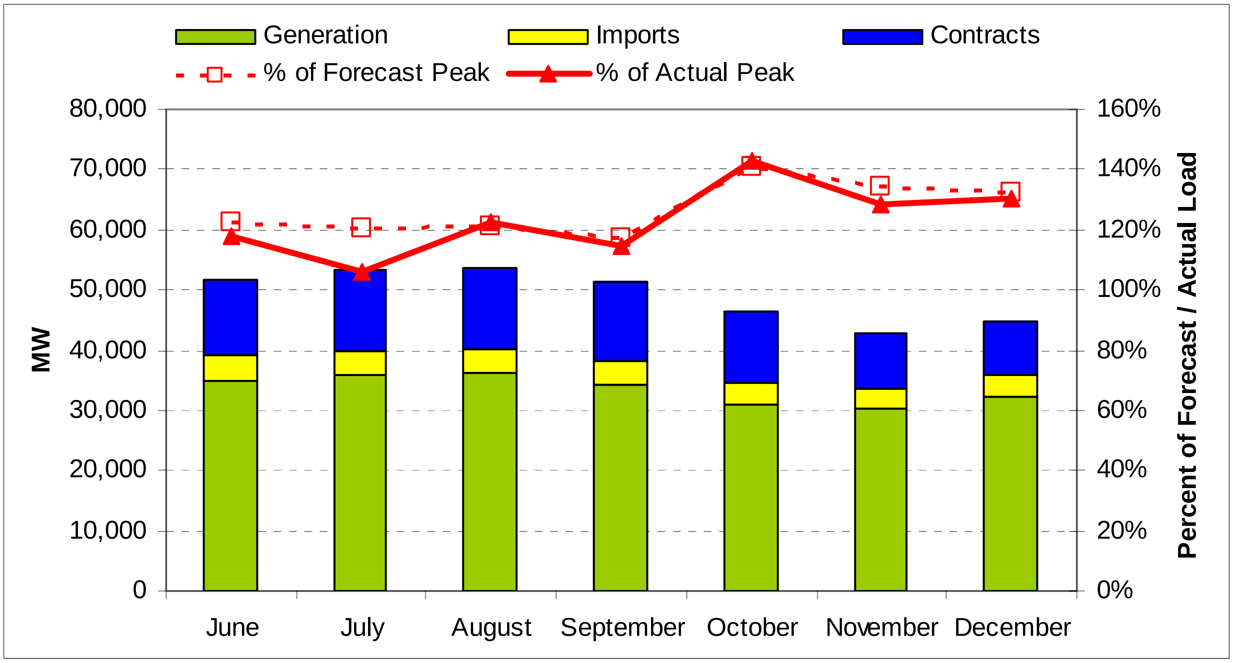
LSEs fully complied with the 2006 Interim Reliability Requirements Program for all months during the June to December time frame. Figure E.3 compares the available RA resources system-wide during June through December 2006 to the CAISO system summer peak forecast load and the actual summer peak load. As shown by Figure E.3, LSEs had met the capacity requirements in all months with total monthly capacity showings equal to approximately 120 percent of forecasted load for June through September and even higher percentages in the October through December time frame.[3] For the month of July 2006, capacity showings totaled 53,192 MW, which was 121 percent of the CAISO system summer peak forecast load of 44,026 MW, and 106 percent of the 50,270 actual system summer peak load (which was a CAISO record system peak).[4] Not shown explicitly in Figure E.3, but as a point of reference, LSEs subject to CPUC jurisdiction procured resources with a total capacity of 48,111 MW for July

[3] The percentages shown in Figure E.3 ("% of Forecast Peak" and "% of Actual Peak") are calculated by dividing the total capacity showing for each month by the forecasted or actual peak load for each month.

[4] The 44,026 summer peak load forecast is calculated as the 46,063 MW CAISO peak load forecast minus 2,037 MW of demand response resources, consistent with the procurement requirement calculation. All LSEs 53,192 MW resource capacity excludes 2,037 MW of demand response resources. The 50,270 MW actual system summer peak load includes the contribution of demand response resources.

2006, which was 128 percent of their forecast peak load of 37,537 MW.[5] Figure E.3 also summarizes the mix of RA resources that were available system-wide for the month of July, which included 35,927 MW of generation within the CAISO control area, 4,117 MW of imports, and 13,147 MW of Liquidated Damage (LD) contracts.

Figure E.3 Summary of System RA Compliance



Reliability Capacity Service Tariff (RCST)

Under terms of the IRRP taking effect in June 2006, all RA capacity that is available must be scheduled or made available to the CAISO for commitment through the CAISO's must-offer waiver denial process. Since RA units are eligible for capacity payments under bilateral contracts, IRRP tariff changes taking effect in June 2006 also specified that RA resources committed through the CAISO's must-offer process would be eligible to recover only minimum load operating costs from the CAISO and would no longer receive an additional payment for minimum load energy at the real-time energy price.

In recognition of the fact that RA and RMR resources may not be sufficient to meet all system reliability needs, CAISO continues to have the authority to commit other resources with Participating Generator Agreements through the must-offer waiver denial process. However, the IRRP specified that the CAISO could commit non-RA resources through the must-offer waiver process only if there were insufficient RA or RMR resources available to meet any local, zonal or system reliability needs. Any non-RA resources committed through the must-offer process continue to receive payments for minimum load operating costs along with an additional

[5] The 37,537 MW forecast peak load of CPUC-jurisdictional LSEs is calculated as the California Energy Commission's (CEC) 39,546 MW peak load forecast for July minus 2,009 MW of demand response resources. CPUC-jurisdictional LSEs' 48,111 MW resource capacity excludes 2,009 MW of demand response resources. (Values obtained from CPUC "2006 Resource Adequacy Report," Feb 2, 2007)

payment for minimum load energy at the real-time energy price. These non-RA units are now sometimes referred to as “FERC-MOO” units, due to the fact that they are subject to Must-Offer Obligation (MOO) under the must-offer provisions of the CAISO tariff approved by the Federal Energy Regulatory Commission (FERC), rather than a bilateral RA contract or RMR contract with the CAISO.

In addition, starting in June 2006, any non-RA resources committed through the must-offer process also became eligible to receive additional payments under the terms of proposed tariff changes filed by the CAISO along with certain other settling parties under an Offer of Settlement stemming from a 2005 complaint which alleged that compensation under the must-offer waiver process is unjust and unreasonable.

The Offer of Settlement proposed tariff changes, which were approved by FERC, establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST settlement also provided the CAISO with the authority to designate non-RA units to provide services under the RCST as a “backstop” in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

Although final FERC approval of RCST provisions was not granted until February 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006. Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. These capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. This net RCST capacity payment is calculated on a monthly basis by allocating this annual fixed cost to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

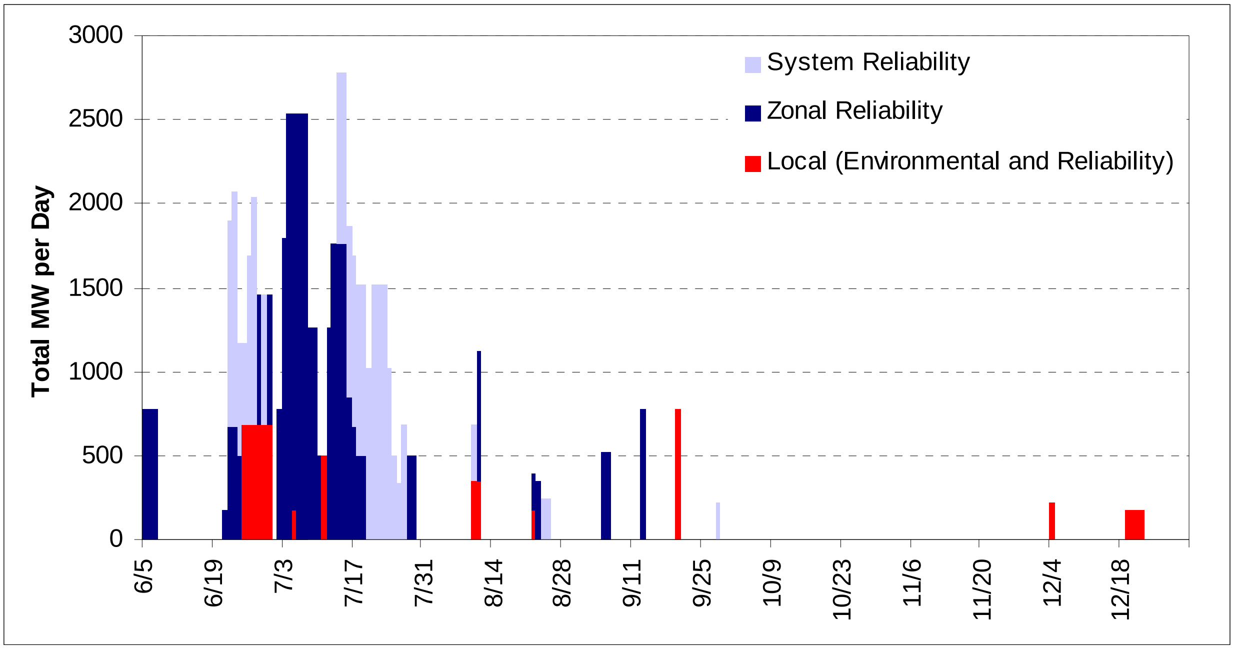
- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO’s must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. Preliminary estimates provided by the CAISO indicate that approximately $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with over three-quarters of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the current CAISO's local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[6] Preliminary calculations by the CAISO indicated that, from June though July, costs due to this potential $40 adder would total only about $23,000.

Figure E.4 shows the amount of non-RA generation capacity committed under the CAISO must-offer waiver process since June 2006 and demonstrates that the majority of non-RA commitments occurred during the peak summer period of late June through July.

Figure E.4 Non-RA Capacity Committed Under Must-Offer Waiver Process



Long-term Procurement Plans

In addition to addressing short-term capacity requirements through the Resource Adequacy program, the CPUC has also required that LSEs under its jurisdiction develop and file 10-year long-term procurement plans (LTPPs) designed to comply with any and all policy constraints and to adequately meet bundled customer load needs. The 2006 LTPPs will need to reflect all procurement related decisions from prior rule makings, including the following:

- Adopted Demand Response programs and attainment goals.

[6] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs that exceed $50 or 200 percent of the real-time interval price are mitigated to their incremental reference price. Under the RCST tariff provisions, bids mitigated under these LMPM provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

- Procurement "loading order" as reflected in the state agencies' Energy Action Plan II and adopted by the CPUC.

- Identify the key planning decisions required to meet a renewable portfolio standard of 33 percent by 2020.

On December 11, 2006, CPUC jurisdictional entities submitted their long-term procurement plans to the CPUC. Intervener testimony was submitted on March 2, 2007, and reply testimony is due on April 9, 2007. The CAISO has been reviewing the LTPPs to determine whether the proposals raise any operational issues that parties should be aware of. The CPUC is expected to approve the LTPPs later in 2007.

Additionally, in a July 21, 2006 decision, the CPUC directed Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) to procure 1,500 MW and 2,200 MW of new generation, respectively, and to unbundle the capacity and energy products from this new generation. It was determined that PG&E needed 1,200 MW of new peaking generation and 1,000 MW of new peaking and dispatchable generation by 2010 and that SCE would have the option of a two track approach with a "fast-track" RFO for new generation coming on-line beginning mid-2009 and a "standard track" with expected on-line dates of 2012-2013. However, if SCE does not pursue all 1,500 MW under a fast track, it must justify to the CPUC why it is appropriate to pursue some of the generation under the standard track. Under this decision, the capacity of the new generation would be allocated to each LSE in the IOU's service territory and count towards its RA requirements. The costs of the capacity would be allocated similarly. The energy product will be auctioned off by a third party. The CPUC action was taken due to the urgency for new generation investment in California and the recognition that a more permanent long-term procurement structure, that effectively addresses the need for long-term procurement and retail competition, would not be completed for some time.

The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid and achieving other state energy policy objectives.

General Market Conditions

Demand

Loads in 2006 were significantly above those in 2005 both on an overall basis as well as a peak load basis. The significant increase in overall energy consumption was driven primarily by significantly higher load levels in June and July. Total energy consumption in June 2006 was approximately 12 percent higher than June 2005, primarily because June 2005 was an unusually cool month. July 2006 loads were 8 percent above July 2005 levels due to the extraordinary 3-week heat wave in July 2006. The record peak load was achieved on July 24, 2006 at 50,270 MW, shattering the previous peak load record of 45,597 MW that occurred on September 8, 2004. While these two months accounted for most of the increase in annual energy consumption, load levels for most months in 2006 were higher than 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.

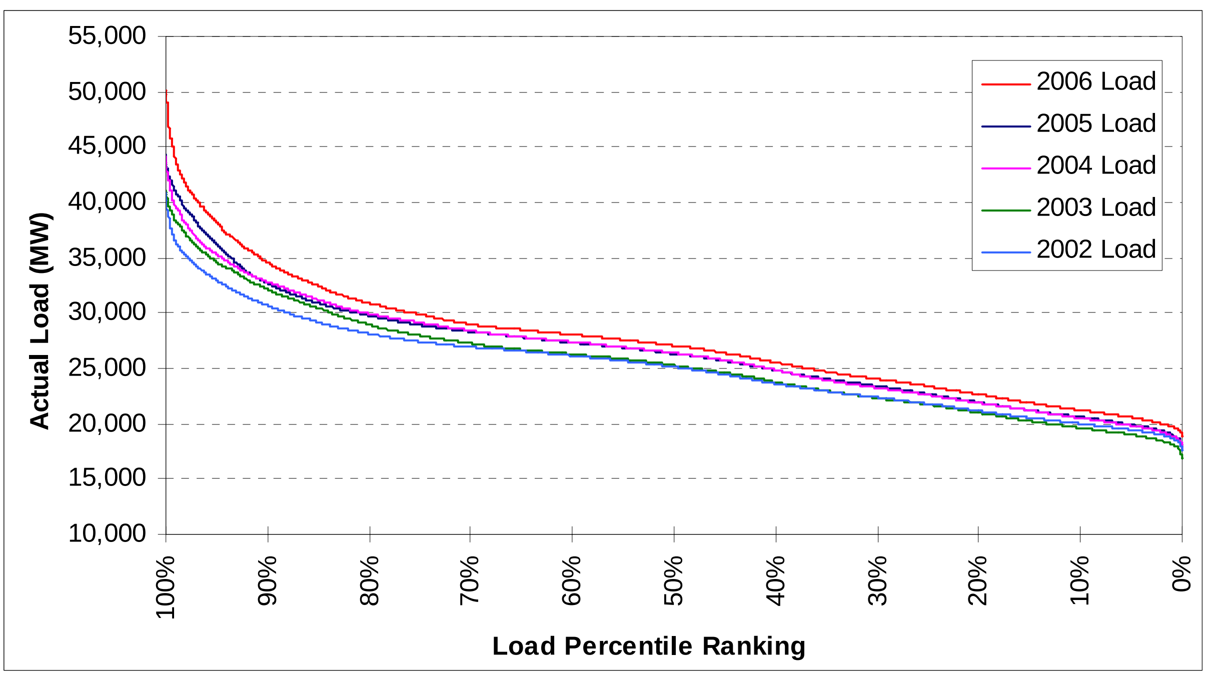
Table E.1 Load Statistics for 2002 – 2006*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2002 Actual	26,548		232,612	42,352	
2003 Actual	26,334	-0.8%	230,735	42,581	0.5%
2004 Actual	27,303	3.5%	239,231	45,597	6.5%
2005 Actual	26,989	-1.2%	236,481	45,562	0.1%
2006 Actual	27,426	1.6%	240,303	50,270	9.3%
2002 Adjusted	25,143		220,278	40,979	
2003 Adjusted	25,459	1.2%	223,047	41,063	0.2%
2004 Adjusted	26,429	3.7%	231,542	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,962	44,260	0.1%
2006 Adjusted	27,426	3.5%	240,303	50,270	12.0%

* Adjusted figures are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 leap year.

Figure E.5 depicts load duration curves for each of the last five years and demonstrates the significant increase in load during 2006. Most striking in 2006 is the percentage of hours that load exceeded 40,000 MW, which used to be considered an extreme peak level. In 2006, hourly loads exceeded 40,000 MW in 3.2 percent of the total annual hours, compared to 1.6 percent and .8 percent in 2005 and 2004, respectively.

Figure E.5 Hourly Load Duration Curves



Supply

Approximately 633 MW of new generation began commercial operation within the CAISO Control Area in 2006. The majority of new capacity in the north was wind generation (150 MW out of 199 MW total in the north). Approximately 1,535 MW of generation capacity was removed from service in 2006, the majority of which was located in the SP15 congestion zone. The most notable of the retirements were the Mohave generating units (1,320 MW of effective capacity), which were the only coal-powered resources in the CAISO Control Area.[7]

Table E.2 below shows an annual accounting of generation additions and retirements since 2001, with projected 2007 changes included and totals across the seven years depicted. There was a 902 MW net decline in installed generation in the CAISO control area in 2006, the first net decline in installed generation in the post energy crisis period. The total net increase in installed generation in the CAISO control area over the seven years spanning 2001 – 2007 is approximately 10,300 MW. When accounting for an estimated 2 percent load growth over the same seven year period of approximately 6,200 MW, the supply margin increased by roughly 4,100 MW since the energy crisis.

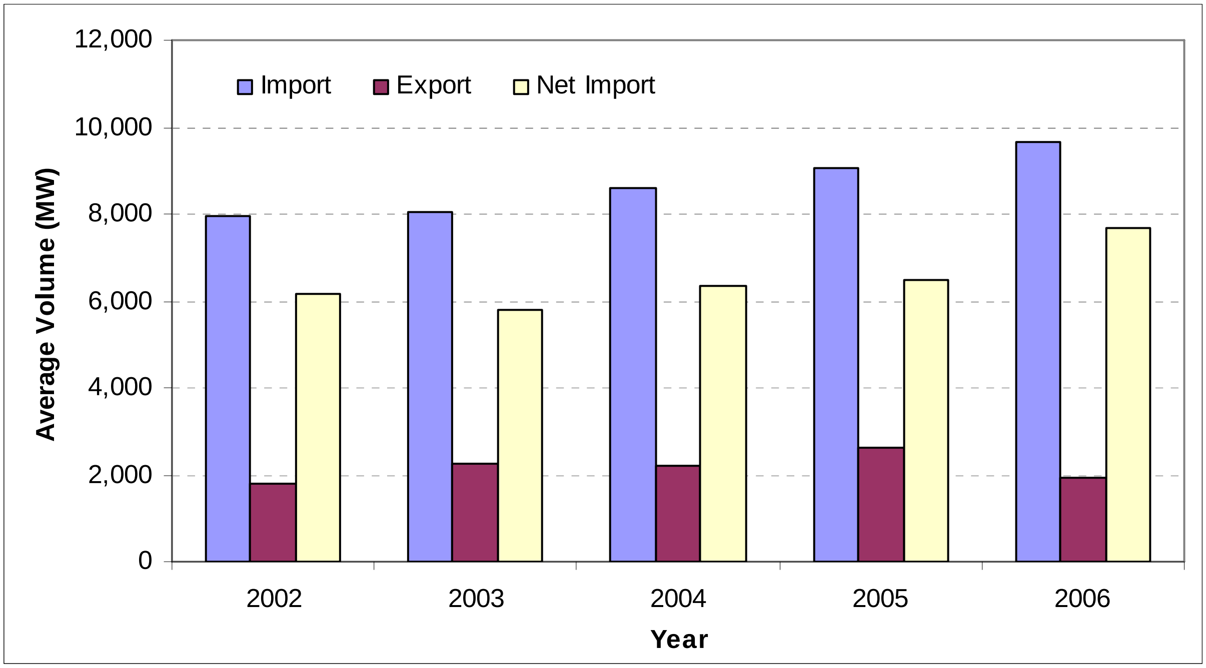
Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	2006	Projected 2007	Total Through 2007
SP15								
New Generation	639	478	2,247	745	2,376	434	1,348	8,267
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	(4,280)
Forecasted Load Growth*	148	500	510	521	531	542	553	3,305
Net Change	**491**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**795**	**682**
NP26								
New Generation	1,328	2,400	2,583	3	919	199	136	7,568
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	2,895
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(303)**	**3,438**
ISO System								
New Generation	1,967	2,878	4,830	748	3,295	633	1,484	15,835
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	(5,515)
Forecasted Load Growth*	537	897	915	934	953	972	991	6,199
Net Change	**1,402**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**493**	**4,121**

Imports continue to play a key role in meeting demand. Figure E.6 shows average annual gross imports, exports, and net imports for the five-year period covered by 2002-2006. Average hourly imports and net imports increased significantly in 2006 by approximately 6 percent and 19 percent, respectively. The increase is predominately attributed to a higher level of imports from the Pacific Northwest brought on by the exceptionally high levels of hydroelectric generation from this region. Additionally, average exports declined in 2006 by approximately 25 percent, which helped to increase the average net-import amount. Figure E.6 also demonstrates a four-year trend of increasing imports (both gross and net) indicating a growing reliance on imports to meet energy demands within the CAISO Control Area.

[7] Though the Mohave coal-fired generating units are physically located outside of California (Southern Nevada), they were incorporated into the CAISO Control Area, which is why they are included in Table E.2.

Figure E.6 Average Annual Imports, Exports, and Net Imports (2002-2005)



Generation Outages

Figure E.7 depicts monthly average planned and forced outages between 2003 and 2006. In 2006, planned outages were high during the first five months of the year (compared to past years) and both planned and forced outages were exceptionally high in April 2006. In this month, three nuclear resources were out for refueling (although two of these seasonal refueling outages were technically classified as forced outages), and several other large combined-cycle and steam resources were also out for annual maintenance. With plentiful hydroelectric power available at this time, the multiple planned outages during this period did not impose any reliability issues.

Given the aggressive maintenance schedule in the first half of 2006, forced outages were relatively modest in July and August. The low level of forced outages in July 2006 is remarkable given the extraordinary heat wave that resulted in power plants having to remain online under extremely hot weather conditions for most of July.

Figure E.7 Monthly Average Planned and Forced Outages (2003 – 2006)

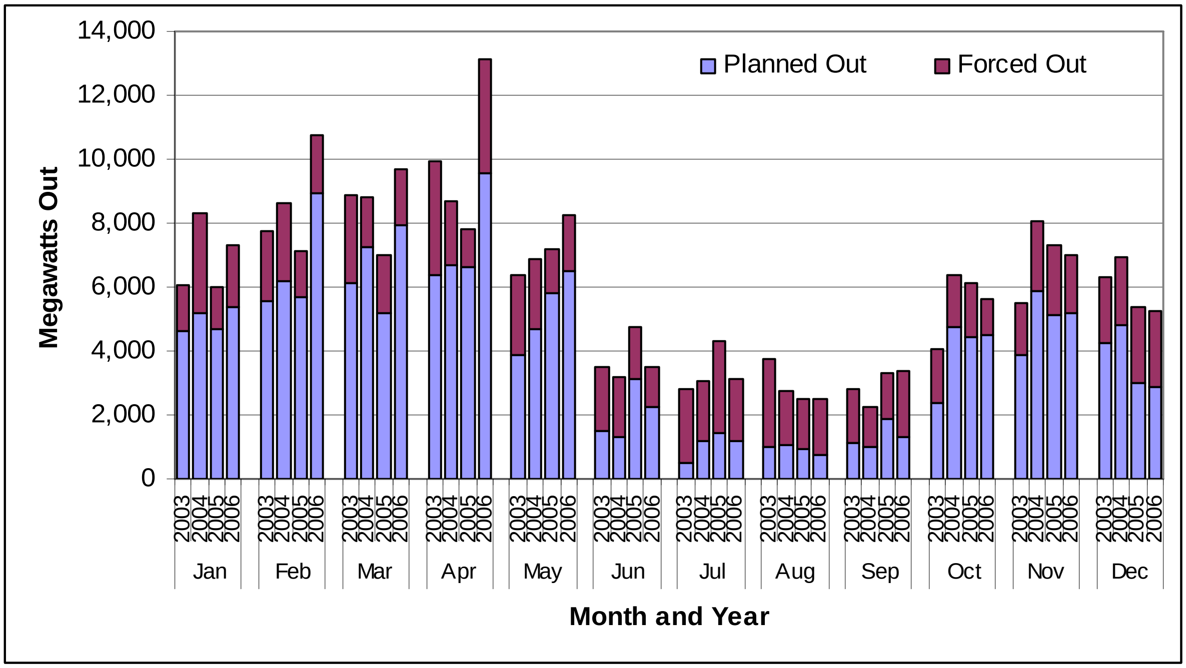
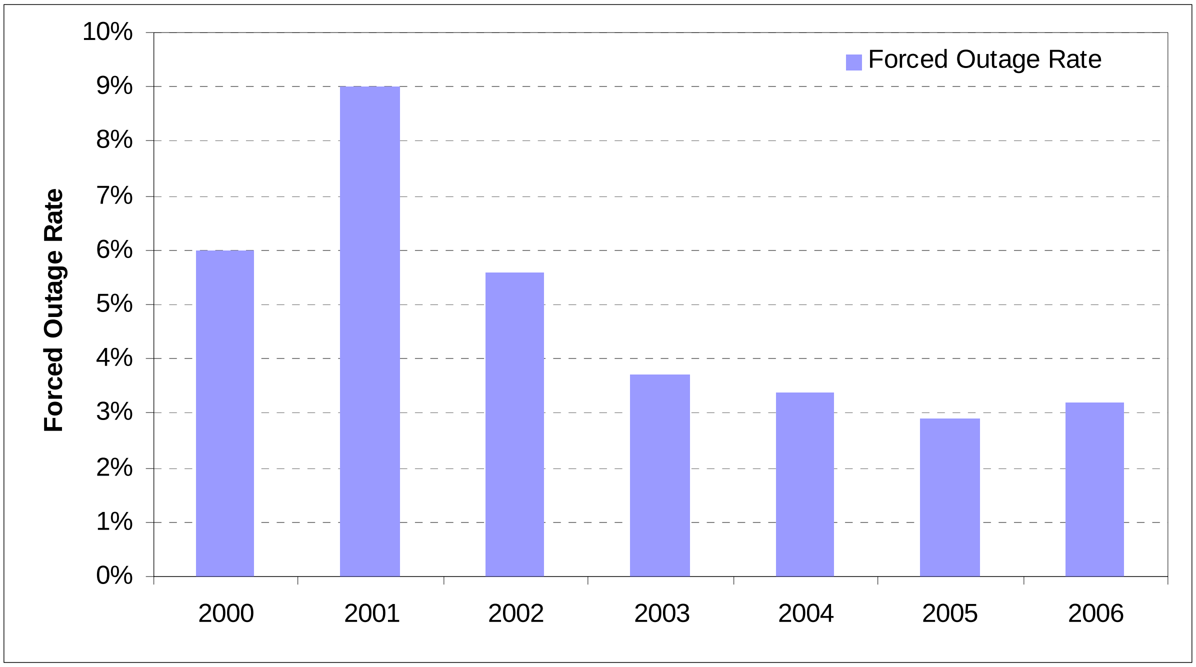


Figure E.8 compares annual forced outage rates since 2000. Over the past three years, annual forced outage rates have averaged approximately 3 percent, a dramatic improvement over the levels experienced during the energy crisis (2000-2001). This change can be primarily attributed to the substantial increase in new generation since 2000, which has a decreasing effect on overall outage rates.

Figure E.8 Annual Forced Outage Rates (2000 – 2006)



Short-term Energy Market Performance

The significant number of long-term contracts entered into by the state of California in 2001 and by LSEs since then combined with the large amount of new generation added to the Western energy markets provided effective market power mitigation in the 2006 short-term energy markets. When LSEs 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 long-term energy contracting 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 LSEs to reduce their forward contract cover and rely more on the spot markets.

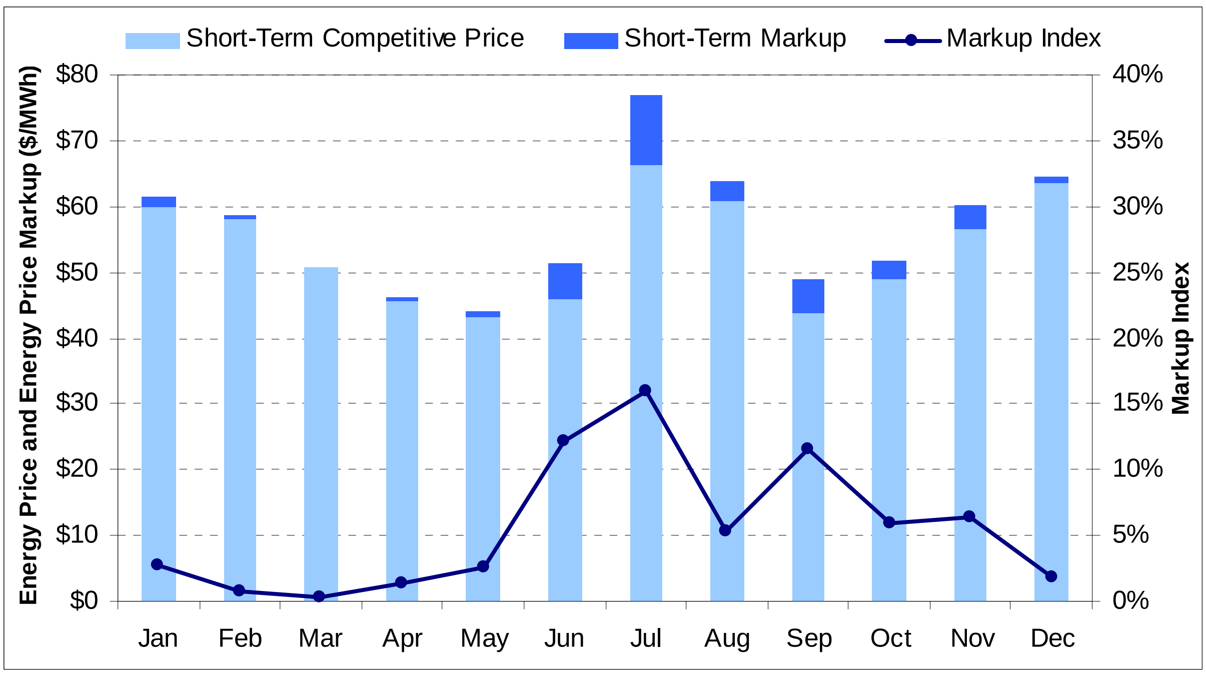
Estimated Mark-up of Short-term Bilateral Transactions

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 CAISO has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[8] 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

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

detailed generation unit and system cost information. Figure E.9 shows the monthly average of estimated hourly mark-ups for short-term bilateral transactions. A detailed description of the methodology and assumptions used in the analysis can be found in Chapter 2. Short-term average monthly mark-ups in 2006 ranged between .2 percent in March to a high of 16 percent in July. Overall, the index indicates that short-term wholesale energy markets produced competitive outcomes in 2006 with mark-ups averaging around 5 percent. The high mark-up in July reflects the severe heat wave, which increased spot bilateral prices at or near the $400/MWh bid cap in numerous hours. Though mark-ups were significant in July, they were highly correlated with expected scarcity conditions and appear to have had minimal cost impacts to California LSEs due to the high level of hedging, which minimized spot market exposure.

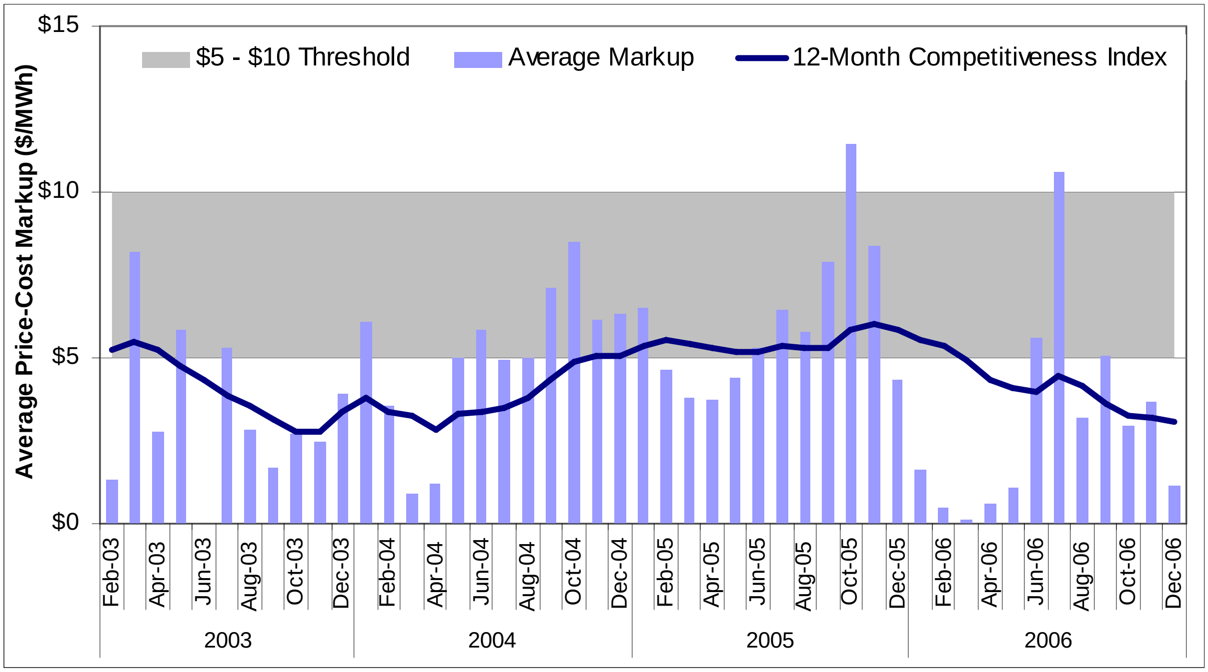
Figure E.9 Short-term Price-Cost Mark-up Index (2006)



Twelve-Month Market 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 2006. This indicates that the short-term energy market in California that stabilized in late 2001 has produced fairly competitive results over the past five years. Figure E.10 below shows the market competitiveness index values for the past four years (2003-2006).

Figure E.10 Twelve-Month Market Competitiveness Index (2003-2006)



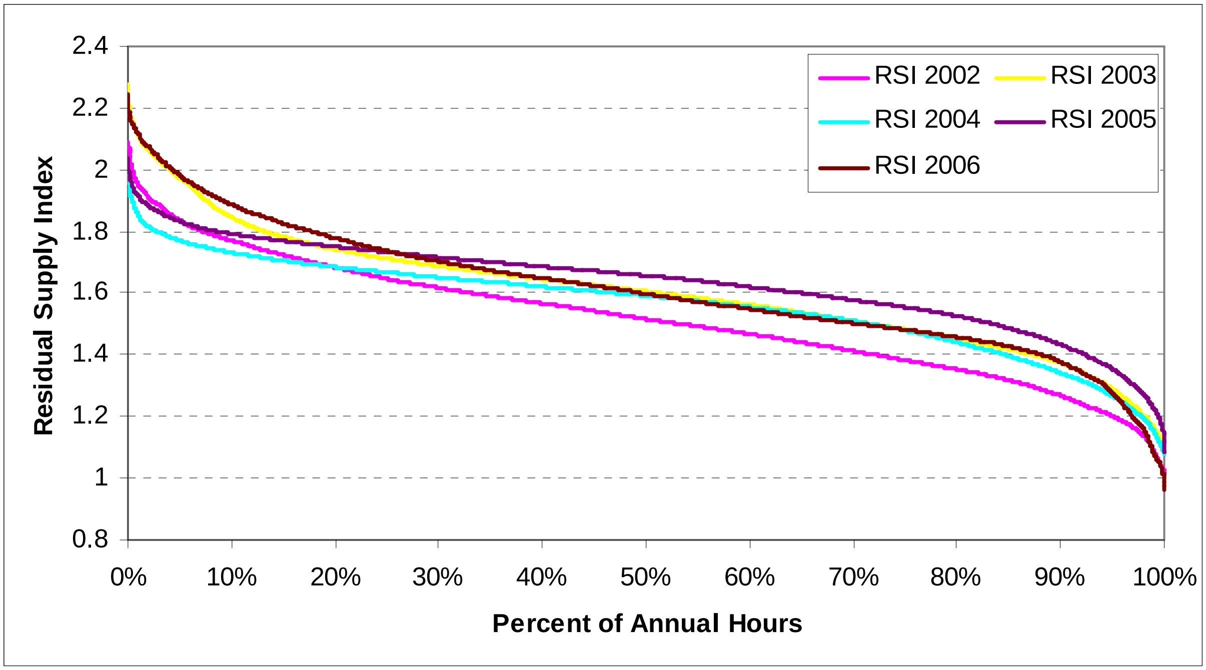
Structural Measure of Market Competitiveness: Residual Supplier Index

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 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 2006 were generally similar to the past several years (2003-2005) with two notable differences. First, using an RSI level of 1.1 to compare between years,[9] in 2006 the RSI levels were less than 1.1 in more hours than in the previous three years, suggesting greater market power potential compared to past years – albeit moderately so. This result is mainly due to the July 2006 heat wave which resulted in very tight supply margins in numerous hours that translated into lower RSI values. Second, 2006 also experienced some of the highest RSI values of the past several years. This result is reflective of the abundance of hydroelectric generation during the first half of the year. Overall, the RSI levels in 2006 are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2006.

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

Figure E.11 Hourly Residual Supply Index (2002-2006)



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 2006 indicates potential spot market revenues fell short of the unit's annual fixed costs (Figure E.12 and Figure E.13). While this result is consistent across the past four years, there is a favorable three year trend evident in the combined cycle analysis (Figure E.12). Specifically, the combined cycle analysis shows a trend of net spot market revenues increasing for both Southern (SP15) and Northern (NP15) California with estimated net revenues in 2006 approaching the break-even point of $90 kW-year. The increase in 2006 is primarily attributed to a higher bid cap of $400/MWh and very high day-ahead spot prices during the July 2006 heat wave. While estimated net spot market revenues also increased in 2006 for a new combustion turbine (Figure E.13), net revenues were still well below the $78/kW-year estimated break-even point.

Figure E.12 Financial Analysis of New CC Unit – SP15 (2003-2006)

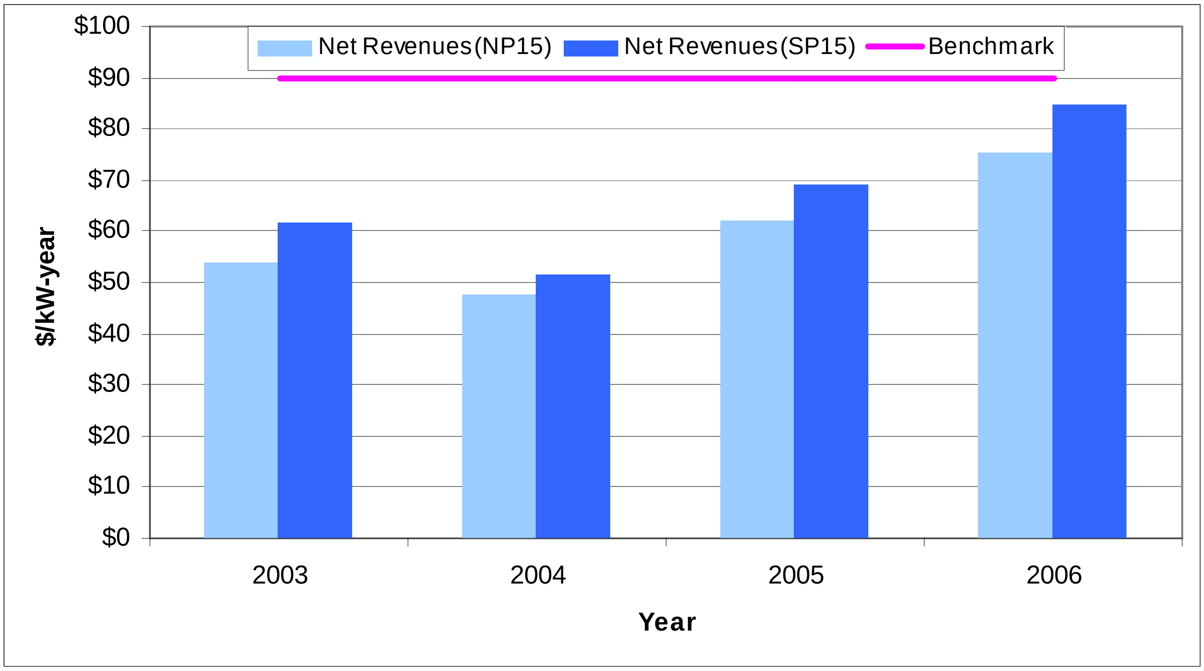
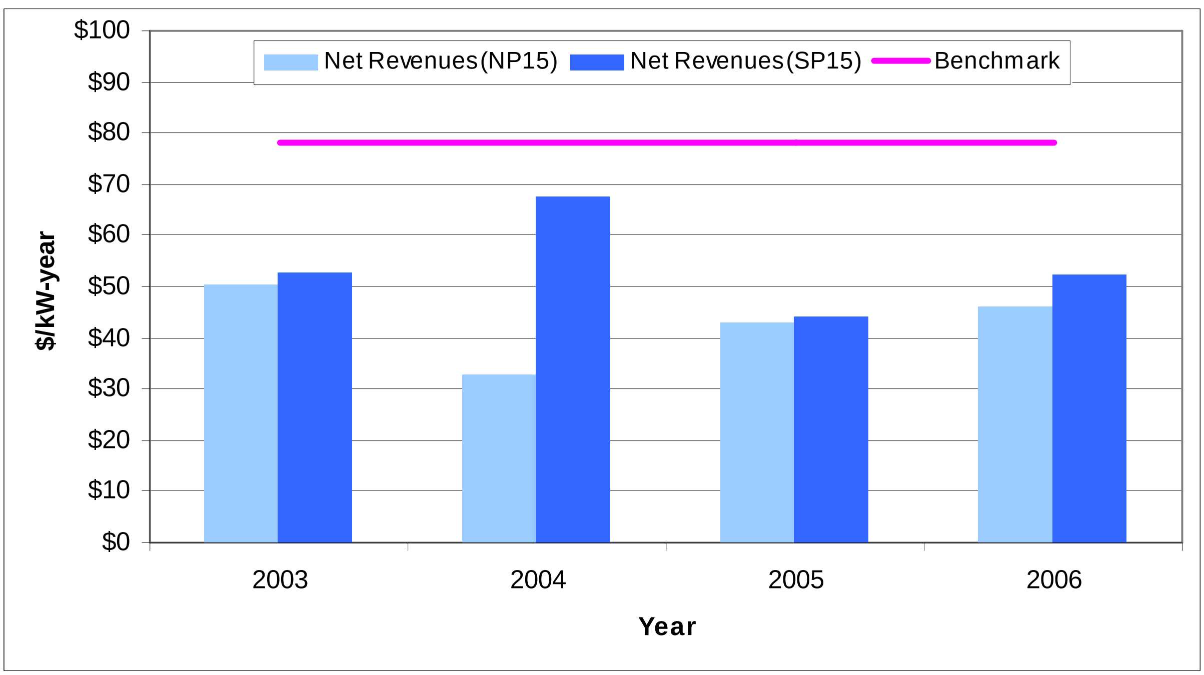


Figure E.13 Financial Analysis of New CT Unit (2003-2006)



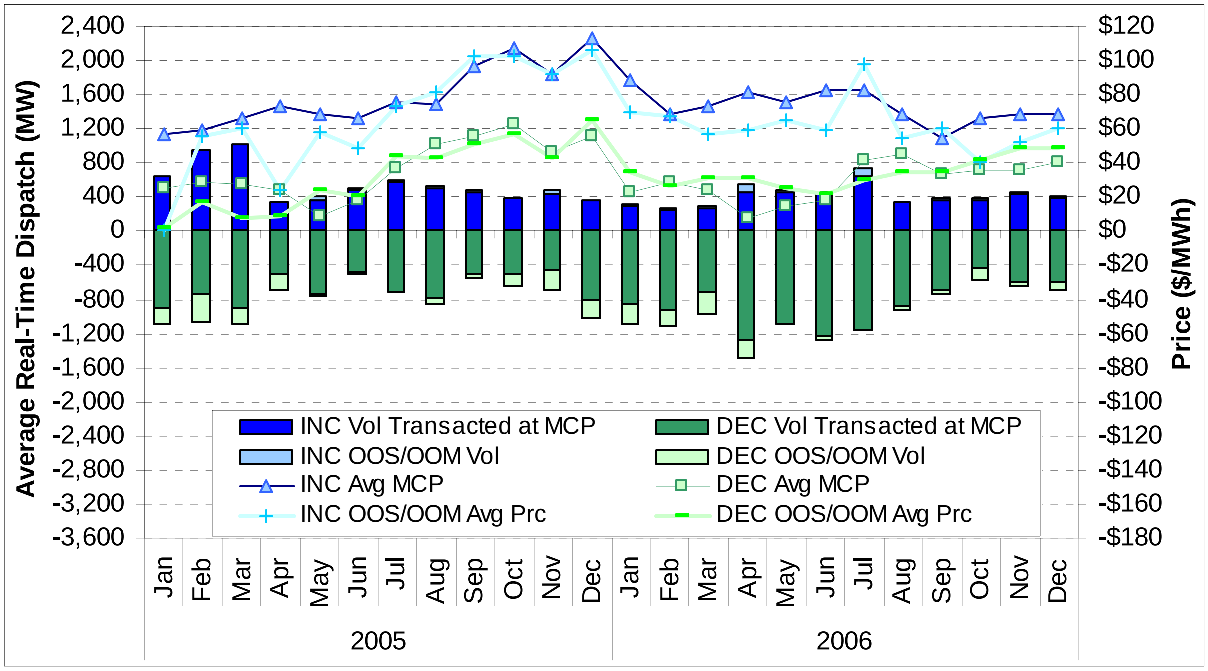
Given the need for new generation investment in California, the finding that estimated spot market revenues failed to provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2006) but the net revenues earned in 2006 is not indicative of future market revenue opportunities, which is the primary driver for new investment. In any case, 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, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation on February 1, 2008, will provide some of these elements (LMP, some degree of scarcity pricing). 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 similar programs for non-CPUC jurisdictional entities.

Real Time Energy Market

For the fifth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2006 (Figure E.14). Real-time balancing energy was again overwhelmingly in the decremental direction as a high level of forward scheduling plus unscheduled energy from units committed under the must-offer obligation and excessive levels of hydroelectric generation resulted in frequent over-generation in the real-time imbalance energy market. As shown in Figure E.14, the average hourly levels of decremental dispatches were particularly high in the first half of 2006, averaging close to 1,200 MWh.

Monthly average prices in 2006 for periods when the CAISO was issuing incremental energy dispatches were stable, averaging between $60 and $80/MWh for most of the year. Average monthly prices for periods when the CAISO was issuing decremental dispatches were significantly lower, particularly during the first half of 2006 when demand for decremental energy bids was greatest. During this period, energy prices for decremental dispatches averaged around $20/MWh but increased in the second half of 2006 to approximately $40/MWh.

Figure E.14 Monthly Average Real-time Prices and Volumes (2005-2006)



Competitiveness of Real-time Energy Market

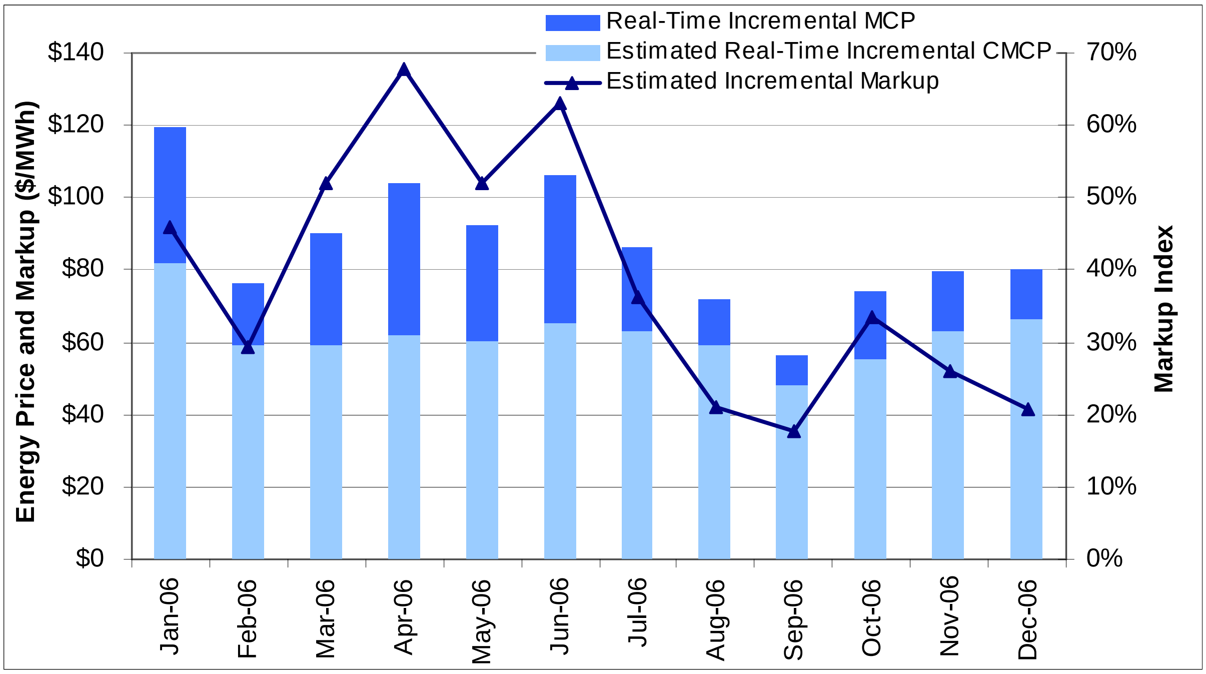
The CAISO uses a real-time price-to-cost mark-up index to measure market performance in the Real Time Market. This index compares Real Time Market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[10] It is important to note that an index based upon the extremely small volume of transactions in the Real Time Market is not indicative of overall wholesale market competitiveness. Nonetheless, it provides a useful metric for Real Time Market performance.

Throughout 2006, estimated monthly average mark-ups in the Real Time Market were significantly higher than 2005, averaging approximately 40 percent throughout the year, compared to approximately 12 percent in 2005. The significant increase can be attributed to both a higher energy bid cap ($400/MWh vs. $250/MWh) and a much higher frequency of price spikes. The increase in price spikes was most pronounced in the first half of 2006 and was driven primarily by an abundance of hydroelectric generation which reduced the number of thermal generation units on-line and, in turn, the supply of 5-minute dispatchable energy bids to the Real Time Market. The abundance of hydroelectric generation created other real-time operational challenges in terms of managing loop flow, which also contributed to high imbalance energy demands and price spikes. While the unusually high mark-ups suggest a lack of market competition, it is important to note that the extremely small volumes of energy clearing this market (typically less than 2 percent of the load) coupled with a limited supply of 5-minute

[10] 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.

dispatchable bids makes this market extremely volatile.[11] High volatility of both price and dispatch quantities coupled with overall low market clearing volumes serve as disincentives for additional supply to enter the market. Given the very small market volumes and high volatility observed in the CAISO Real Time Market, the competitiveness of the day-ahead spot bilateral market is a much more indicative measure of overall spot market competitiveness and as reported above, the estimated mark-ups in the day-ahead spot market were much lower and overall indicate that the spot market was workably competitive in 2006.

Figure E.15 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market



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 market. 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. 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

[11] It is important to note that real-time imbalance energy markets are inherently volatile and thus the volatility observed in the CAISO Real Time Market is not necessarily an indication of market design deficiencies.

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 was the sharp reduction in intra-zonal congestion costs. In 2005, intra-zonal congestion costs totaled $222 million,[12] compared to $426 million in 2004, representing a 48 percent decrease (Table E.3). Intra-zonal congestion cost is comprised of three components: 1) MLCC for units denied must-offer waivers due to local constraints, 2) real-time RMR costs, and 3) real-time out-of-sequence (OOS) redispatch costs. For 2006, estimated total intra-zonal congestion declined further to $207 million. The MLCC for units committed for local reliability needs dropped slightly in 2006 to $109 million, compared to $114 million in 2005. Real-time redispatch costs associated with OOS dispatches also declined from $36 million in 2005 to $17 million in 2006. However, these reductions were offset by an increase in real-time RMR dispatches from $72 million in 2005 to $80 million in 2006, resulting in total intra-zonal congestion costs for 2006 of $207 million (compared to $222 million in 2005). Though not shown in Table E.3, it should be noted that total RMR dispatch cost (day-ahead and real-time) did decline significantly in 2006 from approximately $254 million in 2005 to $168 million in 2006, a 34 percent decrease. However, because day-ahead RMR dispatches are for a variety of local reliability needs (e.g., voltage support, contingencies, etc.), they are not considered in this analysis as intra-zonal congestion costs. The relatively low levels of intra-zonal congestion costs over the past two years as well as the decline in total RMR costs is the result of various transmission enhancements in 2005 and 2006 that were targeted to address frequently congested areas.

Table E.3 Comparison of 2005 and 2006 Monthly Intra-zonal Congestion Costs by Category ($/million)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**
Jan	$ 12	$ 8	$ 10	$ 3	$ 3	$ 13	$ 4	$ 6	$ 4	$ 19	$ 17	$ 27
Feb	$ 13	$ 4	$ 8	$ 4	$ 3	$ 15	$ 7	$ 3	$ 2	$ 24	$ 10	$ 25
Mar	$ 20	$ 3	$ 11	$ 4	$ 5	$ 13	$ 8	$ 3	$ 3	$ 32	$ 11	$ 27
Apr	$ 18	$ 6	$ 27	$ 4	$ 5	$ 8	$ 5	$ 3	$ 6	$ 27	$ 14	$ 41
May	$ 22	$ 14	$ 12	$ 3	$ 5	$ 3	$ 4	$ 2	$ 1	$ 29	$ 21	$ 16
Jun	$ 25	$ 7	$ 15	$ 3	$ 2	$ 4	$ 2	$ 0	$ 0	$ 30	$ 9	$ 19
Jul	$ 29	$ 13	$ 14	$ 6	$ 5	$ 2	$ 11	$ 1	$ 0	$ 46	$ 19	$ 17
Aug	$ 29	$ 14	$ 5	$ 5	$ 9	$ 3	$ 15	$ 1	$ 0	$ 49	$ 24	$ 8
Sep	$ 23	$ 8	$ 3	$ 4	$ 6	$ 2	$ 12	$ 3	$ 0	$ 39	$ 17	$ 5
Oct	$ 21	$ 13	$ 1	$ 4	$ 8	$ 3	$ 18	$ 4	$ 1	$ 43	$ 25	$ 5
Nov	$ 29	$ 12	$ 1	$ 5	$ 5	$ 6	$ 9	$ 6	$ 0	$ 43	$ 23	$ 7
Dec	$ 33	$ 11	$ 2	$ 4	$ 16	$ 7	$ 8	$ 5	$ 0	$ 45	$ 32	$ 9
Total	**$ 274**	**$ 114**	**$ 109**	**$ 49**	**$ 72**	**$ 80**	**$ 103**	**$ 36**	**$ 17**	**$ 426**	**$ 222**	**$ 207**

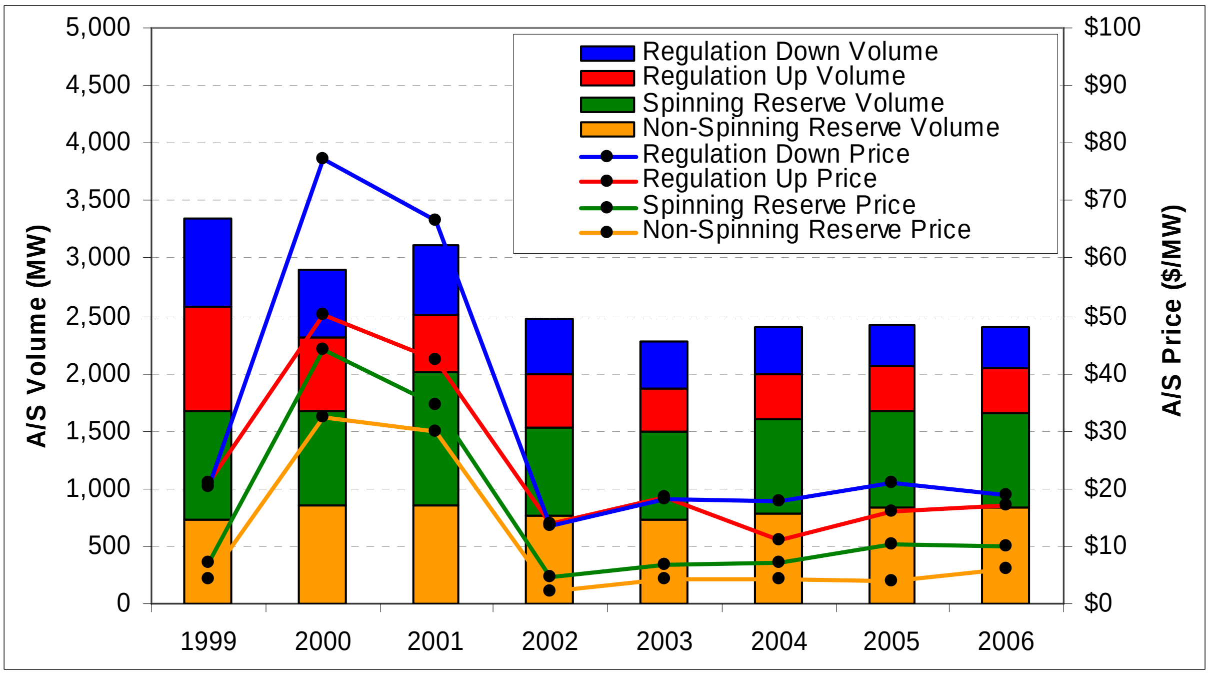
Ancillary Services Market

In the Ancillary Service Markets, prices were stable in 2006 and very similar to 2005. Overall, A/S prices increased 4 percent from a weighted average price of $10.72/MW in 2005 to

[12] In last year's report, total intra-zonal congestion costs of $203 million were reported in 2005. However, this estimate was based on preliminary settlement information for November and December 2005. The $222 million estimate for 2005 shown here reflects final settlement data for those months as well as other settlement corrections, which in total, amount to an increase of $19 million over last year's reported estimate. A similar issue may occur next year with regard to the reported costs for 2006.

$11.12/MW in 2006. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.16). Bid insufficiency, in terms of the number of hours there were insufficient ancillary service bids to meet the CAISO requirements for ancillary services, was down considerably from 2005 in all the Ancillary Service Markets (Table E.4). The majority of the bid insufficiency of Regulation Reserves occurred during the spring months of 2006. During these periods of heavy hydro flows, hydroelectric generators tend to sell large volumes of energy cheaply, which essentially creates a disincentive for would-be non-hydroelectric suppliers of Downward Regulation to be online. Most of the Spinning and Non-Spinning bid insufficiencies occurred during the summer peak months.

Figure E.16 Annual A/S Prices and Volumes, 2000-2006



While the number of hours of bid insufficiency declined in 2006, when bid insufficiency did occur, the average MW amount of deficiency was greater than in 2005. Table E.4 shows that the average amount of bid insufficiency (measured as percent of the total requirement) increased from 7 percent in 2005 to 13 percent in 2006.

Table E.4 Ancillary Service Bid Insufficiency

	Number of Hours With Shortage				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	163	135	279	107	684
2006	159	110	145	113	527
Percent Δ	-2%	-19%	-48%	6%	-23%

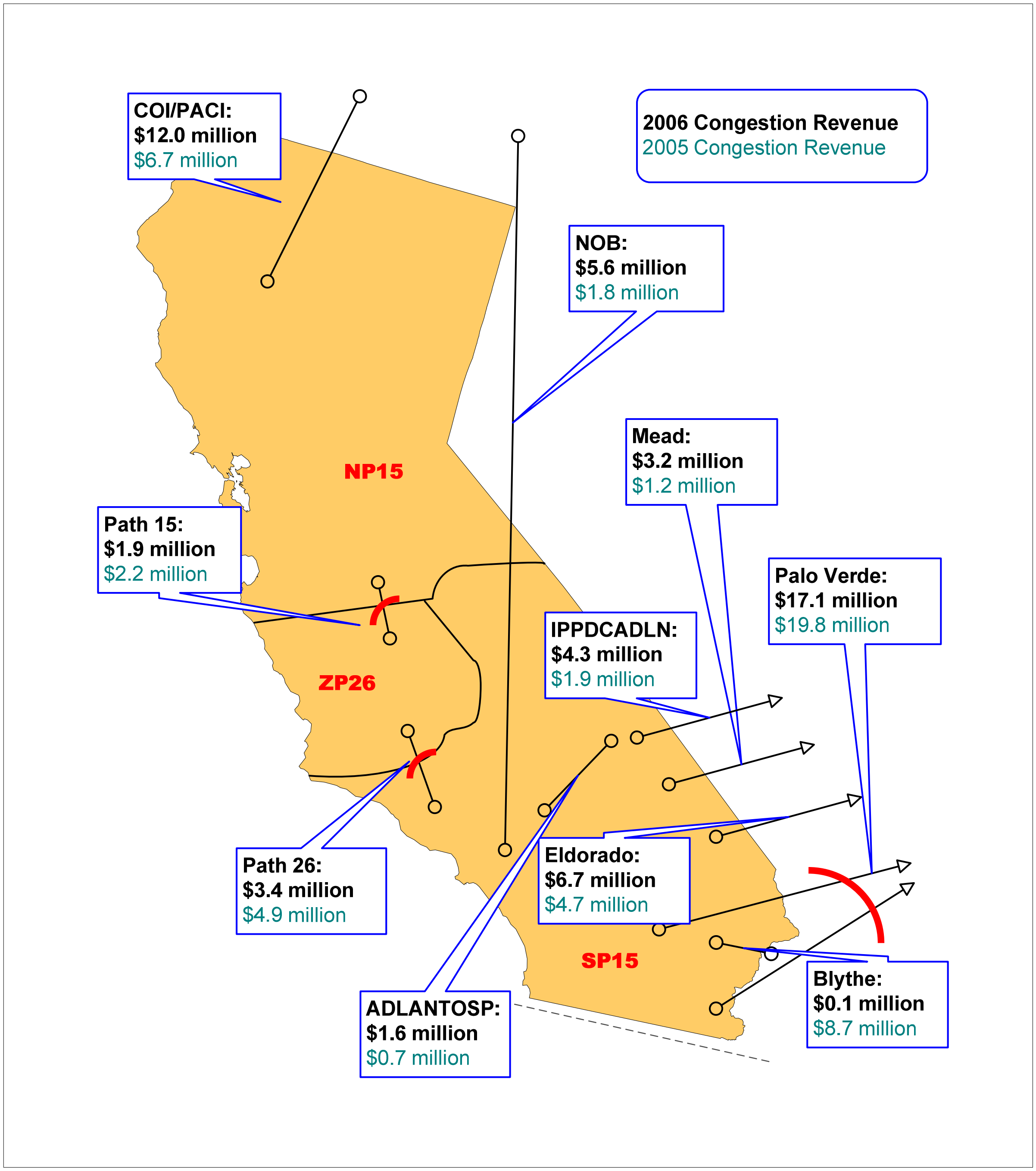
	Average Percent of Requirement Short				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	9%	14%	5%	6%	7%
2006	21%	16%	8%	15%	13%

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 2006 were $56 million, slightly higher than the $54.6 million in 2005. Figure E.17 shows the total annual congestion costs for the most commonly congested paths in 2005 and 2006. Congestion costs on Path 15 went from $2.2 million in 2005 to $1.9 million in 2006. Not surprisingly, Palo Verde continued to have the highest congestion costs in 2006 at $17.1 million (compared to $19.8 million in 2005, which was also the highest). Congestion costs on COI/PACI increased to $12 million in 2006 (compared to $6.7 million in 2005).

The two most frequently congested transmission paths in 2005, the Pacific AC Inter-tie (PACI) from the Northwest (formerly known as the California-Oregon Inter-tie (COI) prior to the separation of the California-Oregon Transmission Project (COTP) from the CAISO grid) and the Palo Verde branch group from the Southwest, remained the top two congested paths in 2006 with COI being congested in 18 percent of the hours in the Day Ahead Market (compared to 18 percent in 2005) and Palo Verde congested in 15 percent of the hours (compared to 23 percent in 2005).

Figure E.17 Major Congested Inter-ties and Congestion Costs



Summary and Conclusions

Overall, the CAISO markets and short-term bilateral energy markets were stable and competitive in 2006. The markets were tested to the limit during the extreme heat wave in July and performed remarkably well. This performance reflects the significant strides that California has made since the energy crisis both in terms of infrastructure enhancements (transmission and generation) as well as in long-term power contracting. Long-term power contracting provides a number of critical benefits to the market. First, it protects LSEs from spot market volatility (i.e., is an important hedging tool). Second, it shifts spot market risk to the supply side of the market and in so doing largely reduces incentives for suppliers to exercise market power. Finally, it provides a means for facilitating new generation investment. When load is effectively hedged, periodic price spikes, such as occurred during the July heat wave, impose manageable costs to load and provide important market benefits such as incentives to avoid generation forced outages, revenues for generation fixed cost recovery, and market prices that encourage demand response programs.

While five consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs. 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. This trend 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. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California. The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid.