California ISO
Your Link to Power
10 Year Anniversary 1998–2008

Market Issues & Performance

2007 Annual Report

Department of Market Monitoring
California Independent System Operator Corporation

ACKNOWLEDGEMENT

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Overview

Each year the Department of Market Monitoring (DMM) publishes a report on the performance of markets administered by the California Independent System Operator (CAISO). In 2008 the CAISO is celebrating the ten year anniversary of its operational launch on March 31, 1998. This report covers the period of January 1, 2007 through December 31, 2007.

For the sixth consecutive year (2002-2007), California's wholesale energy markets remained stable and competitive in 2007. This trend is predominantly due to a high level of forward energy contracting by the state's investor owned utilities, which limits their exposure to spot market price volatility, enhances competition, and facilitates new generation investment. Over the past seven years (2001-2007), approximately 14,900 MW of new generation has been added to the CAISO Control Area, enabling the retirement of 5,500 MW of older inefficient generation, resulting in a net increase of 9,400 MW of new generation. Additionally, another 1,800 MW of new generation is projected to be operational in 2008.

While very low snowpack levels in 2007 for most of the West, including California, raised concerns about hydroelectric supply availability during the critical summer months, relatively moderate summer temperatures mitigated this concern and produced generally competitive conditions with no major reliability issues. California did experience two heat waves in 2007 – both occurring over holidays, which may have tempered their effect. The first occurred over the Independence Day holiday, and the second, which set the annual peak load, occurred over Labor Day weekend. Both events were managed without any significant reliability issues. The energy markets were also generally stable and competitive during the heat waves, but did experience some escalation in prices and increased volatility – particularly in the bilateral energy and ancillary service markets. Overall, the market and operational impacts of the two heat waves were moderate compared to 2006, which saw an extraordinary heat wave that lasted three weeks in July, and reached a peak well above that seen in 2007.

From a grid operations standpoint, the most notable event of the year was the California wildfires that raged through large portions of Southern California from October 21 to 25. These fires were exceptional in terms of geographical span, number of acres burned, and number of businesses and residences impacted. They burned across Southern California, threatened generation and transmission facilities, and challenged grid stability, especially in the San Diego area. Remarkably, the CAISO, in close coordination with the Southern California utilities and assistance of the control area operator for Baja, Mexico (Comisiòn Federal de Electricidad (CFE)), was able to maintain reliable grid operation throughout the wildfire period. The wholesale market impacts from the wildfires were predominantly local in nature as various forced limitations within Southern California required real-time Out-of-Sequence dispatches as well as day-ahead unit commitment of generation at specific locations. Spot bilateral prices for Southern California did experience moderate and brief increases during this period. Congestion costs for some of the major inter-ties to Southern California increased as well, particularly in the Hour Ahead Market, where significant transmission derates occurred due to shifts in the paths of the fires. Overall, the market impacts during the fires were moderate and of short duration.

In terms of the general performance of the wholesale energy markets during the entire year, one of the primary metrics that DMM uses to gauge overall market competitiveness is a 12-month

Market Competitiveness 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). MCI values below $10/MWh are considered to be reflective of a workably competitive market. The monthly MCI values estimated for 2007 were well below this level for all months of the year.

The average estimated cost of wholesale energy in 2007 was $48.94/MWh of load compared to $47.52/MWh in 2006. Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The increase in the costs in 2007 was primarily due to greater reliance on fossil fueled generation – due to limited hydroelectric supplies – and to increased congestion costs on major importing paths to California.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend continued in 2007 with intra-zonal congestion costs dropping from $207 million in 2006 to $101 million in 2007. Intra-zonal congestion costs are 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. The decline is primarily attributable to lower MLCC payments and reduced RMR dispatch costs. MLCC costs declined by $65 million in 2007, mainly due to the completion of various transmission upgrades in Southern California during 2006. This construction caused the cost of MLCC payments in 2006 to increase, due to the need to commit units while the transmission work was being completed, but resulted in lower MLCC costs in 2007 once the upgrades, which relaxed the local constraints that previously required additional unit commitments through the must-offer waiver denial process, were complete. The cost of real-time RMR dispatches declined by $54 million in 2007. However, most of this decline was due to a reduction in RMR contracts that was enabled by the introduction of Local Resource Adequacy (RA) requirements in 2007. Thus, the cost savings from reduced RMR contracts may have been largely offset by higher RA costs, which are not accounted for in these figures. The cost savings for these two components of intra-zonal congestion costs were partially offset by an increase in the third component, real-time redispatch cost, of $13 million. The increase in this component was largely attributed to the need to redispatch units needed in the Humboldt area that were previously under RMR contracts.

The RMR costs noted above only pertain to the cost of real-time RMR energy dispatches. The total cost of RMR units, which includes both fixed cost payments and variable cost payments for day-ahead and real-time dispatches, declined substantially, from approximately $428 million in 2006 to $125 million in 2007, a reduction of approximately $303 million. This reduction is predominantly due to the reduction in the amount of capacity under RMR contracts, from approximately 9,300 MW in 2006 to 3,300 MW in 2007.

Another reliability management cost, which is relatively new, is the capacity payments made to generation units that are neither RMR units nor RA units. These capacity payments are made pursuant to the Reliability Capacity Services Tariff (RCST) and provide for both a daily capacity payment for non-RA units that are committed by the CAISO and potentially monthly capacity payments if a non-RA unit is designated by the CAISO as RCST. In 2007, the CAISO did not make any forward RCST designations but did make numerous daily capacity payments to non-RA units, amounting to approximately $26 million.

Another important market performance metric that DMM reports on each year is the extent to which spot market revenues for the entire year cover the annualized fixed cost of new generation facilities. The DMM's financial assessment of the potential revenues a new generation facility could have earned in California's spot market in 2007 indicates estimated spot market revenues fell short of the unit's annual fixed costs. The gap is significantly more pronounced given the recently released estimates from the California Energy Commission on the cost of new generation, which DMM used for purposes of this analysis. This marks the fifth straight year that the DMM's analysis found that estimated spot market revenues did not provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past four years (2004-2007) does show a positive trend of net revenues increasing for a new combined cycle unit, with estimated net-market revenues in 2007 of approximately $84/kW-year and $95/kW-year for Northern and Southern California, respectively, but these estimates are well short of the estimated annualized fixed costs of $132.6/kW-year.

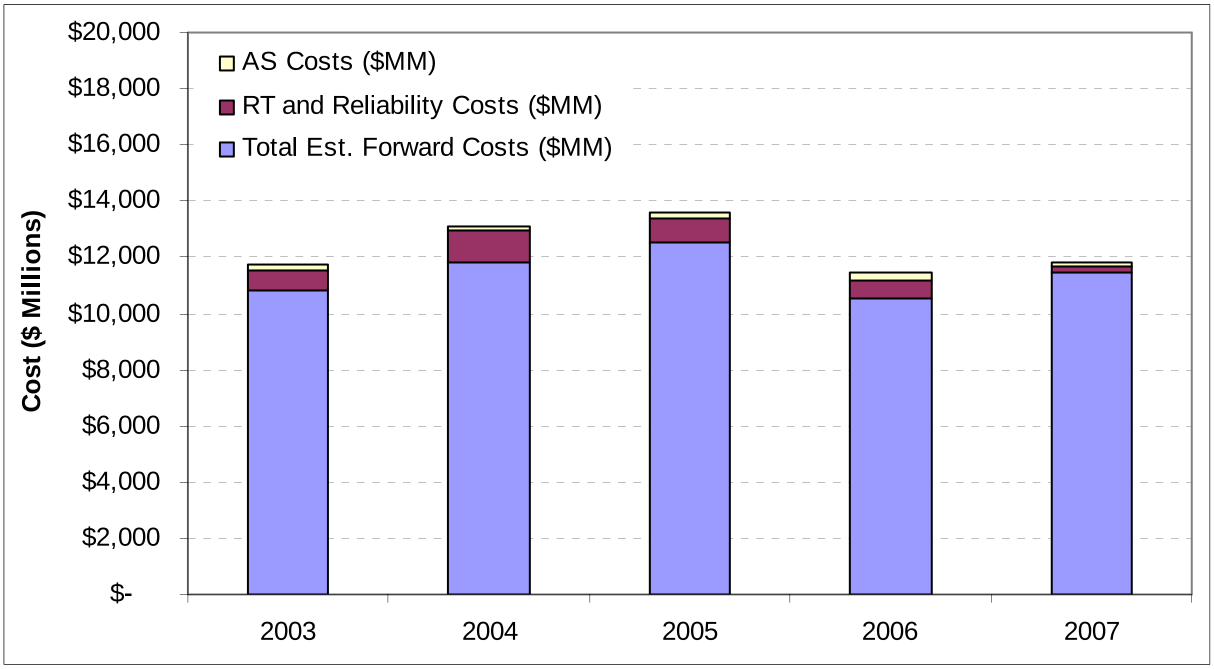
Despite the positive trend in spot market revenues, the fact that California's spot markets did not provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. 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

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility-retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. The real-time component of costs also includes reliability costs (minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs). These estimates do *not* include resource adequacy procurement costs, as these costs are not available to the CAISO.

As shown in Figure E.1, estimated total wholesale energy costs increased slightly in 2007, to approximately $11.8 billion (compared to $11.4 billion in 2006). The slight increase is due primarily to a greater reliance on more expensive fossil-fuel generation in 2007 due to less availability of hydroelectric energy. Total costs may have been even higher in 2007 but for generally lower natural gas prices compared to 2006.

Figure E.1 2003 – 2007 Wholesale Energy Costs



Market Rule Changes

There were two market design changes implemented in 2007. The first involved certain modifications to the current load scheduling requirement for the Day Ahead Market, and the second was the enforcement of local capacity requirements in the CPUC's Resource Adequacy program, whereby Load Serving Entities (LSEs) became required to procure capacity to satisfy specific local requirements determined by the CAISO. This more granular requirement complements the system-wide capacity requirements that were enforced beginning in June of 2006. A brief summary of the impact of each of these changes is provided below.

Day Ahead Load Scheduling Requirement

On April 24, 2007, FERC issued an order accepting several key changes to the day-ahead load scheduling requirements initially established in October 2005 under Amendment 72. The major change taking effect in 2007 was to lower the day-ahead scheduling requirement in off-peak hours from 95 to 75 percent of each SC's forecasted load. Another change provided an exemption during all hours for *de minimus* deviations below the scheduling requirement. The changes were proposed by the CAISO in response to concerns expressed by LSEs about the costs and difficulty of complying with the 95 percent scheduling requirement during all hours, and to reduce over-scheduling of load,[1] particularly during off-peak hours, which can create operational challenges in real-time.

Overall, these modifications, which were implemented on April 26, 2007, appear to have resulted in a moderate decrease in over-scheduling and a reduced need to routinely decrement energy in the Real Time Market. As expected, these impacts occurred primarily during off-peak hours. In addition, while some participants opposing a lower scheduling requirement for off-peak hours expressed concerns that these changes would cause the need to dispatch significant amounts of incremental energy in real-time, there is no evidence that such impacts materialized. A more detailed analysis and review of this change is provided in Chapter 1.

Local Resource Adequacy Requirements

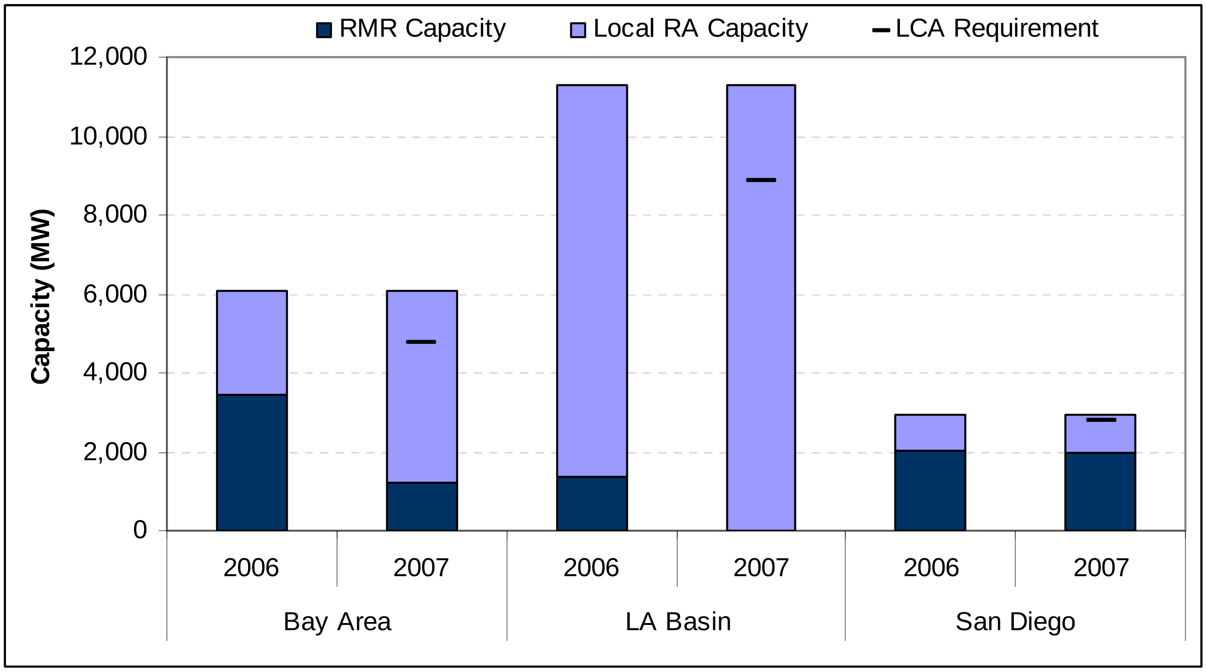
In 2006, the Resource Adequacy (RA) program developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserve margins. In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. In 2006, the RA program was limited to imposing system-wide capacity requirements. In 2007, the program was expanded to include Local Resource Adequacy Requirements, which require LSEs to procure minimum levels of RA capacity within various Local Capacity Areas (LCAs), or transmission constrained “load pockets” within the CAISO system. Minimum capacity requirements for LCAs are established through technical studies performed by the CAISO based on NERC Planning Standards and any other applicable local reliability criteria.

One of the goals of the CAISO and the CPUC is to rely on capacity contracted by LSEs to meet local RA requirements, and thereby reduce reliance on RMR contracts or any other “backstop” capacity procurement that may be done by the CAISO. For example, as noted in last year’s Annual Report on Market Issues and Performance, the CAISO’s RCST provisions, which were established pursuant to a settlement filed in 2006, authorize the CAISO to designate non-RA units to provide services under the RCST tariff as a “backstop” in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

In 2007, substantial progress in the goal of reducing reliance on RMR contracts was achieved, as the total volume of capacity under RMR contracts was reduced from approximately 10,000 MW to only 3,300 MW. In addition, all local reliability requirements were met by units under RA and RMR contracts. Consequently, the CAISO did not need to designate any capacity under RCST provisions as a “backstop” to RA resources procured by LSEs. As shown in Figure E.2, reliance on RMR contracts in the LA Basin was eliminated in 2007, and was significantly reduced in the San Francisco Bay Area. In addition, since the minimum reliability requirement for each LCA was met through a combination of RA and RMR capacity, the CAISO did not need to designate any additional capacity through the RCST provisions.

[1] Over-scheduling can arise under this requirement because in order to meet a 95 percent scheduling requirement in all hours, Load Serving Entities would sometimes have to purchase multi-hour blocks of energy from the inter-ties, which resulted in over-scheduled load during some hours – particularly off-peak hours.

Figure E.2 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements



General Market Conditions

Demand

Annual average hourly load in 2007 was moderately higher than in 2006 (Table E.1). Monthly average hourly load was significantly higher in most months of 2007, except for June and July, where average hourly load in 2007 was significantly lower than in 2006. Average hourly loads in June and July of 2007 were 3.4 percent and 5.1 percent below the monthly averages for the same months in 2006. However, average hourly loads in August 2007 were significantly higher than August 2006 (9.2 percent), due primarily to lower temperatures throughout August 2006.

Table E.1 Load Statistics for 2003 – 2007*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2003 Actual	26,345		230,857	42,581	
2004 Actual	27,309	3.5%	239,312	45,597	7.1%
2005 Actual	26,990	-1.2%	236,483	45,562	-0.1%
2006 Actual	27,427	1.6%	240,344	50,270	10.3%
2007 Actual	27,646	0.8%	242,265	48,615	-3.3%
2003 Adjusted	25,471		223,206	41,063	
2004 Adjusted	26,436	3.7%	231,660	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,994	44,260	0.1%
2006 Adjusted	27,427	3.5%	240,344	50,198	11.8%
2007 Adjusted	27,646	0.8%	242,265	48,615	-3.3%

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

Supply

Approximately 600 MW of new generation began commercial operation within the CAISO Control Area in 2007, and no generation capacity was retired from service in 2007. The CAISO projects construction of 1,810 MW of new generation in 2008, of which roughly 941 MW are expected to be commercially available prior to the anticipated summer peak season. Currently, there are no planned generation retirements in 2008; however, unlike the lengthy process for constructing a new resource, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table E.2 below shows an annual accounting of generation additions and retirements since 2001, with projected 2008 changes included along with totals across the eight year period (2001-2008). Including estimates for 2008, the total net increase in installed generation in the CAISO Control Area over the eight years spanning 2001-2008 is estimated to be approximately 11,200 MW. When accounting for an estimated 2 percent load growth over the same seven year period of approximately 7,500 MW, the net supply margin increased by roughly 3,700 MW since the energy crisis. Interestingly, Table E.2 indicates that generation additions in Southern California just kept pace with load growth and unit retirements, resulting in a minor net-loss of approximately 262 MW, but in Northern California (NP26) there was approximately a 3,950 MW increase in new generation after accounting for load growth and generation retirement.

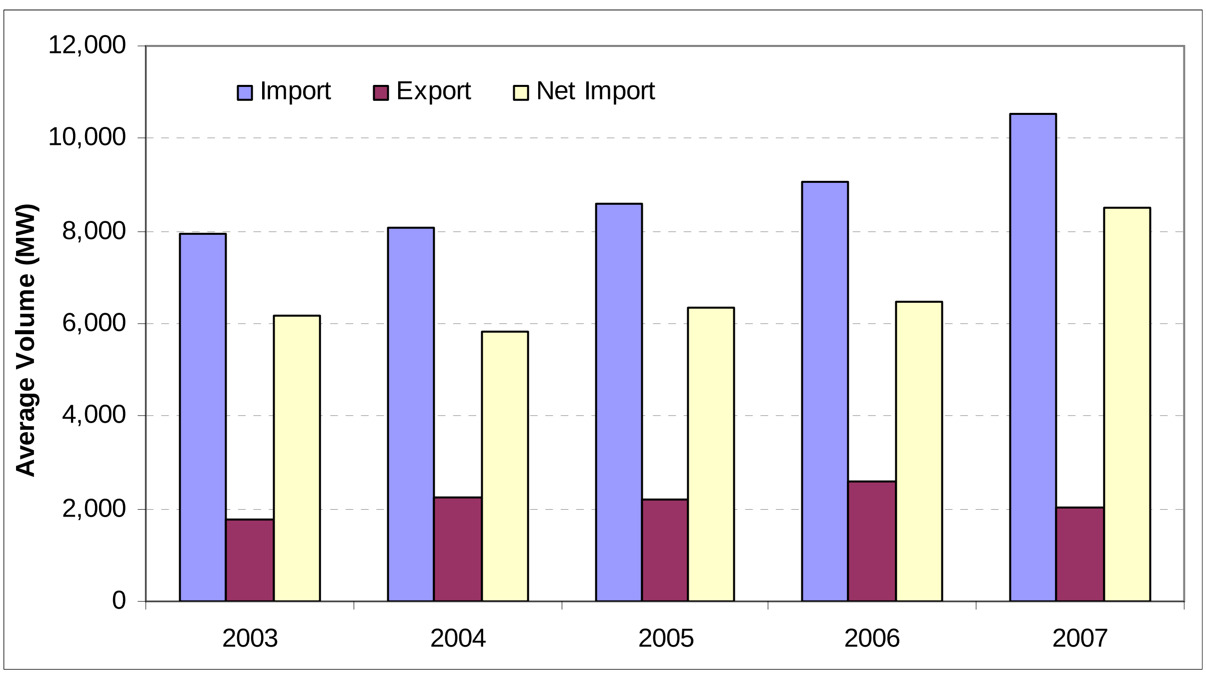
Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	2006	2007	Projected 2008	Total Through 2008
SP15									
New Generation	639	478	2,247	745	2,376	434	485	826	8,230
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	4,212
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**262**	**(262)**
NP26									
New Generation	1,328	2,400	2,583	3	919	199	112	984	8,528
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	3,342
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**536**	**3,951**
ISO System									
New Generation	1,967	2,878	4,830	748	3,295	633	598	1,810	16,758
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(5,515)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	7,554
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**798**	**3,689**

*Assumes 2% peak load growth.

Imports continue to play a key role in meeting demand. Figure E.3 shows average annual gross imports, exports, and net imports for the five-year period covered by 2003-2007. Average hourly gross imports increased significantly in 2007. This was primarily due to the reduced availability of hydroelectric generation within California, which resulted in more imports from the Pacific Northwest and the Southwest. Lower availability of hydroelectric generation within California may have also accounted for the reduction in annual exports also observed in 2007. Overall, hourly net-imports in 2007 averaged a little over 8,000 MWh, the highest level observed over this five year period.

Figure E.3 Average Annual Imports, Exports, and Net Imports (2003-2007)



Generation Outages

Figure E.4 depicts monthly average planned and forced outages between 2004 and 2007. Similar to previous years, planned outages were high during the first five months of the year, lower during the peak summer months, and high again in the fall months. Monthly averages of planned and forced outages in 2007 were generally comparable to 2006, with the exception of April 2006, where both planned and forced outages were exceptionally high. 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.

Figure E.4 Monthly Average Planned and Forced Outages (2004 – 2007)

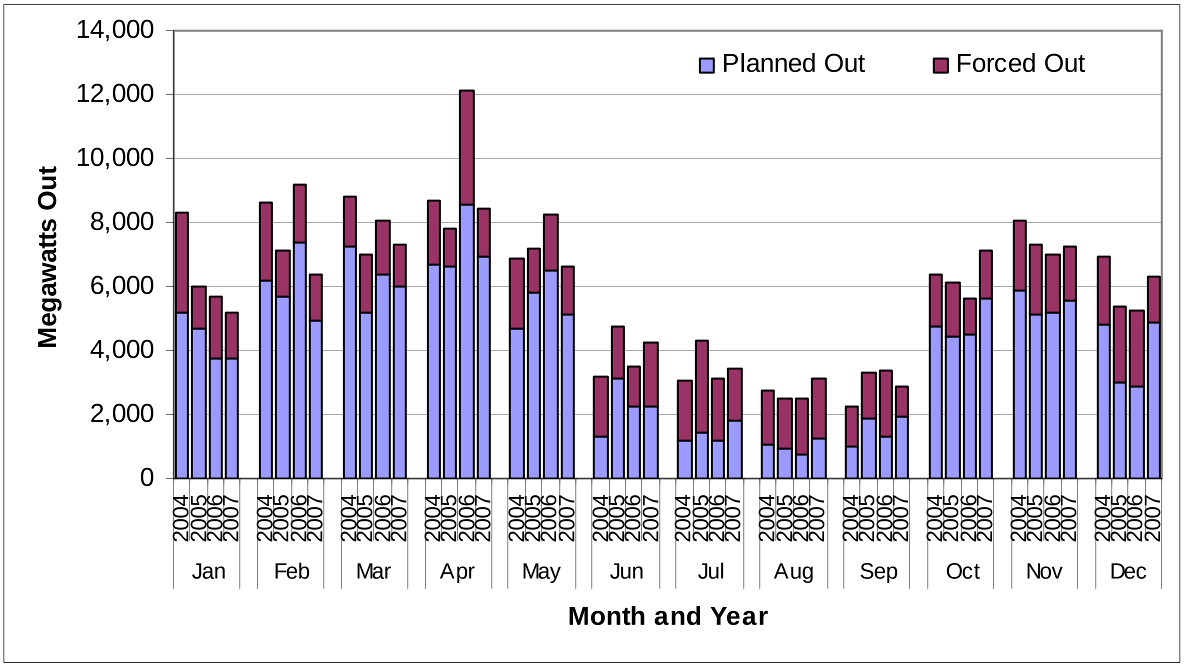
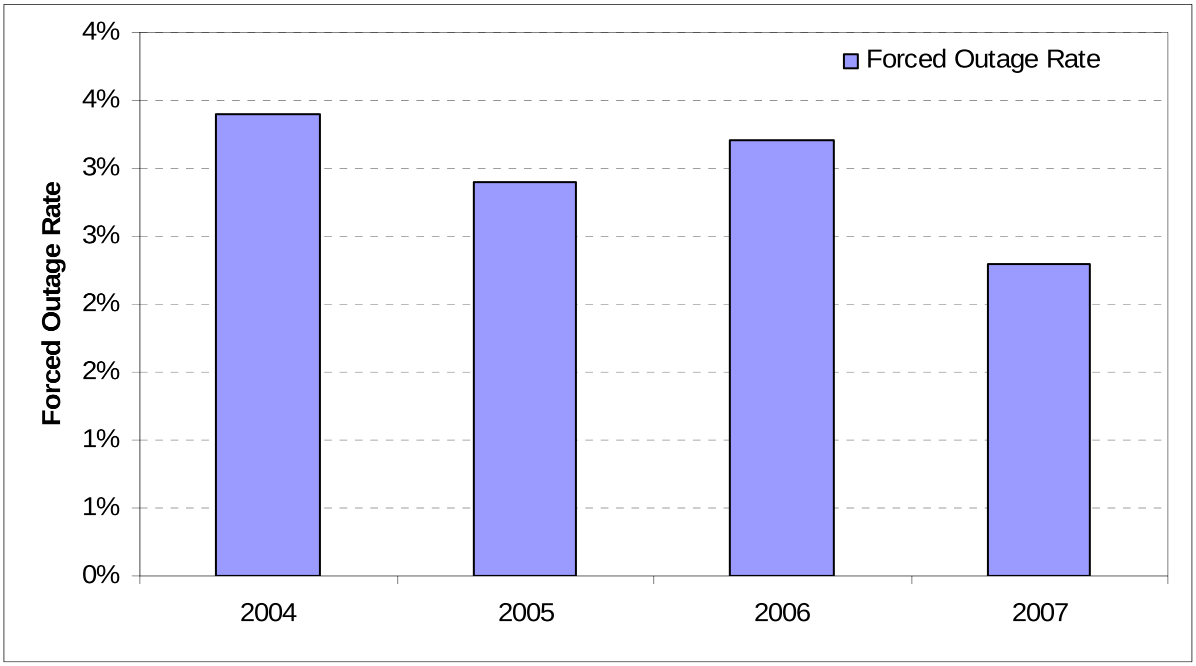


Figure E.5 compares annual forced outage rates since 2004. The annual forced outage rate in 2007 was approximately 2.6 percent, which is the lowest rate observed over this period. The decline can be partly attributable to the installation of new generation and transmission upgrades in recent years, which have enabled older, high-maintenance resources in California to be reserved for limited critical periods.[2] In addition, recent retirements of aging plants that had been outage-prone such as the Mohave coal-fired units (retired December 31, 2005) and the availability incentives provided by long-term energy contracting also contribute to lower outage rates.

[2] See Sections 2.2.3 and 2.6.4 in Chapter 2 for more information.

Figure E.5 Annual Forced Outage Rates (2004 – 2007)



Short-term Energy Market Performance

The significant number of long- to medium-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 2007 short-term energy markets. When LSEs are substantially hedged by longer-term fixed price 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 coverage and rely more on the spot markets.

Estimated Mark-up of Short-term Bilateral Transactions

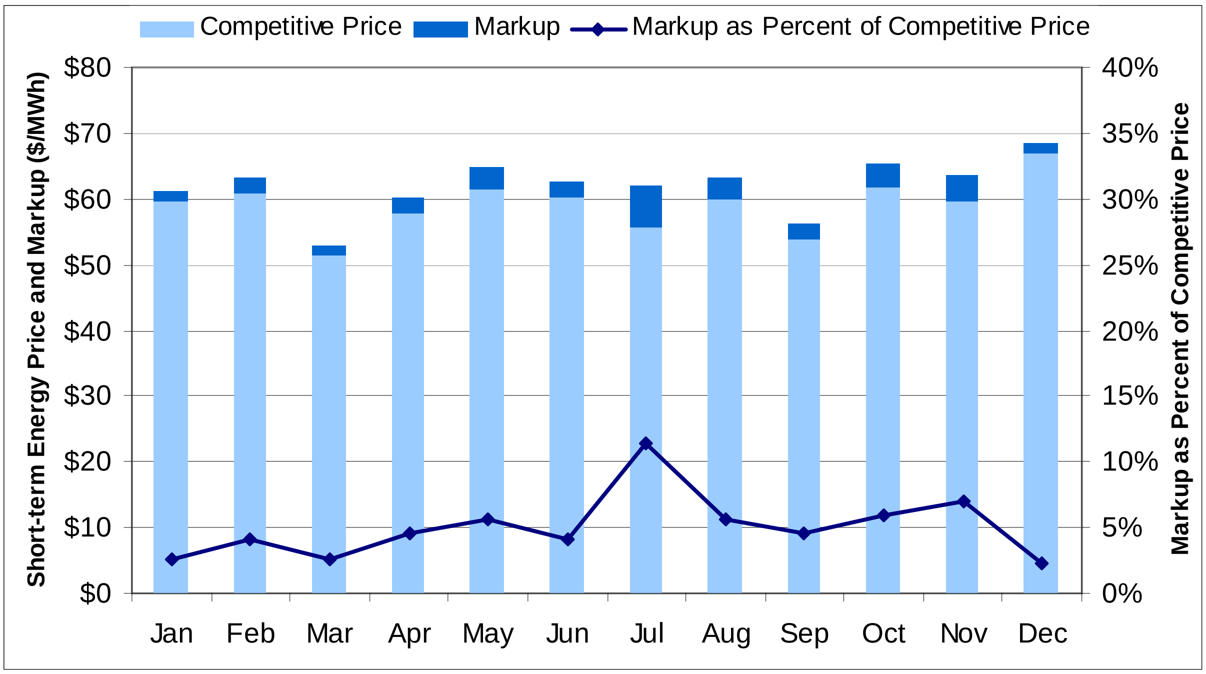
Having no formal forward energy market makes a comprehensive review of competitiveness difficult due to the lack of reporting on transactions in the short-term bilateral energy market. The CAISO has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[3] an independent energy information company that provides hourly wholesale power indexes in the WECC, as well as 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

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

incorporating detailed generation unit and system cost information. Figure E.6 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.

For 2007, monthly short-term mark-ups ranged from 2 to 11 percent, compared to 1 to 16 percent in the prior year. July was the only month when mark-ups were greater than 10 percent, corresponding to the summer high demand period. Overall, 2007 short-term forward markets functioned competitively. Though mark-ups were significant in July, they were highly correlated with high demand conditions and appear to have had minimal cost impacts to California LSEs due to the high level of hedging, which minimized spot market exposure.

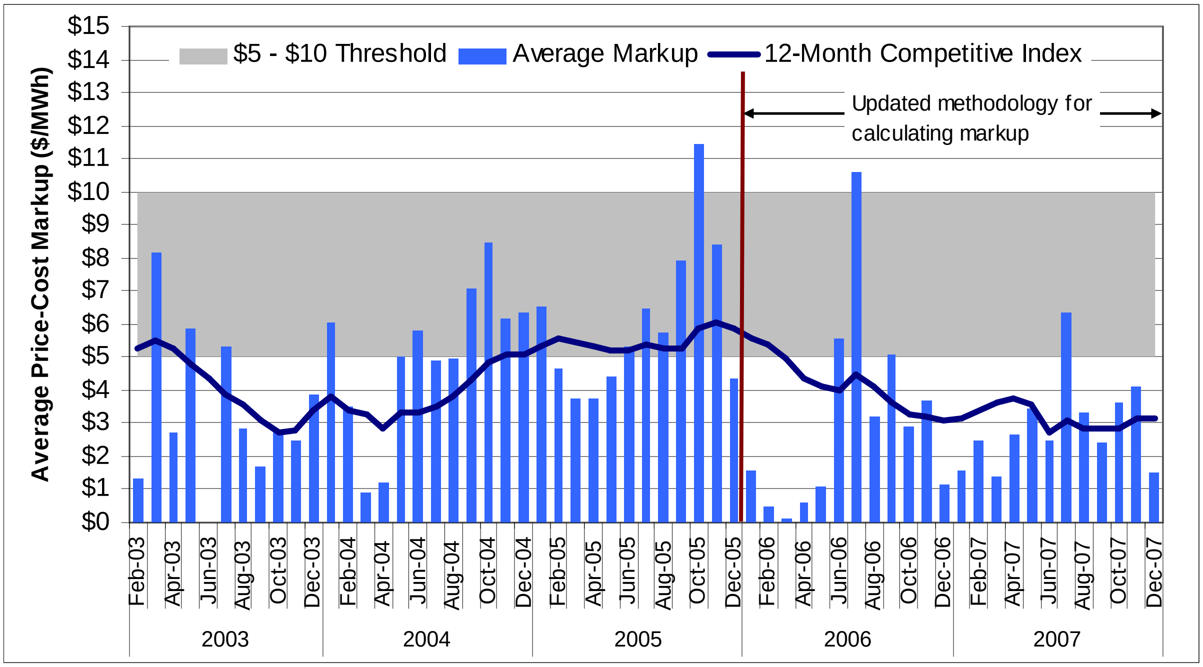
Figure E.6 Short-term Price-Cost Mark-up Index (2007)



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 longer period of time. 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 2007. This indicates that the short-term energy market in California stabilized in late 2001 and has produced fairly competitive results over the past six years. Figure E.7 below shows the market competitiveness index values for the past five years (2003-2007).

Figure E.7 Twelve-Month Market Competitiveness Index (2003-2007)



Revenue Adequacy of New Generation

Another benchmark often used for assessing the competitiveness of markets is the degree to which spot 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 the 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 2007 indicates that potential spot market revenues fell short of a new unit's annual fixed costs (Figure E.8 and Figure E.9). The gap this year is significantly more pronounced given the recently released estimates from the California Energy Commission on the cost of new generation, which were used for purposes of this analysis. The new cost estimates indicate the average annualized fixed cost of a new combined cycle generating unit is $132.6/kW-year (compared to the previous 2003 CEC estimate of $90/kW-year) and the average annualized cost of a new combustion turbine is $162.1/kW-year (compared to previous the 2003 CEC estimate of $78/kW-year). The dramatic increase is primarily due to increases in construction material costs, siting and permitting costs, and the cost of investment capital. While this result is consistent across the past four years, there is a favorable four year trend evident in the combined cycle analysis (Figure E.8). 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 2007 of approximately $84/kW-year and $95/kW-year for Northern and Southern California, respectively, but these estimates are well short of the estimated annualized fixed costs of $132.6/kW-year. While estimated net spot market revenues also increased in 2007 for a new combustion turbine (Figure E.9), net revenues were still well below the $162.1/kW-year estimated break-even point.

Figure E.8 Financial Analysis of New CC Unit (2003-2007)

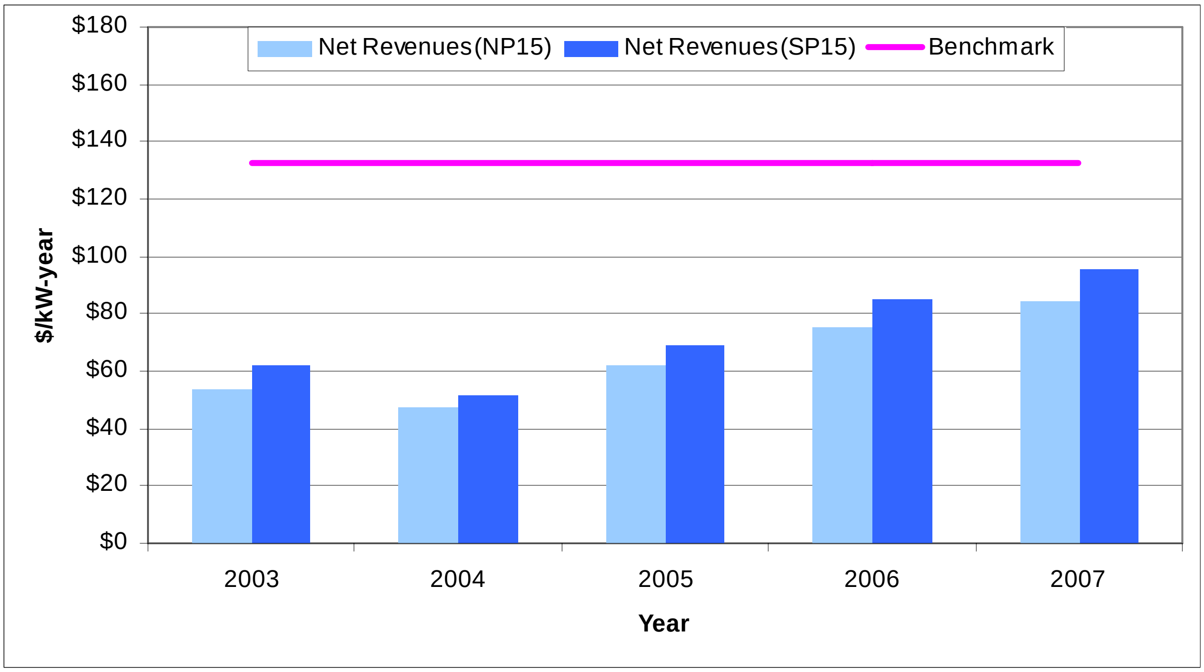
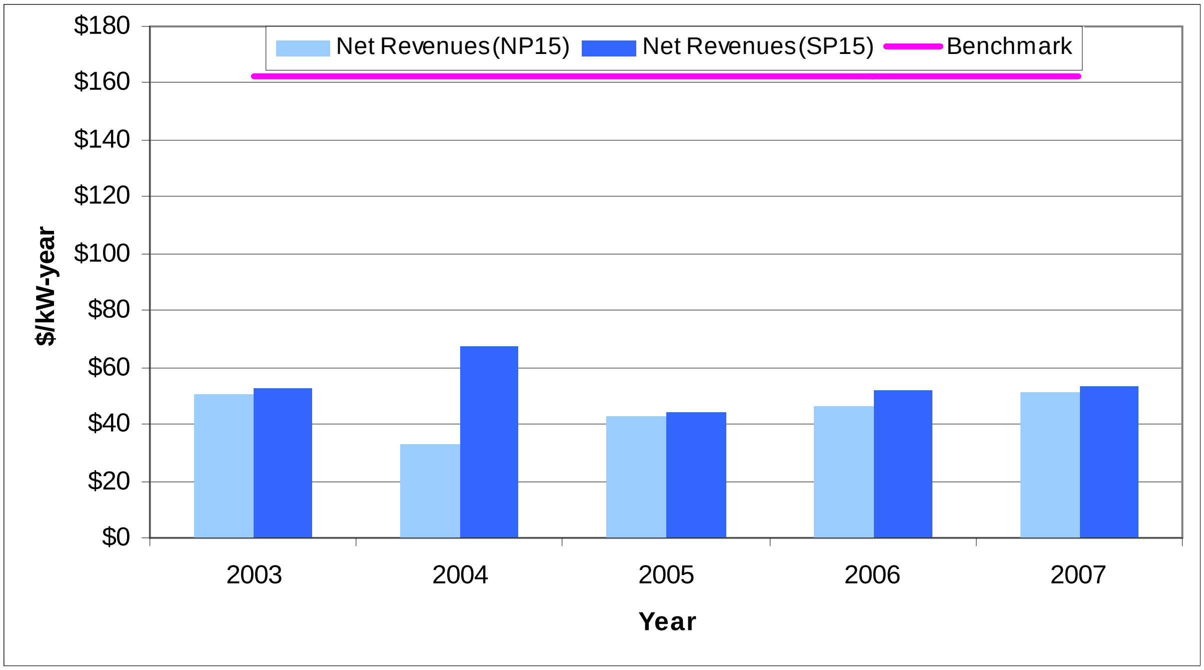


Figure E.9 Financial Analysis of New CT Unit (2003-2007)



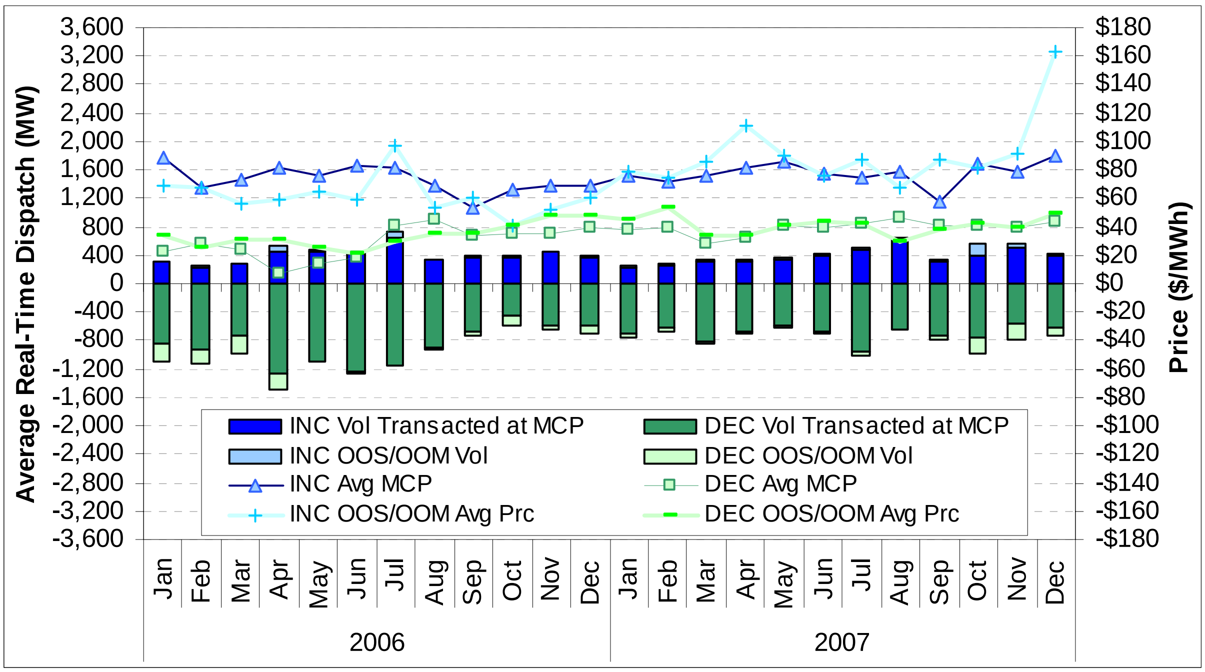
The finding that estimated spot market revenues do not provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are 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 2007) but the net revenues earned in 2007 are not indicative of future market revenue opportunities, which are 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 in 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) are being 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 sixth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2007 (Figure E.10). 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 resulted in frequent over-generation in the real-time imbalance energy market. As shown in Figure E.10, the average hourly levels of decremental dispatches were fairly consistent throughout each month of 2007, averaging close to 800 MWh. In contrast, 2006 saw much higher levels of decremental dispatch during the first half of the year. The difference is most likely due to the abundance of hydroelectric generation in 2006, which frequently created over-generation conditions, requiring larger volumes of decremental dispatch.

Monthly average prices in 2007 for periods when the CAISO was issuing incremental energy dispatches were stable, averaging around $80/MWh for most of the year. Though there was a significant increase in the average cost of incremental Out-of-Sequence dispatch in December 2007, these dispatches were limited to a very small volume of energy. Average monthly prices for periods when the CAISO was issuing decremental dispatches were significantly lower, averaging approximately $40/MWh.

Figure E.10 Monthly Average Real-time Prices and Volumes (2006-2007)



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.[4] It is important to note that an index based upon the extremely small volume of transactions in the

[4] 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.

Real Time Market is not indicative of overall wholesale market competitiveness.[5] Nonetheless, it provides a useful metric for Real Time Market performance.

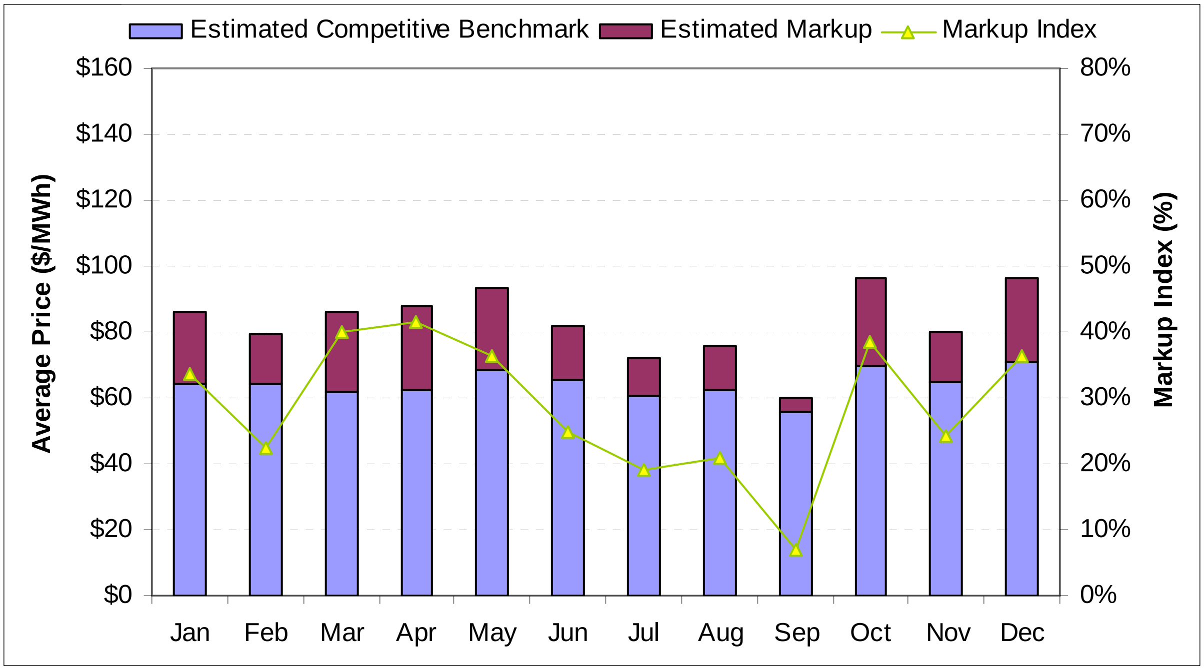
Throughout 2007, estimated monthly average mark-ups in the Real Time Market were generally higher in the off-peak months than in the peak summer months. For example, during the spring (March-May), average monthly mark-ups were in the 35-40 percent range, but declined steadily through the summer to the 10-20 percent range, then increased back to the 30-40 percent range in the fall. Mark-ups were generally lower in the summer months because there were typically more units on-line to provide real-time energy, particularly thermal units with greater ramping capability than are available in the off-peak months. Additionally, peak loads during the summer months in 2007 were fairly moderate, which in turn moderated imbalance energy demands.

While the unusually high mark-ups for the Real Time Market 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 dispatchable bids makes this market extremely volatile.[6] 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, indicating that the spot market was workably competitive in 2007.

[5] Volumes and prices in the Real Time Market are sensitive to a number of factors (i.e., uninstructed deviations, Grid Operator activities taken to mitigate local or zonal reliability issues, unscheduled flows from neighboring control areas, brief perturbations in load) that are outside of fundamental supply and demand conditions that drive market prices. For this reason, and the fact that volumes in the Real Time Market are overall quite small, we look to the spot bilateral market for more meaningful indicators of competitiveness in the wholesale market.

[6] 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.

Figure E.11 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market (2007)



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 lower 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.

One significant positive trend that has been reported in prior annual reports has been the sharp reduction in intra-zonal congestion costs. This trend continued in 2007 with intra-zonal congestion costs dropping from $207 million in 2006 to $101 million in 2007. 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. Costs for all three of these components are shown in Table E.3. The decline is primarily attributable to lower MLCC payments and reduced RMR dispatch costs. MLCC costs declined by $65 million in 2007, mainly due to the completion of various transmission upgrades in Southern California during 2006, which both raised the cost of MLCC payments in 2006 – due to the need to commit units while the transmission work was being completed – and lowered MLCC cost in 2007 once the upgrades were complete, which relaxed the local constraints that previously required additional unit commitments through the must-offer waiver denial process.

The cost of real-time RMR dispatches declined by $54 million in 2007. Most of this decline is due to a reduction in RMR contracts that was enabled by the introduction of Local Resource Adequacy (RA) requirements in 2007, thus the cost savings from reduced RMR contracts may have been largely offset by higher RA costs which are not accounted for in these figures. The cost savings for these two components of intra-zonal congestion costs in 2007 were partially offset by an increase in the third component, real-time redispatch cost, of $13 million. The increase in this component is largely attributed to the need to redispatch units needed in the Humboldt area that were previously under RMR contracts.

Table E.3 Monthly Intra-Zonal Congestion Costs by Category ($ Million)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**
Jan	$ 8	$ 10	$ 3	$ 3	$ 13	$ 2	$ 6	$ 4	$ 2	$ 17	$ 27	$ 6
Feb	$ 4	$ 8	$ 2	$ 3	$ 15	$ 1	$ 3	$ 2	$ 2	$ 10	$ 25	$ 4
Mar	$ 3	$ 11	$ 2	$ 5	$ 13	$ 1	$ 3	$ 3	$ 1	$ 11	$ 27	$ 4
Apr	$ 6	$ 27	$ 2	$ 5	$ 8	$ 2	$ 3	$ 6	$ 2	$ 14	$ 41	$ 6
May	$ 14	$ 12	$ 2	$ 5	$ 3	$ 1	$ 2	$ 1	$ 2	$ 21	$ 16	$ 4
Jun	$ 7	$ 15	$ 3	$ 2	$ 4	$ 1	$ 0	$ 0	$ 1	$ 9	$ 19	$ 5
Jul	$ 13	$ 14	$ 7	$ 5	$ 2	$ 1	$ 1	$ 0	$ 2	$ 19	$ 17	$ 10
Aug	$ 14	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 24	$ 8	$ 4
Sep	$ 8	$ 3	$ 2	$ 6	$ 2	$ 0	$ 3	$ 0	$ 1	$ 17	$ 5	$ 4
Oct	$ 13	$ 1	$ 10	$ 8	$ 3	$ 6	$ 4	$ 1	$ 8	$ 25	$ 5	$ 25
Nov	$ 12	$ 1	$ 5	$ 5	$ 6	$ 3	$ 6	$ 0	$ 4	$ 23	$ 7	$ 12
Dec	$ 11	$ 2	$ 5	$ 16	$ 7	$ 8	$ 5	$ 0	$ 4	$ 32	$ 9	$ 17
Total	**$ 114**	**$ 109**	**$ 44**	**$ 72**	**$ 80**	**$ 26**	**$ 36**	**$ 17**	**$ 30**	**$ 222**	**$ 207**	**$ 101**

Ancillary Service Markets

In the Ancillary Service (A/S) Markets, prices were stable in 2007, and lower than prices in 2006. Overall, A/S prices decreased 35 percent from a weighted average price of $11.12/MW in 2006 to $7.41/MW in 2007. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.12). The A/S markets also experienced a significant decline in hours of bid insufficiency in 2007 compared to the previous year. With the exception of Non-Spinning Reserve in the summer, bid deficiency occurred in less than one percent of the operating hours (102 hours) in each month for all four services, compared to six percent in 2006 (527 hours), representing an 81 percent decline in the number of bid insufficiency hours (Table E.4). In 2006, bid insufficiency in the A/S markets was particularly high due, to the abundance of hydroelectric energy which displaced thermal generation and generally reduced the available unloaded capacity for providing reserves. With much less hydroelectric energy available in 2007, more thermal units were on-line throughout the year, and more unloaded capacity was available to provide ancillary reserves. The higher frequency of bid insufficiency for Non-Spinning Reserve in July and August can be attributed to tight supply conditions and high opportunity costs during periods of high loads.

Figure E.12 Annual A/S Prices and Volumes (1999-2007)

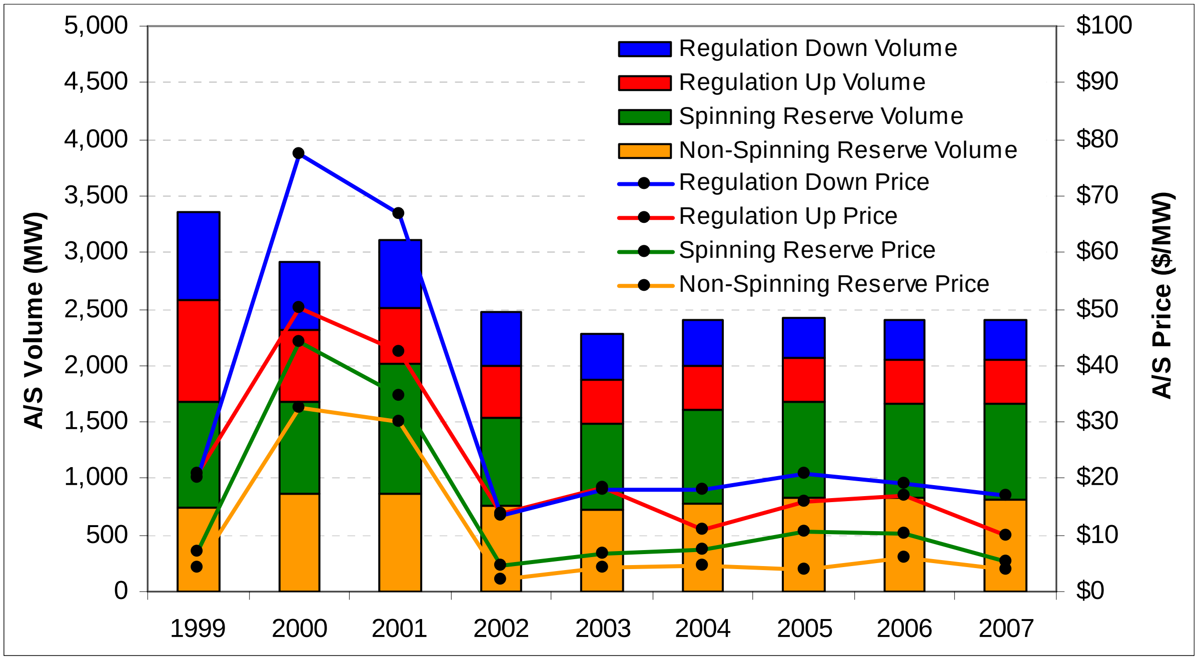


Table E.4 Ancillary Service Bid Insufficiency

	Number of Hours With Shortage				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2006	159	110	145	113	527
2007	20	11	35	36	102
Percent Δ	-87%	-90%	-76%	-68%	-81%

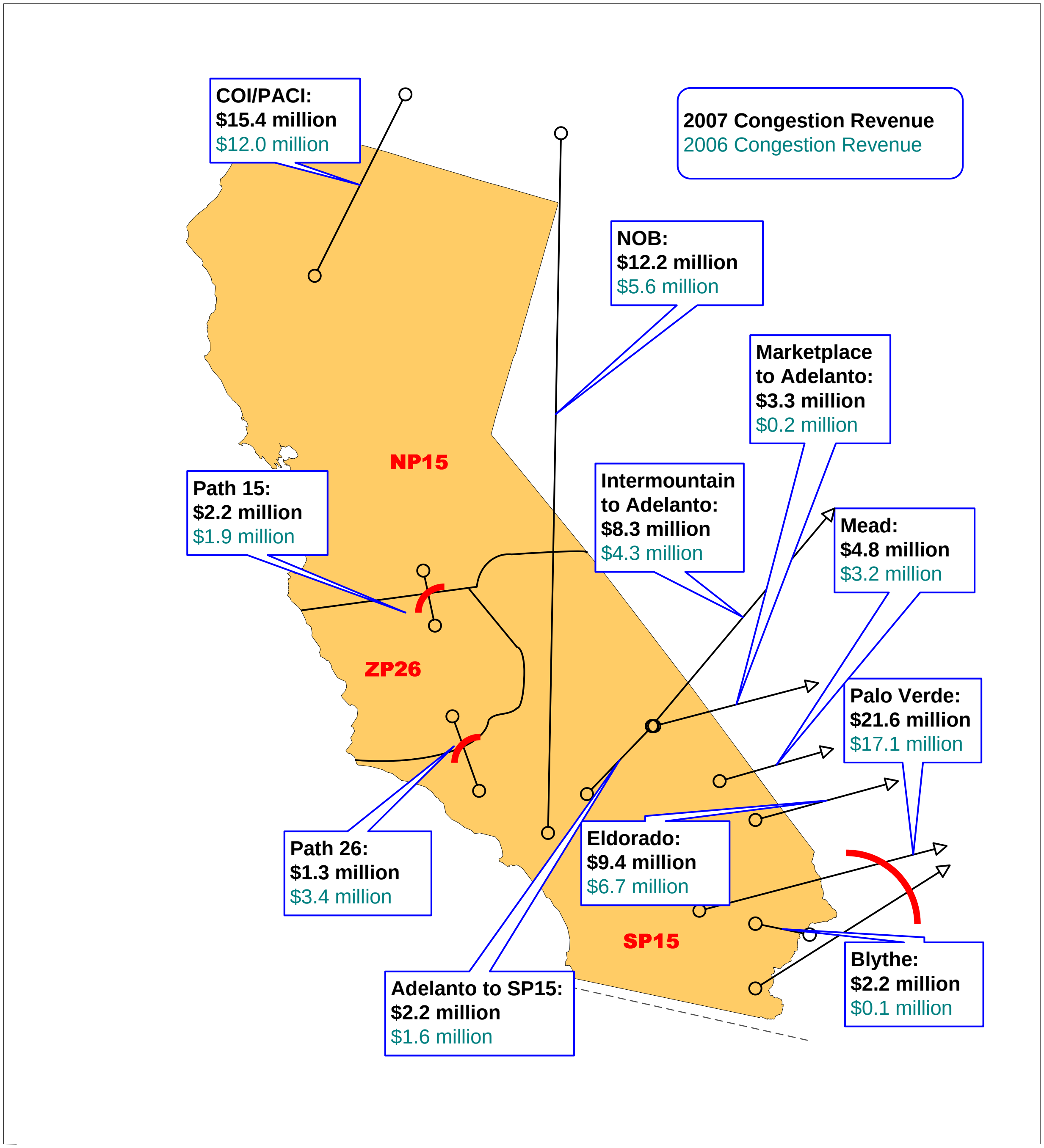
	Average Percent of Requirement Short				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2006	21%	16%	8%	15%	13%
2007	15%	7%	6%	8%	8%

Inter-Zonal Congestion Market

The CAISO Inter-Zonal Congestion Management Market was also generally stable and competitive in 2007, but inter-zonal congestion did increase significantly from 2006. Total inter-zonal congestion costs in 2007 were $85 million, significantly higher than the $56 million in 2006. Figure E.13 shows the total annual congestion costs for the most commonly congested paths in 2006 and 2007. Congestion costs on Path 15 increased from $1.9 million in 2006 to $2.2 million in 2007. Not surprisingly, Palo Verde continued to have the highest congestion costs in 2007, at $21.6 million (compared to $17.1 million in 2006, which was also the highest). Congestion costs on PACI increased to $15.4 million in 2007 (compared to $12 million in 2006), and had the highest congestion frequency, at 32 percent of total annual hours.

The increase in inter-zonal congestion frequency and costs is mostly attributed to high north-to-south flows during the spring and early summer months, coupled with transmission outages throughout the year and a few distinct events in the fall. During the spring and early summer months, congestion charges were concentrated on PACI and the Pacific DC Inter-tie, as hydro electricity was imported from the Northwest across PACI and NOB to meet California load. The pattern of higher congestion frequency and cost transitioned to Palo Verde and Eldorado in the fall months, as Northwest hydro went into the re-charge season and California shifted to rely more heavily on thermal generation from the Southwest.

Figure E.13 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 2007. 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 forward energy contracting. Medium- to long-term forward energy contracting provides a number of critical benefits to the market. First, it protects LSEs from spot market volatility (i.e., it 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 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.

In terms of the spot market signals being provided for new generation investment, the spot markets continue to produce net-market revenues that are far short of what would be needed to cover the annualized costs of new generation facilities. 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. Nonetheless, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in the spot markets over the year. The fact that California's spot markets do not 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. 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, but the net revenue earned in 2007 is not indicative of future market revenue opportunities, which are the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities 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 in 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) are being seriously considered for future adoption.

While six consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs, particularly for Southern California. Though approximately 8,900 MW of new generation has been added to Southern California since the energy crisis, which enabled the retirement of 4,300 MW of older inefficient generation, net generation additions for that region have only just kept pace with load growth. Consequently, reliability needs for that region continue to be met, in part, by older less efficient generation, which cannot be sustained indefinitely. Moreover, major state environmental policies, such as greenhouse gas reductions, Renewable Portfolio Standards (RPS), and a potential ban on once-through cooling systems, will call for even more aggressive and coordinated action on addressing infrastructure issues.

1 Market Structure and Design Changes

1.1 Introduction and Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2007. There were two market design changes implemented in 2007. The first involved certain modifications to the current load scheduling requirement for the Day Ahead Market, which included a lower day-ahead scheduling requirement in off-peak hours, reducing the requirement from 95 to 75 percent of each SC's forecasted load. Accompanying the reduction in scheduling requirement was an exemption during all hours for *de minimus* deviations below the scheduling requirement (i.e., the minimum of 3 MWh or 5 percent of forecasted demand). The other market design change implemented in 2007 was the enforcement of local capacity requirements in the CPUC's Resource Adequacy program, where load serving entities became required to procure capacity to satisfy specific local requirements determined by the CAISO. This more granular requirement complements the system-wide capacity requirements that were enforced beginning June of 2006.

The infrastructure changes discussed below include changes in generation retirements and additions and various transmission upgrades implemented in 2007 and potential future projects. The chapter concludes with an overview of some notable activities in 2007 relating to the CAISO Enforcement Protocols.

1.2 Market Design Changes

1.2.1 Day Ahead Load Scheduling Requirement

On April 24, 2007, FERC issued an order accepting several key changes to the day-ahead load scheduling requirements initially established in October 2005 under Amendment 72. The major change taking effect in 2007 was to lower the day-ahead scheduling requirement in off-peak hours from 95 to 75 percent of each SC's forecasted load. Another change provided an exemption during all hours for *de minimus* deviations below the scheduling requirement (i.e., the minimum of 3 MWh or 5 percent of forecasted demand). The changes were proposed by the CAISO in response to concerns expressed by Load Serving Entities (LSEs) about the costs and difficulty of complying with the 95 percent scheduling requirement during all hours, and to reduce over-scheduling of load,[7] particularly during off-peak hours, which can create operational challenges in real-time.

The modifications in day-ahead load scheduling provisions appear to have resulted in a moderate decrease in over-scheduling and a reduced need to routinely decrement energy in the Real Time Market. As expected, these impacts occurred primarily during off-peak hours. As

[7] Over-scheduling can arise under this requirement because in order to meet a 95 percent scheduling requirement in all hours, LSEs would sometimes have to purchase multi-hour blocks of energy from the inter-ties, which in some cases resulted in over-scheduled load during some hours – particularly off-peak hours.

shown in Table 1.1, analysis of scheduling and dispatch data in the weeks before and after these changes went into effect shows a reduction in three key indicators of over-scheduling and excessive energy in real-time:

- **Day Ahead Over-scheduling**. The amount of day-ahead over-scheduling – measured by the degree to which day-ahead load schedules exceed the CAISO's day-ahead load forecast – dropped by an average of about 218 MW during off-peak hours and about 34 MW during peak hours. This represents an average drop in day-ahead over-scheduling of about 1 percent of total CAISO load during off-peak hours.

- **Average Net Energy Dispatched in Real Time Market**. In the CAISO's Real Time Energy Market, the CAISO dispatched an average of 409 MW of net decremental energy during off-peak hours before the changes, but dispatched an average of only 22 MW of net decremental energy since the modifications. During peak hours, the average amount of real-time energy dispatched dropped from 462 MW of net decremental energy to an average of 345 MW of net decremental energy.

- **Percent of Hours with Net Decremental Energy Dispatched in Real Time Market**. The percentage of off-peak hours during which the total energy dispatched by the CAISO in the Real Time Market was negative – indicating a net dispatch of decremental energy (i.e., a net dispatch that requires generation to operate at levels below what was originally scheduled) – dropped from 82 percent to 58 percent of hours after the scheduling requirement was lowered to 75 percent for off-peak hours.

While the reduction in over-scheduling and over-generation during off-peak hours has been relatively moderate, this may be in part attributable to the relatively low hydro conditions experienced in 2007.[8] In addition, while some participants opposing a lower scheduling requirement for off-peak hours expressed concerns that these changes would cause the need to dispatch significant amounts of incremental energy in real-time, there is no evidence that such impacts materialized.

[8] The overall level of over-generation and decremental energy dispatched by the CAISO was significantly higher in the spring and early summer of 2006 than 2007, largely due to the much higher hydro conditions in 2006 than in 2007. Consequently, analysis of the potential impacts of changes in load scheduling requirements in this report was not based on a comparison of 2006 and 2007 data since this could overestimate impacts under actual hydro conditions in 2007. However, one of the key reasons for modifying off-peak scheduling requirements was to avoid the problems that the 95 percent scheduling requirement created during off-peak hours under the extremely high hydro conditions that did occur in 2006.

Table 1.1 Key Indicators of Over-scheduling Before and After Modification of Day Ahead Scheduling Requirement

	Before	After	Reduction
Average Day Ahead Over-scheduling			
Off-Peak Hours	406 MW (1.8%)	188 MW (8%)	218 MW (1.0%)
Peak Hours	174 MW (.6%)	140 MW (5%)	34 MW (1%)
Average Net Real Time Dispatch (MW/hour)			
Off-Peak Hours	-409 MW	-22 MW	-387 MW
Peak Hours	-462 MW	-345 MW	-117 MW
Percent of Hours with Net Decremental Energy Dispatch in Real Time Market			
Off-Peak Hours	82%	58%	-24%
Peak Hours	78%	75%	-3%

Note: Analysis based on comparison of data for six weeks prior to the April 26, 2007 effective date of changes in day-ahead scheduling requirements with data for seven weeks after the effective date of changes.

Modifications in day-ahead scheduling requirements taking effect in late April 2007 also did not appear to have any detrimental effects on scheduling during high load days during the summer months. For example, as shown in Figure 1.1:

- Day-ahead schedules tended to slightly exceed actual loads during the off-peak hours during typical high load summer days in 2007 (i.e., when loads ranged from 40,000 to 45,000 MW). During peaks hours, day-ahead schedules tended to be slightly lower than actual loads. Specifically, during Hour Ending 16 of these high load summer days, day-ahead schedules averaged about 98 percent of actual loads in 2007.

- Meanwhile, hour-ahead schedules were even closer to actual load during both peak and off-peak hours. During Hour Ending 16 of these high load summer days, hour-ahead schedules averaged about 99.7 percent of actual loads in 2007.

Figure 1.2 shows a similar comparison of day-ahead and hour-ahead schedules to actual loads during days in 2006 with comparably high loads of 40,000 to 45,000 MW. As shown in Figure 1.2:

- During high load days in 2006, day-ahead schedules tended to exceed actual loads during the off-peak hours slightly more than in 2007, while day-ahead schedules tended to fall short of actual loads by a slightly higher level.

- For example, during Hour Ending 16 of high load summer days in 2006, day-ahead and hour-ahead schedules averaged about 97 and 99 percent of actual loads, respectively, compared to about 98 and 100 percent, respectively, during similar days in 2007.

These trends are further illustrated in Figure 1.3, which show the difference in day-ahead schedules and actual loads during similar high load days in 2006 and 2007. Negative values in Figure 1.3 indicate hours when hour-ahead schedules were less than actual loads on average, while positive numbers indicate hours when hour-ahead schedules tended to be greater than actual loads. As shown in Figure 1.3, during most hours, final hour-ahead schedules tended to track actual load somewhat more closely during high load days in 2007 than in 2006. This provides further indications that the modification made in day-ahead scheduling requirements for off-peak hours did not have any detrimental effects on overall scheduling trends.

Figure 1.1 Day Ahead and Hour Ahead Schedules Compared to Actual Load for Days with Peak Loads of 40 to 45 GW in 2007

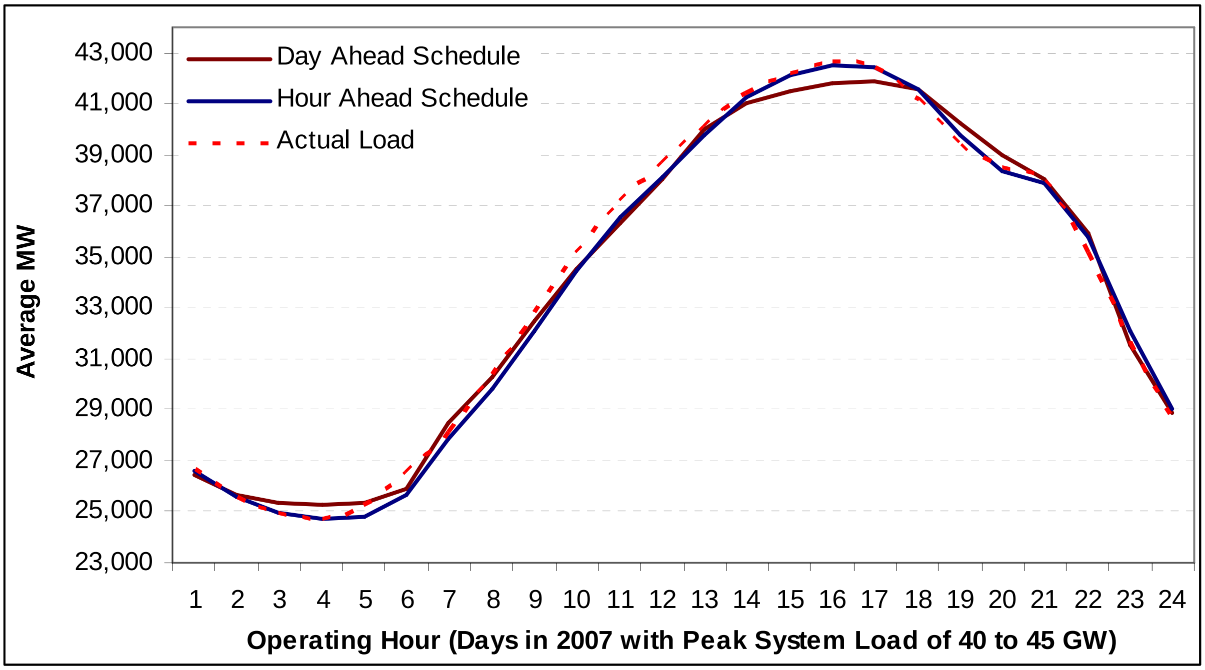


Figure 1.2 Day Ahead and Hour Ahead Schedules Compared to Actual Load for Days with Peak Loads of 40 to 45 GW in 2006

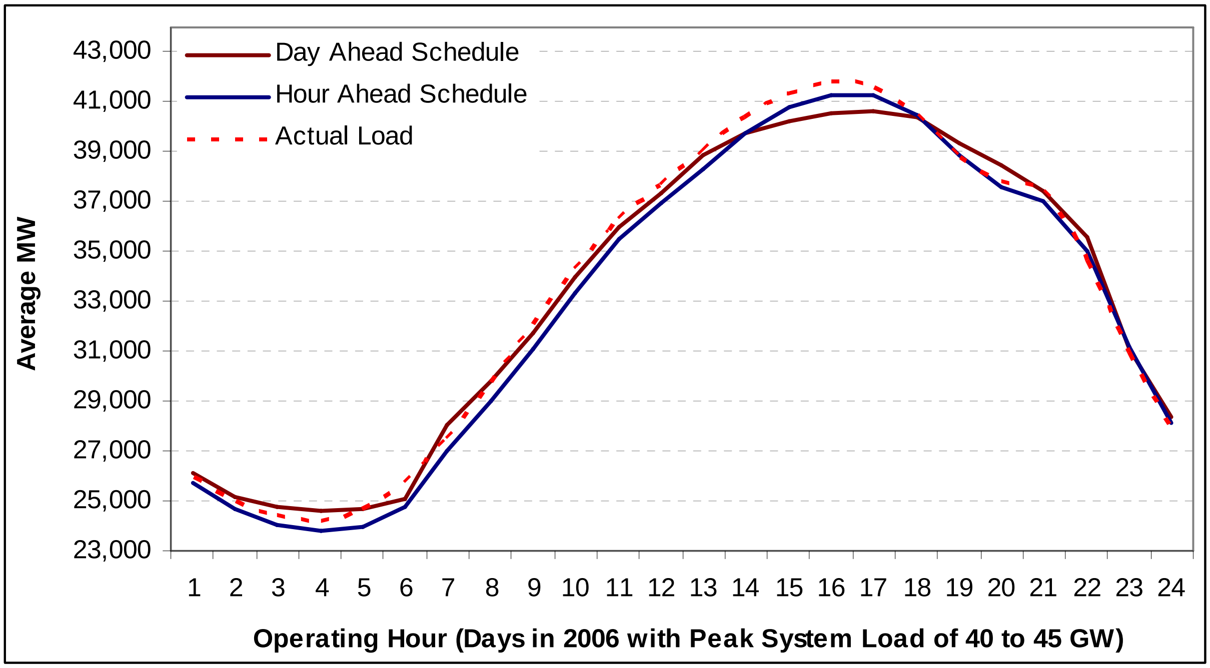
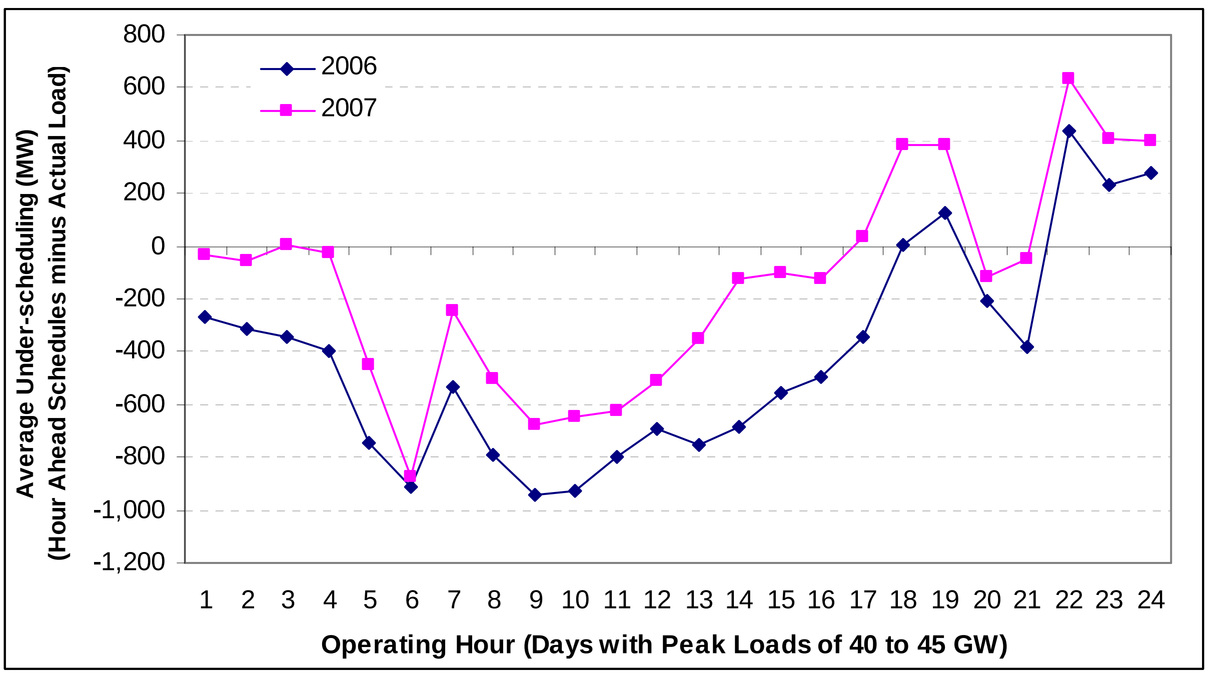


Figure 1.3 Average Difference Between Hour Ahead Schedules and Actual Loads during High Load Days in 2006 and 2007



1.2.2 Local Resource Adequacy Requirements

In 2006, the Resource Adequacy (RA) program developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserve margins.[9] In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. In 2006, the RA program was limited to imposing system-wide capacity requirements. In 2007, the program was expanded to include Local Resource Adequacy Requirements (LRAR) for LSEs subject to CPUC jurisdiction.[10] Under this component of the state's RA program, LSEs are required to seek to procure minimum level of RA capacity within various Local Capacity Areas (LCAs), or transmission constrained "load pockets" within the CAISO system. Minimum capacity requirements for LCAs are established through technical studies performed by the CAISO based on NERC Planning Standards and any other local reliability criteria established by the CAISO or Participating Transmission Owners (PTOs).[11] LCAs are defined based on the same areas that have been used in Local Area Reliability Services (LARS) studies conducted in previous years to determine requirements for capacity under Reliability Must Run (RMR) contracts.

One of the goals of the CAISO management and the CPUC is to rely on capacity contracted by LSEs to meet local RA requirements, and thereby reduce reliance on RMR contracts or any other "backstop" procurement that may be done by the CAISO. For example, as noted in last year's Annual Report on Market Issues and Performance, the CAISO's Reliability Capacity Services Tariff (RCST) provisions, which were established pursuant to a settlement filed in 2006, authorizes the CAISO to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

In 2007, substantial progress in the goal of reducing reliance on RMR contracts was achieved, as the total volume of capacity under RMR contracts was reduced from approximately 9,300 MW to only 3,300 as seen in Table 1.2. In addition, all local reliability requirements were met by units under RA and RMR contracts. Consequently, the CAISO did not need to designate any capacity under RCST provisions as a "backstop" to RA resources procured by LSEs.

Table 1.2 and Figure 1.4 provide a more detailed comparison of capacity under RMR and RA contracts in 2006 and 2007, along with the minimum capacity requirement for each of the major three LCAs in the CAISO system. Since the minimum capacity requirement for each LCA is based on peak summer conditions, RMR and RA capacity in Table 1.2 and Figure 1.4 are based on each unit's Net Qualified Capacity (NQC) for the month of July, which represents the amount of a unit's capacity that may be used to meet local RA requirements for this peak summer month.[12] The NQC for each unit is determined through accounting rules used in the RA program, which are designed to reflect the amount of each unit's nameplate capacity that will actually be available during peak hours each month, after accounting for factors such as the

[9] Background information on other components of the Resource Adequacy program, which became effective in 2006, are provided in DMM's *2006 Annual Report on Market Issues and Performance,* pp.6-7 and 1.2-1.5.

[10] Opinion on Local Resource Adequacy Requirements, Before the Public Utilities Commission of the State of California, Decision 06-06-64, June 29, 2006.

[11] A description of the CAISO's methodology for establishing minimum capacity requirement for each LCA is provided in the Manual for the *2009 Local Capacity Area Technical Study*, December 2007.

[12] In addition, some units that are under RA contracts were still designated as RMR in 2007, based on a determination that RA contract provisions did not satisfy all of the reliability services that are provided and needed under an RMR contract, such as black-start and dual fuel capability. In Table 1.2 and Figure 1.4, units under both RMR and RA contracts are counted as RMR capacity, but are not also counted under the RA category.

intermittent nature of renewable energy resources or other environmental factors affecting unit availability.

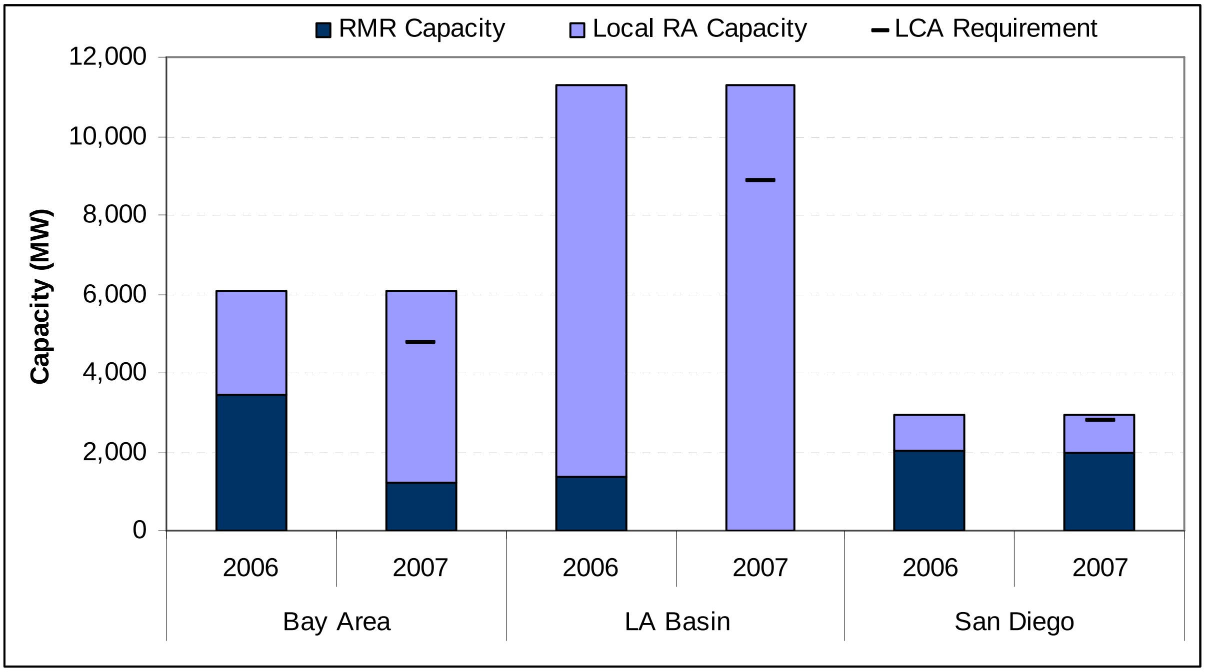
As shown in Table 1.2 and Figure 1.4, reliance on RMR contracts in the LA Basin was eliminated in 2007, and was significantly reduced in the San Francisco Bay Area. In addition, since the minimum reliability requirement for each LCA was met through a combination of RA and RMR capacity, the CAISO did not need to designate any additional capacity through the RCST provisions of the CAISO. As discussed in Chapter 6, the reduction in capacity under RMR contracts and lack of RCST designations as a "backstop" to the RA process were a major factor underlying the reduction in overall reliability related costs incurred by the CAISO.

Table 1.2 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements

Local Capacity Area (LCR	Year	RMR Capacity (MW)*	RA Capacity (MW)**	Total Capacity (MW)	LCA Requirement (MW)
LA Basin	2006	1,390	9,889	11,279	
	2007	0	11,279	11,279	8,843
Bay Area	2006	3,434	2,651	6,085	
	2007	1,218	4,867	6,085	4,771
San Diego	2006	2,010	912	2,922	
	2007	1,963	959	2,922	2,781
Other LCRs	2006	2,451	21,516	26,916	
	2007	130	23,436	26,916	
Totals	2006	9,259	37,943	47,202	
	2007	3,311	43,891	47,202	

* RMR capacity based on each unit's NQC rating for month of July under the RA program.
** Excludes units under both RMR and RA contracts.

Figure 1.4 Comparison of RMR and Local Resource Adequacy Capacity with Local Capacity Area (LCA) Requirements



1.3 Generation Additions and Retirements

Trends in the net-generation capacity being added to the CAISO Control Area each year provides important insight into the effectiveness of the California market and regulatory structure in bringing about new generation investment and facilitating the retirement of older inefficient plants. The Department of Market Monitoring tracks changes in the portfolio of installed capacity in the CAISO Control Area and conducts revenue analysis for new generation investment to determine the extent to which the California market is providing sufficient incentives for new generation investment.[13]

1.3.1 Generation Additions and Retirements in 2007

Approximately 598 MW of new generation began commercial operation within the CAISO Control Area in 2007. The majority of new capacity was added in the South. Table 1.3 shows the new generation projects that began commercial operation in 2007.

[13] Generator revenue analysis is provided in Chapter 2.

Table 1.3 New Generation Facilities in 2007

Generating Unit	Net Dependable Capacity (MW)	Commercial Operation Date	Zone ID
Midsun	22.0	01-Feb-07	NP 26
Santa Clara Wind Project	24.1	03-May-07	NP 26
Lake Mendocino Hydro	3.5	02-Jul-07	NP 26
Marina LFG2 Power Plant	2.6	01-Sep-07	NP 26
Bottle Rock Power Plant	55.0	01-Oct-07	NP 26
Palo Alto	5.2	15-Oct-07	NP 26
NP26 New Generation in 2007	***112.4***		
Long Beach Unit 1, 2, 3, 4	280.0	01-Aug-07	SP26
Center Peaker	49.0	20-Sep-07	SP26
Barre Peaker	49.0	20-Sep-07	SP26
Grapeland Peaker	49.0	20-Sep-07	SP26
Mira Loma Peaker	49.0	20-Sep-07	SP26
Puente Hills GTE Facility Phase II	9.3	07-Dec-07	SP26
SP26 New Generation in 2007	***485.3***		
Total New Generation in 2007	**597.7**		

Source: California ISO Grid Planning Department

No generation capacity was retired from service in 2007. Therefore, the net capacity increase in the CAISO Control Area was 598 MW. Table 1.4 summarizes the net change in installed generation by region.

Table 1.4 Generation Capacity Change in 2007 by Region

Region	Generation Additions (MW)	Generation Reductions (MW)	Net Change in Generation (MW)
NP26	112	0	112
SP26	485	0	485
CAISO Control Area	**598**	**0**	**598**

1.3.2 Anticipated New and Retired Generation in 2008

The CAISO projects construction of 1,810 MW of new generation in 2008, of which roughly 941 MW are expected to be commercially available prior to the anticipated summer peak season. Most significantly, there are two 405 MW resources, the Inland Empire units shown in Table 1.5 below, that are expected to be operational in May 2008.

Table 1.5 Planned Generation Facilities in 2008

Generating Unit	Resource Owner / QF ID	Resource Capacity (MW)	Expected Operational Date	Zone ID
Chowchilla Biomass	Global Common LLC	12.5	31-Jan-08	NP26
Keller Canyon Landfill Generating Facility	Ameresco Keller Canyon LLC	3.8	06-Aug-08	NP26
Gateway Generating Station	PG&E	530	01-Sep-08	NP26
Shiloh Wind Farm II	enXco	150	01-Sep-08	NP26
Ox Mountain Landfill Gas Generation	Ameresco Renewables	11.4	04-Sep-08	NP26
Eastshore Energy Facility Project	Tierra Energy	118	01-Nov-08	NP26
NP26 Planned New Generation in 2008		***826***		
Dillon Wind Project	PPM Energy	45.0	15-Feb-08	SP26
Wintec III	Wintec Energy, LTD	11.57	28-Feb-08	SP26
El Nido	Global Common LLC	12.5	29-Feb-08	SP26
Inland Empire Energy Center Unit 1	Inland Empire Energy Center, LLC	405	15-Mar-08	SP26
Inland Empire Energy Center Unit 2	Inland Empire Energy Center, LLC	405	01-May-08	SP26
Wellhead Power Margarita	Wellhead Electric Company	49.0	01-May-08	SP26
Garnet Wind Project	Garnet Energy Corporation	6.5	01-Jun-08	SP26
Olivenhain-Hodges Pumped Storage Unit 1	San Diego County Water Authority	20	01-Sep-08	SP26
Olivenhain-Hodges Pumped Storage Unit 2	San Diego County Water Authority	20	01-Sep-08	SP26
Chiquita Canyon Landfill	Ameresco Renewables	9.2	15-Nov-08	SP26
SP26 Planned New Generation in 2008		***984***		
Total Planned New Generation in 2008		**1,809**		

Currently there are no planned generation retirements in 2008; however, unlike the lengthy process for constructing a new resource and bringing it online, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table 1.6 below shows an annual accounting of generation additions and retirements since 2001, with projected 2008 changes included along with totals across the seven year period (2001-2008).

Table 1.6 Changes in Generation Capacity Since 2001

	2001	2002	2003	2004	2005	2006	2007	Projected 2008	Total Through 2008
SP15									
New Generation	639	478	2,247	745	2,376	434	485	826	8,230
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	4,212
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**262**	**(262)**
NP26									
New Generation	1,328	2,400	2,583	3	919	199	112	984	8,528
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	3,342
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**536**	**3,951**
ISO System									
New Generation	1,967	2,878	4,830	748	3,295	633	598	1,810	16,758
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(5,515)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	7,554
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**798**	**3,689**

* Forecasted load growth is based on an assumed 2 percent peak load growth rate applied each year.

As shown in Table 1.6, there was a 598 MW net increase in installed generation in the CAISO Control Area in 2007 with no unit retirements. Although this positive turn in net change in installed capacity was significant at nearly 600 MW, adjusted for projected load growth of 991 MW the net ability of installed generation to meet load was decreased somewhat as indicated by the last row in Table 1.6. The total net increase in installed generation in the CAISO Control Area over the eight years spanning 2001-2008 is roughly 11,250. When adjusted for annual load growth, the net increase in installed generation drops from 11,250 MW to just under 3,700 MW over this eight year period.

1.4 Transmission System Enhancements

Though there were no major transmission projects completed in 2007, various upgrades throughout the system did result in approximately 1,175 MW of new transmission capacity. A few major transmission projects were approved by the CAISO in 2007 and are currently awaiting environmental permits and other regulatory approvals, which are discussed below.

- Palo Verde Devers #2 Project, sponsored by Southern California Edison, was approved by the CAISO board in February, 2005. The project consists of a second Palo Verde to Devers 500 kV line running between the Palo Verde Hub (Hassayampa Substation) in Arizona and the Devers Substation in California. On May 31, 2007, the Arizona Corporation Commission (ACC), which has state regulatory jurisdiction over the portion of the line to be built in Arizona, denied approval of the project. SCE appealed that decision and is pursuing all options to obtain approval of the project in Arizona, including potential federal remedies under Section 216 of the Energy Policy Act of 2005. If ACC or other regulatory approvals can be obtained by July 2008, construction may start as early as November 2008. Construction of the Devers-Valley No. 2 segment of the project within California may be completed by June 2010 to support the interconnection of new generation projects.

- The Tehachapi Transmission Project was approved by the CAISO board on January 24, 2007 and is sponsored by Southern California Edison. The project will interconnect 4,350 MW of generating resources in the Tehachapi area, which will address reliability needs in the Antelope Valley and South of Lugo areas and set up a foundation to integrate renewable generation in the future. There are eleven proposed segments to the overall Tehachapi Transmission Project. Segments 1 through 3 have received approval from the CPUC by means of a Certificate of Public Convenience and Necessity (CPCN). Southern California Edison has submitted an application for a CPCN for segments 4 through 11, which remain pending before the CPUC.

- The Sunrise Powerlink Project, sponsored by San Diego Gas & Electric, was approved by the CAISO board in July 2006. The project consists of a new 91 mile 500kV line between the existing Imperial Valley Substation to a proposed new SDG&E owned substation, “Central”, and a new 59 mile 230 kV line between the new Central Substation and SDG&E’s existing Penasquitos Substation. The project will increase reliability in the San Diego area and provide access to renewable resources in the Imperial Valley and Salton Sea areas. SDG&E filed for a Certificate of Public Convenience and Necessity (CPCN) for Sunrise with the CPUC in August 2006 and the case is still pending. The Draft Environmental Impact Report (DEIR/EIS) was issued jointly by the CPUC and the

Bureau of Land Management in January 2008 and a final decision is expected in August 2008. The CAISO has been actively involved in the regulatory approval process.

In addition to these planned transmission projects, a total of 1,175 MW of new capacity was added to the transmission system through several upgrades. The various upgrades associated with individual lines or equipment and the additional capacity generated by each are listed below in Table 1.7.

Table 1.7 2007 Transmission Projects*

Transmisison Project	Net Capacity Increase	In-Service Date
New Miguel 230kV Capacitors	150 MW	Jun-07
Henrietta - Gregg 230kV Line Reconductoring	50 MW	Feb-07
Davis - UC Davis 60kV Line conversion to 115kV	79 MW	Mar-07
Replace the existing Ignacio 115/60kV Transformer	140 MW	May-07
Mountain Quarries 60kV Tap Reconductoring	34 MW	May-07
Newark - Dumbarton 115kV Line Reconductoring		Dec-06
Vasona - Metcalf 203kV Line Reconductor		Oct-07
Hicks - Metcalf 230kV Line Reconductor	207 MW	Oct-07
Ravenswood Reactive Support		Jun-07
Metcalf - Monta Vista 230kV Nos. 1 and 2 Reconductoring		Oct-07
Bair - Belmont 115kV Reconductoring		Jun-07
Install Second Henrietta 230/70kV Transformer	7 MW	Jun-07
New Plumas Sierra - Sierra Pacific 60kV Interconnection	15 MW	Feb-07
Valley 500 kV Shunt Capacitors	50 MW	May-07
Replace Mesa 230/115kV Transformers	285 MW	Apr-07
Network Upgrades for the Interconnection of Fresno Cogen Expansion	22 MW	Mar-07
Install 200 MVAR 230kV SVC at Rector	50 MW	Jun-07
Replace Schindler 115/70 kV No. 1	9 MW	Apr-07
Replace Herndon 230/115 kV No. 2	17 MW	Feb-07
Replace Contra Costa 230/115 kV No. 3	60 MW	May-07
Total	**1,175 MW**	

* Certain projects completed in 2007 that are listed in the table above have no MW value in the "Net Capacity Increase" column. These projects are included in this table despite having no net capacity increase because they were performed to provide other reliability benefits.

1.5 Administration of the Enforcement Protocol

DMM's responsibilities include administering the Enforcement Protocol of the CAISO Tariff. The Enforcement Protocol is designed to provide clear Rules of Conduct specifying the behavior expected of market participants, and establish in advance the sanctions and other potential consequences for violations of the specified Rules of Conduct. The CAISO has the authority to enforce penalties only for objectively identifiable violations of the CAISO Tariff for which specific penalties are established in the Enforcement Protocol. FERC rules require that all other potential violations of the CAISO Tariff or FERC market rules be referred to FERC's Office of Enforcement for potential investigation and sanction.

Last year's Annual Report on Market Issues and Performance described two tariff requirements with specific penalties in the Enforcement Protocol for non-compliance for which DMM was initiating enforcement programs: (1) submission of daily load forecasts as part of the 95 percent load scheduling requirement, and (2) the requirement to submit generation outage reports. In 2007, following DMM's enforcement of the requirement to submit daily load forecasts, compliance with this requirement has been virtually 100 percent. As described in more detail below, compliance with the generation outage reporting requirements has vastly improved since DMM began to enforce these requirements in July 2007.

Finally, in the spring of 2007, the CAISO experienced increased non-delivery, or “declines,” of pre-dispatched bids of supplemental energy at the inter-ties. As described in more detail below, the CAISO is proposing a settlement charge to deter this behavior.

1.5.1 Outage Reporting

Beginning in July 2007, DMM began to enforce penalties for two key generation outage reporting requirements incorporated in the CAISO Tariff:

- **Forced Outage Reporting within 30 Minutes**. Forced outages of generating units must initially be reported within 30 minutes from the time outages are discovered. Sanctions for non-compliance with this requirement start with a warning letter, and then escalate up to $5,000 per outage with each additional violation for each unit within each 12 month period.

- **Forced Outage Explanations within Two Days.** Generators must also provide a follow-up explanation of forced outages within two working days. The penalty for not providing a follow-up explanation of a forced outage within two working days is $500 per day the explanation is late.

These requirements and associated penalties were included in the CAISO Tariff because timely and accurate information on unit availability was deemed to be critical for reliable operation of the grid. Implementation of penalties for non-compliance with these requirements on July 1, 2007 coincided with marked improvement in market participants’ compliance with the forced outage reporting requirements. The significant improvement in compliance likely contributed to reliable grid operations during the critical peak summer months as it gave operators more accurate and timely information on the status of the generation fleet. It also shows that penalties, when structured and implemented correctly, can provide an effective incentive for market participants to comply with tariff requirements.

DMM’s initiation of enforcement of these penalties followed a stakeholder process conducted in the second half of 2006 to modify the reporting requirements and the reporting tools. The CAISO requested and FERC approved a suspension of the penalties until July 1, 2007 to allow the CAISO time to make needed improvements to the reporting tools and to allow market participants time to become familiar with the new tools and the revised reporting requirements.

Compliance with the forced outage reporting requirements has improved significantly since the outage reporting penalties went into effect.[14]

- **Forced Outage Reporting within 30 Minutes.** As shown in Figure 1.5, in the months prior to July 2007, an average of about 8 to 12 percent of forced outages were not reported within the 30 minute requirement. Since then, an average of less than 2 percent

[14] Because DMM did not investigate all individual instances of apparent non-compliance with the reporting requirements prior to the time penalties went into effect, the data for months prior to July 2007 may slightly overstate non-compliance rates.

of forced outages have been reported late each month. This translates to about 20 to 70 late reports of forced outages per month prior to penalties going into effect, compared with 6 to 12 late reports per month since the penalties went into effect.

- **Forced Outage Explanations within Two Days.** As shown in Figure 1.6, during the months prior to July 2007, market participants submitted forced outage explanations late (or did not submit the explanations at all) for about 30 to 40 percent of forced outages. After penalties went into effect, non-compliance with this two-day requirement dropped to under 3 percent in the months from August 2007 onward. Also, while forced outage explanations were sometimes never provided prior to July, market participants have submitted explanations for all forced outages since penalties went into effect on July 1.

Figure 1.5 Non-Compliance with 30-minute Outage Reporting Requirement, July 2006 through December 2007

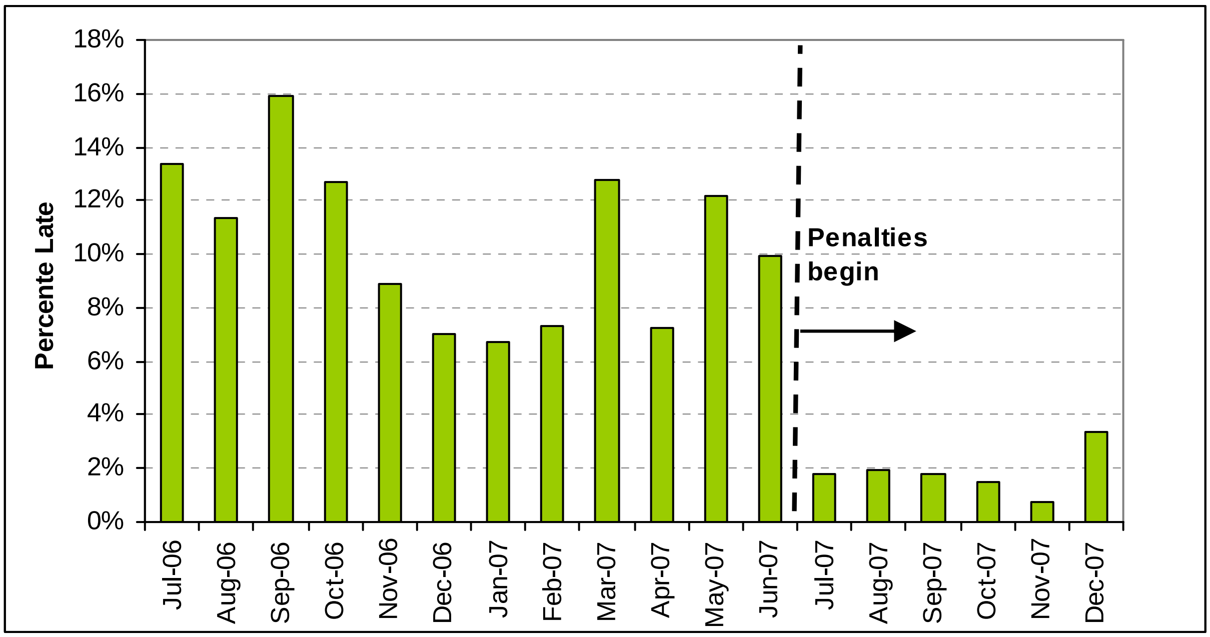
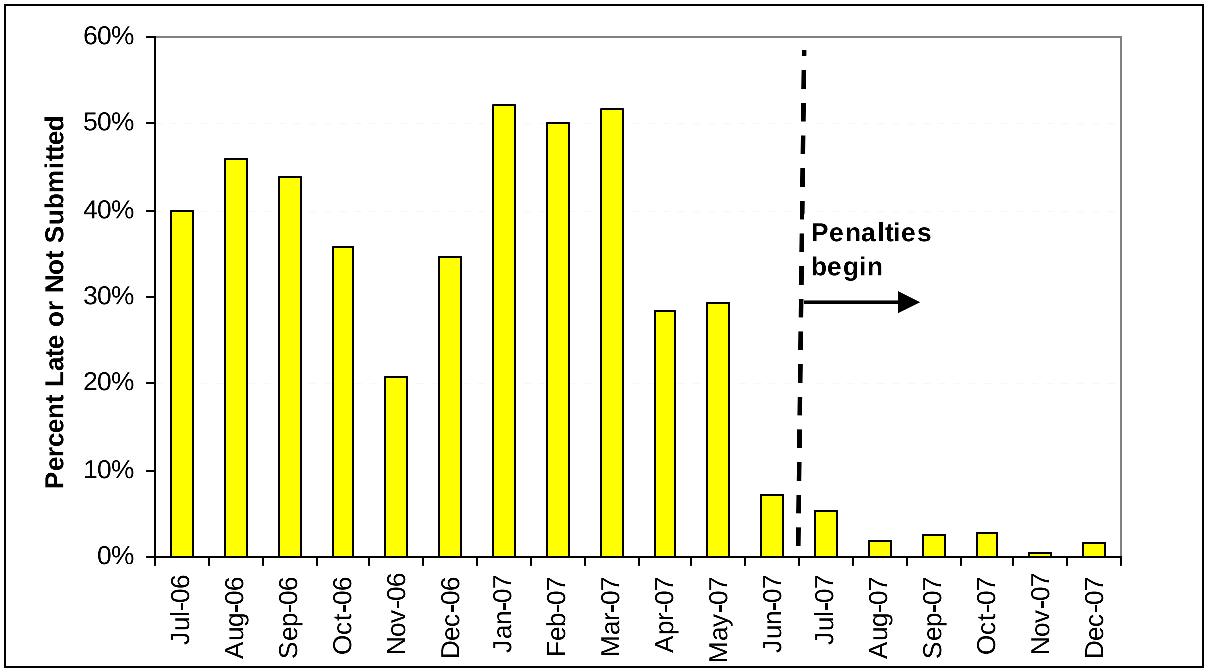


Figure 1.6 Non-Compliance with Two-day Outage Explanation Requirement, July 2006 through December 2007



2 Summary of Energy Market Performance

2.1 Demand Conditions

2.1.1 Actual Loads

System peak loads in 2007 averaged similar to those in 2006, with two statewide heat waves, each lasting less than a week. Overall, average loads adjusted for changes in the day of the week were 0.8 percent higher in 2007 than in 2006. In comparison, 2006 saw an extraordinary heat wave that lasted three weeks in July, and reached a peak well above that seen in 2007.

The heat wave producing the highest peak load in 2007 occurred over the Labor Day holiday weekend. The 2007 peak load was 48,615 megawatts (MW), and occurred on the afternoon of Friday, August 31. This was between the 1-in-2 and 1-in-10 peak estimates of 47,847 MW and 50,609 MW, respectively.[15] All of the 20 hours in which loads were in excess of 45,000 MW in 2007 occurred between August 28 and 31. The only other heat wave of note occurred during the week of the Independence Day holiday during which inland areas were actually hotter than during the Labor Day heat wave, but high-population coastal areas were cooler.

Table 2.1 CAISO Annual Load Statistics for 2003-2007[16]

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2003 Actual	26,345		230,857	42,581	
2004 Actual	27,309	3.5%	239,312	45,597	7.1%
2005 Actual	26,990	-1.2%	236,483	45,562	-0.1%
2006 Actual	27,427	1.6%	240,344	50,270	10.3%
2007 Actual	27,646	0.8%	242,265	48,615	-3.3%
2003 Adjusted	25,471		223,206	41,063	
2004 Adjusted	26,436	3.7%	231,660	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,994	44,260	0.1%
2006 Adjusted	27,427	3.5%	240,344	50,198	11.8%
2007 Adjusted	27,646	0.8%	242,265	48,615	-3.3%

[15] California ISO, *2007 Summer Loads and Resources Operations Assessment,* page 15, available at http://www.caiso.com/1b95/1b95abb649df4.pdf as of January 26, 2008. The 1-in-2 peak estimate is the estimate of peak load with a 1 in 2 probability that the peak will actually be higher than the estimate. The 1-in-10 peak estimate is the estimate of peak load with a 1 in 10 probability that the peak will actually be higher than the estimate.

[16] This and all remaining tables, charts, and figures on load statistics reported in this section are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 leap year. For this reason, figures reported in this report will differ slightly from prior published figures.

Table 2.2 Rates of Change in Load: Same Months in 2007 vs. 2006

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-07	3.9%	3.5%	5.7%	7.0%
February-07	0.7%	1.2%	-0.8%	4.5%
March-07	2.2%	1.1%	0.3%	3.4%
April-07	6.2%	6.4%	4.9%	9.1%
May-07	2.7%	1.8%	5.0%	7.6%
June-07	-5.3%	-7.3%	-2.1%	-6.6%
July-07	-7.2%	-8.2%	-5.0%	-11.0%
August-07	6.6%	7.9%	4.1%	11.4%
September-07	1.4%	0.8%	1.3%	0.2%
October-07	0.7%	0.4%	2.7%	3.4%
November-07	-0.4%	-0.9%	-0.3%	-2.1%
December-07	0.6%	0.5%	0.6%	-0.4%

The relatively sharp changes in monthly peak loads reflect the fact that peaks occurred in different months in 2007 than in 2006. All four indicators for August were sharply higher in 2007 than in 2006, as August 2006 was a relatively mild month. While the April peak was 9.1 percent higher in 2007 than in 2006, it was not unseasonably warm, with a peak load of 33,238 MW.

Figure 2.1 California ISO System-wide Actual Loads: August 2007 vs. August 2006

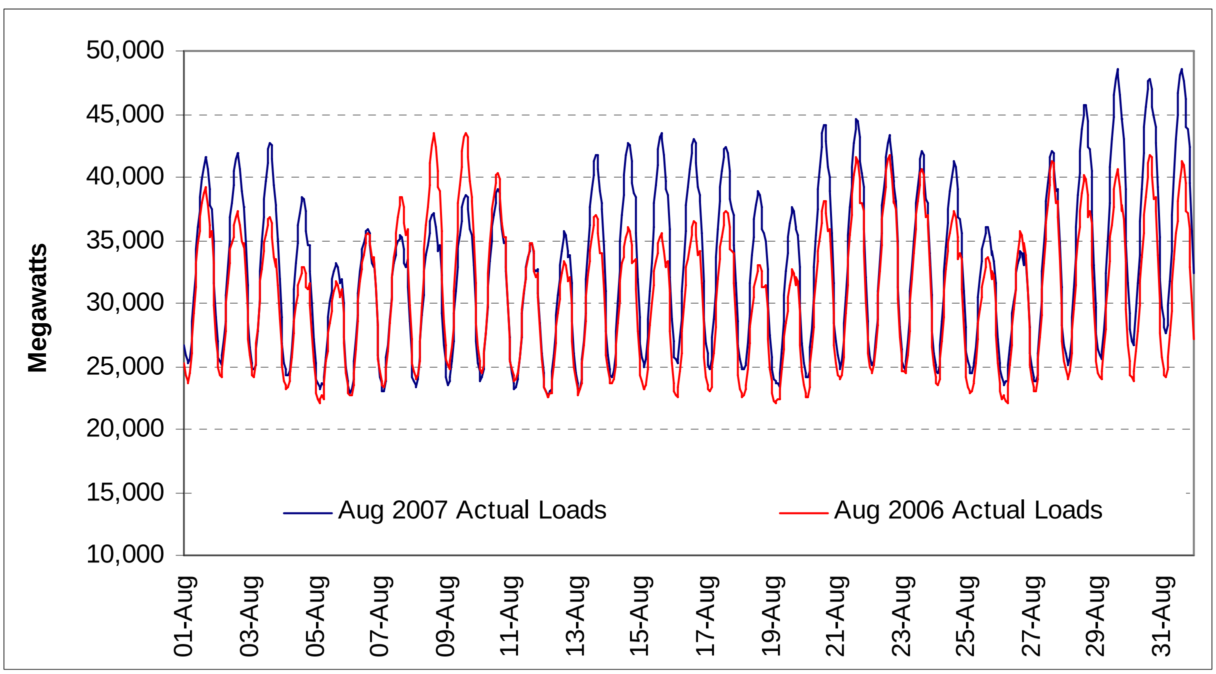


Figure 2.1 shows hourly system load for August 2007, the month in which the annual peak load occurred, compared to August 2006. August loads were higher for most days in 2007 compared with 2006, with daily peak loads well in excess of 2006 levels in all but six days. As noted

above, the temperatures in August 2006 were mild, leading to lower than average load levels throughout the month. While August 2007 load levels appear to be exceptional when compared to 2006 levels, August 2007 levels were actually within the historical normal range.

Figure 2.2 depicts load duration curves for each of the last four years, and shows the significant increase in load seen over the last two years. In 2007 there were 228 hours (2.6 percent of all hours) where load was above 40,000 MW, down from the 281 hours (3.2 percent) seen in 2006 where a prolonged heat wave contributed significantly to more hours of high loads. In comparison, there were only 144 hours (1.6 percent) in 2004 with loads above 40,000 MW.

Figure 2.2 CAISO System-wide Actual Load Duration Curves: 2004-2007

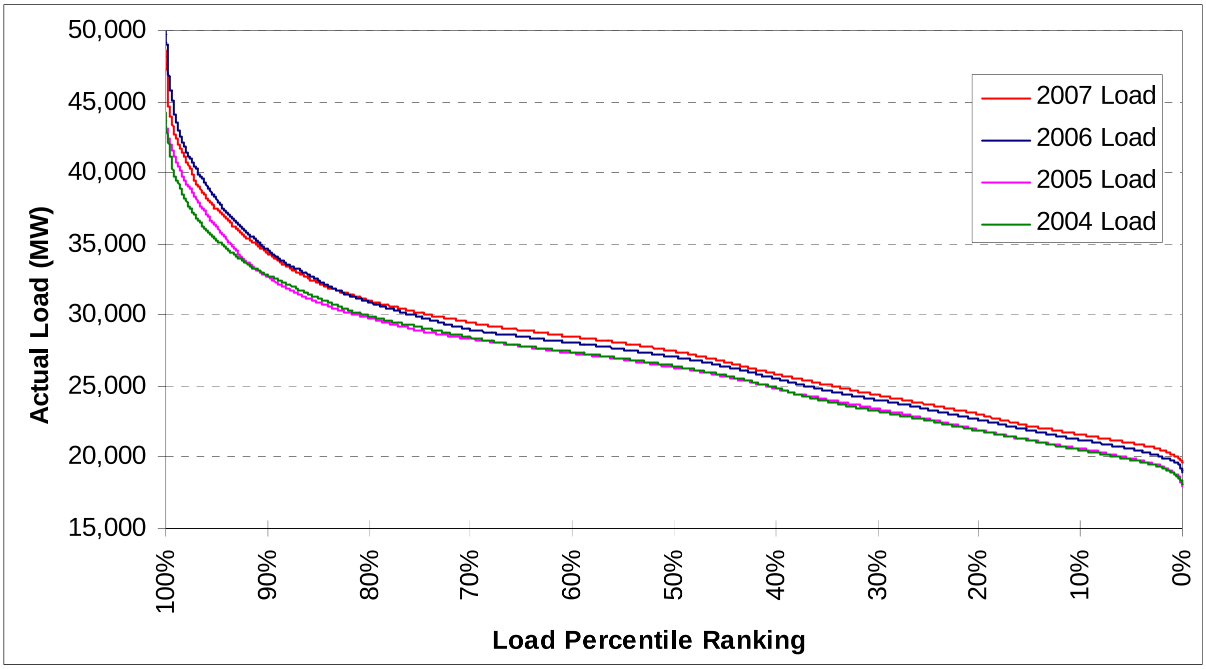


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO Control Area as a whole. NP26 and SP15 average loads were only moderately higher than 2006 levels at 1.1 and 0.6 percent, respectively. The California Energy Commission (CEC) has estimated that NP26 load grew 1.3 percent when normalized for weather.[17] In comparison, the difference between average zonal loads in 2005 and 2006 was greater, with 2006 average hourly loads being 3.6 percent higher than 2005 in both zones. Of course, the large increase in 2006 was predominately driven by weather as opposed to underlying load growth.

[17] Marshall, L., *Demand Forecast and Preliminary Summer 2007 Temperature Load Assessment,* California Energy Commission, January 16, 2008, downloaded February 11, 2008 from http://www.energy.ca.gov/2008_summer_outlook/documents/2008-01-16_workshop/presentations/Marshall_Lynn_Demand_forecast_and_Preliminary_Summer_2007_Temperature-Load_Assessment.PDF. As of this writing the CEC had not estimated growth in SP15 load.

Table 2.3 CAISO Annual Load Change: 2007 vs. 2006

Zone	Avg. Hourly Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP26	1.1%	0.7%	0.8%	-6.3%
SP15	0.6%	0.0%	1.6%	2.1%
CAISO Control Area	0.8%	0.3%	1.3%	-3.3%

2.1.2 Role of Demand Response

Various demand response programs operating in California play an important role in meeting peak summer energy demands. This section provides a brief overview of the various demand response programs available for meeting peak summer demand and the extent to which those programs were utilized in 2007.

The vast majority of demand programs available for managing peak summer demands are managed by California's three investor owned utilities (SCE, PG&E, SDG&E). However, the CAISO markets also provide an opportunity for certain demand resources (Participating Loads) to directly participate in the Ancillary Service (Non-Spinning Reserve) and Real Time Markets. Currently, Participating Loads are comprised of pumped-hydroelectric facilities and water pumping facilities that in aggregate amount to approximately 4,380 MW of demand response capability. However, because pumped-hydroelectric facilities typically pump water (i.e., consume energy) only during off-peak hours, their contribution to peak demand management is limited.

The utility-managed demand programs can be grouped into two general categories "reliability-based" and "price-based". Reliability-based programs consist primarily of large retail customers under interruptible tariffs and air conditioning cycling programs. These programs are primarily triggered by the CAISO declaring a system emergency. Price responsive programs include Critical Peak Pricing retail tariffs in which program participants are charged significantly higher rates for peak hours of declared critical peak days. They also include various price-based programs where customers are paid to reduce consumption when certain market conditions are triggered. Table 2.4 provides a summary of the total megawatts enrolled in each of these categories by utility for July and August 2007, along with an estimate of the "Expected MW", which is based on historical performance.

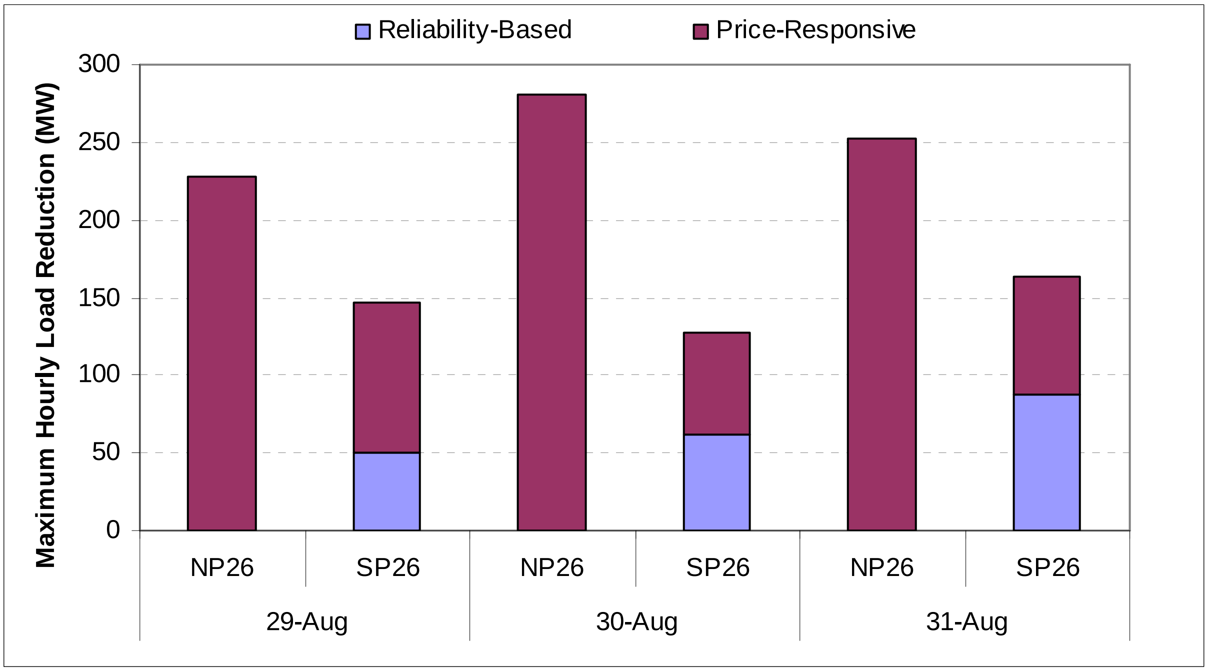
Table 2.4 Summary of Utility Operated Demand Programs[18]

Utility	Program	July		August	
		Enrolled MW	Expected MW	Enrolled MW	Expected MW
SCE	Price-Responsive	240	34	256	40
PG&E	Price-Responsive	608	313	623	318
SDG&E	Price-Responsive	117	69	121	72
	Price-Responsive Total	964	416	999	430
SCE	Reliability-Based	1,283	1,228	1,305	1,250
PG&E	Reliability-Based	322	306	323	308
SDG&E	Reliability-Based	93	64	98	68
	Reliability-Based Total	1,698	1,598	1,726	1,626
	Combined Total	2,662	2,013	2,725	2,056

In terms of actual utilization of these programs during critical peak summer days, Figure 2.3 provides a summary of actual response from these programs during the heat wave of August 29-31. It should be noted that the CAISO did not issue a Stage 2 alert during this period so many of the reliability-based programs were not triggered. As evident in Figure 2.3, essentially all of the demand response in Northern California during this period came from price-responsive programs with an hourly maximum value for each day of approximately 230-280 MW of demand reduction. The majority of demand response in Northern California (200 MW) came from a demand response contract between PG&E and the California Department of Water Resources. Conversely, demand response in the South was made up of a more even mix of reliability-based and price-responsive programs that in total provided an hourly maximum for each day of approximately 130-160 MW of demand reduction.

[18] Data reported in Table 2.4 are based primarily on utility monthly reports to the CPUC on the operation of interruptible and demand response programs. However, the expected MW values shown for PG&E and SDG&E are based on estimates provided to DMM from CPUC staff.

Figure 2.3 Summary of IOU Programs - Actual Demand Reductions (Aug 29-31)[19]



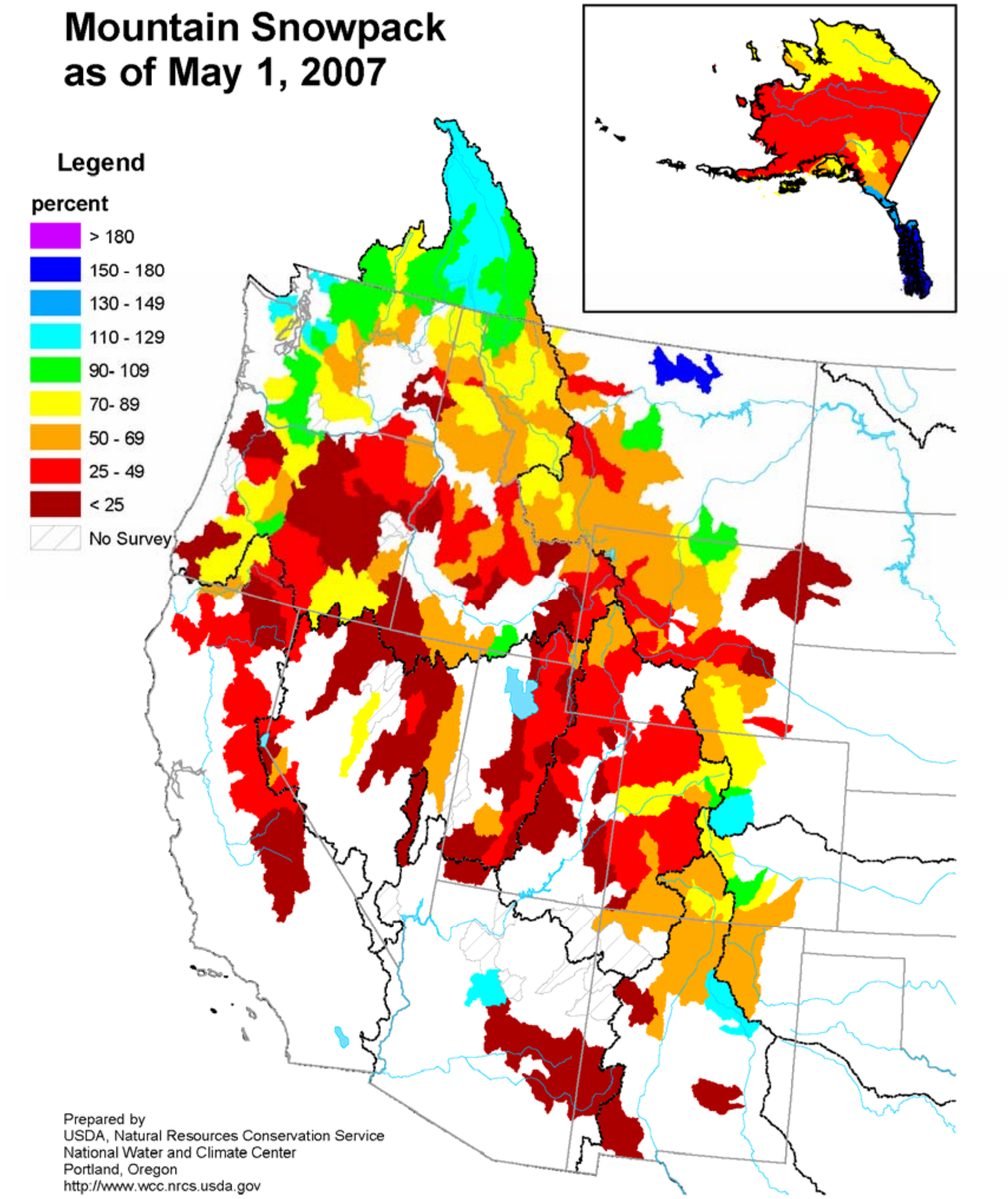
2.2 Supply Conditions

2.2.1 Hydroelectric

The 2006-07 winter hydro season was the driest in five years across the West, with the exception of parts of British Columbia. California snowpack was particularly low, at less than 50 percent of historic average across the Sierra Nevada, and less than 25 percent of average in much of the Southern Sierra. The effect of the drought was mitigated somewhat by the fact that the previous year was one of the wettest on record with Sierra snowpack at least 150 percent of average, and left some reservoirs full by the end of the summer.

[19] Data reported in Figure 2.3 are based on utility monthly reports to the CPUC on the operation of interruptible and demand response programs supplemented with additional information provided by CPUC staff on the maximum amount of hourly demand response provided under the SDG&E Peak Day Credit Program.

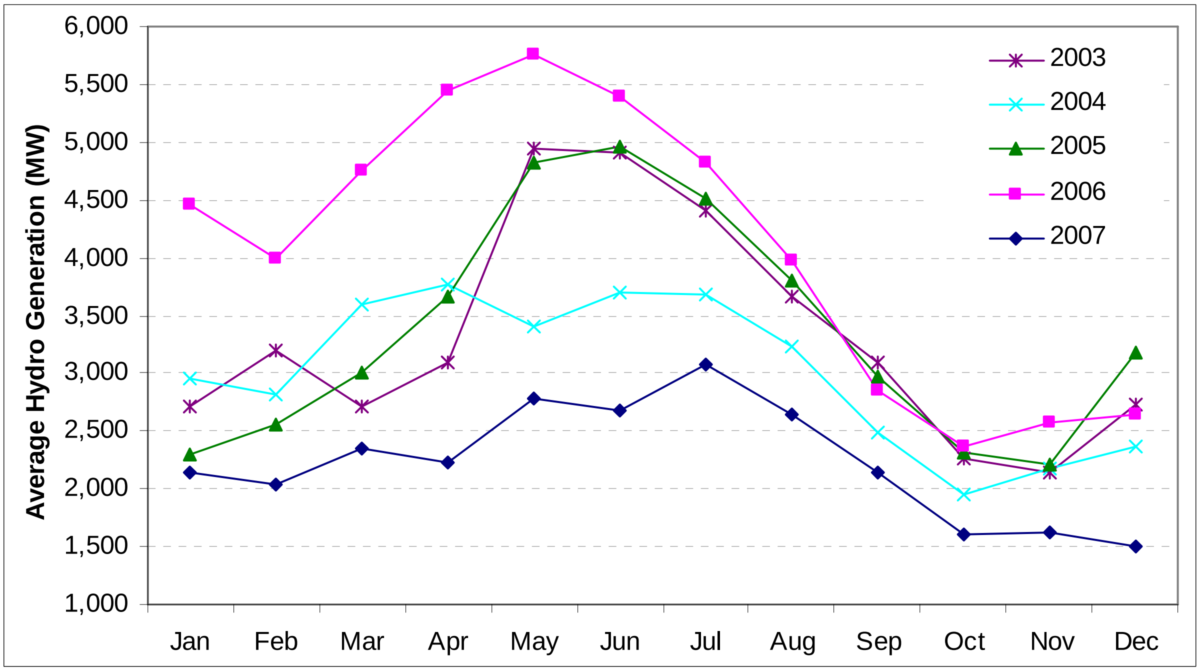
Figure 2.4 Mountain Snowpack in the Western U.S., May 1, 2007[20]



[20] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/snowcourse/snow_map.html

Figure 2.5 shows hourly average hydroelectric power production by month for each year between 2003 and 2007. It is evident from this chart that hydroelectric generated energy played a much smaller role in the power portfolio in 2007 than in previous years.

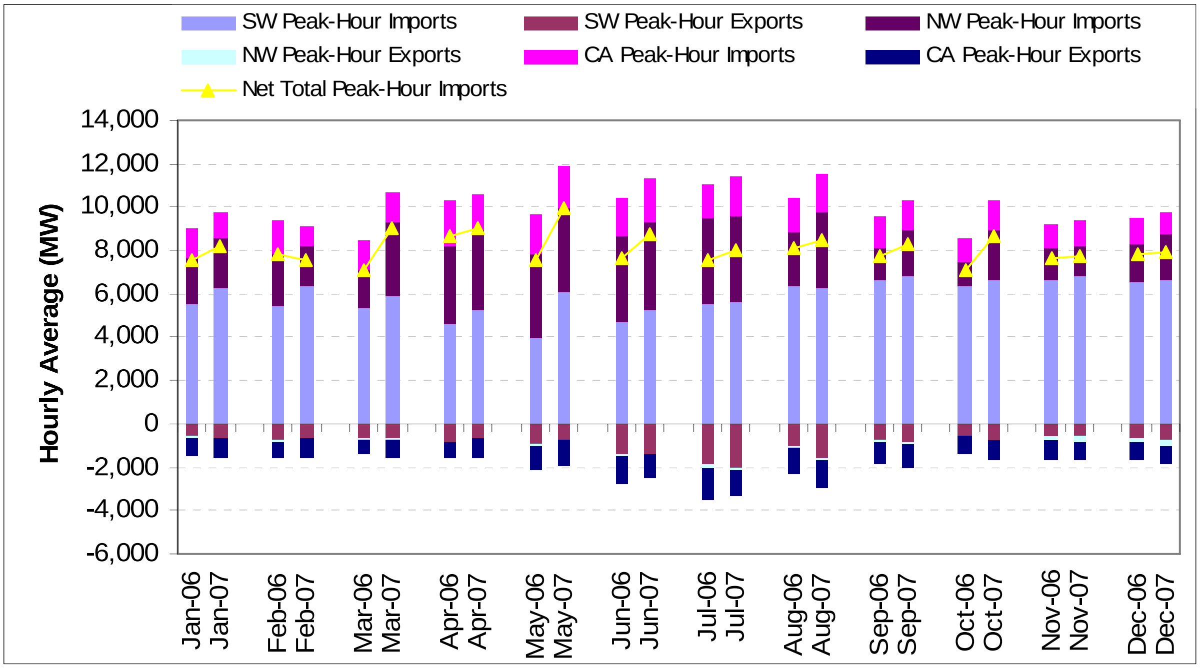
Figure 2.5 Average Hourly Hydroelectric Production by Month: 2003-2007



2.2.2 Imports and Exports

Figure 2.6 compares peak imports and exports for each month in 2006 and 2007, and includes wheeled power. Imports from the Southwest increased in the spring of 2007, primarily replacing the hydroelectric production that had been available in 2006. Imports from the Northwest were slightly higher in October, likely to compensate for lower native hydroelectric storage in 2007. Otherwise, imports and exports in 2007 followed a pattern similar to that in 2006.

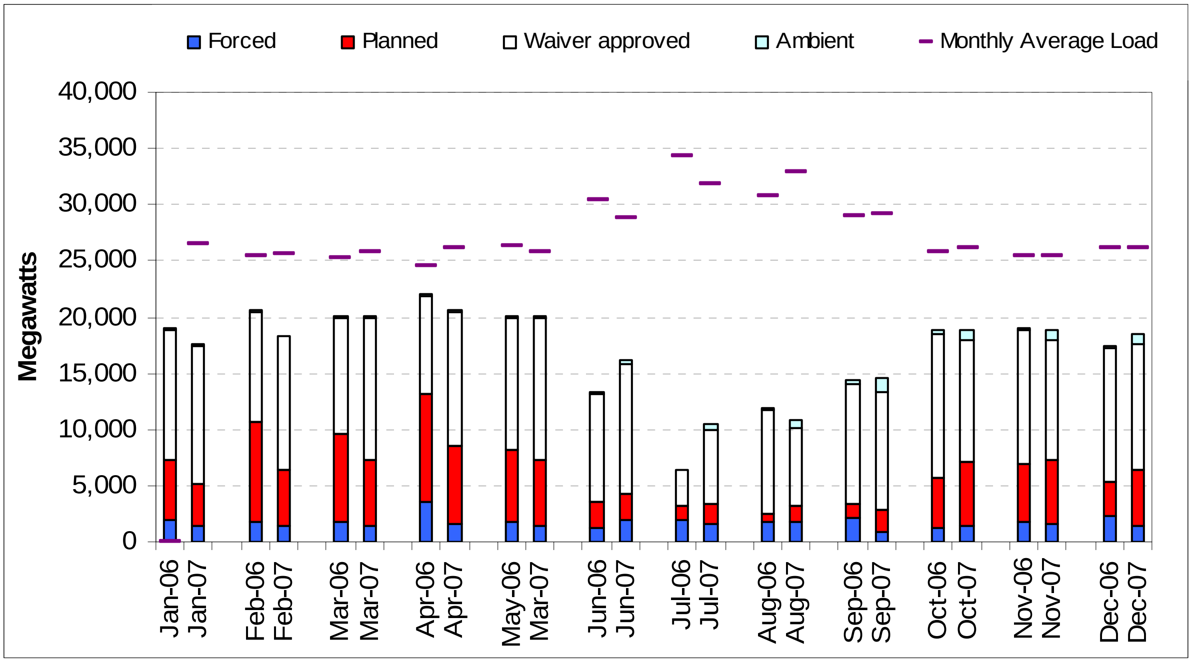
Figure 2.6 Year to Year Comparison of Hourly Average Scheduled Imports and Exports by Month: 2007 vs. 2006



2.2.3 Generation Outages

Figure 2.7 compares monthly average outages between 2006 and 2007. In the spring of 2006, many thermal resources were out of service for maintenance, with as many as three nuclear units out in the same month accounting for over 3,300 MW. This coincident maintenance outage schedule was facilitated by the large amount of hydroelectric generation that year, which could replace the thermal generation. However, more thermal resources were in operation in the spring of 2007 as low hydro production required more thermal resources to support loads.

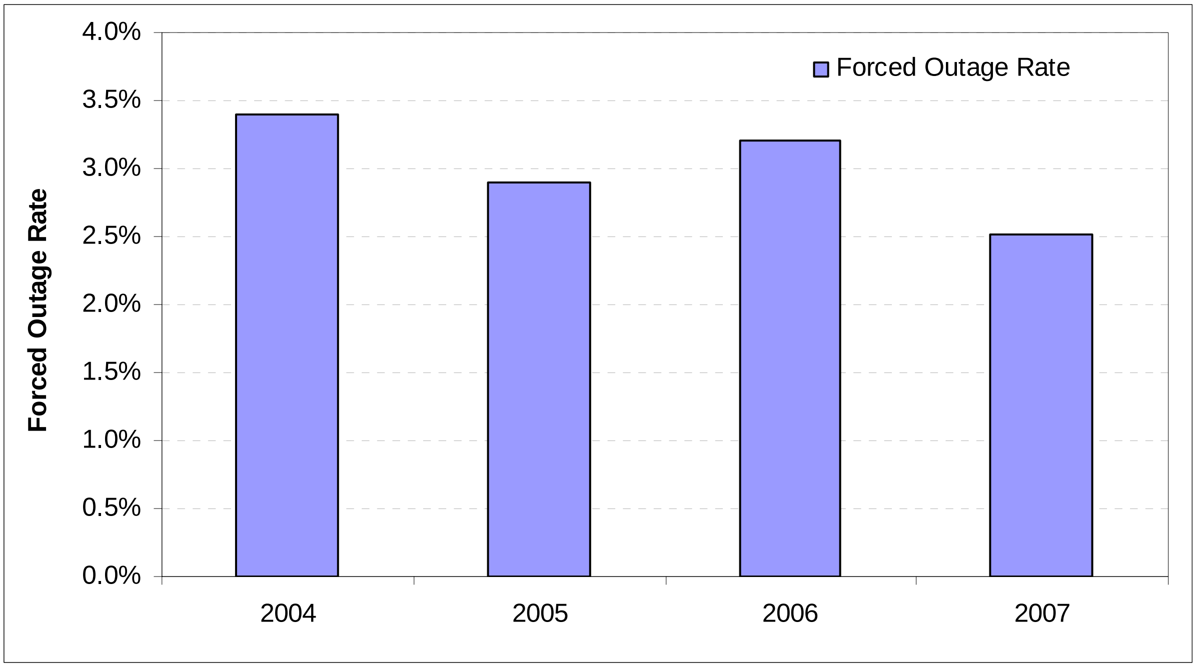
Figure 2.7 Year-to-Year Comparison of Hourly Average Outages by Month: 2007 vs. 2006



The forced outage rate declined in 2007 to below 3 percent for the first time since 1999. The decline can be partly attributable to the installation of new generation and transmission upgrades in recent years, which have enabled older, high-maintenance resources in California to be reserved for limited critical periods.[21] In addition, recent retirements of aging plants that were more susceptible to outages such as the Mohave coal-fired units (retired December 31, 2005) and the availability incentives provided by long-term energy contracting also contribute to lower outage rates.

[21] See Section 2.6.4 for more information.

Figure 2.8 Year-to-Year Comparison of Forced Outage Rates: 2004-2007[22]



[22] Methodology is similar to one used by the California Energy Commission to count generation in the CAISO Control Area since 2001, with additions and retirements of generation taken from the CAISO 2007 Summer Loads and Resources Assessment, p. 12.

2.2.4 Natural Gas Prices

Natural gas prices were relatively stable in 2007. Weekly average prices at California delivery points stayed between $5 and $8 per million British thermal units (mmBtu) for the entire year. In comparison, prices have varied over the past six years from approximately $2/mmBtu in 2002 to as high as $14/mmBtu following Hurricanes Katrina and Rita in 2005. In addition to being impacted by storage levels and supply disruptions (e.g., hurricanes), the variation in natural gas prices are also weather-driven, as natural gas is used for heating as well as for producing electricity. However, the spread between Northern and Southern California prices, as well as between California and national (Henry Hub) prices, tends to be driven by network constraints, and can increase when operational flow orders ("take-or-pay" requirements on gas purchases) arise. This was the case in the brief drops in the Southern California gas price in March and November. Natural gas storage is increasing nationally, with storage generally above the 5-year average for over two years now. Figure 2.9 shows weekly average natural gas prices in 2007 at Northern and Southern California and the national Henry Hub delivery points.

Figure 2.9 Weekly Average Natural Gas Prices in 2007

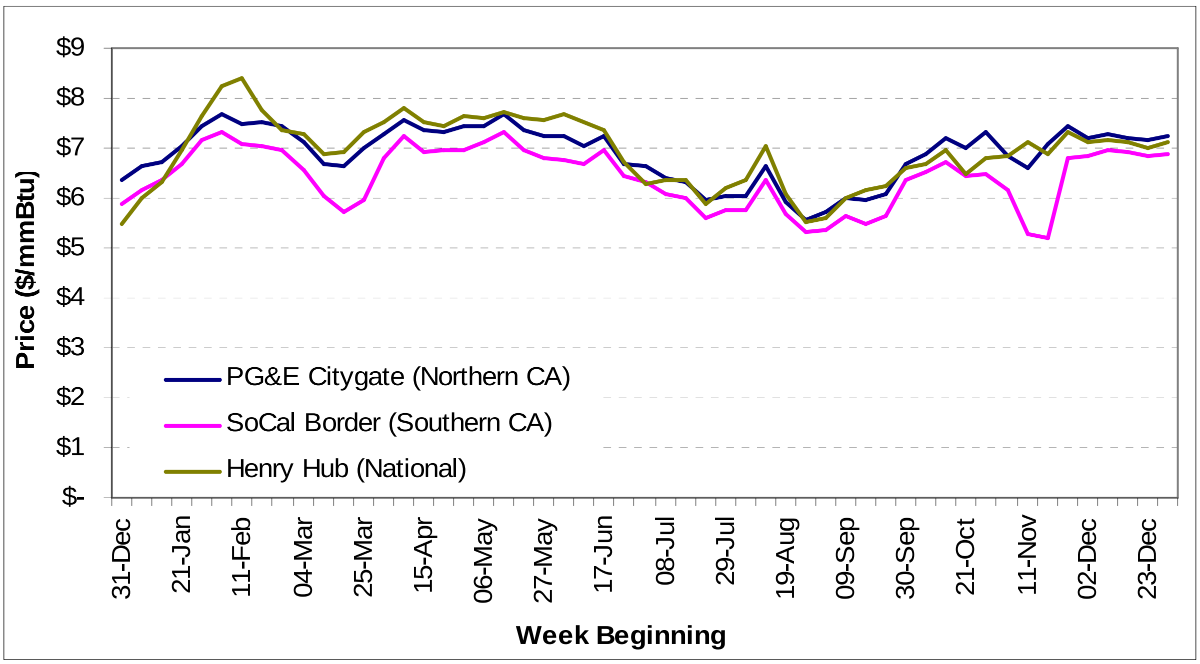
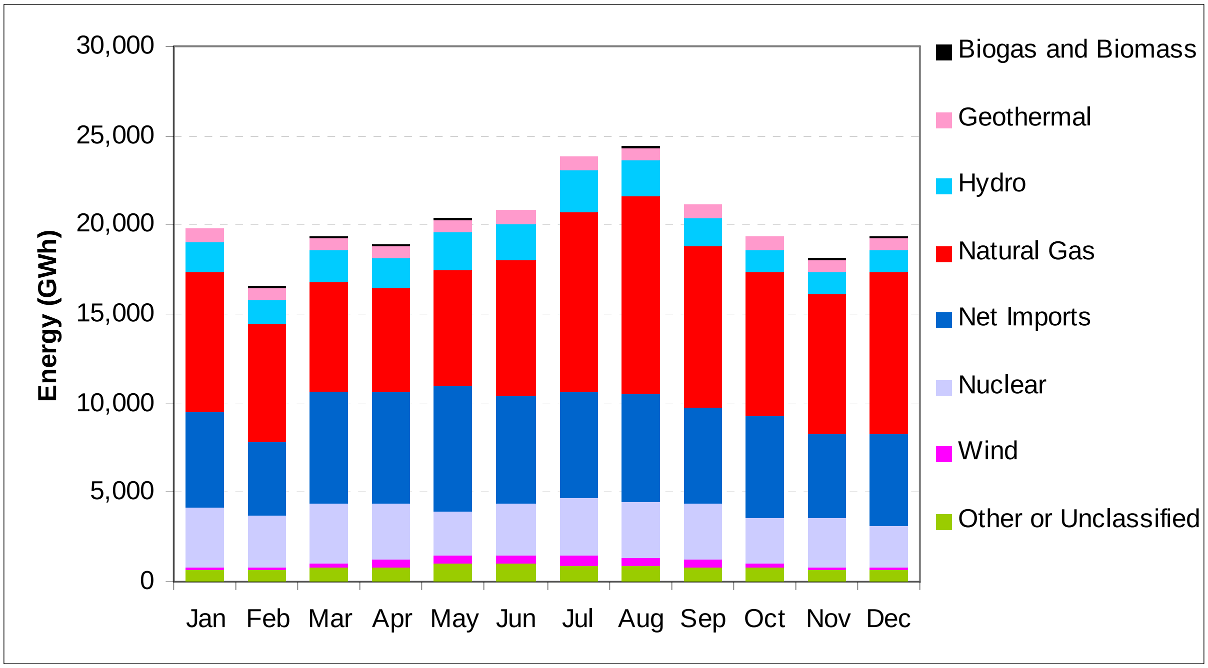


Figure 2.10 provides a profile of monthly generation by fuel type. The hydroelectric resources that had provided nearly 20 percent of total energy in the spring and summer of 2006 accounted for less than 10.5 percent of production in any month in 2007. The limited hydroelectric production was replaced primarily by natural gas and nuclear production during these months, which remained in service at a higher rate in the spring of 2007 than in the spring of 2006.

Figure 2.10 2007 Monthly Energy Generation by Fuel Type



2.3 Periods of Market Stress

California's spot wholesale electricity markets were generally stable and performed well in 2007. Each year, however, there are events that pose operational challenges and also have an impact on the markets that are operated by the CAISO. In 2007 there were three such events: two heat waves in the summer and a series of wildfires that burned throughout much of Southern California in late October.

Periods of high load as a result of hot weather are inherent to summers in California. Traditionally, the peak summer months are July through September, with heat waves often occurring between mid-July and late-August. In 2007, the first heat wave occurred in the first week of July coincident with the Independence Day holiday. The second heat wave occurred in late August and extended into early September and was also coincident with a national holiday, Labor Day. In addition to heat waves, California is also prone to wildfires during the dry summer months. The wildfires in Southern California in October 2007 were exceptionally severe in terms of number of acres burned, number of businesses and residences impacted, geographical span, and impact on reliable grid management. These fires burned across Southern California spanning the Los Angeles and San Diego areas, threatened generation and transmission facilities, and challenged grid stability, especially in the San Diego area.

Because the CAISO relies primarily on market mechanisms to manage grid reliability, events such as heat waves and wildfires can have a distinct impact on the wholesale markets. Overall, despite the extreme system conditions, California's spot wholesale markets functioned reliably and effectively, with certain outcomes influenced by these events. The following three subsections are devoted to a closer look at market impacts and performance during these exceptional events.

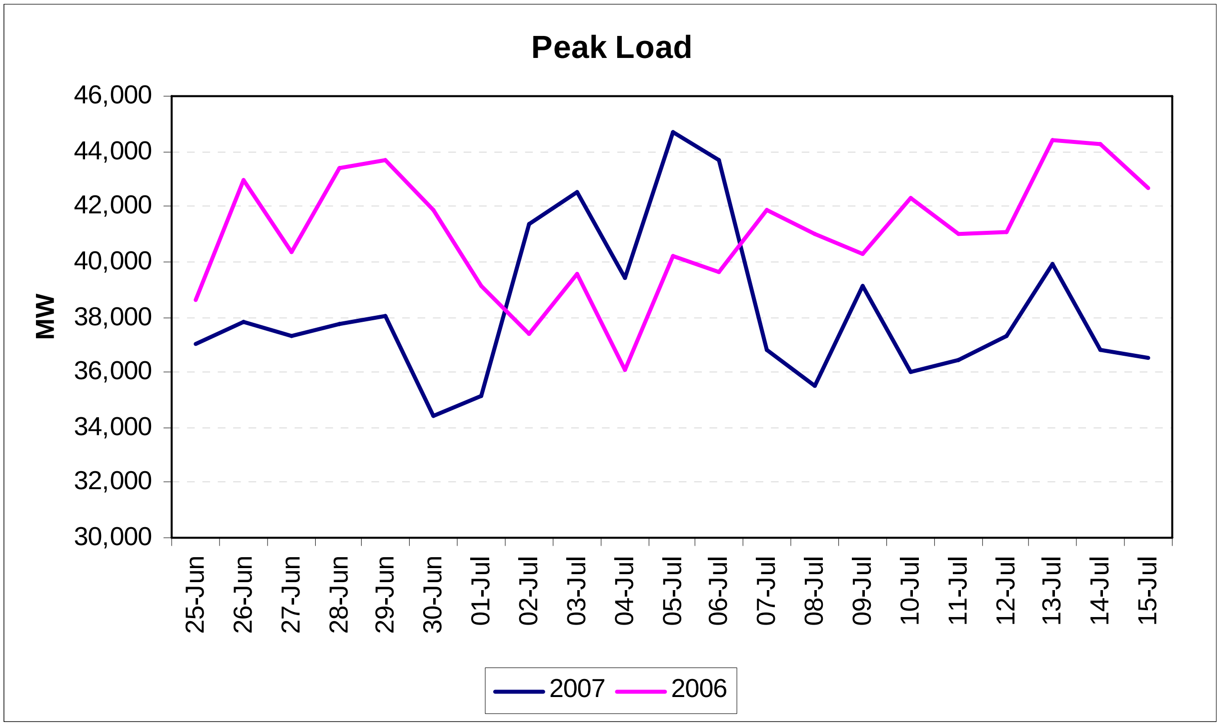
2.3.1 July Heat Wave

Although temperatures were generally mild during the summer of 2007, the summer began with a brief heat wave in the first week of July. During this week, high temperatures persisted across the state. With the exception of a national holiday on July 4, CAISO daily peak load surpassed 40,000 MW in all days during this period. This heat wave was not too severe, and wholesale markets performed well throughout it. This subsection focuses on several market characteristics that were evident during the July heat wave:

- Imbalance prices were moderate in both the pre-dispatch and 5-minute markets,
- High forward scheduling and a weekday holiday helped to moderate the impacts of the heat wave on the imbalance energy market,
- High decline rates for pre-dispatch import bids impacted markets on July 2nd and 3rd,
- Imbalance prices and Ancillary Service prices were correlated with spot bilateral prices, and
- Congestion on the major inter-ties was consistent with historical summer high load patterns.

The five-day average peak load of July 2-6, 2007 was 4,700 MW higher than that of the previous week and 3,700 MW above the 2006 level as shown in Figure 2.11. The weekly peak of 44,672 MW was set at HE 17 on Thursday, July 5.

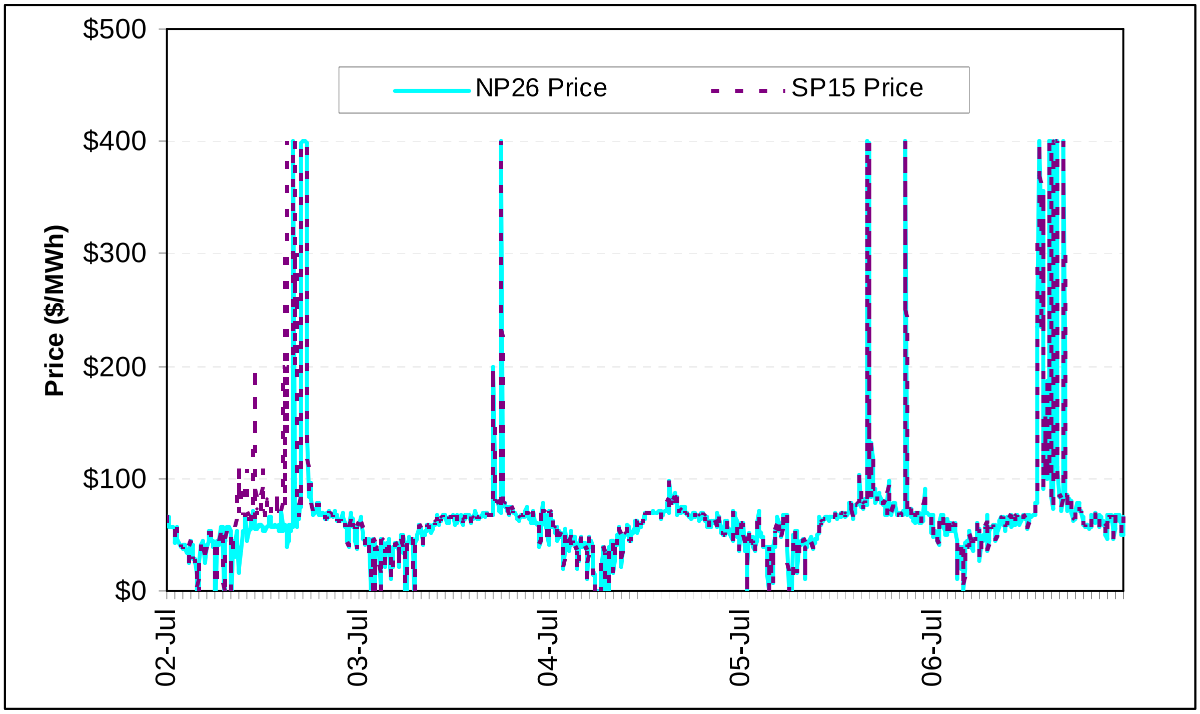
Figure 2.11 Daily Peak Load for Early Summer 2006 and 2007



Considering the distinct increase in load levels, prices were moderate in both the pre-dispatch (import/export) and real-time (internal generation) markets. The average price for pre-dispatch imports during the super-peak hours (HE 12-18) for July 2-6 was $116/MWh, which was higher than prices for the week prior to and after the heat wave, where the price range was between $60/MWh - $70/MWh. While this price difference may appear to be high, it is worth noting that, during the record-setting loads observed during the July 2006 heat wave, average super-peak prices for pre-dispatch imports were in excess of $300/MWh.

Figure 2.12 shows that 5-minute imbalance prices during the heat wave generally stayed at low levels, ranging from $50 to $100/MWh with occasional and brief excursions as high as $399/MWh. The figure below also shows a notable degree of price volatility across the week. Because the imbalance market is designed to quite literally balance supply and demand in real-time after buyers and sellers have had an opportunity to clear supply and demand in the forward and spot markets, the volume dispatched in the imbalance market is itself generally small and volatile. This has a direct impact on the volatility of 5-minute imbalance Market Clearing Prices as the market moves up and down a relatively small supply curve to balance the residual demand on the grid.

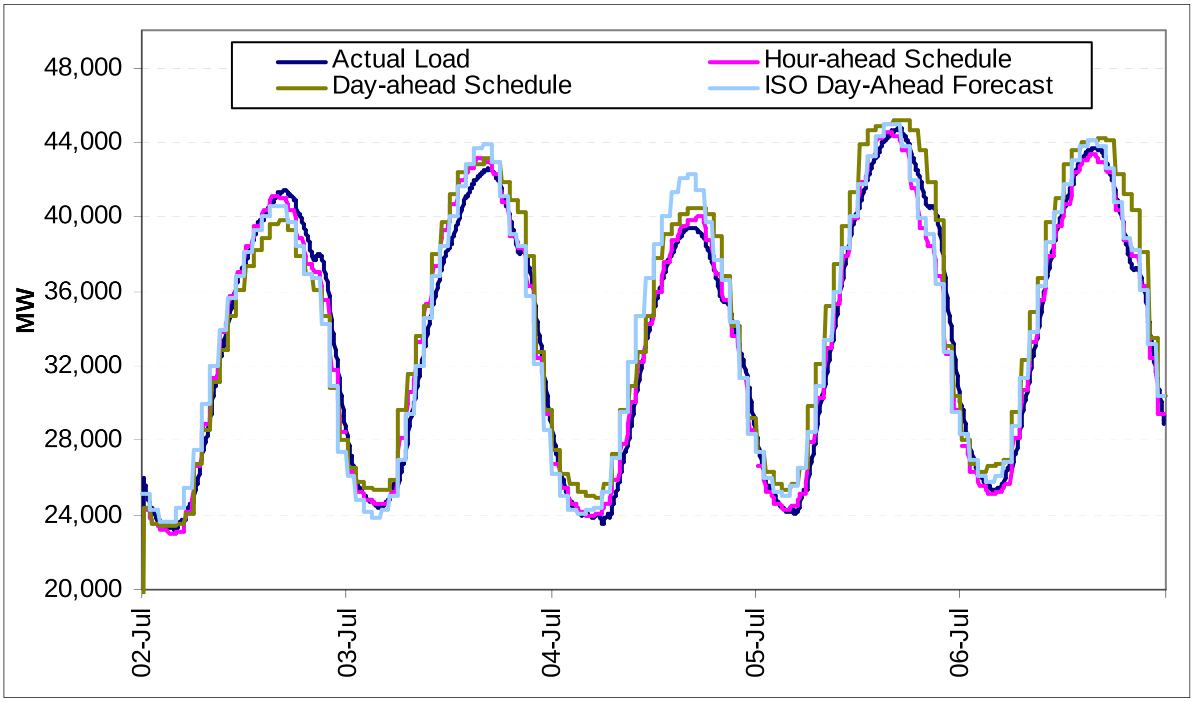
Figure 2.12 Real Time Energy Prices for July 2-5, 2007



Real-time price volatility may be attributable to transmission and generation limitations, forecast inaccuracies, forward scheduling, pre-dispatches, uninstructed deviations, and other system conditions. For example, real-time energy price spikes on July 2, when the heat wave just started, can mainly be explained by relatively low forward scheduling due to under forecasting of load as well as the congestion of a major transmission line that limited imports into the CAISO Control Area.

Some degree of error is inherent in load forecast, especially when weather changes abruptly. When the heat wave first struck California on July 2, forecasted load was well below actual load. As a consequence, there was a relatively lower level of forward scheduling of load which left up to 2,000 MW of load to be met through the imbalance market (Figure 2.13). As a result, the CAISO had to dispatch further up the imbalance supply curve to meet this demand, which translated into higher imbalance prices. In contrast, when load was over-forecasted (and consequently over-scheduled) on the July 4 holiday, the CAISO was primarily dispatching resources down, moving further down the imbalance supply curve and resulting in lower 5-minute imbalance energy prices.

Figure 2.13 Actual Load vs. Day-Ahead and Hour-Ahead Schedules and Forecast, July 2-6



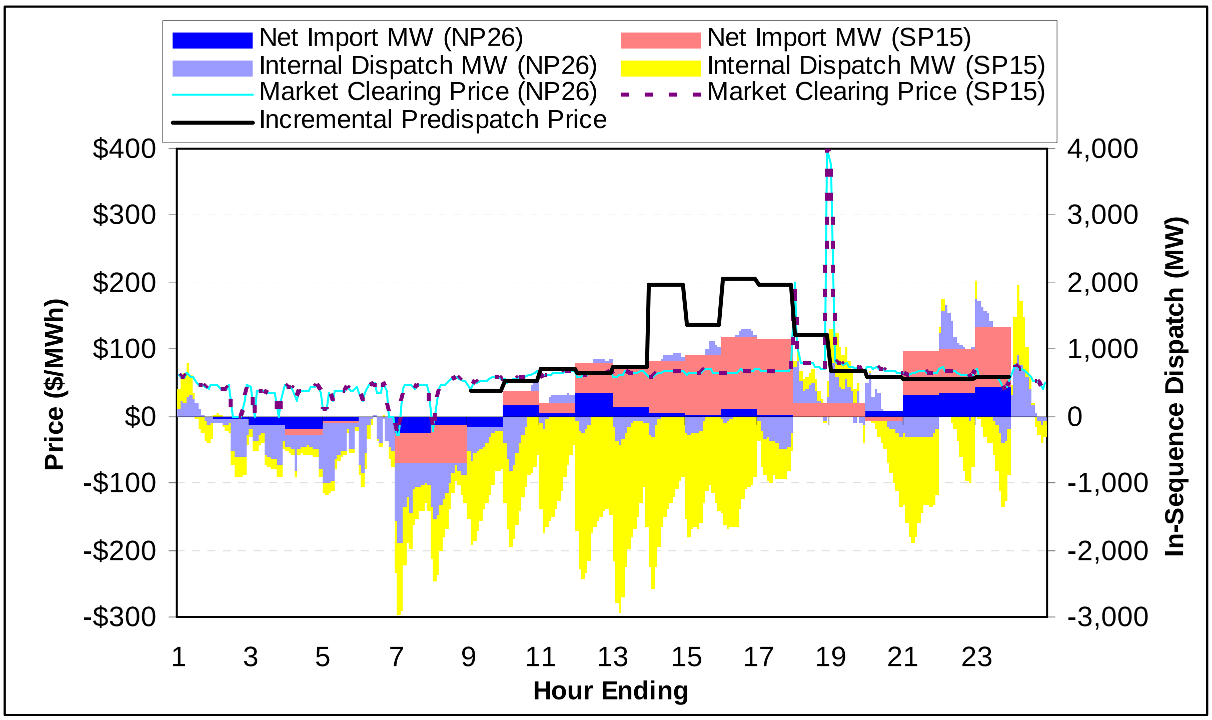
One pattern that is often observed during high load periods in the summer is an increase in the scheduling of energy from the Pacific Northwest into California to serve native load and also for export to the Southwest. During such periods, it is not uncommon to observe congestion on the transmission corridors that facilitate north-to-south schedules. One such corridor within the CAISO Control Area is Path 26 which joins the northern and southern parts of the state. During the July heat wave, Path 26 was derated, at times significantly (from 4,000 MW down to 1,700 MW on July 2, for example). As a result, the imbalance market split during several periods, and cleared in two separate zonal markets, producing two Market Clearing Prices. Because of the relative load distribution and scheduling patterns during this period, this split reduced the amount of imbalance supply available to meet Southern California load and resulted in a higher frequency of prices set above $250/MWh in SP15. These price spikes can be seen in Figure 2.12.

As noted above, the CAISO pre-dispatches import bids in the imbalance market in advance of the operating hour. These bids are a useful supplement to the regular real-time energy markets, and during periods of market stress are often critical in meeting load and managing grid reliability. These imports contribute to meeting the imbalance requirement (as do 5-minute dispatches of internal resources) but are not eligible to set the 5-minute real-time price. Pre-dispatched bids across the inter-ties are paid “as-bid” and may have an average settlement price that diverges from the 5-minute interval price.

One challenge in relying on pre-dispatched import bids is that if the dispatch is declined, there is no second pass in the pre-dispatch run to dispatch a substitute import bid. When the decline rate is significant, it places additional stress on the 5-minute imbalance market that is run within the hour. On July 2, the decline rate for pre-dispatch import bids was as high as 50 percent during the super peak hours.

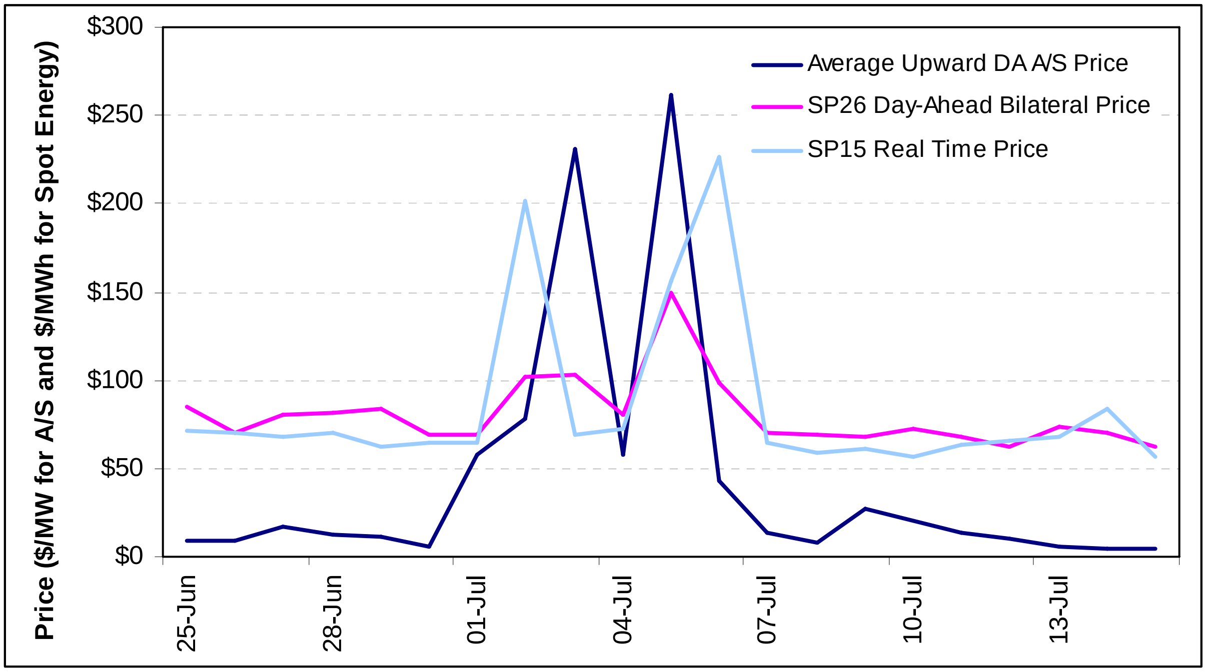
This high decline rate, and the additional imbalance requirement that had to be met by internal resources in the 5-minute market, directly impacted imbalance prices on July 2, as seen in Figure 2.12. An indirect impact of the high decline rate can also be seen on July 3. High forecast load for July 3 coupled with the uncertainty about how much import energy could be expected from the pre-dispatch resulted in a conservative imbalance dispatch by CAISO Grid Operators. On July 3, the CAISO dispatched the imbalance import bids to meet the imbalance requirement expecting a similar decline rate. However, the actual decline rates on July 3 were trivial, which resulted in an abundance of imbalance energy delivered, and required internal resources to be dispatched downward in the 5-minute imbalance market to balance the grid. This decremental dispatch pattern (up to 3,500 MW) throughout the peak period of the day resulted in lower-than-expected Market Clearing Prices in the 5-minute imbalance market as seen in Figure 2.14.

Figure 2.14 Pre-dispatch and Internal Dispatch Quantities and Prices for July 3, 2007



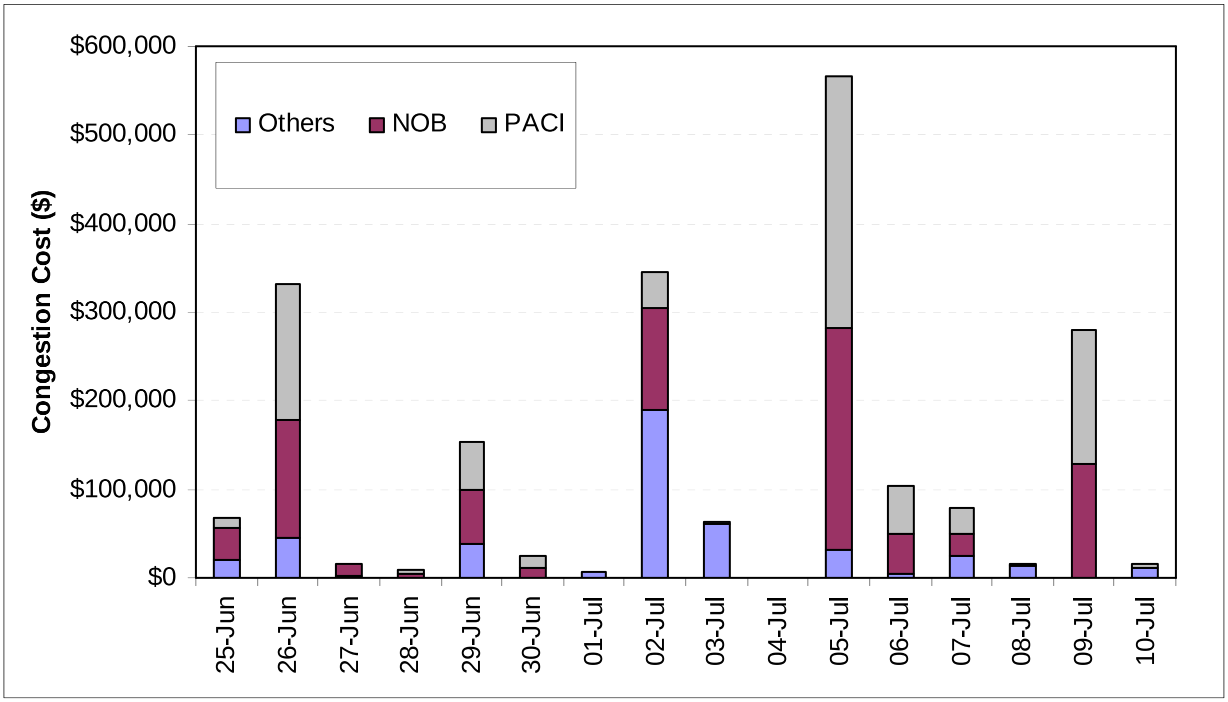
Day-ahead spot bilateral energy prices during system peak load hours can reflect scarcity and risk premiums (i.e., an aversion to not being able to cover contract positions or serve load). If markets function effectively, prices of upward Ancillary Services (Regulation-Up, Spinning Reserve, and Non-Spinning Reserve) purchased in the day-ahead market will reflect the opportunity cost of offering the generation capacity as reserve as opposed to selling the energy in the bilateral market or the expectation of being held down as reserve through the operating hour in lieu of receiving the imbalance price for dispatched energy. Real-time energy prices should generally be correlated with day-ahead spot prices but are inherently more volatile. During the July heat wave, spot bilateral prices, imbalance prices, and upward Ancillary Service prices were all to some degree correlated, with a stronger observed relationship between the SP15 day-ahead bilateral price (spot price) and the upward Ancillary Service price, as seen in Figure 2.15. The SP15 real time price was less correlated with the other two prices due in part to its inherent volatility and sensitivity to the various factors (e.g., day-ahead scheduling, pre-dispatches, etc.) described above.

Figure 2.15 Prices of Day-Ahead Upward Ancillary Service, Real Time Price, and Hourly Spot Bilateral Price for June 25 – July 13, 2007 (HE 12-18)



Despite high demand of energy during the July heat wave, CAISO congestion markets were generally quiet. Figure 2.16 shows that total congestion costs were higher during the heat wave; however, the costs were still within the normal range given the demanding system conditions. Similarly, two major importing lines connecting California and the Northwest, NOB and PACI, were generally congested during the July 2-6 heat wave as high demand within California and the Southwest pulled power from the Northwest. Notably, Figure 2.16 shows the effect of the July 4 holiday when CAISO incurred no inter-zonal congestion as load dropped significantly.

Figure 2.16 Inter-zonal Congestion Costs (June 25 – July 10, 2007)



2.3.2 August / September Heat Wave

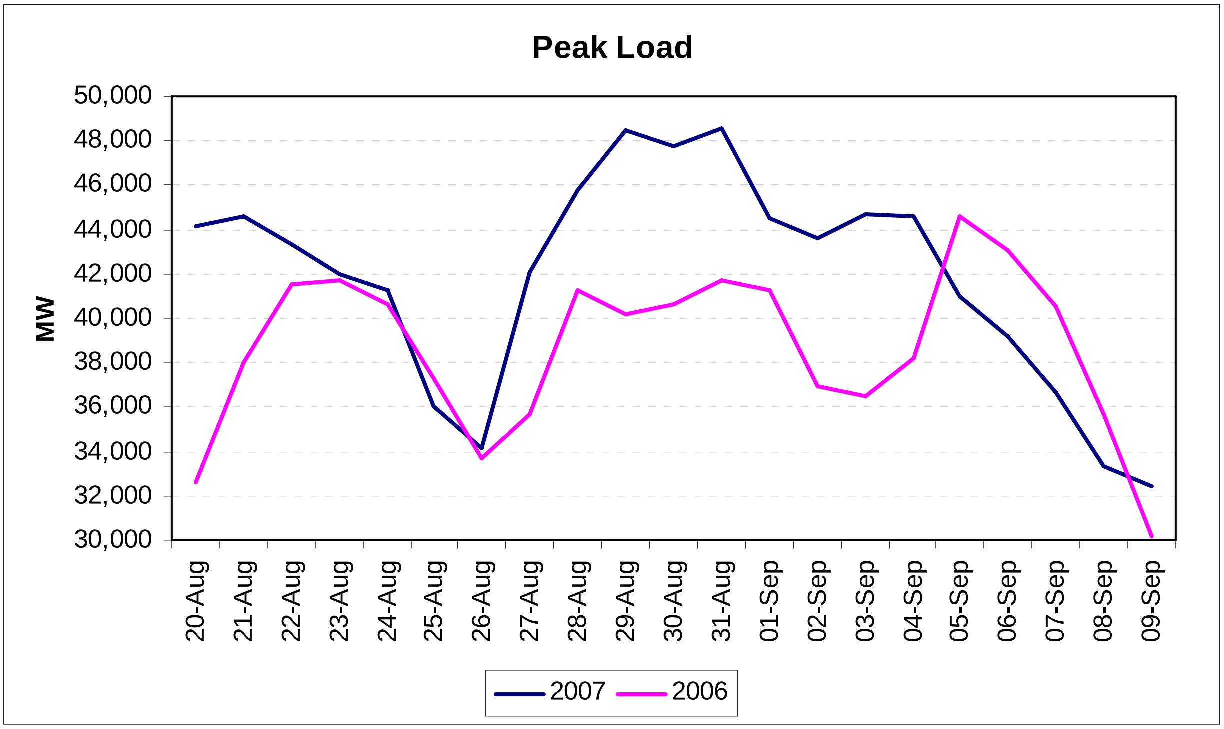
California experienced another heat wave toward the end of the summer, spanning the period August 28 through September 3, which produced the top four peak load days of 2007 on four consecutive days from August 28 through August 31. The annual peak load of 48,535 MW occurred on August 31 in HE 16, which was almost 4,000 MW higher than the peak of the July heat wave. Despite the high energy demand during the heat wave, CAISO wholesale electricity markets generally functioned well. This subsection summarizes market performance during this heat wave with the emphasis on the following notable characteristics:

- Imbalance energy prices spiked periodically in the beginning of the heat wave, but became more stable as temperatures and loads across the region moderated,
- High forward scheduling, pre-dispatch imports, and a national holiday had a moderating effect on imbalance requirements and, consequently, imbalance energy prices,
- Imbalance prices and Ancillary Service prices were generally correlated with spot bilateral prices,
- Prices for upward Ancillary Services increased somewhat during the heat wave; however, there were no significant procurement shortages during this period,
- Congestion on the major interfaces was consistent with historical summer high load patterns, and

- Despite the high demand for energy, forced outage rates for generation were fairly low during the heat wave.

As shown in Figure 2.17, CAISO system loads began increasing on Sunday, August 27, as temperatures throughout the region increased and the heat wave began taking shape. The daily peak load increased over 14,000 MW from August 27 through August 29, stabilizing in the neighborhood of 46,000 – 48,000 MW for the four days spanning August 29-31. Although daily peak loads during the summer of 2007 were less severe than those observed in 2006, the daily peak loads observed in late August and early September were well in excess of those observed during the same period in 2006.

Figure 2.17 Late Summer Peak load in 2006 and 2007

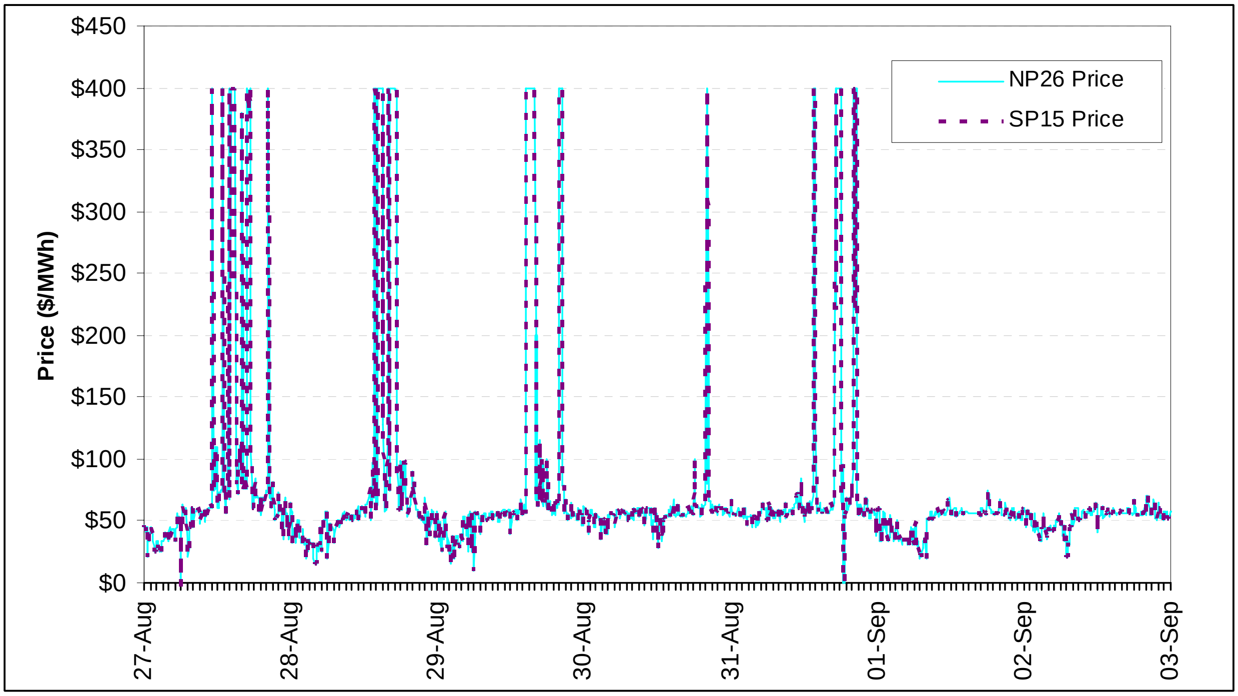


Often, with rapid increases in system load we observe coincident increases in the requirement for imbalance energy and imbalance prices. As seen in Figure 2.18, imbalance 5-minute prices were higher, on average, and more volatile during the first two days of the heat wave period with a decline in the frequency of price spikes the following five days.

Imbalance price patterns during the more volatile hours in this period were extremely volatile, fluctuating between normal levels ($25/MWh to $100/MWh) and prices near the bid price cap of $400/MWh, with no prices in between these two extremes. This type of price volatility typically arises under two different conditions. First, larger sustained rates of change in positive imbalance requirement can result in a relatively thin supply of available 5-minute ramping energy as internal resources that bid into the imbalance market are already ramping up and there is little else in additional energy that can be dispatched in the current 5-minute interval. Second, when system loads are sufficiently high, the amount of capacity from available internal resources may be thin or insufficient, causing the CAISO to dispatch up to or near the top (price) of the imbalance supply curve.

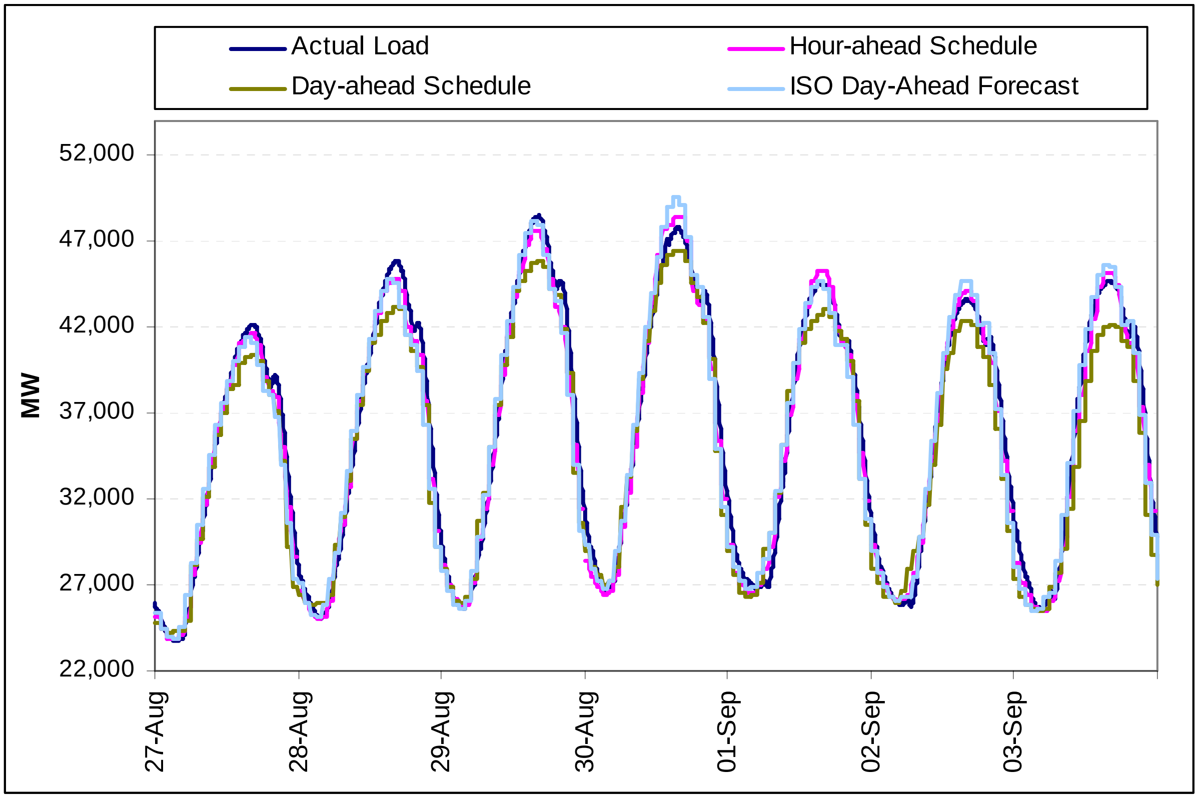
In the first few days of the heat wave, system load was under-forecasted which resulted in forward schedules that were well below actual load. When this occurs, the difference must be met in the imbalance market through the pre-dispatch of import bids and 5-minute dispatch of internal resources. In this circumstance, there is generally an increased imbalance requirement (i.e., only a portion of the imbalance requirement is met through the pre-dispatch of imports) and the CAISO must dispatch into the higher-priced portion of the supply curve. As shown in Figure 2.19, day-ahead forecast load was as much as 3,000 MW below actual load, which may impact the number of internal resources that are online and available in real-time to provide imbalance energy. In addition, hour-ahead schedules were as much as 1,000 MW below actual load, contributing to the increase in the requirement for imbalance energy.

Figure 2.18 Real Time Energy Prices for August 27 - September 3, 2007



In contrast, imbalance 5-minute prices generally remained at lower, more normal levels when load was more fully scheduled in advance of real-time. This occurred on August 30, when the day-ahead load forecast was above actual load and forward scheduled load was also in excess of actual load. This over-scheduling of load actually reduces the imbalance requirement, often to negative levels, and results in lower prices as the CAISO does not have to dispatch into the high priced bids to meet the lower imbalance requirement.

Figure 2.19 Actual Load vs. Day-Ahead and Hour-Ahead Schedules and Forecast, August 27 – September 3, 2007



In addition to higher levels of forward scheduling, the pre-dispatch of import bids and the lower loads associated with a national holiday (Labor Day) on September 3 also helped to moderate imbalance prices. Note that system load declined by roughly 3,000 MW across the weekend and on September 3, the Labor Day holiday. Figure 2.20 shows that the average hourly amount of net pre-dispatched imports during the super peak hours of the heat wave was as much as 400 MWh. While average prices for imbalance imports were above average for the period of August 29 -31, they remained in the range of $225/MWh to $275/MWh and were consistent with average imbalance import prices seen in prior high-load periods over the past two summers. During high-load periods, when much of the western region is experiencing high temperatures and high loads, spot bilateral prices often reach $200/MWh to $300/MWh and bid prices for imports into the CAISO imbalance market generally reflect these same conditions.

Figure 2.20 Average Hourly Prices and Quantities for Pre-dispatch Imports and 5-Minute Real Time Dispatch – Hours 12-18 for Aug 20 through Sep 6, 2007

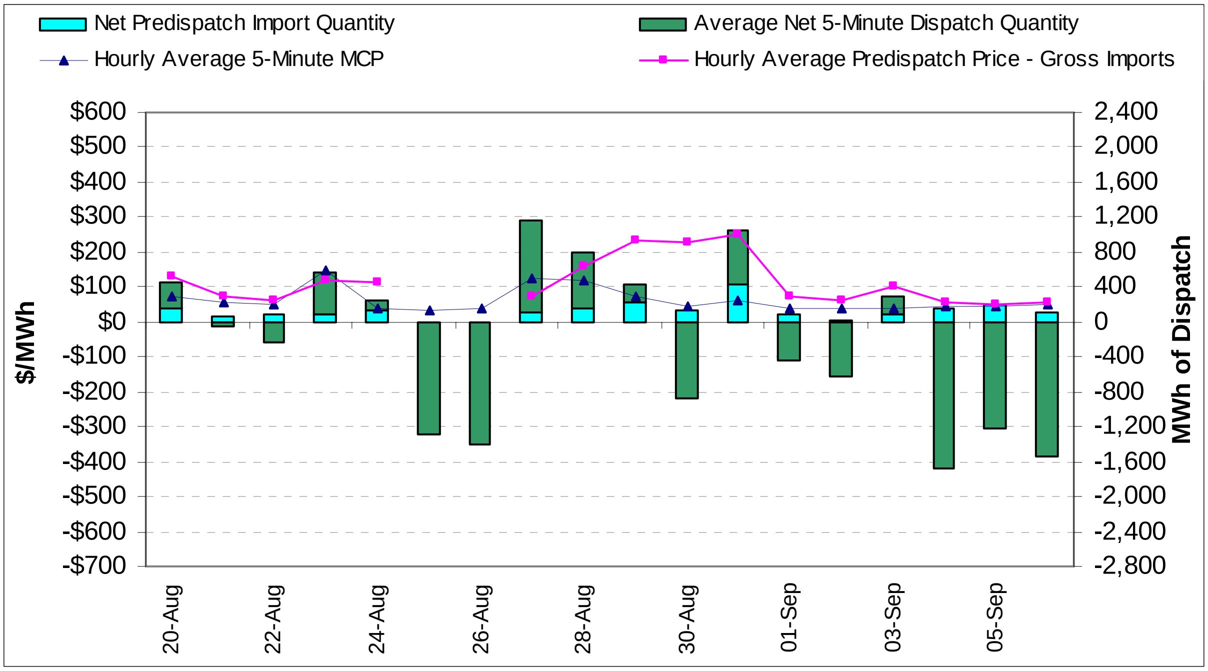
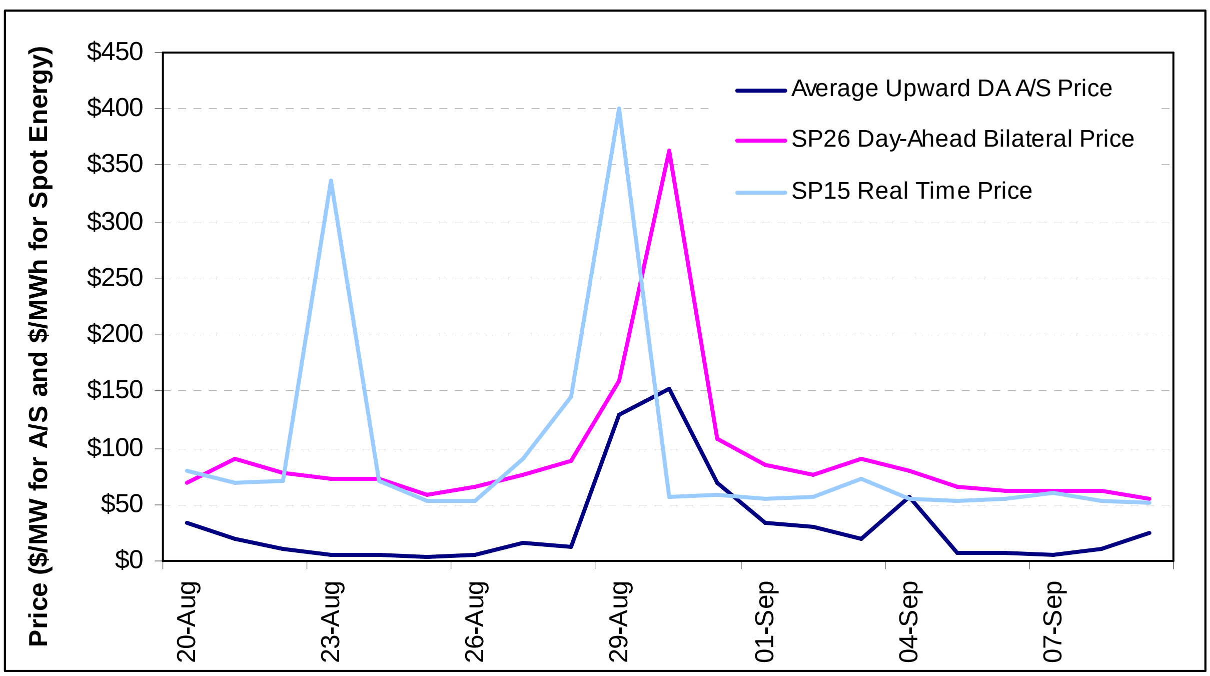


Figure 2.21 Prices for Day-Ahead Upward Ancillary Service, 5-Minute Imbalance Energy, and Spot Bilateral Energy for Aug 20 – Sep 10, 2007



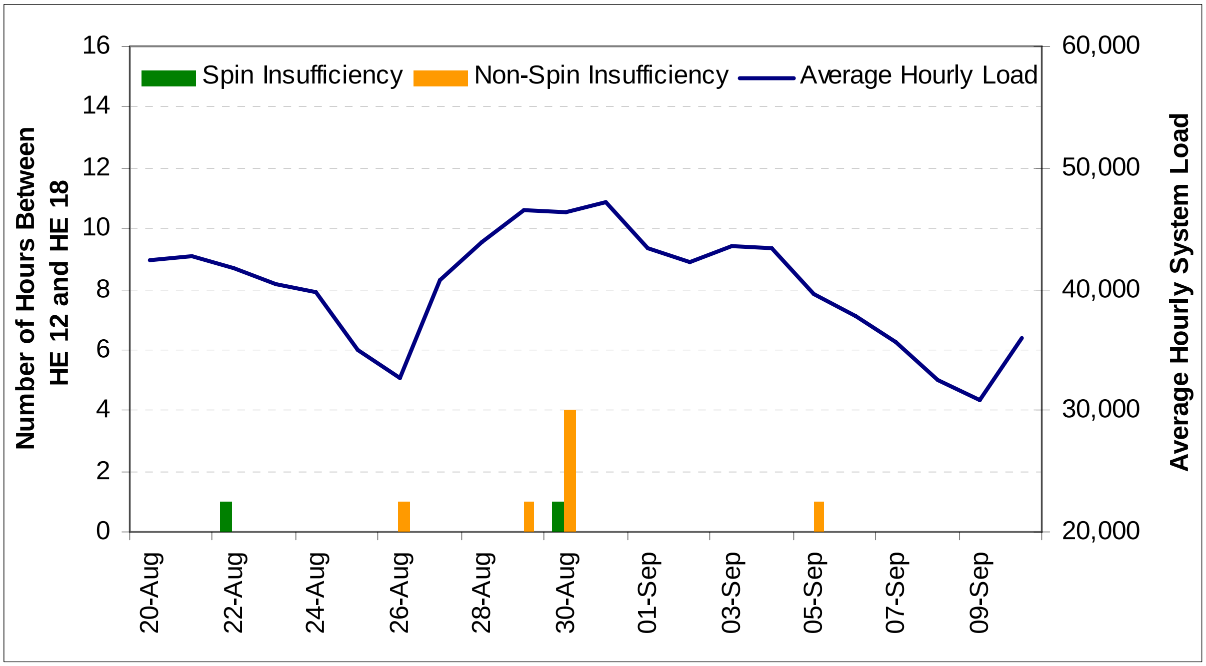
As discussed in the July heat wave section, prices of upward Ancillary Services purchased in the Day Ahead Market will reflect the opportunity cost of offering the generation capacity as reserve as opposed to selling that capacity as energy in the spot bilateral market or the imbalance market. Figure 2.21 shows that upward Ancillary Service prices were generally correlated with spot bilateral energy prices during the August/September heat wave. During this period both prices showed notable increases when loads increased, reflecting the relative scarcity of energy and potential risk premiums associated with concerns about high real-time prices.

Figure 2.21 also shows two periods of high real-time energy prices in late August. The more significant and persistent one occurred at the beginning of the heat wave, and the other brief price spike happened on August 23.[23] Real-time prices may depend on many factors such as load forecast accuracy, forward scheduling, pre-dispatches, uninstructed deviations, and other system conditions. As discussed above, the price spike at the beginning of the heat wave was due primarily to low forward scheduling levels resulting from load forecast error.

The CAISO did experience six hours of procurement deficiency in Spinning Reserve or Non-spinning Reserve during the heat wave, where prices in these hours ranged between $180/MW and $300/MW which were similar to the prices for Spinning Reserve and Non-spinning Reserve during the July 2006 heat wave where there was procurement deficiency. Figure 2.22 shows the frequency of procurement deficiency during the August heat wave period. Six hours of procurement deficiency during a heat wave period is not unexpected, and is well below the procurement insufficiency levels observed during the July 2007 and July 2006 heat waves. Despite the procurement deficiency during these six hours, real-time operating reserve levels did not drop below five percent for any significant length of time and generally were above 7 percent.

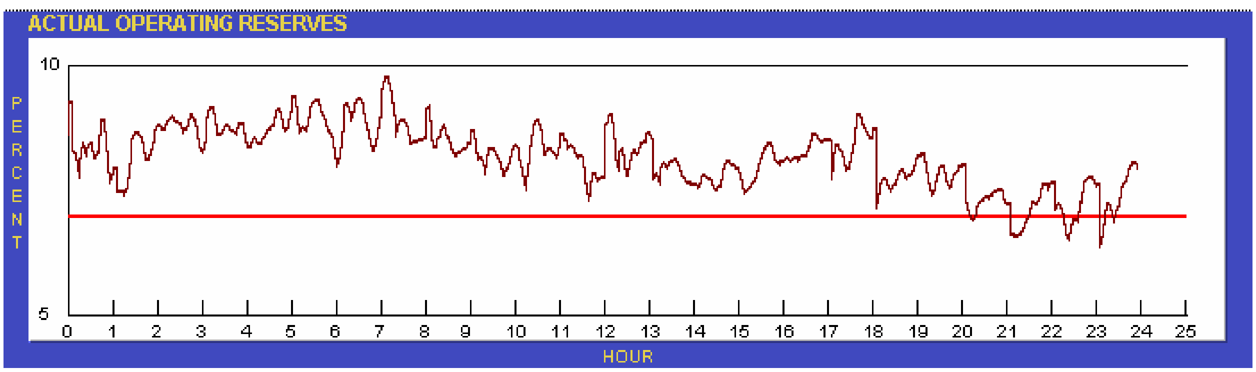
[23] The high prices observed on August 23 were the result of above average use of load bias in the imbalance market. On this day, up to 700 MW of load bias was used in the 5-minute imbalance market to adjust the 5-minute dispatch for unanticipated or unaccounted for factors that cause a discrepancy between the actual imbalance requirement and the 5-minute imbalance dispatch. Two examples of factors that are mitigated using load bias are severe uninstructed deviations and load ramps that are either more severe than anticipated or begin sooner than anticipated.

Figure 2.22 Ancillary Service Bid Insufficiency



For example, on August 30 there were four hours of procurement insufficiency in Non-spinning Reserve and one hour in Spinning Reserve. Furthermore, bid insufficiency on August 30, 2007 did not have a significant impact on real operating reserve levels, as illustrated in Figure 2.23. With the exception of a few brief dips in off-peak hours, actual operating reserve stayed well above the 7 percent requirement.

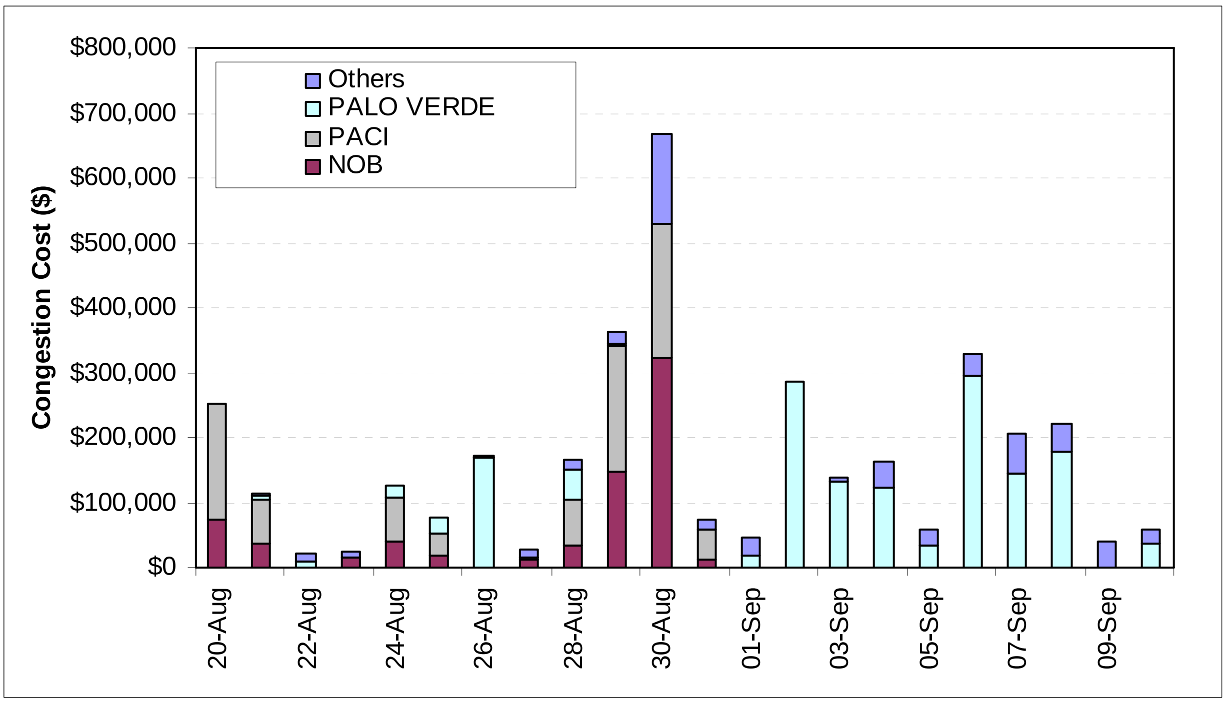
Figure 2.23 Actual Operating Reserve Levels for August 30, 2007



It is not uncommon to see increased inter-zonal congestion costs during periods of market stress such as heat waves, as demand of energy increases, creating an increased demand for transmission resources into the CAISO Control Area. Figure 2.24 compares inter-zonal congestion costs on major branch groups during the heat wave week with the two neighboring weeks. Relatively higher congestion costs were incurred during the heat wave week, especially on August 30, which the day-ahead load forecast predicted to be the peak load day to date for 2007. As a result of the high load, day-ahead congestion prices on two Northwest importing lines, NOB and PACI, reached $30 in the super peak hours compared to non-peak day prices that historically have been under $10. Aside from costs incurred on August 30, inter-zonal congestion costs during the heat wave were reasonable considering the magnitude of the heat wave that covered much of the Southwestern United States.

During the summer, California is a net importer of electricity from both the Northwest and Southwest regions. Imports from the Northwest primarily come down PACI and NOB, and the bulk of imports from the Southwest are across Palo Verde, Eldorado, and Mead.[24] As indicated in Figure 2.24, high loads throughout California and the Southwest resulted in congestion on PACI, NOB, and Palo Verde.

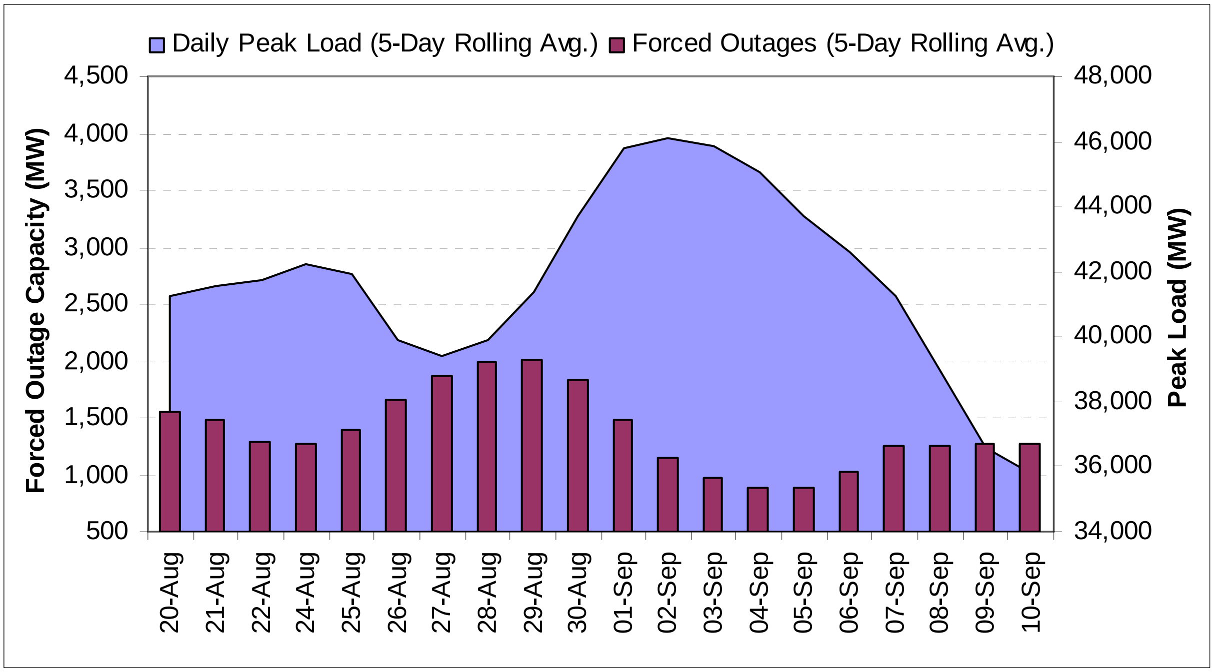
Figure 2.24 Congestion Costs on COI, PACI, Palo Verde, and the Other Branch Groups for August 20 – September 10, 2007



Periods of market stress such as summer heat waves typically result in high rates of generation forced outages, as the continuous operation of generation under high temperatures and high output stresses equipment resulting in a higher failure rate. During the August heat wave, forced outages were generally low, with less than 2,000 MW of generation forced outages. This low forced outage rate can be attributed to fairly mild summer loads overall, a relatively short heat wave period in August and September, and a concerted effort by the CAISO to coordinate with the generation community through the summer preparedness process.

[24] See Chapter 5 for a map of major interfaces in the CAISO Control Area.

Figure 2.25 Peak Load vs. Forced Outages: Five Day Rolling Average for August 20 – September 10, 2007



2.3.3 October Wildfires in Southern California

As a result of the especially dry summer in 2007, a dozen wildfires broke out in Southern California on October 20 and were not contained until more than a week later. These wildfires were exceptional in terms of geographical span, number of acres burned, and number of businesses and residences impacted. They burned across Southern California, threatened generation and transmission facilities, and challenged grid stability, especially in the San Diego area. Numerous physical derates to the system (transmission and generation) were necessary during this period, which challenged reliable operation of the grid and impacted the wholesale markets. The following subsection reports key performance of CAISO markets during the October wildfires, with focus on the following:

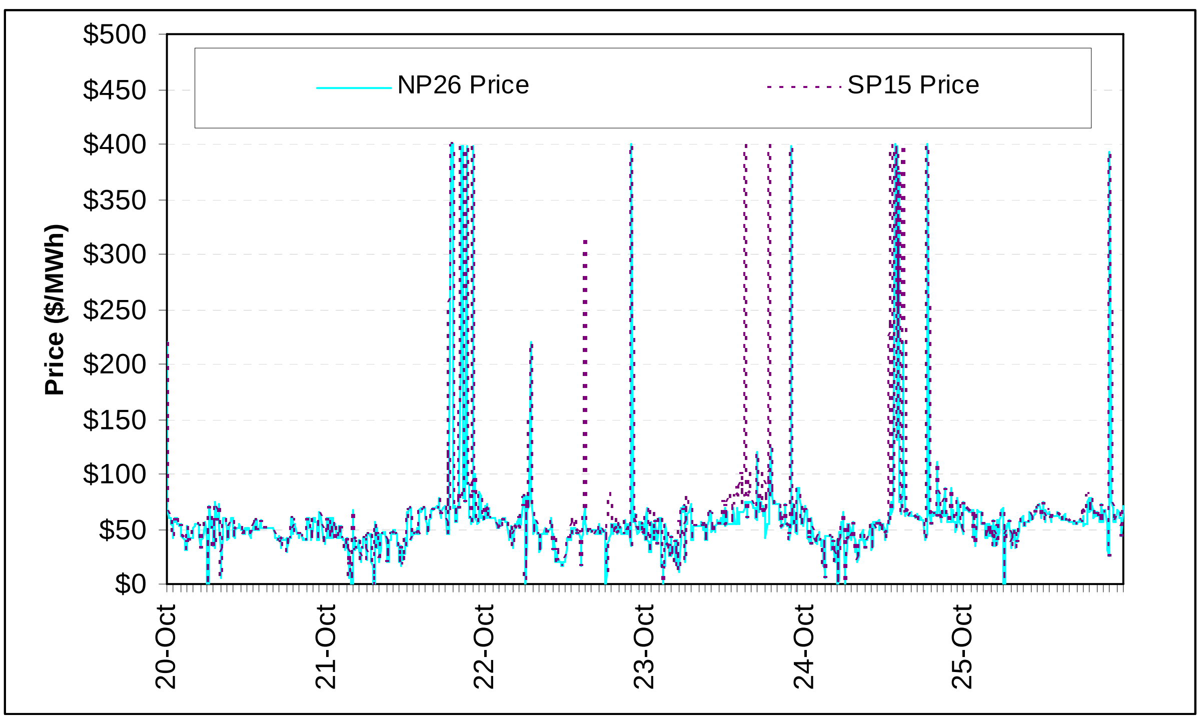
- Imbalance market prices were relatively moderate, with intermittent price spikes and market separation,
- Out-of-sequence dispatches were made frequently throughout this period to manage local reliability issues stemming from the wildfires. These dispatches occur outside the price-setting mechanism and as such contributed to the moderate imbalance prices,
- Spot bilateral prices in Southern California mildly and briefly increased during the wildfires,
- Ancillary Service market prices were not materially impacted by the wildfires,
- CAISO Grid Operators committed more units in the day-ahead process than normal for this season in order to provide additional support for grid reliability in SP15, and

- Congestion costs on the major inter-ties in Southern California increased compared to normal days.

Even though the combination of rapid load increase and widespread wildfires caused a few brief imbalance price spikes, especially on October 21, 5-minute imbalance energy prices generally were within the normal range of $25/MWh to $75/MWh, as illustrated in Figure 2.26. While wildfires were spreading quickly on August 22 - 23, imbalance prices remained low, primarily because most of the real-time energy needs stemming from the wildfires were highly localized and therefore addressed through non-market dispatches. Moreover, the wildfires themselves caused a decline in load as businesses were closed down and homes evacuated. In fact, actual load on August 22 was about 2,000 MW below the forecasted load due in large part to the wildfires. The decrease in load, to levels below forward scheduled load, along with "out of market" energy from OOS and minimum load energy, resulted in low imbalance requirements on these days and, consequently, low imbalance prices. As the effect of the wildfires resulted in transmission line derates, including the Southwest Power Link (SWPL) and Pacific DC Inter-tie, Grid Operators had to rely on OOS dispatches to support local reliability and to avoid transmission line overloading. These dispatches reduced in-sequence (in-market) real-time energy dispatch quantities, and had a moderating effect on imbalance prices.

Real-time energy markets in the North and South were also separated intermittently, as Path 26 limits were reached (due to a significant line derate) in real-time, resulting in higher imbalance prices in SP15. This price separation is also depicted in Figure 2.26.

Figure 2.26 Real Time Energy Prices during the October Wildfires



While imbalance prices showed some degree of volatility, upward Ancillary Service prices were little impacted by the wildfires. October loads are far below summer peak loads, which ensures that there will generally be sufficient certified Ancillary Service capacity available to the CAISO, provided resources are online and not out on maintenance. As mentioned above, the CAISO committed additional resources during the wildfires to provide additional reliability to the grid, which increased the supply of certified Ancillary Service capacity and tempered any upward shifts in prices that might be expected during periods of market stress.

Spot bilateral energy prices in Southern California increased slightly during the wildfire period due to a combination of major transmission and generation outages (reducing available supply in Southern California) and the uncertainty caused by the wildfires. Several major 500kV and 230kV transmission lines, including SWPL and San Onofre-Serrano, as well as a dozen lower voltage lines, were temporarily forced out of service during the wildfires. The transmission outages were compounded by the outages of two major nuclear units in Southern California with over 2,200 MW of capacity (SONGS). These outages prompted the CAISO to issue a Southern California Regional Transmission Emergency Notice, as well as two Southern California Regional Restricted Maintenance notices, to reduce the chance of further limitations on meeting loads in the area.

Figure 2.27 Day-Ahead Upward Ancillary Service, Real Time, and Hourly Spot Bilateral Prices for Oct 13 – Nov 2, 2007

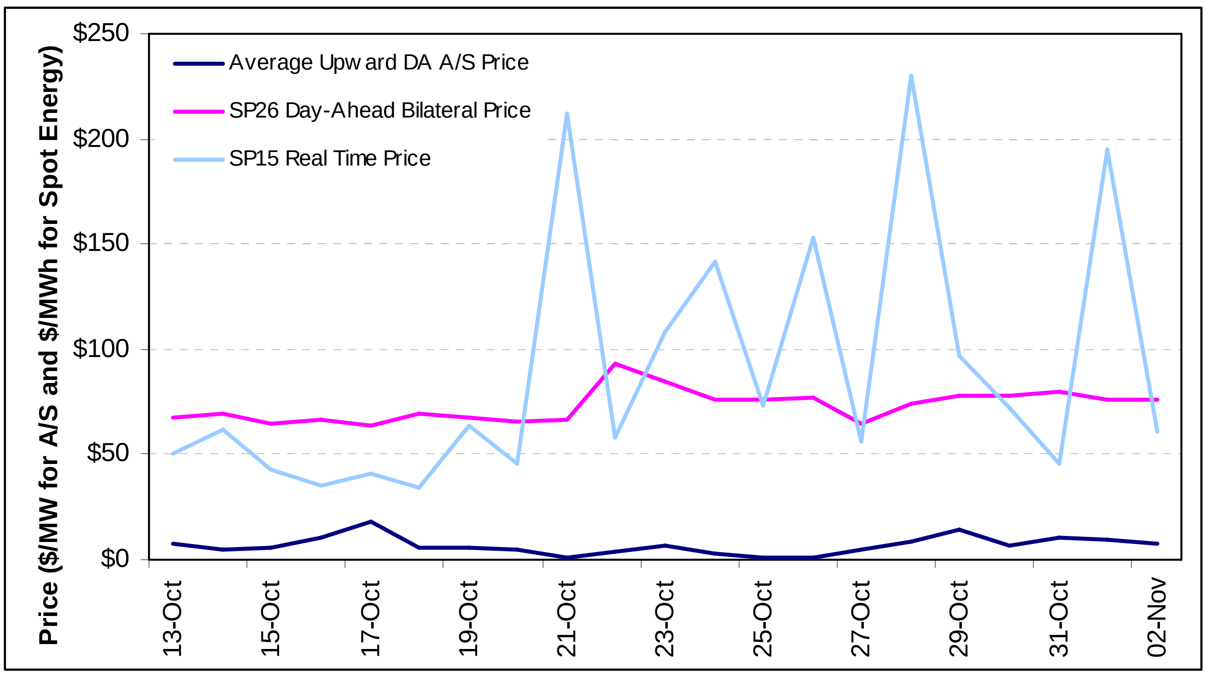


Figure 2.28 and Figure 2.29 indicate an increase in the number of resources committed on by the CAISO during the wildfire period. At the peak, seventeen units with over 5,000 MW of generation capacity were committed to mitigate grid reliability issues brought on by the wildfires. As expected, the primary reason for the increase in unit commitments was to support Southern California zonal reliability, as indicated by the commitment classifications taken from Operator Logs and represented in Figure 2.29.

During the week of the fire, minimum load costs attributed to zonal and local reliability issues in Southern California increased from about $350,000 per day to a peak of $1.2 million per day. This increase in unit commitment is primarily attributable to transmission issues created by the fires, and likely compounded by the roughly 2,200 MW forced outage of the SONGS facility.

Figure 2.30 shows the daily commitment cost totals for zonal and local reliability reasons for Southern California.

Figure 2.28 Capacity Committed through FERC Must-Offer and RA Processes for Oct 13 – Nov 2, 2007

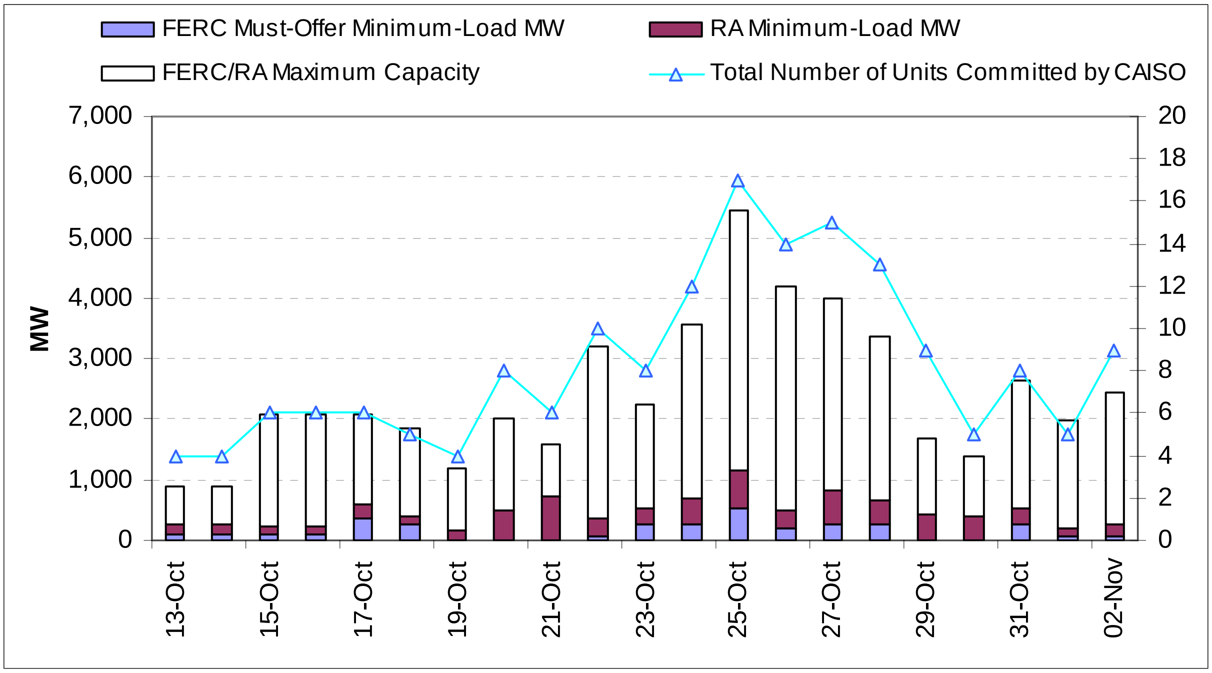


Figure 2.29 Units Committed by Commitment Type for Oct 13 – Nov 2, 2007

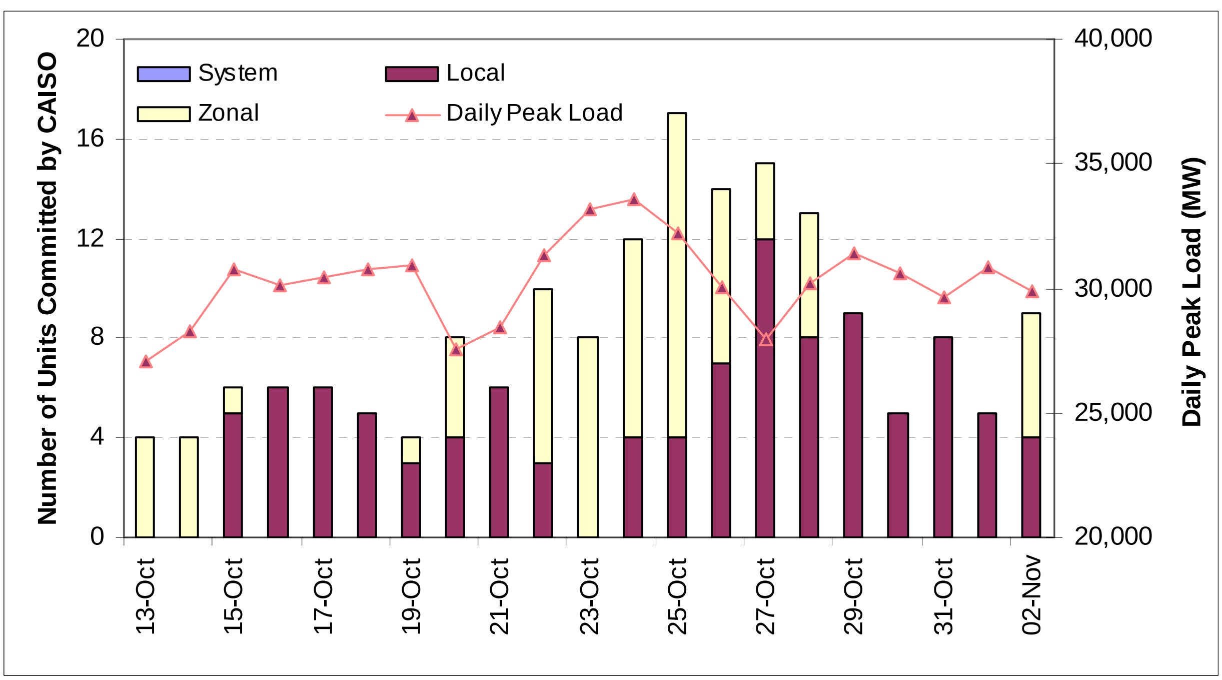
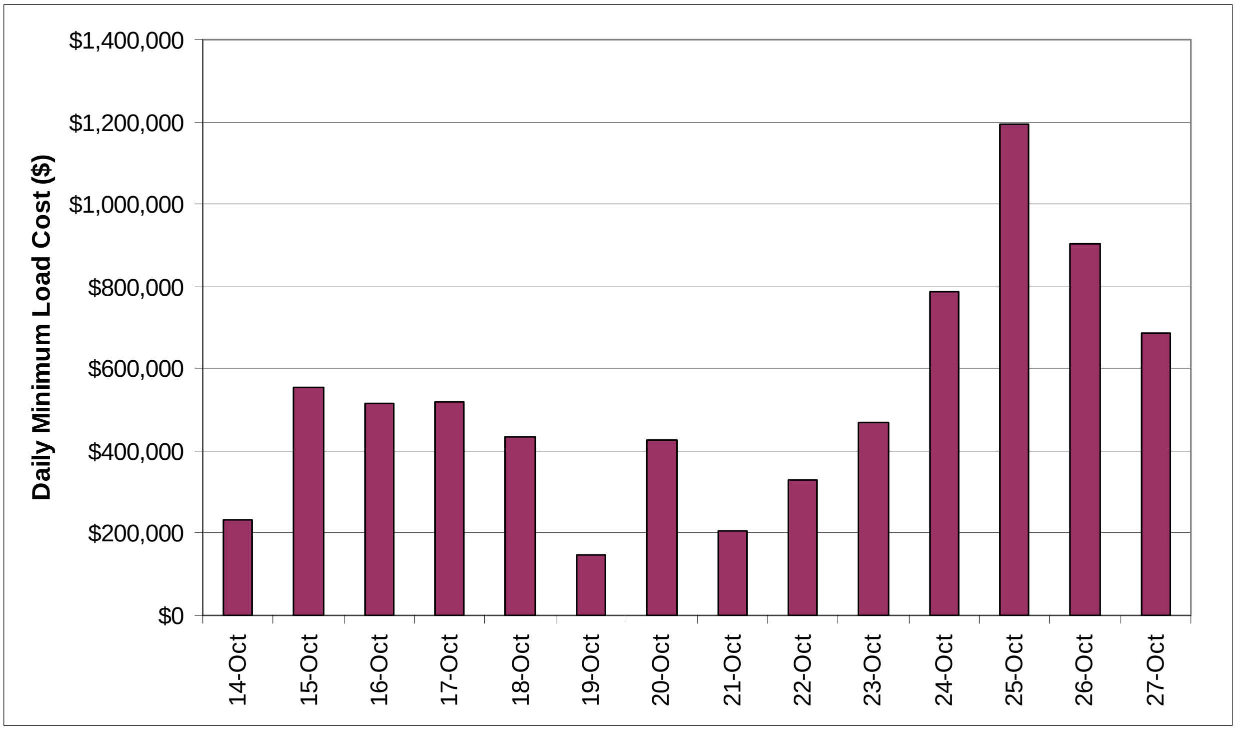
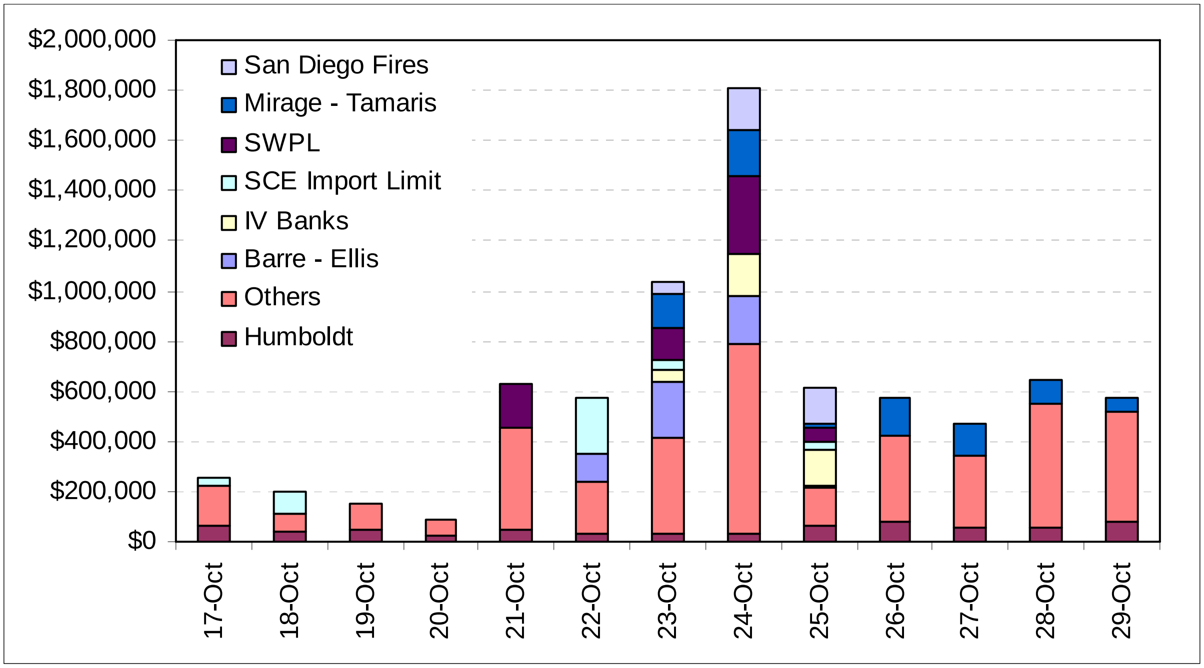


Figure 2.30 Daily Minimum Load Cost (MLCC) Associated with Day Ahead Unit Commitment for Zonal and Local Reliability Issues



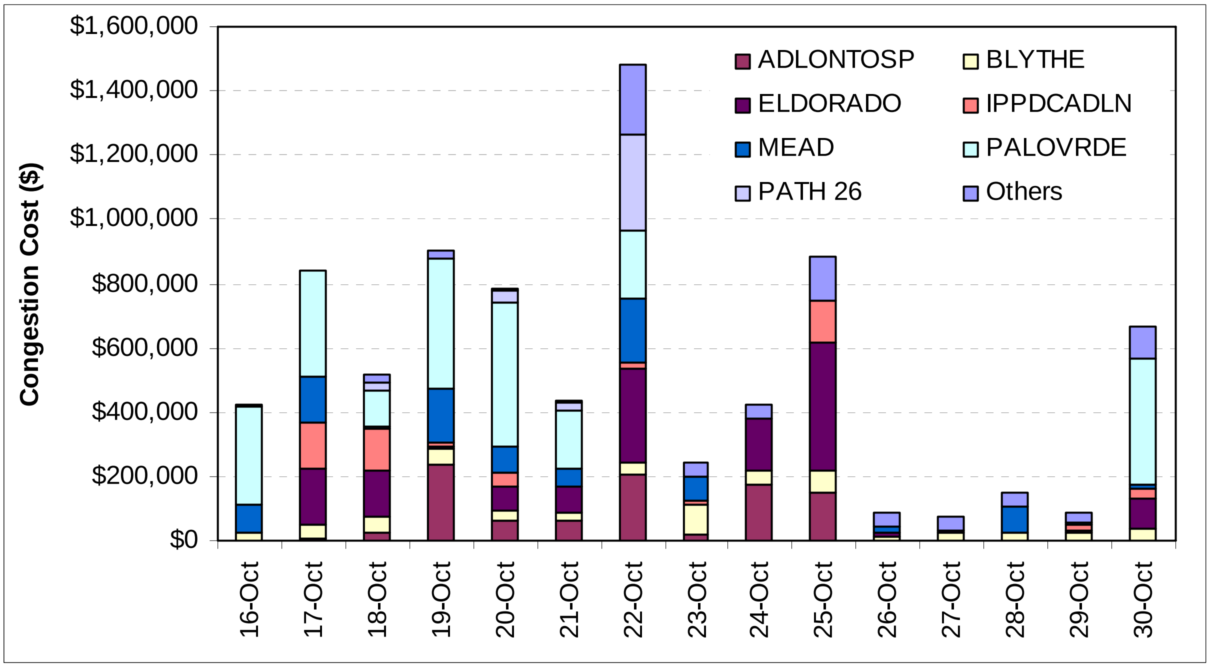
When some transmission lines were taken out of service by the wildfires, power flow shifted and other transmission lines became at risk for overload. To mitigate further threats to grid reliability resulting from additional lines being forced out of service, the CAISO relied heavily on OOS dispatches, as seen in Figure 2.31. This mitigation measure was effective in averting additional forced transmission outages; however, it also resulted in a significant increase in redispatch costs associated with mitigating risks to grid reliability. The cost of out-of-sequence dispatches is measured in terms of the redispatch cost, which is the difference between paying the OOS dispatch its bid price outside the market and balancing that dispatch with an in-sequence dispatch within the market. As shown in Figure 2.31, net redispatch costs were significantly higher during the peak of the wildfire week compared to the neighboring periods.

Figure 2.31 Out-of-Sequence Redispatch Costs for October 17-29, 2007



Not surprisingly, inter-zonal congestion costs also increased as a result of the wildfires. There are generally two reasons for significant inter-zonal congestion costs: high demand for transmission capacity and transmission derates or outages. The increase in costs during the wildfires was primarily due to capacity derates on some Branch Groups and shifts in scheduling as importers needed to avoid the Southwest Power Link (SWPL) facility which was forced out during this period. This resulted in excess demand for import capacity compared to the (derated) available capacity, and increased congestion charges during this period. Figure 2.32 shows the inter-zonal congestion costs on the Eldorado Branch Group increased significantly during the wildfires, and that Path 26 incurred a high congestion cost on August 22, when the line was significantly derated.

Figure 2.32 Inter-Zonal Congestion Costs on Major Branch Groups for October 16 – 30, 2007



2.4 Wholesale Energy and Ancillary Services Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility-retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. The real-time component of costs also includes reliability costs (must-offer payments and minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs). These estimates do *not* include resource adequacy procurement costs, a regulatory requirement for bilateral capacity arrangements between generators and LSEs that has been in place since June 2006. Costs associated with these bilateral capacity contracts are not visible to the CAISO.

The estimated total wholesale energy and ancillary service cost for 2007 was $11.8 billion, or $48.94 per megawatt-hour (MWh) of load served, slightly above the total cost figure of $47.57/MWh of load served for 2006. These estimates reflect not only CAISO market prices, but also estimated costs of spot market transactions, long-term contracts entered into during the 2001 energy crisis, production of utility-owned generation, and other cost components, all of which are described in the notes accompanying Table 2.5. The minor increase in cost between 2007 and 2006 may be attributed to the increased use of thermal generation in 2007 in place of lower-cost hydro power (both imported and generated internally) that was used more heavily during the late spring and summer of 2006. Other factors that would cause costs to decrease in 2007 include the expiration of long-term contracts and subsequent replacement of them by new short- or long-term contracts, and greater availability of nuclear power. A factor that caused costs to increase is the new charge for the Reliability Capacity Services Tariff that has been in effect since mid-2006.

Table 2.5 shows estimated wholesale energy costs by month for 2007, and annual summaries for each previous year since 1998.

Table 2.5 Monthly Wholesale Energy Costs: 2007 and Previous Years

Month	ISO Load (GWh)	Total Est. Forward Costs ($MM)	RT and Reliability Costs ($MM)	AS Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and A/S ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of A/S ($/MWh load)	A/S as % of Wholesale Cost	Avg Cost of Energy & A/S ($/MWh load)
Jan-07	19,752	$ 892	$ (1)	$ 3	$ 891	$ 895	$ 45.12	$ 0.17	0.4%	$ 45.29
Feb-07	17,160	$ 775	$ (1)	$ 2	$ 774	$ 776	$ 45.09	$ 0.11	0.2%	$ 45.20
Mar-07	19,132	$ 849	$ 5	$ 2	$ 854	$ 856	$ 44.64	$ 0.12	0.3%	$ 44.76
Apr-07	18,784	$ 832	$ 8	$ 2	$ 840	$ 843	$ 44.73	$ 0.13	0.3%	$ 44.86
May-07	20,256	$ 1,018	$ 7	$ 2	$ 1,025	$ 1,027	$ 50.62	$ 0.09	0.2%	$ 50.70
Jun-07	20,798	$ 1,045	$ 7	$ 6	$ 1,052	$ 1,058	$ 50.58	$ 0.27	0.5%	$ 50.85
Jul-07	23,710	$ 1,153	$ (0)	$ 9	$ 1,152	$ 1,161	$ 48.61	$ 0.37	0.8%	$ 48.98
Aug-07	24,439	$ 1,231	$ 18	$ 4	$ 1,249	$ 1,253	$ 51.09	$ 0.16	0.3%	$ 51.25
Sep-07	21,000	$ 920	$ (4)	$ 4	$ 916	$ 920	$ 43.61	$ 0.18	0.4%	$ 43.79
Oct-07	19,162	$ 926	$ 20	$ 11	$ 946	$ 957	$ 49.36	$ 0.56	1.1%	$ 49.92
Nov-07	18,334	$ 837	$ 25	$ 5	$ 862	$ 867	$ 47.01	$ 0.26	0.6%	$ 47.27
Dec-07	19,463	$ 948	$ 15	$ 5	$ 963	$ 969	$ 49.49	$ 0.28	0.6%	$ 49.77
Total 2007	**241,990**	**$ 11,427**	**$ 264**	**$ 153**	**$11,691**	**$ 11,844**	**$ 48.31**	**$ 0.63**	**1.3%**	**$ 48.94**
Total 2006	**240,260**	**$ 10,563**	**$ 633**	**$ 234**	**$11,196**	**$ 11,430**	**$ 46.60**	**$ 0.97**	**2.0%**	**$ 47.57**
Total 2005	236,449	$ 12,526	$ 830	$ 228	$13,356	$ 13,584	$ 56.49	$ 0.96	1.7%	$ 57.45
Total 2004	239,788	$ 11,832	$ 1,099	$ 184	$12,931	$ 13,115	$ 53.93	$ 0.77	1.4%	$ 54.70
Total 2003	230,668	$ 10,814	$ 696	$ 199	$11,510	$ 11,709	$ 49.90	$ 0.86	1.7%	$ 50.76
Total 2002	232,011	$ 9,865	$ 532	$ 157	$10,397	$ 10,554	$ 44.81	$ 0.68	1.5%	$ 45.49
Total 2001	227,024	$ 21,248	$ 4,586	$ 1,346	$25,834	$ 27,180	$ 113.79	$ 5.93	5.0%	$ 119.72
Total 2000	237,543	$ 22,890	$ 3,446	$ 1,720	$26,336	$ 28,056	$ 110.87	$ 7.24	6.1%	$ 118.11
Total 1999	227,533	$ 6,848	$ 562	$ 404	$ 7,410	$ 7,814	$ 32.57	$ 1.78	5.2%	$ 34.34
1998 (9mo)	169,239	$ 4,704	$ 1,061	$ 638	$ 5,765	$ 6,403	$ 34.07	$ 3.77	10.0%	$ 37.83

Notes to Wholesale Costs Table:

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

1998-2000:

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

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

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

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

1998-2001:

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

2001 and 2002:

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

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

2002 through 2007:

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

2003:

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

2003 through 2007:

Forward energy costs revised slightly upward using a methodology developed for the 2006 Report to include: utility-retained generation at estimated production costs, long-term contract (formerly managed by CDWR/CERS) estimated using 2002 delivery volumes; and short-term bilateral procurement estimated at utility-supplied procurement prices, when available, or Powerdex hour-ahead prices.

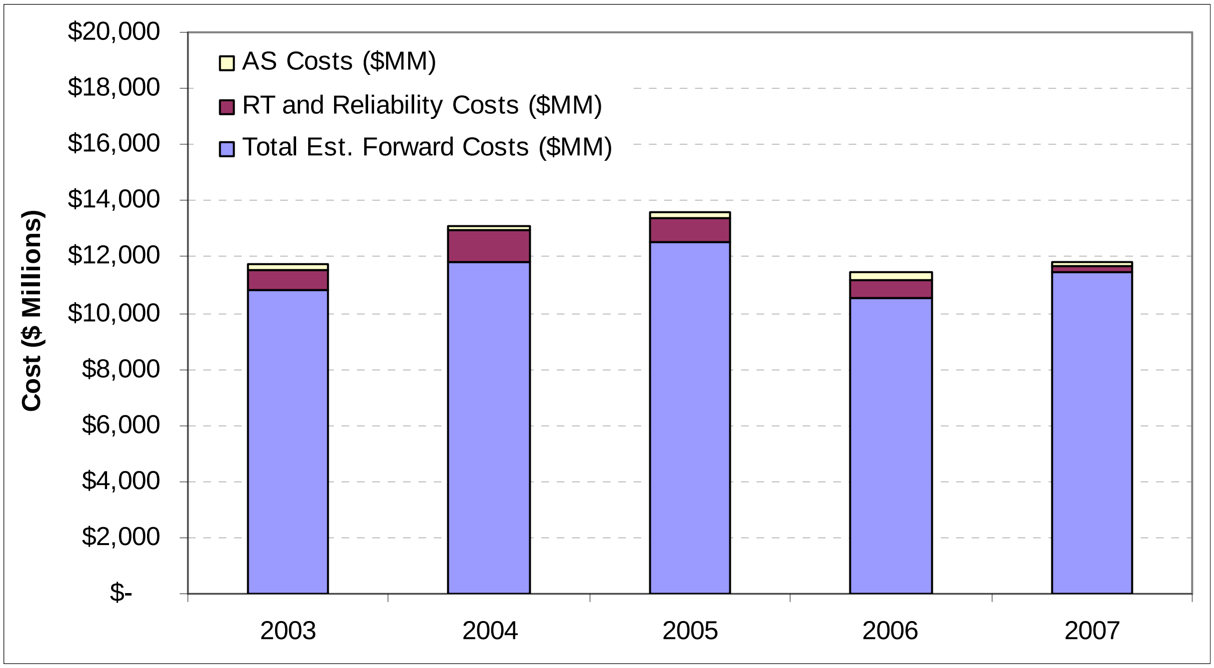
2006 and 2007 figures do not include RA capacity payments, which are not visible to the CAISO.

All years:

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

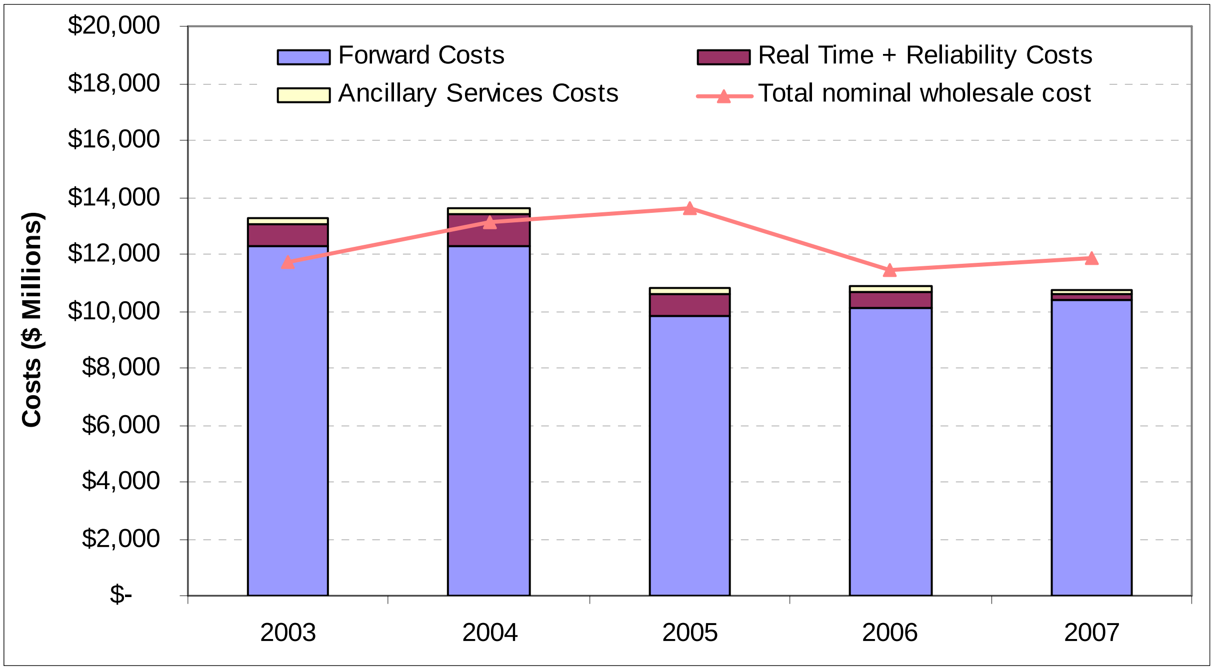
Figure 2.33 shows total wholesale costs from 2003 to 2007. With the addition of new generation and transmission infrastructure, and significant amount of forward energy procurement, costs have been stable for the past five years. Importantly, the trend in real-time balancing and reliability costs has been downward, totaling $264 million in 2007, compared to $619 million in 2006.

Figure 2.33 Total Wholesale Costs: 2003-2007



Since the cost of natural gas historically has had a strong influence on the total energy cost estimate, DMM also calculates an estimate of energy costs normalized to a fixed natural gas price. As shown in Figure 2.34, costs normalized to a fixed gas price were very close in 2007 to the 2006 level. Normalized total costs (excluding, in particular, RA capacity payments – the costs of which are not known by the CAISO) were $10.8 billion in 2007, compared to $10.9 billion in 2006. On a per-megawatt-hour basis, normalized total costs decreased by $0.88/MWh between 2006 and 2007. Normalized average costs per unit of load served in 2007 and 2006 respectively were $44.46 and $45.34/MWh. The low hydro conditions in 2007 necessitated greater reliance on costlier thermal generation. This added cost was offset by lower reliability and ancillary services costs. Again, it is important to note that the reported reliability costs understate the true reliability costs as they do not include the cost of previous RMR capacity that is now contracted through the Resource Adequacy Program.

Figure 2.34 Total Wholesale Costs Normalized to Fixed Gas Price: 2003-2007[25]



The aforementioned increase in energy costs and decrease in reliability costs is evident in Table 2.6, which provides a component breakdown of contributing factors to energy costs. This table serves as a useful benchmark of CAISO and market performance. Note that RMR costs in particular decreased by over $1 per MWh of load served in 2007; however, this reduction presumably was offset to some degree by an increase in RA costs, which are not visible to the CAISO.

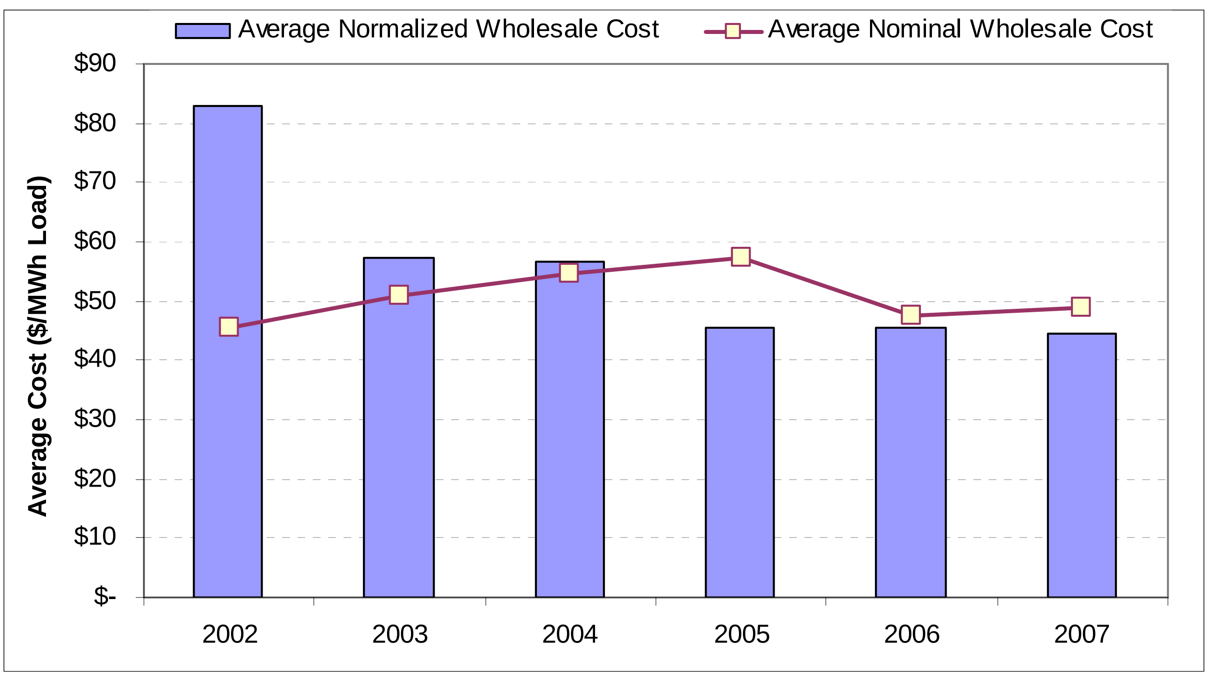
[25] July 2004 gas price ($5.70/mmBtu) is used as the basis for normalization. Energy costs were normalized separately for each month by dividing the monthly nominal energy costs by the ratio of the applicable monthly gas price and the July 2004 indexed gas price and then adding the non-energy cost components. Total costs include all actual or estimated energy costs adjusted for differences in natural gas price along with unadjusted costs of grid management, ancillary services, RCST charges, and fixed RMR payments. Total costs do not include RA capacity payments, which are not visible to the CAISO.

Table 2.6 Contributions to Estimated Average Wholesale Energy Costs per Unit of Load Served in CAISO, 2003-2007[26]

	2003	2004	2005	2006	2007	Change '06-'07
Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	$ 45.77	$ 48.21	$ 52.28	$ 43.01	$ 46.11	$ 3.10
Interzonal Congestion Costs	$ 0.12	$ 0.23	$ 0.23	$ 0.23	$ 0.35	$ 0.12
GMC	$ 1.00	$ 0.90	$ 0.84	$ 0.72	$ 0.76	$ 0.04
Incremental In-Sequence RT Energy Costs	$ 0.63	$ 0.86	$ 1.55	$ 1.04	$ 1.05	$ 0.01
Explicit MLCC Costs (Uplift)	$ 0.54	$ 1.21	$ 0.55	$ 0.50	$ 0.23	$ (0.28)
RCST Costs				$ 0.06	$ 0.11	$ 0.05
Out-of-Sequence RT Energy Redispatch Premium	$ 0.19	$ 0.43	$ 0.14	$ 0.10	$ 0.15	$ 0.05
RMR Net Costs (Include adjustments from prior periods)	$ 1.95	$ 2.67	$ 2.14	$ 1.78	$ 0.52	$ (1.26)
Less In-Sequence Decremental RT Energy Savings	$ (0.29)	$ (0.59)	$ (0.87)	$ (0.85)	$ (0.96)	$ (0.11)
Average Total Energy Costs	**$ 49.90**	**$ 53.93**	**$ 56.86**	**$ 46.60**	**$ 48.31**	**$ 1.71**
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	$ 0.86	$ 0.77	$ 0.96	$ 0.97	$ 0.63	$ (0.34)
Average Total Costs of Energy and A/S	**$ 50.76**	**$ 54.70**	**$ 57.83**	**$ 47.57**	**$ 48.94**	**$ 1.37**

Figure 2.35 shows average total annual wholesale cost of energy and ancillary services ($/MWh of load) for 2003 through 2007, expressed in both nominal terms and normalized to a fixed gas price. This nominal average cost increased in 2002 through 2005 in step with increasing gas prices, but declined sharply in 2006 due primarily to abundant hydroelectric power, which displaced more expensive gas-fired generation. Nominal average cost increased in 2007, as hydroelectric production declined, and reliance on gas-fired generation returned to historically normal levels. When normalized for changes in natural gas prices, the 2006 and 2007 average costs are similar.

Figure 2.35 Average Total Wholesale Cost per Unit of Load, 2002-2007



[26] Figures reported in this table for the prior reporting year have been adjusted to reflect the most current and accurate data and therefore are slightly different from those reported last year.

2.5 Market Competitiveness Indices

There are several indices calculated by the Department of Market Monitoring that provide insight into the overall competitiveness of the wholesale market. The first index is the Residual Supplier Index, or RSI. The RSI is a structural measure of supply adequacy that accounts for portfolio concentration of internal generation and measures the extent to which the largest supplier may be pivotal in setting prices. The other type of index used to monitor market competitiveness is an empirical index that measures the price-to-cost mark-up of wholesale energy. This index is calculated for both bilateral short-term (spot) energy markets as well as the real-time imbalance energy market operated by the CAISO. The Price-Cost Index measures the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the marginal unit of energy needed to serve load. The RSI and Price-Cost Index are both good indicators of overall competitiveness when viewed over a period of time sufficient that the indices are measuring the structural drivers within the market and are not overly influenced by very short-term market disturbances.[27] There is also a strong statistical relationship between RSI values and estimated Price-Cost values where lower RSI values are positively correlated with higher price-cost mark-ups.

2.5.1 Residual Supplier Index for Total Energy Purchases

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. Mathematically, RSI values are calculated for each hour (*i*) based on the following formula:

$$RSI_i = \frac{TS_i - LSS_i}{TD_i}$$

Where,

TS_i = Total Supply in hour *i*

LSS_i = Supply of Largest Single Supplier in hour *i*

TD_i = Total Demand in hour *i*

The total supply (TS) includes hour-ahead energy schedules and real-time imbalance energy market generator and import bids. The total demand (TD) is the metered load for that hour. The largest single supplier is defined as the largest market participant in terms of hour-ahead generation schedules, imbalance energy market generator and import bids.

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

[27] Both the spot market and imbalance market are subject to swings that are caused by short-term issues such as unexpected unit or line outages, load forecast errors, or other unforeseen issues (for example, the Southern California wildfires last October).

RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

Figure 2.36 Residual Supply Index for All Energy (2002-2007)

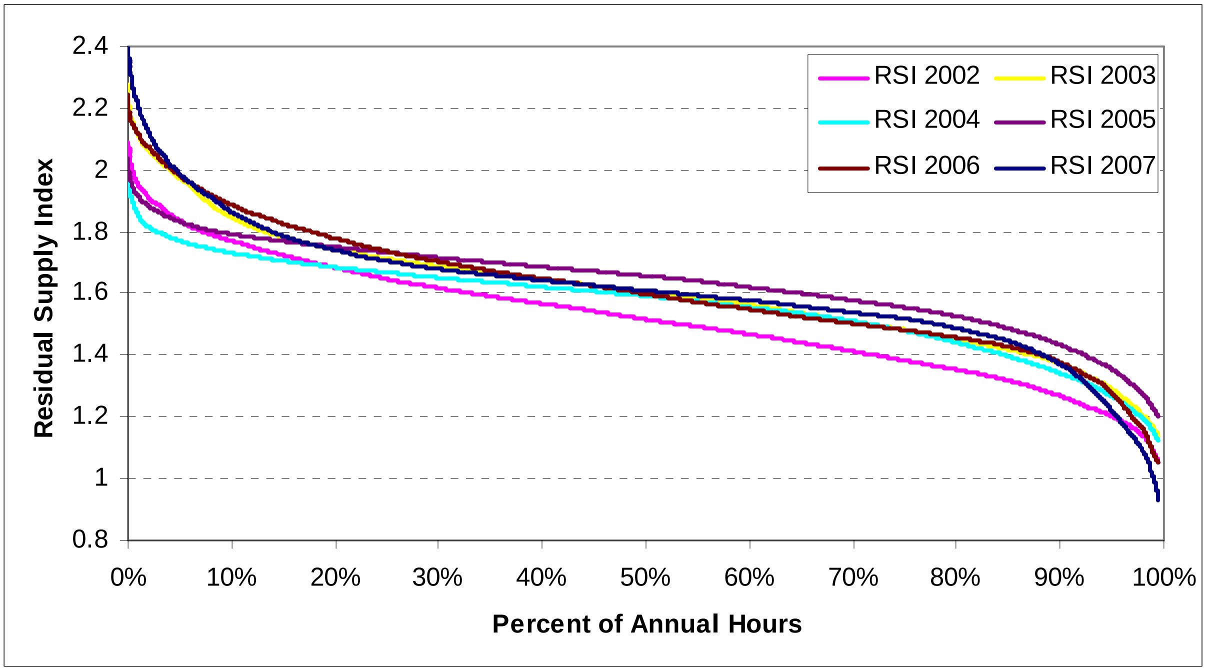


Figure 2.36 shows estimated hourly RSI values from highest to lowest values for years 2002-2007. In 2006, there were roughly 125 hours, or 1.7 percent of hours, when the RSI level dropped below 1.1.[28] This frequency was marginally higher in 2007 than in the prior four years; however, the statistic does indicate a competitive market overall where there are less than two percent of hours where structural market power at the system level may be of concern. For reference, the frequency of hours where the RSI was below 1.1 in the 2000 – 2001 period was between 20 percent and 35 percent of hours. The 2007 RSI values are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2007. The significant amount of long-term energy contracts entered into since 2001 have also led to more stable and 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 and ownership concentration was much more favorable for competitive market outcomes in the period 2002 through 2007 than 2001 as reflected by the higher RSI values.

2.5.2 Price-to-Cost Mark-up for Short Term Energy Purchases[29]

Another index used to measure market performance in the California wholesale electricity markets is the price-to-cost mark-up. This is the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the most expensive, or

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

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

marginal, unit of energy needed to serve load. The ratio of the volume-weighted average mark-up to marginal cost is a metric that can be used to identify market performance trends over time.

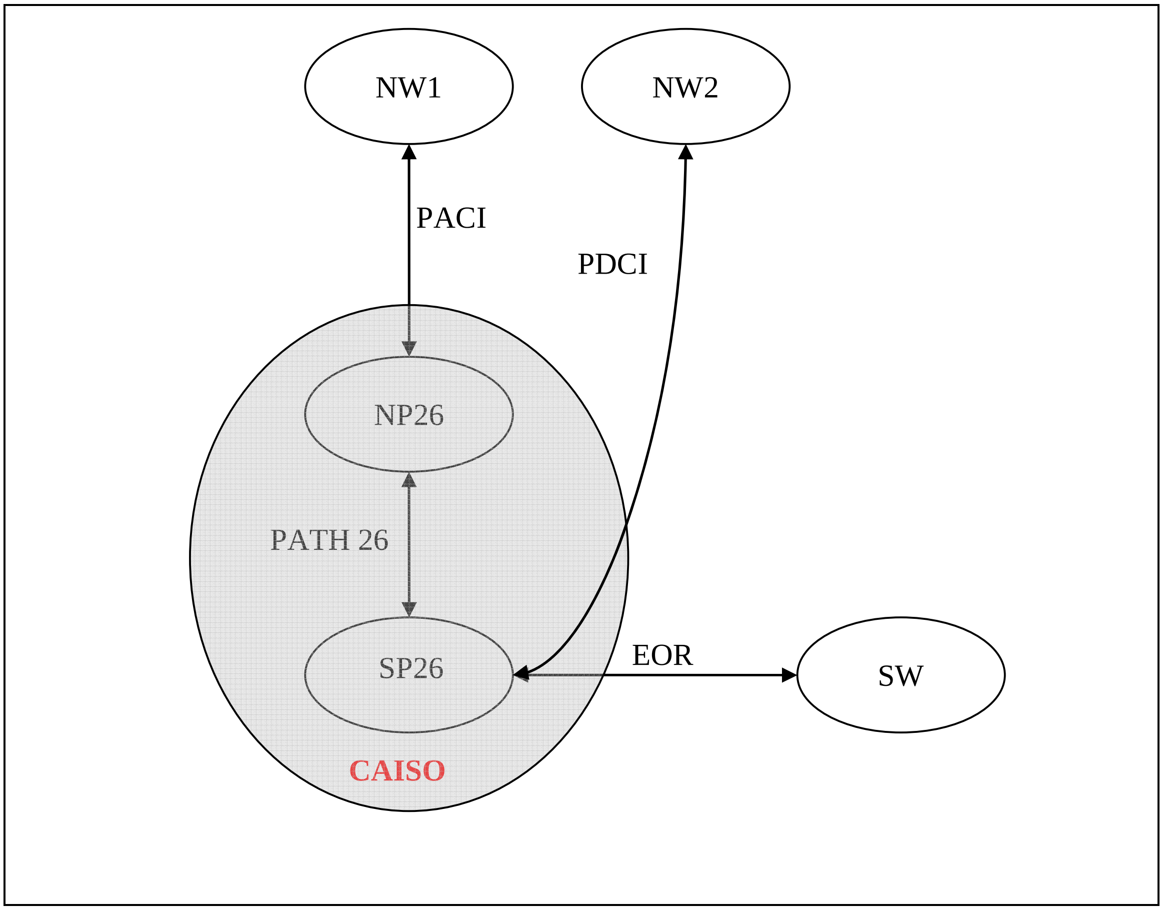
Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from the Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. The methodology used here has been updated to include data sources that were previously not available. However, there are still periods in calendar year 2004 for which short-term energy procurement information is not available. During these periods, hourly short-term forward price data purchased from Powerdex is used as a substitute. For 2005 through 2007, the actual short-term prices paid were obtained from confidential bilateral transactions data of three major utilities that participate in the CAISO markets. Only the transactions that occurred 24 hours prior to the operating day were considered in the analysis to be short-term.

The simulation of competitive benchmark prices considers a single-price auction framework consistent with the current CAISO imbalance market design and clears offers against hour-ahead scheduled load subject to the following assumptions:

- Simplified five node, four line zonal model.
- Import and export bids are fixed in quantity at observed hour-ahead scheduled import levels, and priced at the regional spot trading hub reported price reported from Powerdex, with the California-Oregon Border (COB) as Northwest and Palo Verde (PV) as Southwest pricing points.
- Internal thermal generators with heat rate data bid in at marginal cost as determined by their incremental heat rate, hourly natural gas price, and variable operating and maintenance costs.
- Internal hydroelectric units, nuclear units and the rest of thermal units without heat rate data bid in zero as price and hour-ahead schedule as quantity.
- All the remaining internal generators, including biomass, geothermal, Qualified Facility, wind, etc., bid in zero as price and metered output as quantity.
- Unit commitment decisions are based on historical hour-ahead schedules and metered output.

Figure 2.37 shows the simplified zonal radial network model used in the simulation.

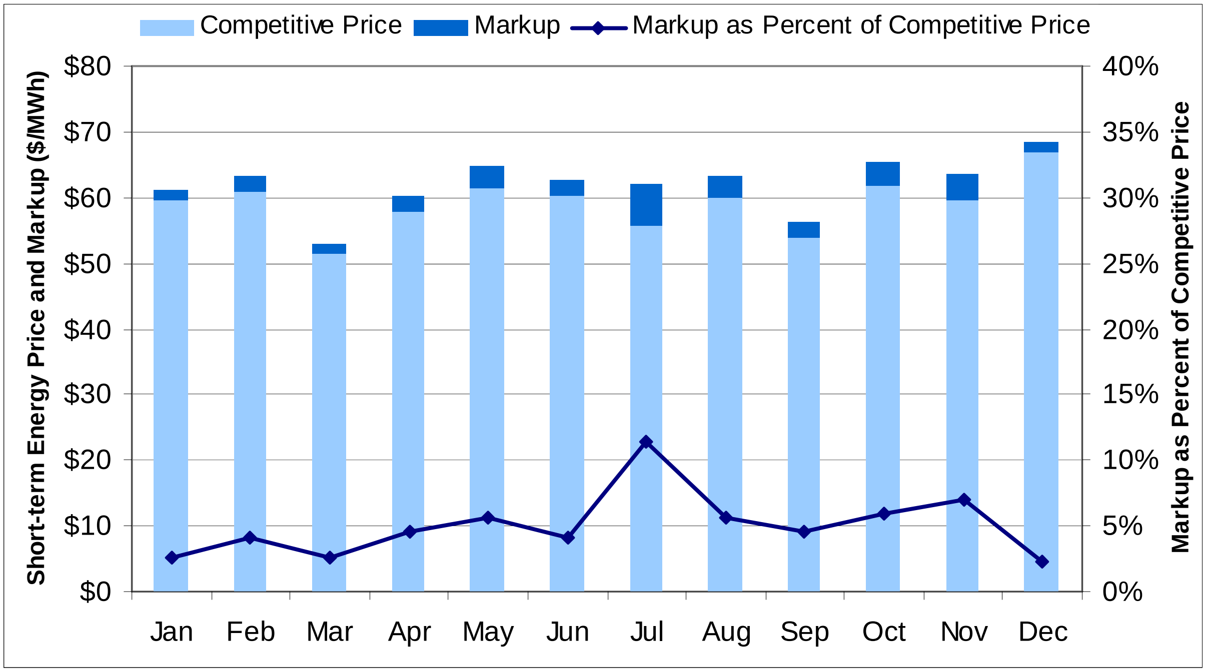
Figure 2.37 Simplified Network Topology Used in Competitive Price Simulation



The CAISO market model utilizes PLEXOS for Power Systems as the market simulation tool. PLEXOS employs a linear programming-based production cost minimization model, which allows for co-optimization with ancillary service markets.

For calendar year 2007, the CAISO observed monthly short-term mark-ups ranging from 2 to 11 percent, compared to 1 to 16 percent in the prior year. Figure 2.38 summarizes competitiveness in the short-term forward energy markets. July was the only month when mark-ups were greater than 10 percent, corresponding to the summer high demand period. Overall, 2007 short-term forward markets functioned effectively, leading largely to competitive pricing in the CAISO Control Area.

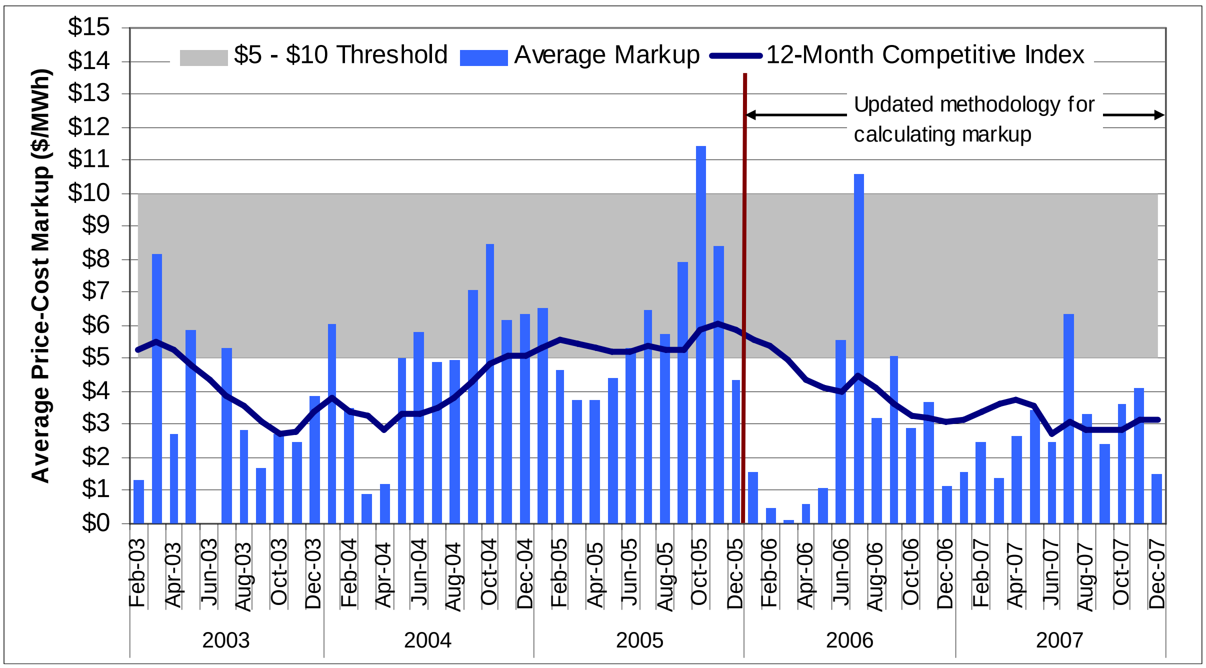
Figure 2.38 2007 Short-term Forward Market Index



2.5.3 Twelve-Month Competitiveness Index

The CAISO employs several indices to assess market competitiveness. The index in Figure 2.39 serves to measure market outcomes over extended time periods against estimated perfectly competitive market outcomes. The 12-Month Competitiveness Index is a rolling average of the short-term energy mark-up above simulated competitive prices during a twelve month period. The CAISO assumes that the short-term energy market is subject to little or no exercise of market power when the index is within or below a $5 to $10 per MWh range. In 2007, the index stabilized at the $2-4 range overall due to low mark-ups during the winter and spring months and relatively mild conditions during the summer and fall, with the exception of July.

Figure 2.39 Twelve-Month Competitiveness Index



2.5.4 Price-to-Cost Mark-up for Imbalance Energy

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

Figure 2.40 and Figure 2.41 show the monthly average mark-up for incremental and decremental real-time energy dispatched in 2007, respectively. As shown in these figures, the incremental Real Time Market mark-ups are above 20 percent for the lower-load months, when the imbalance market was primarily decremental and incremental energy dispatches were relatively infrequent and moderate. The mark-ups were lowest during the summer months, when incremental energy dispatches traditionally are more frequent, and were particularly low for incremental dispatches in September. Mark-ups were generally lower in the summer months because there were typically more units on-line to provide real-time energy, particularly thermal units with greater ramping capability than are available in the off-peak months. Additionally, peak loads during the summer months were fairly moderate, which in turn moderated imbalance energy demands. This is discussed in further detail below.

It is important to note that this market is prone to some degree of market power because of the very low volumes that clear this market and the fact that demand for 5-minute energy is very volatile and price inelastic. A generator submitting a bid at a very high price for the last few megawatt-hours of its unit's capacity will likely have those bids taken periodically, as the total supply of bids in this market can be very thin, thus requiring periodic dispatching of most or all of the available energy. The low volume and highly volatile nature of this market make it unattractive for new supply to enter to "compete away" high energy prices. It is also important to note that the impact of market power in the Real Time Market is relatively minor given the low market volumes and the fact that some of the generation earning the high market prices is owned or under operational control of LSEs. Additional factors that may have contributed to the increase in Real Time Market mark-ups include the following:

- During the mild load months, a relatively large number of units were out on planned maintenance, and relatively few units were committed at minimum load, pursuant to the FERC Must-Offer Obligation (MOO) and/or under Resource Adequacy (RA) contracts. This, along with unseasonably low availability of inexpensive hydroelectric supply, resulted in relatively few units available for balancing services during this period, which resulted in somewhat thinner imbalance supply. Consequently, during short periods where the imbalance requirement was high (in either the incremental or decremental direction), the thinner supply resulted in more frequent intervals where higher priced bids (lower priced bids for decremental intervals) were required to meet imbalance, resulting in higher price-cost mark-ups in those intervals.

- Loads during the summer of 2007 necessitated a much higher level of MOO and RA unit commitment, but were relatively mild when compared with those seen during the summer of 2006. For example, there were 23 percent fewer hours in 2007 with loads above 40,000 MW than in 2006, as noted above in Section 2.1. In addition, very high levels of forward energy scheduling was a frequent occurrence, due in part to the 95 percent day-ahead scheduling requirement, as required by the CAISO Tariff Amendment 72. These factors combined to result in a relatively competitive market for both incremental and decremental balancing during the summer.

- The lower rate of forced outages, as discussed above in Section 2.2.3, also translates to fewer disturbances and contingencies. This reduces the need for frequent sharp upward dispatches of imbalance energy, and results in fewer spikes in prices and lower price-to-cost mark-up.

Figure 2.40 Average Hourly Real-time Incremental Energy Mark-up above Competitive Baseline Price by Month for 2007

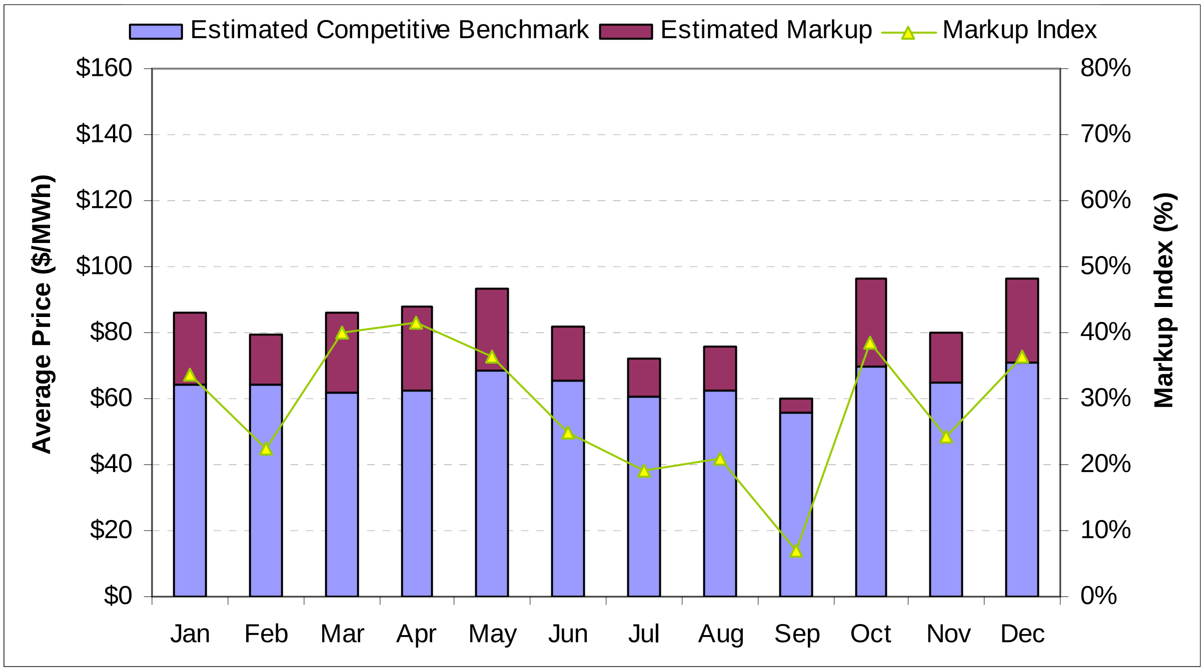
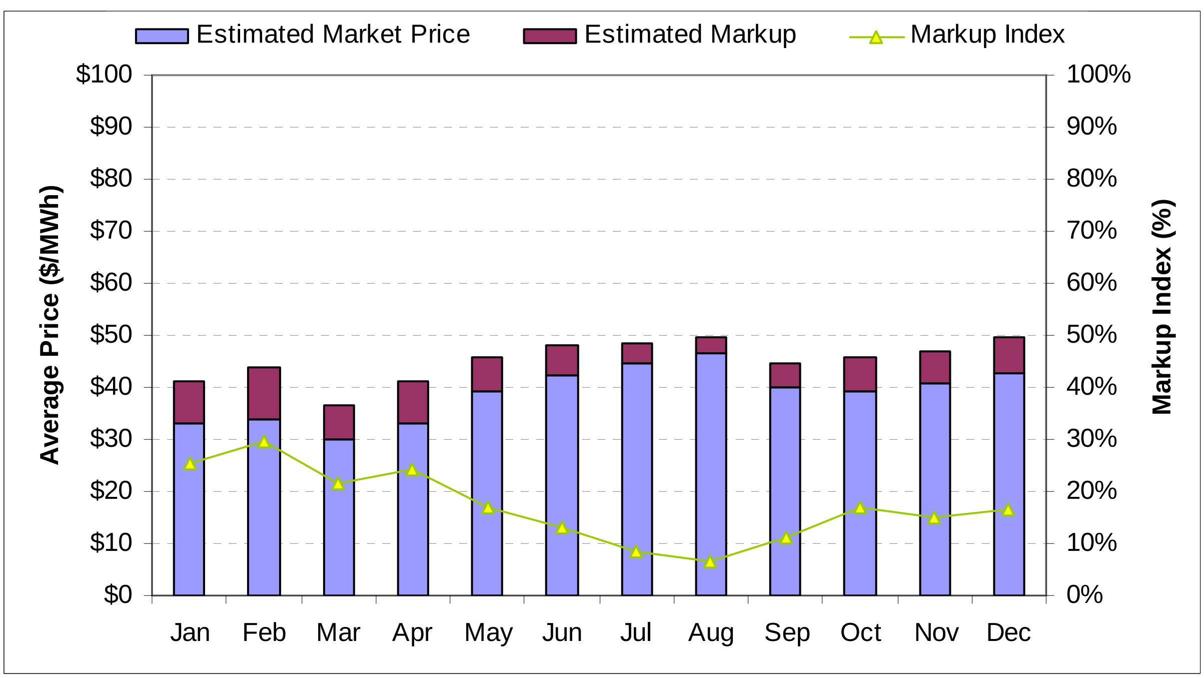


Figure 2.41 Average Hourly Real-time Decremental Energy Mark-up below Competitive Baseline Price by Month for 2007



2.6 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past several years, the relationship between grid reliability, new investment, the retirement of aged plants, and price signals remains an important focus of the CAISO. In recent years, there has been a declining but continued reliance on very old and inefficient generation to meet Southern California reliability needs. Going forward, it is imperative that California has an adequate market/regulatory framework for facilitating new investment in the critical areas of the grid where it is needed, particularly Southern California. This section begins with an assessment of the extent to which spot market revenues in 2007 were sufficient to cover the annualized fixed cost of new generation. A review of the generation additions and retirements for 2001 through 2007 and projections for 2008 is provided at the end of this section, along with a review of the continued reliance on older generation facilities.

2.6.1 Revenue Adequacy for New Generation Investment

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

The annualized fixed costs used in this analysis are obtained from the 2007 California Energy Commission (CEC) report on Comparative Costs of California Central Station Electricity Generation Technologies,[30] which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be $132.6/kW-year and $162.1/kW-year, respectively. The costs of new generation estimates are based substantially on empirical survey data collected from power plant developers in California who built power plants between 2001 and 2006. The cost estimates based on these survey results reflect a more current sampling of costs incurred by builders / investors in new generation compared to the $90/kW-yr for combined cycle and $78/kW-yr for simple cycle units published in the CEC 2003 Integrated Energy Policy Report and used in this study in prior years. The large increase in new generation costs in 2007 can be attributed to increases in material costs, siting and environmental costs, the availability and cost of investment capital, changes to the specific taxes that are included in the cost estimate, and increases in O&M costs. In addition, the higher cost figures reported in the 2007 report are based on empirical survey data from recent plant builders while the figures reported in the 2003 report were based largely on constructed costs. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.7 and Table 2.8.

[30] The CEC report can be found here: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

Table 2.7 Analysis Assumptions: Typical New Combined Cycle Unit[31]

Technical Parameters	
Maximum Capacity	550 MW
Minimum Operating Level	150 MW
Startup Gas Consumption	1,850 MMBtu/start
Heat Rates	
Maximum Capacity	7,100 MBTU/MW
Minimum Operating Level	8,200 MBTU/MW

Financial Parameters	
Financing Costs	$90.2 /kW-yr
Insurance	$6.2 kW-yr
Ad Valorem	$4.9 kW-yr
Fixed Annual O&M	$11.2 /kW-yr
Taxes	$20.1 kW-yr
Total Fixed Cost Revenue Requirement	**$132.6/kW-yr**
Variable O&M	$2.4/MWh

Table 2.8 Analysis Assumptions: Typical New Combustion Turbine Unit[32]

Technical Parameters	
Maximum Capacity	50 MW
Minimum Operating Level	20 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700

Financial Parameters	
Financing Costs	$107.7 /kW-yr
Insurance	$7.3 kW-yr
Ad Valorem	$5.8 kW-yr
Fixed Annual O&M	$20.8 /kW-yr
Taxes	$20.5 kW-yr
Total Fixed Cost Revenue Requirement	**$162.1/kW-yr**
Variable O&M	$10.9/MWh

2.6.2 Methodology

To provide a longer-term perspective, the net revenue analysis provided in this year's Annual Report was conducted over a 4-year period (2004-2007). The methodology used this year is identical to the one used in the 2006 Annual Report on Market Issues and Performance. The net

[31] The Financing Costs, Insurance, Ad Valorem, Fixed Annual O&M and Taxes costs for a typical unit in this table were derived directly from the data presented in the CEC report referenced in footnote 30, which also can be found in this presentation posted to the CAISO website: http://www.caiso.com/1c75/1c75c8ff34640ex.html.

[32] See Footnote 31

revenues earned by the hypothetical combined cycle described in Table 2.7 is based on the generator's participation in all possible markets: the Real Time Market and Ancillary Services Market operated by CAISO and the day-ahead bilateral energy markets. The specific methods used for the approach are described below.

Combined Cycle – Net Revenue Methodology

The operational and scheduling assumptions used to assess the potential revenues that could be earned by a typical new combined cycle unit are summarized below:

1) An initial operating schedule for day-ahead bilateral energy markets was determined based on the hourly spot market price index published by Powerdex and the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.7. The unit was scheduled up to full output when hourly prices exceed variable operating costs subject to observing the ramping limitations.

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

3) If the unit was scheduled to stay off-line in the Day Ahead Market, it may be turned on in the Real Time Market operated by CAISO. The scheduling logic was the same as in the Day Ahead Market except that the Real Time Market clearing prices in both NP15 and SP15 were used instead of the Powerdex prices. The unit was scheduled up to full output when hourly real-time prices exceeded variable operating costs while observing the ramping limits.

4) Ancillary Service revenues were calculated by assuming the unit could provide up to 50 MW of spinning reserve each hour if it was committed in either the Day Ahead Market or Real Time Market for the hour and the output was smaller than its max stable level. The spinning reserve service prices were based on actual CAISO Day Ahead Market prices.

5) All start-up gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

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

In prior years, the results for SP15 also included possible Minimum Load Cost Compensation (MLCC) payments. The hours when the generator was committed under must-offer waiver denials were obtained from 2002 data. A more recent empirical study shows that the must-offer waiver denial hours for combined cycle units have reduced dramatically in the last four years.[33] Moreover, when combined cycle units were denied waivers, it was typically due to specific local and zonal reliability reasons and most qualified units were very old. Since our study was focused on incentive for new generation and only revenues from normal competitive market conditions were considered, such uplifts were not included in this year's analysis.

Combustion Turbine – Net Revenue Methodology

The net revenues earned by the hypothetical combustion turbine unit described in Table 2.8 were based on market participation limited to the Real Time Market[34] and Ancillary Services Market. The specific methods used for these approaches are described below.

1) For each hour, it was assumed the unit would operate if the average hourly real-time price exceeded the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.8. The unit was scheduled up to full output when Real Time Market hourly prices exceeded variable operating costs while observing the ramping limits.

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

3) Ancillary service revenues were calculated by assuming the unit could provide up to 40 MW of non-spinning reserve each hour if it was committed during the hour. The non-spinning service prices were based on actual CAISO Day Ahead Market prices.

4) All start-up gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

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

[33] For the 2004-2007 period, the total must-offer waiver denial hours for the combined cycle units in the CAISO Control Area ranged from 100 to 300.

[34] Real Time Market prices were used for the Combustion Turbine revenue analysis because this is a more likely market for fast-start units. However, the fact that the CAISO Real Time Market prices were often below prevailing day-ahead and day-of spot market prices, particularly during peak summer periods, makes the use of Real Time Market prices a somewhat conservative measure of potential energy market revenues.

2.6.3 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year's revenue analysis follows the same methodology as last year's which includes the analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated in both energy markets. The above methodologies also assume that the unit could be dispatched based on perfect foresight of market prices in all participated markets, which is not possible in practice. Therefore, the results may overestimate the net revenues and, thus, may be considered the upper limits of potential revenues.

The results for a combined cycle unit are summarized in Table 2.9. It shows a relatively increasing trend in the net revenues from 2004 to 2007. The total capacity factor remains relatively constant throughout the evaluation periods while the revenues from the Day Ahead Market increased in recent years, mainly due to higher prices in the short-term bilateral market, and the revenues from the Real Time Market dropped somewhat. However, the estimated net revenues in both zones in all years are substantially below the $132.6/kW-yr annualized fixed cost of the unit indicated in the CEC report.

Table 2.10 shows the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the CAISO Real Time Market as well as Ancillary Services Market. It shows a relatively stable trend in the net revenues from all years in the study period. Similar to the combined cycle analysis, the estimated revenues for a hypothetical combustion turbine unit fell well short of the $162.1/kW-yr annualized fixed costs indicated in the CEC report for all years (2004-2007) under all scenarios.

Table 2.9 Financial Analysis of New Combined Cycle Unit (2004–2007)

Components	2004		2005		2006		2007	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	69%	72%	65%	72%	63%	75%	69%	76%
DA Energy Revenue ($/kW - yr)	$274.77	$272.85	$372.39	$386.31	$319.65	$355.32	$369.59	$389.41
RT Energy Revenue ($/kW - yr)	$48.79	$56.13	$51.29	$63.83	$34.37	$50.02	$36.20	$41.98
A/S Revenue ($/kW – yr)	$0.71	$0.93	$1.41	$1.76	$1.01	$1.06	$0.37	$0.42
Operating Cost ($/kW - yr)	$276.69	$278.51	$363.06	$382.79	$279.50	$321.59	$321.86	$337.82
Net Revenue ($/kW – yr)	$47.58	$51.41	$62.04	$69.12	$75.53	$84.82	$84.30	$95.23
4-yr Average ($/kW – yr)	*$67.36*	*$75.14*						

Table 2.10 Financial Analysis of New Combustion Turbine Unit (2004-2007)

Components	2004		2005		2006		2007	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	9%	14%	8%	10%	7%	10%	8%	9%
Energy Revenue ($/kW - yr)	$72.80	$121.70	$87.50	$107.50	$69.46	$99.77	$97.54	$104.99
A/S Revenue ($/kW - yr)	$14.10	$27.40	$19.30	$18.50	$22.67	$21.68	$13.30	$12.83
Operating Cost ($/kW - yr)	$54.00	$81.60	$63.70	$82.00	$46.04	$68.92	$59.18	$64.63
Net Revenue ($/kW - yr)	$32.80	$67.50	$43.10	$44.10	$46.10	$52.35	$51.66	$53.19
4-yr Average ($/kW - yr)	*$43.41*	*$54.28*						

2.6.4 Discussion

The results shown in Table 2.9 and Table 2.10 indicate that net revenues appear to be sufficient to cover a unit's fixed operating and maintenance (O&M) costs on an annual basis. These fixed O&M costs are the fixed costs that a unit owner would be able to avoid incurring if the unit were not operated for the entire year (i.e., mothballed). Note that variable (fuel) costs (including start-up costs) are automatically covered since the simulation nets these costs against revenues to calculate net revenue. Fixed O&M costs, as reported by the CEC, are $11.2/kW-year for a combined cycle unit and $20.8/kW-year for a combustion turbine unit. If net revenues are expected to exceed fixed O&M costs, it should be sufficient to keep an existing unit operating from year to year. However, in order to provide an incentive for new generation investment, expected net revenues over a multi-year timeframe would need to exceed the total fixed costs of a unit (e.g., $162.1/kW-year for a combustion turbine unit).

The results above show that total fixed cost recovery, fixed O&M cost plus the cost of capital, was not achieved for either generation technology in any of the four years. In the case of the combustion turbine unit, net revenues were generally well below the total fixed cost estimate of $162.1/kW-year. The four year average net revenues ranged from $33/kW-yr to $52/kW-yr in the NP15 area and $44/kW-yr to $68/kW-yr in the SP15 area. The four year averages were $43/kW-yr in the NP15 area and $54/kW-yr in the SP15 area. However, as previously noted, basing potential energy market revenues solely on CAISO Real Time Market prices may tend to understate potential revenues given that real-time prices are generally below the day-ahead and day-of market prices. The same result is true for combined cycle units, where the total fixed cost of $132.6/KW-year is never fully reached, even when all potential revenues are accounted for. However, revenue analysis for combined cycle units does reveal a favorable trend over the past four years (2004-2007) with estimated net revenues increasing in both zones over this period. Higher short-term bilateral market prices accounted for much of this increase. The annual net revenues ranged from $48/kW-yr to $84/kW-yr in the NP15 area and $51/kW-yr to $95/kW-yr in the SP15 area. The four year averages were $67/kW-yr in the NP15 area and $75/kW-yr in the SP15 area.

The finding that estimated spot market revenues did not 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 2007) but the net revenue earned in 2007 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 and revenue opportunities 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 in 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) are being 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. These programs can provide additional revenue for new generation and cover the gap between annualized capital cost and simulated net spot market revenues provided in the previous section.

While a broader range of market and contracting opportunities are being developed that could provide additional incentives for new generation, the continued reliance on an aging pool of generating units in California remains a concern. Though there has been a favorable and persistent trend over the past six years of reduced reliance on these units, they are still relied on in a significant number of hours. Clearly, California cannot continue indefinitely to rely on the existing pool of aging resources, which tend to be less economically efficient, more environmentally harmful, and less reliable. Table 2.11 shows generation additions and retirements, with a load growth trend figure. The total estimated net change in supply margins through 2008 is negative 262 MW for SP15, indicating that new generation has not quite kept pace with unit retirements and load growth in this region.[35] One of the consequences of this is the continued reliance on older generation facilities.

Table 2.11 Generation Additions and Retirements by Zone

	2001	2002	2003	2004	2005	2006	2007	Projected 2008	Total Through 2008
SP15									
New Generation	639	478	2,247	745	2,376	434	485	826	8,230
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	0	(4,280)
Forecasted Load Growth*	491	500	510	521	531	542	553	564	4,212
Net Change	**148**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**(68)**	**262**	**(262)**
NP26									
New Generation	1,328	2,400	2,583	3	919	199	112	984	8,528
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	447	3,342
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(326)**	**536**	**3,951**
ISO System									
New Generation	1,967	2,878	4,830	748	3,295	633	598	1,810	16,758
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	0	(5,515)
Forecasted Load Growth*	880	897	915	934	953	972	991	1,011	7,554
Net Change	**1,059**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**(394)**	**798**	**3,689**

* Assumes 2 percent peak load growth.

Despite the significant amount of older generation capacity that has been retired in recent years, there remains a large pool of aging units in California, with 46 units built before 1979 having an average age of 43 years, as seen in Table 2.12. Figure 2.42 shows the percent of hours in a year that units built before 1979 are running, and indicates a clear trend of declining utilization of these older units. However, this older pool of units was still relied upon, to provide either energy or reliability services, for roughly 26 percent of the hours in 2007 (down from 58 percent of hours in 2002). Because of the age and relative inefficiency of these units, they are likely to have net revenues below those reported in Section 2.6.3, and have less ability to recover even fixed O&M costs through spot market revenues. For these units, long-term contracting is especially necessary to ensure continued operation in the short-run and re-powering of these facilities in the longer-run if new investment is insufficient to provide replacement capacity.

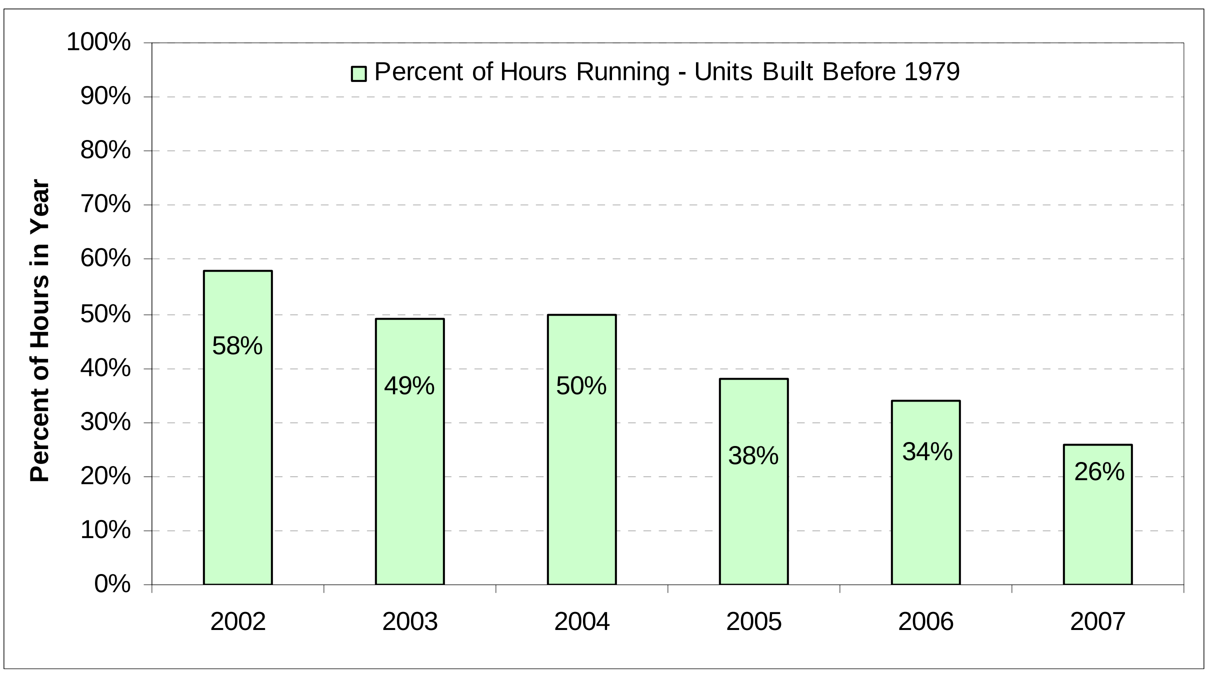
[35] It is important to note that this table only shows part of the supply picture in SP15. Numerous transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone; however, despite these improvements, meeting summer peak load demands in SP15 remains more challenging than in northern California.

Table 2.12 Characteristics of California's Aging Pool of Resources

	Number of Units	Unit Capacity[1]	Average Unit Age (Years)[2]	Capacity Factor[3]	Percent of Hours Running[4]
North of Path 26	13	4,642	45	14%	29%
South of Path 26	33	9,304	43	9%	24%
Total	**46**	**13,946**	**44**	**11%**	**26%**

[1] Total active unit capacity as of date of publication.
[2] Based on build date.
[3] Based on 2007 data. Does not adjust for unit outages.
[4] Based on 2007 data. Percent of all hours in year where unit showed positive metered generation.

Figure 2.42 Percent of Hours Running for Units Built Before 1979



2.7 Performance of Mitigation Instruments

2.7.1 Damage Control Bid Cap

The Damage Control Bid Cap for both energy bids and ancillary service bids remained $400/MWh in 2007. While the change from $250/MWh to $400/MWh in 2006 was significant, the bid price caps in the CAISO markets are still significantly lower than bid price caps in other ISOs. The CAISO recognizes that higher bid price caps do introduce benefits that can be market enhancing. For example, the prospect of higher market prices for energy may provide incentives for generation owners to maintain resources in a higher state of readiness to take advantage of the higher prices during peak demand periods, increasing overall grid reliability and offers into the imbalance market. On the load side, the threat of exposure to higher spot prices that are possible under a higher bid price cap will provide incentives to LSEs to hedge this risk through greater reliance on longer-term energy contracts, which not only reduces risk to LSEs but also provides a more stable revenue environment for supply and a more reliable financial environment to facilitate new investment. In addition to providing incentives for greater use of longer-term contracts, higher bid price caps can also provide greater incentives to further development of demand response as a price risk mitigation instrument. This not only provides risk mitigation to load, but also improves the CAISO's ability to manage the grid reliably under extreme peak conditions and acts as an additional market power mitigation measure, providing some additional price response during periods where there is not an abundance of excess supply and an individual supplier's bids may be able to exercise market power. The energy bid cap will be set at $500/MWh for the first year under MRTU and then gradually rise to $1,000/MWh,[36] more in line with levels seen in other ISOs.

2.7.2 AMP Mitigation Performance

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

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

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

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

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

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[36] Please refer to CAISO conformed MRTU Tariff based on FERC Filings for detailed price cap information: http://www.caiso.com/1c78/1c788230719c0.pdf for more information.

In 2007, impact test failures were minimal throughout the year (Table 2.13). The number of hours with conduct test failures was more pronounced, but still only represented 4.7 percent of hours in the year and peaked in the last two months of the year. This increase in November and December is largely due to two seasonal effects that happen simultaneously and together increase the likelihood of failing the conduct test.

As described above, the price predictor must estimate at least one 15-minute interval price greater than $91.87 in order for the AMP algorithm to run at all. The vast majority of price spikes in the imbalance market occur during periods of more extreme load ramping (morning and evenings). The ramp period price spikes typically last only one 5-minute interval. Since the price predictor estimates 15-minute prices to determine whether to trigger AMP, these short-duration price spikes associated with severe load ramping are "smoothed out" and are less likely to result in 15-minute prices greater that the threshold. During the holiday season, the winter evening load ramp up is more severe due to additional load from holiday decorations. In addition, this is overall a lower load period, so there are fewer internal resources online and available to meet imbalance demand which results in somewhat thinner imbalance bid stacks. These two factors combined result in more sustained predicted price spikes above $91.87/MWh and a higher likelihood that AMP will be run. In most hours, there are bids in the imbalance supply stack that are bid at prices that would violate the conduct threshold and result in failure of the conduct test. As such, the increase in conduct failures in November and December are due more to the higher predicted prices during the evening load ramp than due to changes in bidding behavior.

Table 2.13 Frequency of AMP Conduct and Impact Test Failures

	Conduct Test Failure	Impact Test Failure
Jan-07	43	1
Feb-07	24	1
Mar-07	49	0
Apr-07	36	0
May-07	39	0
Jun-07	16	0
Jul-07	18	2
Aug-07	25	0
Sep-07	9	1
Oct-07	27	2
Nov-07	64	2
Dec-07	66	2
Total	**416**	**11**

Evaluation of the AMP Price Forecast

The effectiveness of the AMP can be impacted by unforeseen events that occur during the gap between the time when the AMP software run is completed and the time of actual market operation. The market energy offers will be subject to the AMP conduct and impact tests only in cases where the real-time market-clearing price is expected to exceed $91.87/MWh in any zone in any 15-minute interval during the hour of operation. Due to operational system limitations, this price screen effectively is applied 53 minutes prior to the hour of operation based on the projected imbalance energy dispatch for that hour of operation. This means that if AMP is not triggered due to an expected price greater than $91.87/MWh in the next hour at 53 minutes before that hour, AMP will not be triggered at all for the next hour, even if a contingency occurs after 53 minutes before the beginning of the hour that causes the actual price to be greater than $91.87/MWh (an interval of time of one hour and 53 minutes).

This section examines the extent to which the AMP was able to correctly forecast prices above $91.87, which is the screen for determining whether the AMP (bid conduct and market impact test) should be run. It should be noted that since the deployment of RTMA certain results of the AMP are no longer accessible for data analysis. In particular, the results of the predicted price screen used to determine whether AMP is activated are not available for analysis. Consequently, the scope of this analysis is limited to data that remains available, which can be categorized as the following two groups:

1) The results of AMP software:

   a) No action

   b) Conduct test failure

   c) Impact test failure and associated offers mitigation

2) The results of RTMA five minute interval prices. These actual prices are produced by offers that have passed the AMP. The internal conduct test and impact test price predictions are not available for analysis. Since the AMP software uses 15 minutes as one interval and RTMA software uses 5 minutes as one interval, the 15 minute average of 5 minute RTMA prices are considered in the evaluation.

Table 2.14 summarizes the results of the AMP's capability to accurately predict prices above $91.87/MWh.

Table 2.14 AMP Price Prediction Accuracy (2007)

		Hours at least one Avg. 15 Minute RTMA price greater than $91.87/MWh	Hours 15-Minute RTMA price less than $91.87/MWh	Total Hours	Predictive Consistency
AMP predicted prices < 91.87		686	7658	**8344**	92%
Conduct Test Failure*	Impact Test Pass	155	250	**405**	38%
	Impact Test Failure	3	8	**11**	Inconclusive
Total Hours		**844**	**7916**	**8760**	

* In all hours where the AMP predicted a price greater than $91.87, there was at least one conduct test failure.

The following observations can be drawn from the results:

- There were 686 hours when at least one 15-minute interval of actual RTMA prices was above $91.87/MWh which the AMP software failed to predict. However, in the vast majority of hours (7,658), both AMP and RTMA 15-minute average prices were below $91.87/MWh, which represents a 92 percent consistency factor.

- In hours when the AMP did run (i.e., AMP predicted a 15-minute price above $91.87/MWh) but no mitigation occurred (i.e., no market impact test failure), the AMP correctly predicted that at least one 15-minute price would be above $91.87 in 38 percent of the 405 hours that AMP ran without mitigating.

- In the hours when the AMP ran and mitigated, the results of the price predictive capability of the AMP are inconclusive as it is not possible to know what actual real-time prices would have been in the absence of bid mitigation.

Evaluation of the Impact Test

The effectiveness of the AMP may also be affected by imperfectness of the impact test and the associated criteria. Since the intermediate system prices using both the original offers and mitigated offers are not accessible, we use the average hourly RTMA price of $250/MWh in any zone as a benchmark to determine whether or not the mitigation should have been triggered. The choice of $250/MWh is due to the fact that it is a relatively high price and no offers were mitigated prior to 2006 when the soft offer cap was set at the same level in the Real Time Energy Market.

To evaluate the performance of the impact test, market hours were categorized with respect to: 1) whether the price screen was expected to trigger AMP; 2) conduct test results; and 3) impact test results, as seen in Table 2.15.

Table 2.15 Impact Test Evaluation results

Average RTMA Hourly Price Greater than $250/MWh	Conduct Test	Impact Test	Number of Hours
Yes	Fail	Fail	3
No	Fail	Fail	33
Yes	Fail	Pass	15
Yes	Pass	Pass	40

The following observations can be drawn from Table 2.15.

- Out of 36 hours of conduct and impact test failures (i.e., bid mitigation), the RTMA hourly average prices dropped below $250/MWh in 33 hours.

- Out of 36 hours of conduct and impact test failures (i.e., bid mitigation), there were 3 hours when the RTMA hourly average prices were still higher than $250/MWh. This may be due to the following reasons:

  - ♦ The right set of generators were mitigated but the reference price curves used to replace the original offers were very high; or,

  - ♦ Some generating units had very high bids that did not violate the conduct test and set the price.

- There were 55 hours when the RTMA prices were higher than $250/MWh but no offers were mitigated by AMP.

- In 40 out of 55 hours, the offers passed the conduct test in the first place. This may be caused by bad price prediction or sudden system condition changes between the completion of the AMP run and the start of the actual operating hour.

- In the other 15 hours, the offers failed the conduct test but passed the impact test. This may be caused by high reference price level.

2.7.3 Local Market Power Mitigation

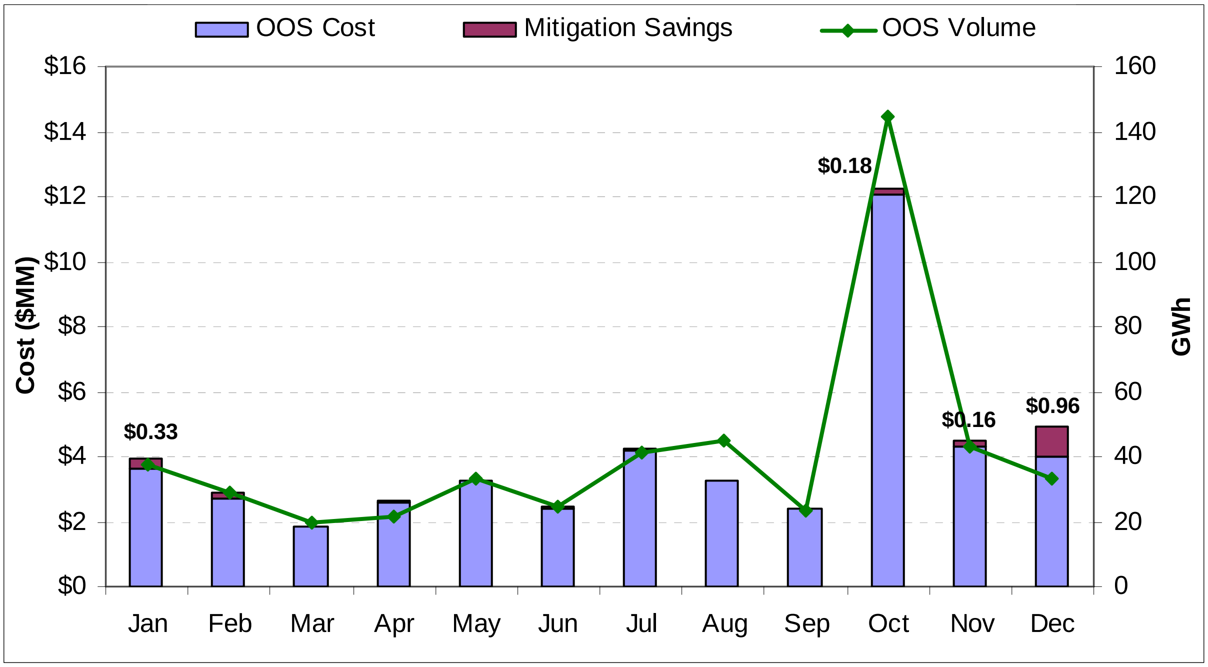
In addition to the conduct and impact tests in place to protect against the exercise of system market power, the CAISO also employs local market power mitigation (LMPM) to specific dispatches in the imbalance market that are made to support local reliability and where the energy bid price is deemed to be excessive. The LMPM is applied to out-of-sequence (OOS) dispatches made to mitigate intra-zonal (local) congestion. When a resource is dispatched OOS, it is often among a limited number of resources that can effectively mitigate the local issue and as such is providing that energy under uncompetitive conditions. LMPM is automatically applied under these circumstances. In addition to the application of LMPM, OOS dispatches are prohibited from setting the Market Clearing Price in the imbalance market.

For incremental OOS energy, the LMPM is applied automatically through a conduct test. If an OOS dispatch is made from an energy bid that is priced greater than $50 or 100 percent above the 5-minute interval imbalance Market Clearing Price, then that bid price is mitigated to the higher of the 5-minute interval imbalance Market Clearing Price or the Reference Price for that resource.[37] This mitigation rule was designed to catch abnormally high bid prices that may have been submitted to take advantage of the reduced competition that is inherent in the supply of local congestion relief.

Monthly total cost savings resulting from the application of LMPM for 2007 are presented in Figure 2.43 below.

[37] The Reference Price is a resource-specific series of prices corresponding to the various levels of output for that resource and is based on one or more factors that are not tied to current market outcomes. Options for the Reference Price basis include resource specific variable cost, average of historical market bids for the resource in competitive periods over the past 90-days, historical Market Clearing Prices in periods where that resource was dispatched over the past 90 days, or through consultation between the resource scheduler and the independent entity that calculates the Reference Prices.

Figure 2.43 Monthly Cost Savings From Applying Local Market Power Mitigation to Incremental Out-of-Sequence Dispatches - 2007



Total savings resulting from the application of LMPM to incremental OOS dispatches were $2.1 million for 2007, with notable cost savings occurring in January and October through December. In general, throughout the year the primary driver of LMPM was low Market Clearing Prices, and not unduly high priced energy bids. The total cost for OOS dispatches increased sharply in October as a result of the wildfires in Southern California and the need to dispatch specific resources to mitigate local reliability issues that were caused by transmission outages resulting from the fires.

It is worth noting that the mitigation of incremental OOS dispatches can be triggered by either a high bid price or by a (very) low Market Clearing Price. For example, a gas fired resource may submit an imbalance energy bid priced at variable cost (say, $75/MWh) and be mitigated for an OOS dispatch simply because the Market Clearing Price was only $20/MWh, which would violate the conduct test and automatically trigger mitigation. While the bid price was consistent with competitive behavior and did not itself warrant mitigation, the resource will not be unduly penalized since the OOS bid price will, in this circumstance, be mitigated to the resource's Reference Price which should not be lower than the resource's variable cost of production.

The same principle of reduced competition exists in circumstances where specific resources are required (through OOS dispatch) to back down in real-time to resolve local reliability issues, and the CAISO also has in place LMPM for decremental OOS dispatches. In the case of decremental OOS dispatches, the LMPM is automatically applied to each such dispatch by replacing the resource's bid prices for these dispatches with that resource's decremental Reference Price. Because the mitigation is applied to every decremental OOS dispatch, the calculation of mitigation cost savings does not shed light on the frequency of potential exercise of local market power or the effectiveness of the mitigation threshold in abating this market power. Consequently, the cost savings attributable to LMPM on decremental OOS dispatches is not calculated.

3 Real Time Market Performance

3.1 Overview

2007 marked the third full year of operation under the Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing or BEEP).

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

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

This chapter reviews the performance of the CAISO Real Time Market in 2007. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. One significant driver on Real Time Market volumes is the level of forward energy scheduling, which is influenced by the CAISO 95 Percent Day-Ahead Scheduling Requirement (Amendment 72). Section 3.3 provides a review of load scheduling practices. An analysis of uninstructed deviations under RTMA is also provided in Section 3.4. Finally, Section 3.5 provides an assessment of recent trends relating to market participants declining inter-tie bids that are pre-dispatched for the Real Time Market.

3.2 Real Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy and both in- and out-of-sequence (OOS) dispatches for 2006 and 2007. Monthly prices for incremental energy in 2007 were fairly stable, averaging between $54 and $89/MWh on a monthly basis, consistent with stable natural gas prices and moderate imbalance requirements. Average monthly prices for decremental energy were relatively low during the peak hydroelectric season (February through May), and averaged between $27 and $47/MWh across the entire year. In-sequence dispatch volumes were predominantly decremental in most months of 2007, albeit to a lesser degree than in 2006, especially during the spring and summer months. The preponderance of decremental dispatches can be attributed in part to high levels of forward energy scheduling which is driven by the CAISO day-ahead load scheduling requirement (Amendment 72) and Load Serving Entities (LSEs) being risk averse to volatile Real Time Market prices. The spikes in the average cost of incremental OOS dispatches in April and December are due to periods where additional local reliability support was required from less efficient resources in Northern California (please see Chapter 6 for additional details). However, incremental OOS volumes in both months were low, especially when compared to October 2007 when excessive OOS dispatch was required to manage various local reliability issues during the wild fires in Southern California.

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2006-2007)

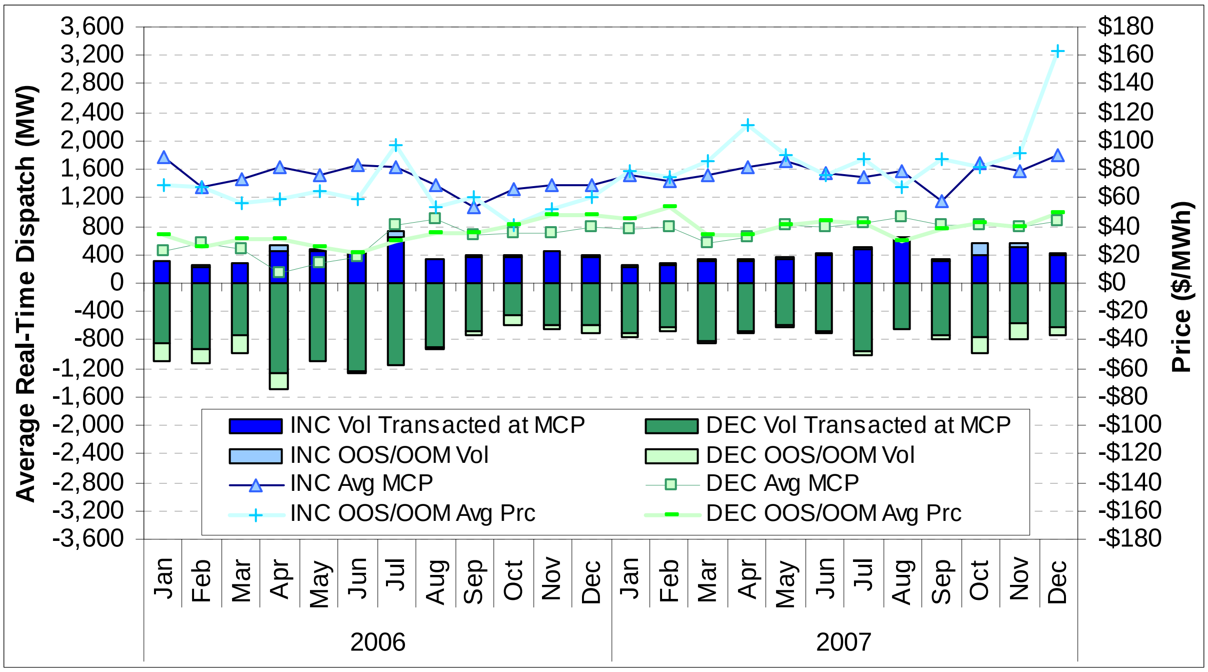


Figure 3.2 and Figure 3.3 show the same metrics presented in Figure 3.1 but separately for peak and off-peak hours, respectively. As can be seen in these figures, the average monthly market volume trends across the two years are fairly similar for peak and off-peak hours. As expected, average monthly prices were generally higher in the peak hours.

Figure 3.2 Monthly Average Dispatch Prices and Volumes in Peak Hours (2006-2007)

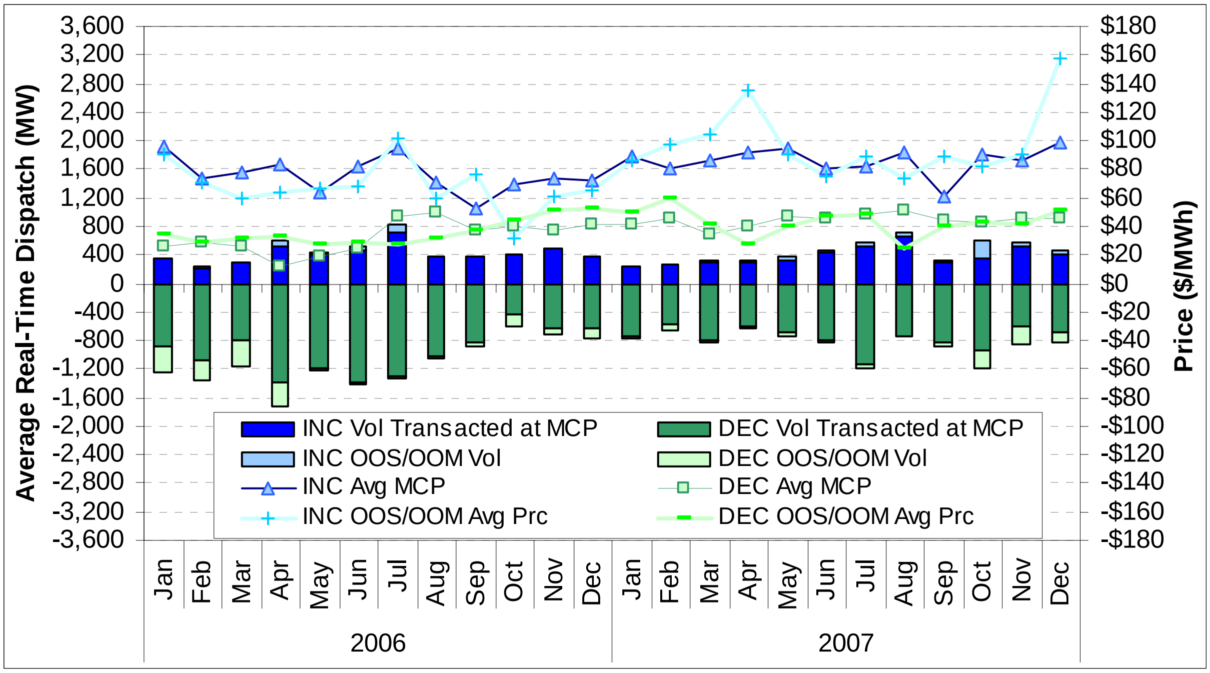


Figure 3.3 Monthly Average Dispatch Prices and Volumes in Off-peak Hours (2006-2007)

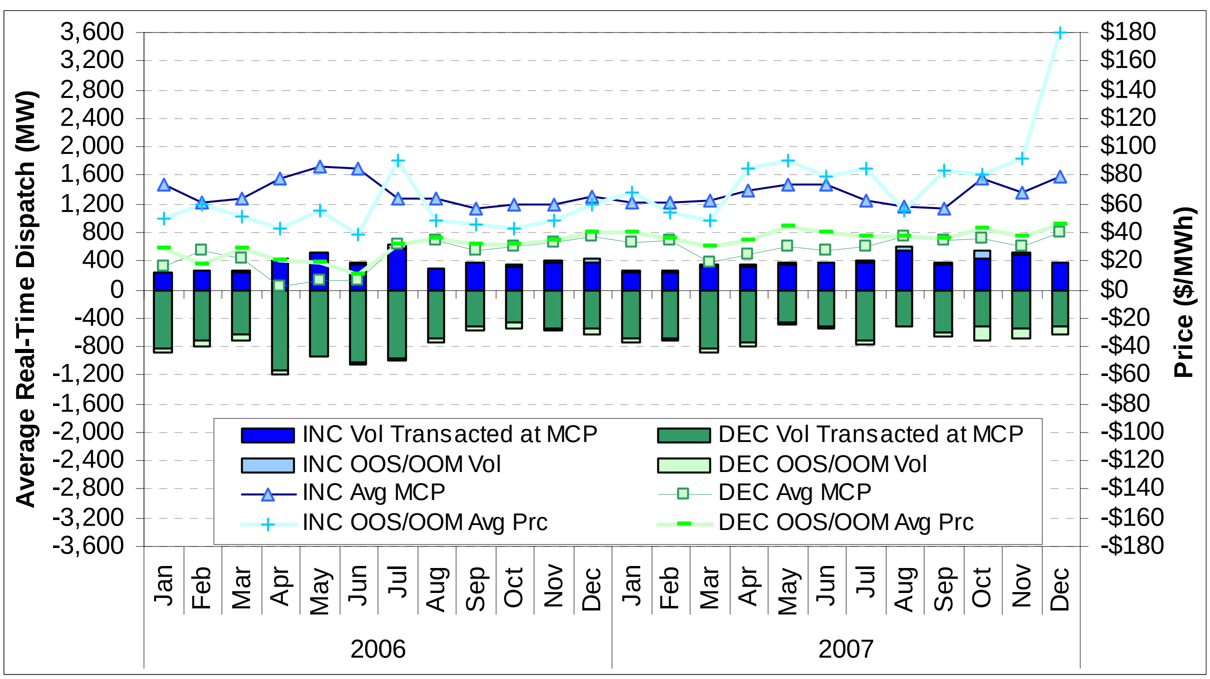


Figure 3.4 compares average annual Real Time Market prices by zone (NP26, SP15) for 2002 through 2007. Congestion on Path 26 in the north-to-south direction has resulted in consistently higher prices in SP15 than in NP26. However, this trend decreased markedly in 2007, as congestion on Path 26 was more sporadic and concentrated around a few specific grid-related events, primarily in July, as discussed below in Section 3.2.2. Historically, prices would split much more frequently than seen in 2007, such as in the spring when operators would need to manually manage flow on Path 26 to help mitigate unscheduled loop flow. The general upward trend in average prices in 2007 can be explained by the lower levels of hydroelectric production compared to 2006, resulting in higher reliance on more costly natural gas generation.

Figure 3.4 Average Annual Real-Time Prices by Zone (2002-2007)[38]

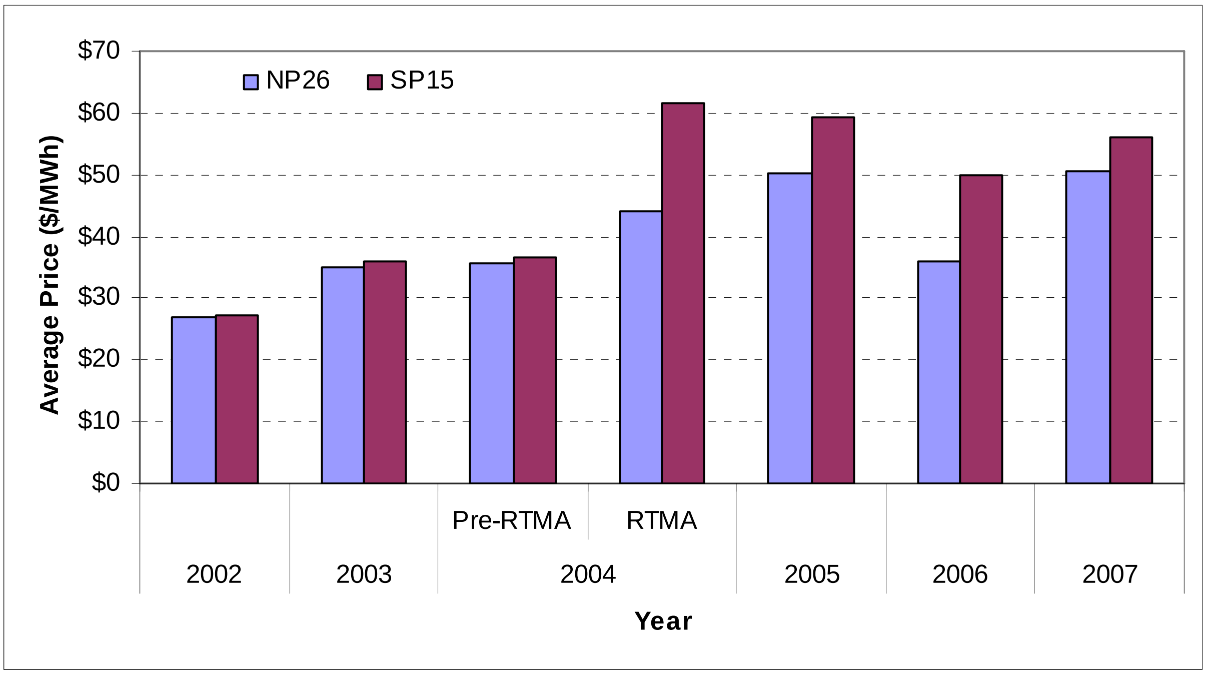


Figure 3.5 shows SP15 real-time 5-minute interval price duration curves for 2003 through 2007 and indicates that real-time interval prices in 2007 were higher than in 2006 across the entire distribution, again due to the much lower level of hydro production and consequent reliance on natural gas generation. Another outcome of lower hydro production in 2007 was a decrease in the number of hours with negative prices to 0.5 percent of hours, compared to 2.5 percent of hours in 2006. Loop flow and other over-generation conditions tend to occur during strong run-of-river hydro conditions, such as occurred in 2006, and result in very low or negative prices; as the runoff from snow melt increases and reservoir levels reach their capacities, hydro facilities are typically running at or near full production regardless of load conditions. There were fewer such hours in 2007. Conversely, the higher volume of negative prices in 2006 is predominantly attributable to high levels of hydroelectric generation, which increased demand for decremental

[38] Chart incorporates most recently available information and may differ from prices reported in previous years. Averages are real-time volume-weighted.

energy bids, and, under severe conditions, resulted in exhausting the supply of decremental bids.

Figure 3.5 SP15 Price Duration Curves (2003-2007)

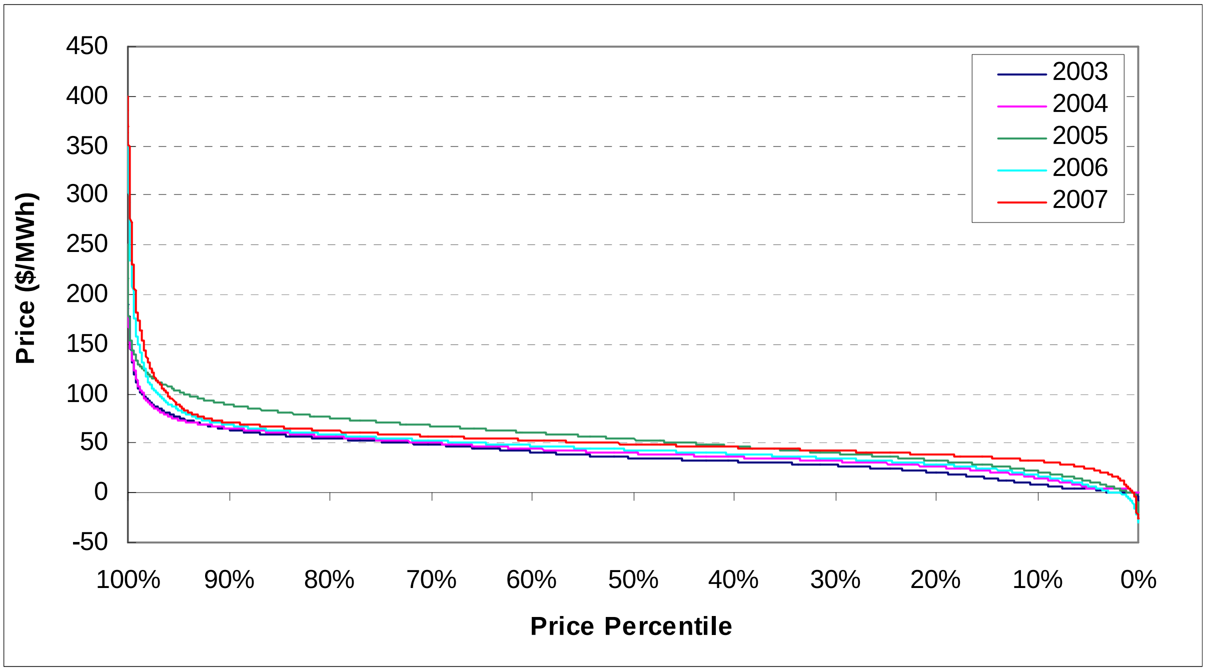
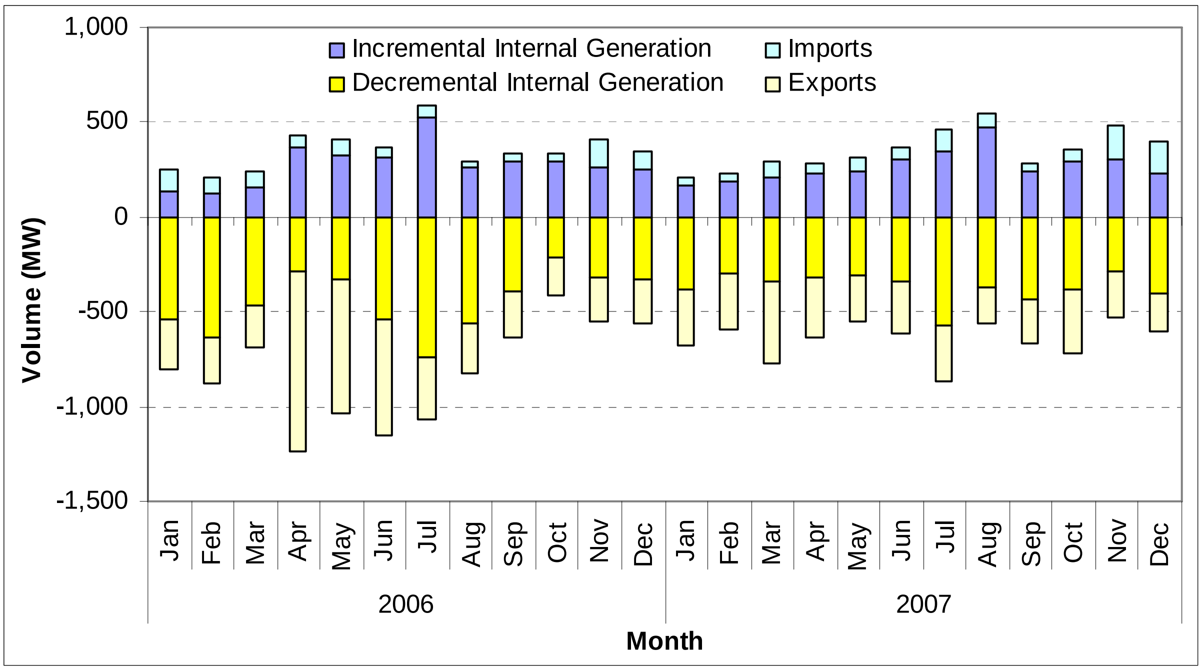


Figure 3.6 shows the monthly average dispatch volumes for internal generation, imports and exports for 2006 and 2007. Since the implementation of Amendment 72, LSEs have been conservative in meeting the 95 percent forward scheduling requirement and often have forward scheduled generation and imports in excess of the requirement. Consequently, real-time balancing in the decremental direction has typically been more prevalent than in the incremental direction. The effect of strong loop flow and over-generation, caused by hydro conditions, can be seen in the spring months of 2006, as large volumes of power were pre-dispatched to the Northwest to manage the unscheduled flow. Otherwise, internal resources constituted the bulk of RTMA dispatch volumes.

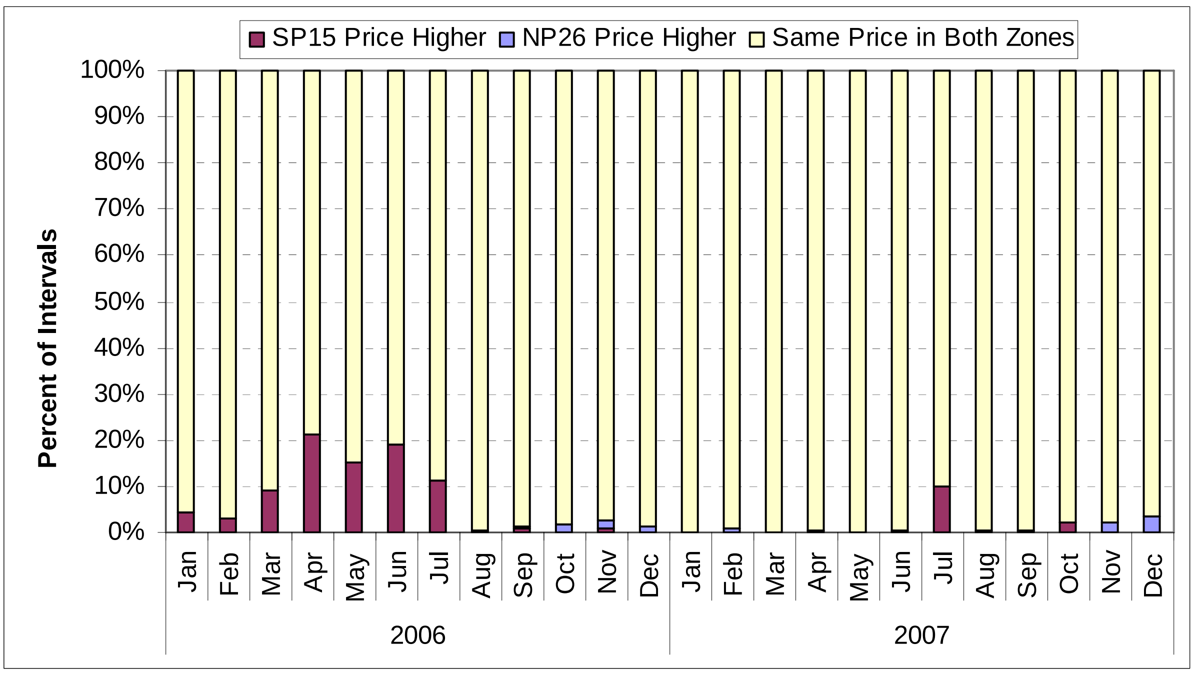
Figure 3.6 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2006-2007)



3.2.2 Real-Time Inter-Zonal Congestion

Figure 3.7 shows the monthly count of market splits in 2006 and 2007. The frequency of splits decreased markedly in 2007, following an increase in the north-to-south rating for Path 26 of 300 MW (3,700 to 4,000 MW) on June 1, 2006. Prices differed between NP26 and SP15 in approximately 1.8 percent of 5-minute intervals in 2007, compared to 7.5 percent in 2006. Of the 1,845 five-minute intervals in 2007 with price differences between NP26 and SP15, 884 were north-to-south congestion (with a higher price in SP15) within the month of July due to Path 26 congestion. On July 1 and 2, market splits occurred due to clearances for work on a transformer bank at the Vincent substation, a key component of Path 26. Another Vincent transformer bank failed on July 11, resulting in a derate of Path 26 for the remainder of July to approximately half its capacity. Work at the Los Banos Substation and a forced outage of a capacitor bank caused south-to-north congestion on Path 15 in November and December, accounting for approximately 527 five-minute intervals.

Figure 3.7 NP26-SP15 Market Price Splits (2006 - 2007)



3.2.3 Bidding Behavior

Figure 3.8 and Figure 3.9 show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for 2006 and 2007. Notable in Figure 3.8 is the significant decrease in the percentage of higher priced incremental energy bids (over $100/MWh) after early 2006, due to the stabilization of natural gas prices within the range of $5 to $8/mmBtu that has persisted throughout 2007. Also notable is the increase in incremental bid prices in the $50-$100/MWh range, in the spring and summer of 2007. This trend may be attributed to the limited supply of hydroelectric energy going in to the summer months of 2007 and more bids being made available from thermal units as more of them came on-line to meet summer loads. With respect to decremental bids, Figure 3.9 shows that the volume of decremental energy bid in at very low prices (e.g., below $0/MWh) decreased in 2007, again due to reduced over-generation caused by excess hydroelectric power. Poor hydro conditions have resulted in greater reliance on gas-fired generation to meet load. Some decline in the low-priced decremental bids can be attributed to a higher proportion of generation (gas-fired) that is willing to pay higher prices to back down their generation schedules and avoid input costs for natural gas. Also, in 2007 hydroelectric facilities were in spill conditions less frequently due to lower hydro conditions which increased their willingness to back down generation since water could be stored and not spilled, or “wasted” in terms of energy production.

Figure 3.8 SP15 Incremental Energy Bids by Bid Price Bin (2006 - 2007)

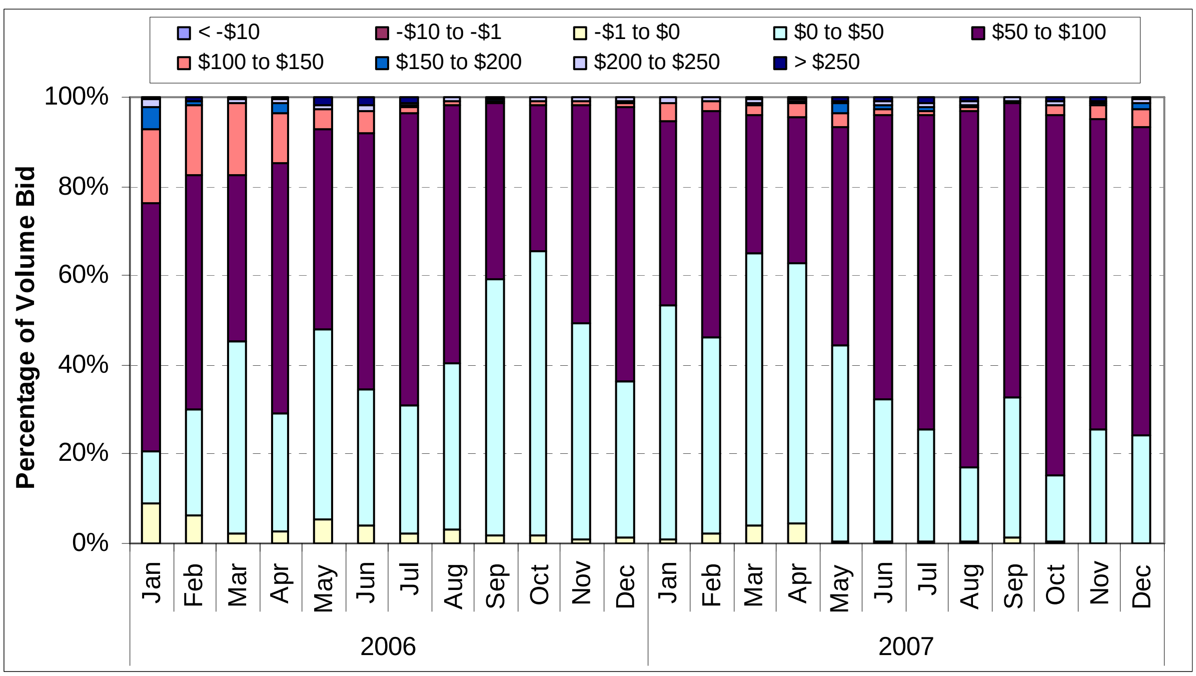
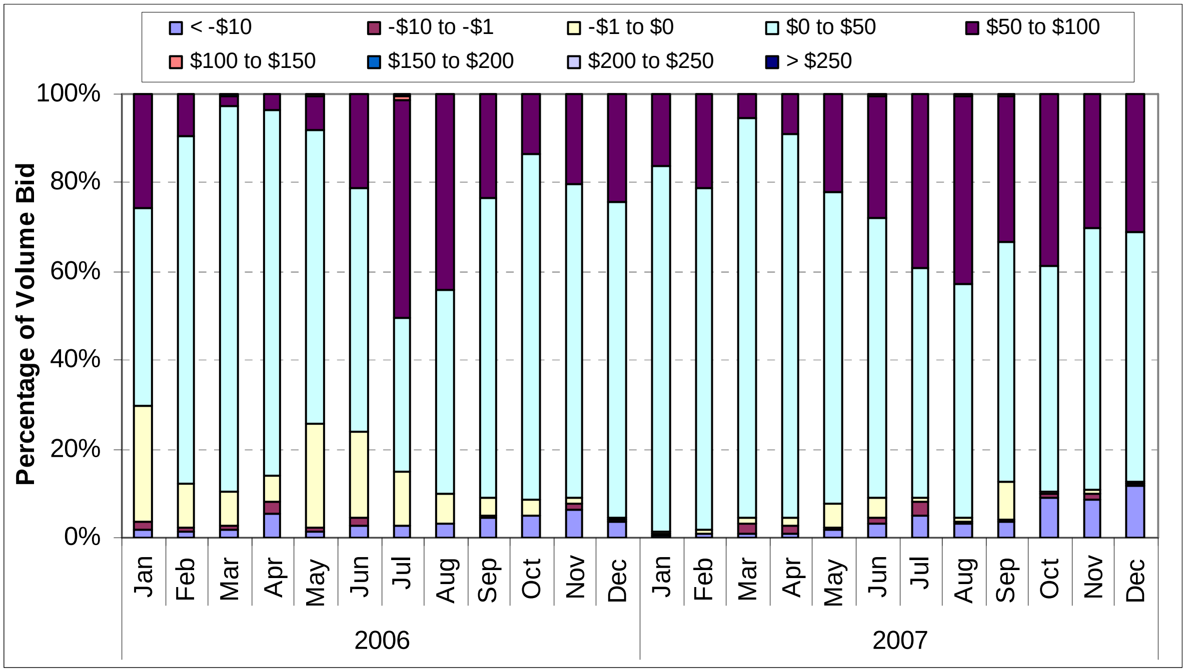


Figure 3.9 SP15 Decremental Energy Bids by Bid Price Bin (2006 - 2007)



3.3 Forward Scheduling

Under the current CAISO market structure, there is no organized Day Ahead Market for energy. Instead, all day-ahead scheduling is based on bilateral contracts and supply resources directly owned or controlled by LSEs. In addition, each SC must submit balanced load and supply schedules. The amount of load and supply scheduled on a day-ahead basis can have a significant impact on CAISO operations. To the extent the amount of load and supply scheduled is insufficient to meet the CAISO's forecast of load and other system conditions, the CAISO may commit additional supply resources on a day-ahead basis through the must-offer waiver denial process. In real-time, significant under-scheduling can also require the CAISO to dispatch additional incremental energy resources through the Real Time Market.

During 2007, the level of forward scheduling was quite high, particularly during peak hours. For example, Figure 3.10 compares the average hourly values of day-ahead and hour-ahead schedules with actual load during 2007. This high level of scheduling can be attributed to a number of factors.

- In October 2005, the CAISO filed and FERC subsequently approved 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 MOW denials and dispatching additional energy in the real-time. In February 2007, the CAISO filed and FERC subsequently approved, with modifications, a Tariff amendment to relax the existing minimum load scheduling requirement during off-peak hours from 95 percent to 75 percent of each Scheduling Coordinator's demand forecast, effective April 26, 2007.

- In addition, the amount of forward scheduling in 2007 was affected by a variety of 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.

- Finally, while Resource Adequacy requirements in effect for 2007 require only 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 LSEs to schedule energy from RA resources on a day-ahead basis.

During peak hours (and, in particular, hour ending 16), day-ahead schedules often exceeded the 95 percent scheduling requirement established under Amendment 72, as illustrated in Figure 3.12. This trend suggests that factors in addition to the 95 percent scheduling requirement – such as CPUC supply procurement guidelines, and the bundling of capacity and energy contracts with RA resources – were primarily responsible for the high degree of forward scheduling seen throughout 2007. One factor may simply be that LSEs are risk averse and therefore want to minimize their exposure to volatile Real Time Market prices.

Figure 3.11 shows, by month for all hours, average actual load together with day-ahead and hour-ahead under-scheduling. Even in July and August when average load peaked, the percent under-scheduled was still less than two percent of actual load. Figure 3.12 similarly depicts the percentage of under-scheduling for all hours ending 16:00 (between 3:00 and 4:00 p.m.) by month for 2007. This chart captures the fact that during the peak hours of 2007, the extent of aggregate under-scheduling was slightly less than three percent of actual load.

As discussed in Section 3.2, high levels of scheduling or over-scheduling required the CAISO to reduce or decrement additional generation in the Real Time Market during many hours in 2007. Even if energy and net import schedules submitted by SCs are approximately equal to actual CAISO system loads, the CAISO may need to decrement significant amounts of energy due to various sources of unscheduled energy that appear in real-time under the current market design. Major sources of unscheduled energy include:

- Minimum load energy from units committed through the MOW process.

- Positive uninstructed energy from resources within the CAISO, including steam generating units operating at minimum load during off-peak hours, cogeneration resources, and intermittent resources such as wind energy.

- Additional net incremental energy from real-time out-of-sequence (OOS) dispatches due to intra-zonal congestion and local reliability requirements.

- Loop flows creating net positive energy from neighboring control areas.

In 2007, the limited amount of under-scheduling that did occur did not detrimentally impact system reliability or significantly increase MOW commitment costs primarily due to the fact that the CAISO was largely decrementing energy in real-time due to various sources of unscheduled energy. For example, Figure 3.13 shows the percent of hours during the year in which the CAISO was decrementing energy along with the average levels of under-scheduling for each of the 24 operating hours of the day. The red portions of the bars depict the MWh by which aggregate day-ahead schedules fell below 95 percent of the CAISO day-ahead forecast. As depicted in Figure 3.13, the bulk of under-scheduling occurred during hours in which the CAISO was, on net, decrementing energy. Thus, under-scheduling did not create a need for additional incremental energy in real-time and, in fact, under conditions such as these, additional forward scheduling may have only increased the need to decrement energy in real-time.

Figure 3.10 Average Actual Load Relative to Hour Ahead and Day Ahead Schedules by Operating Hour for 2007

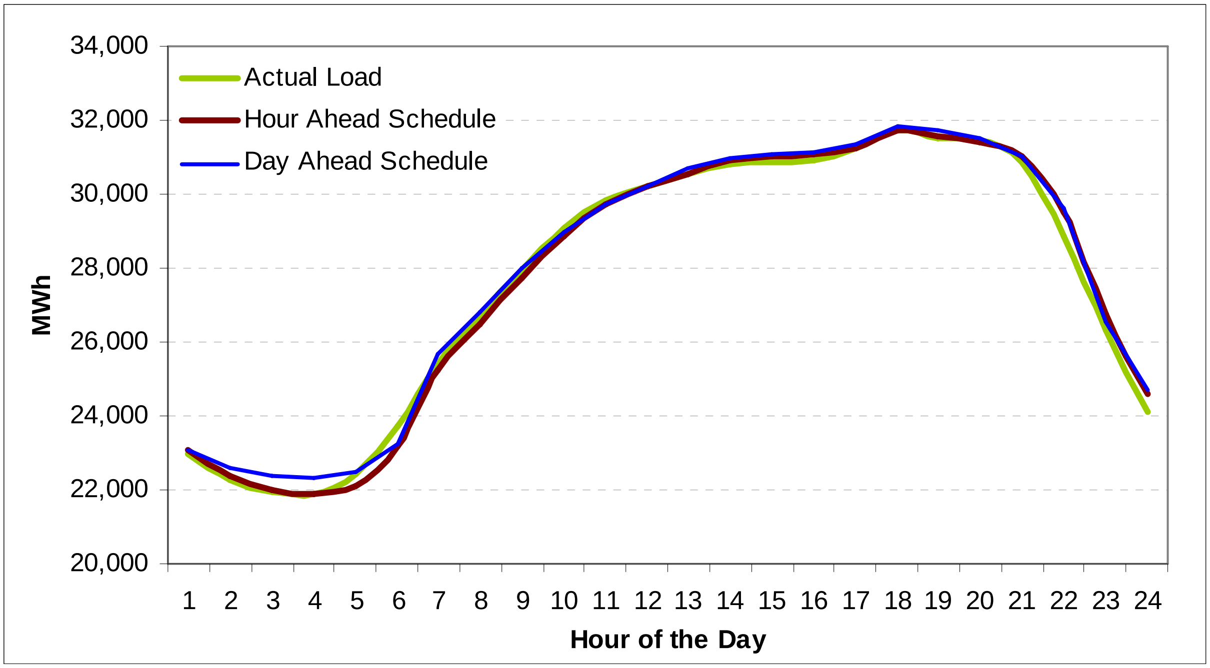


Figure 3.11 Average Hourly Actual Load Relative to Under-Scheduling for 2007 by Month for All Hours

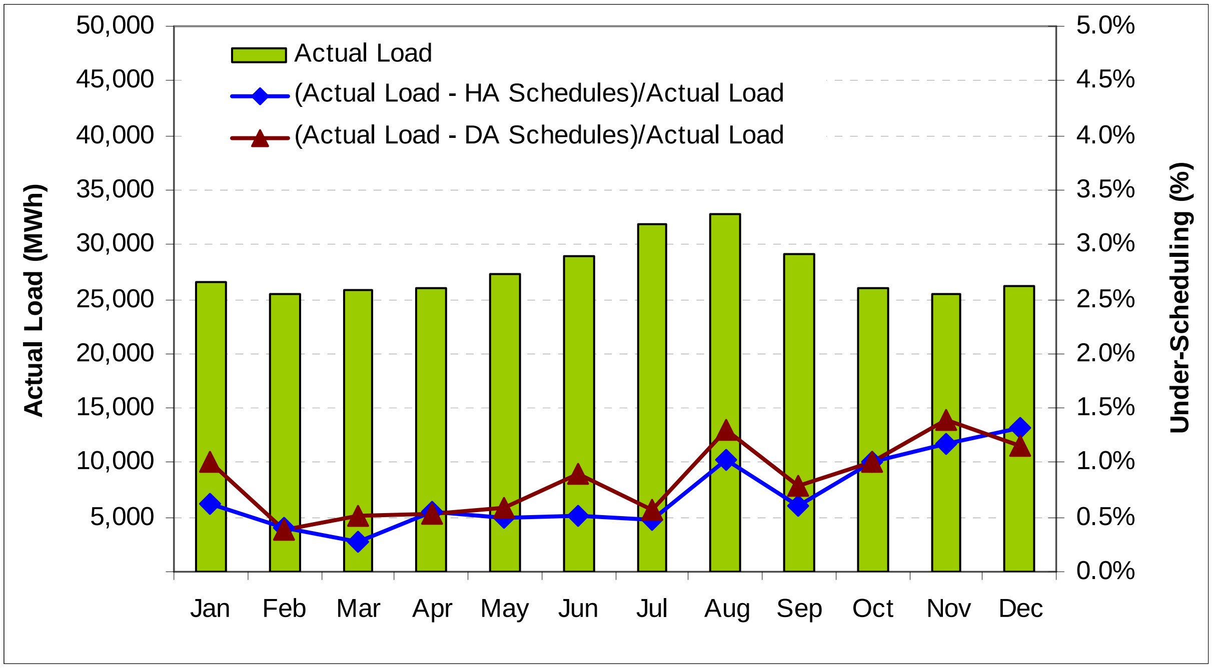


Figure 3.12 Average Hourly Actual Load Relative to Under-Scheduling for 2007 by Month for Hour Ending 16 Only

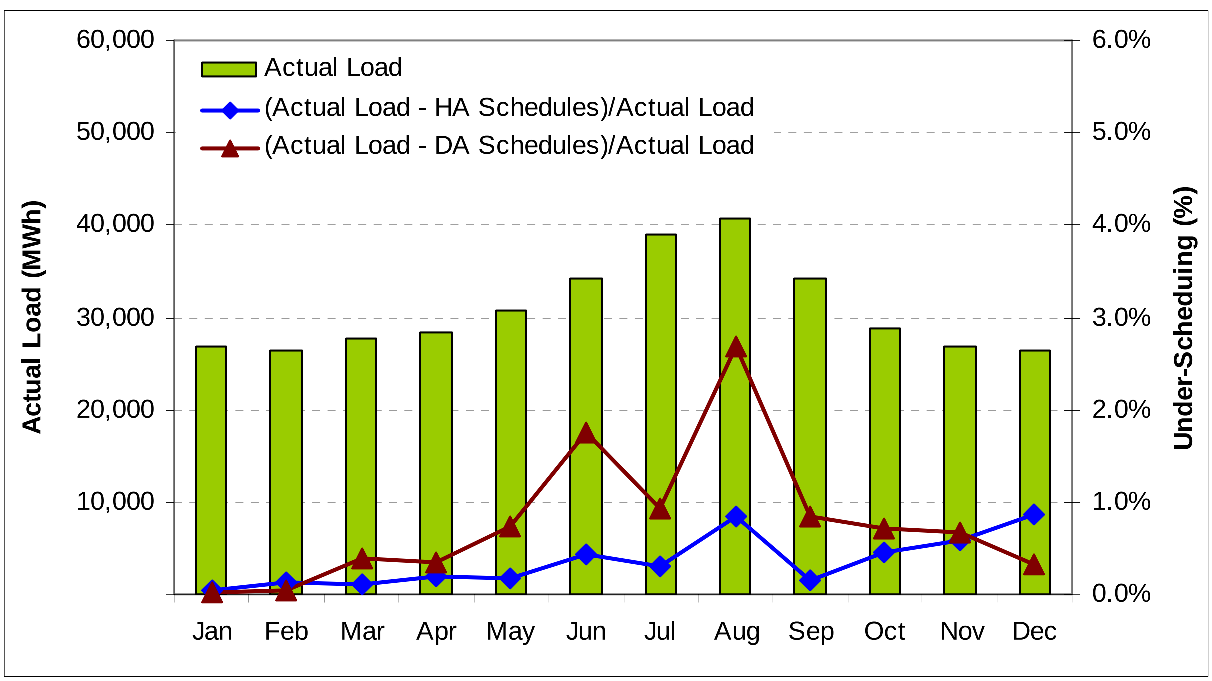
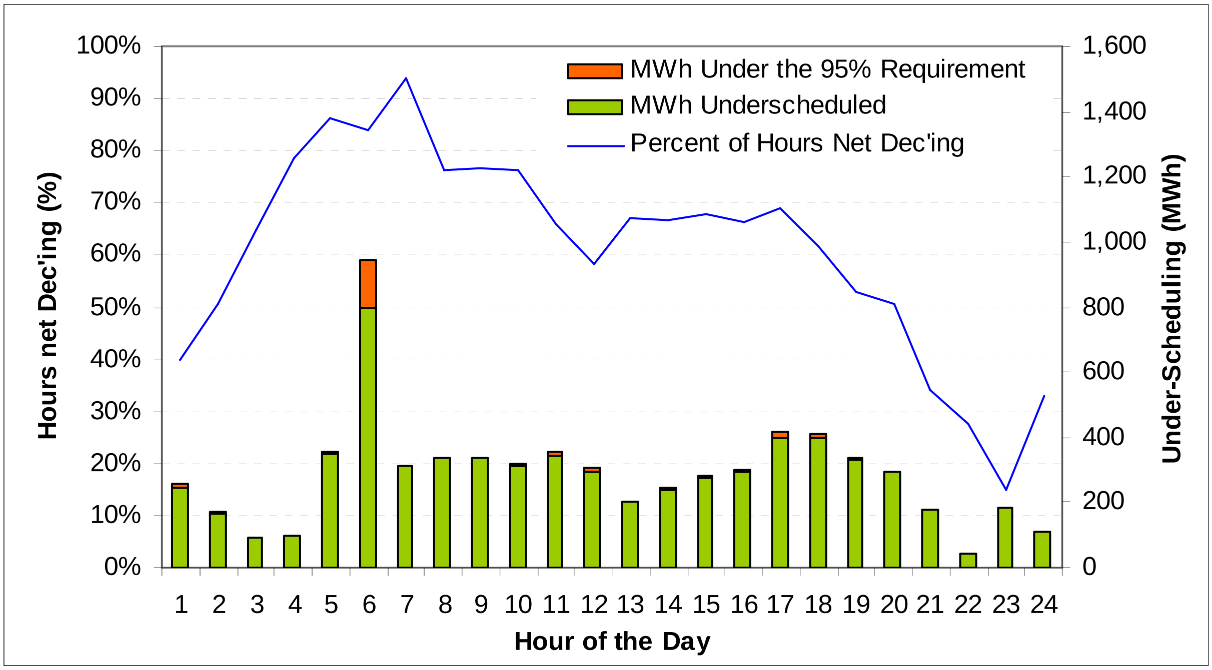


Figure 3.13 2007 Average Under-Scheduling by Hour Relative to Net Decremental Energy



3.4 Uninstructed Deviations

Uninstructed deviations are an important aspect of market performance to the extent that they result in a need to excessively dispatch other resources or that they interfere with RTMA's ability to effectively balance the system. As discussed in more detail below, both the volume and interval-to-interval volatility of system level generating unit uninstructed deviations in 2007 have been relatively consistent with what was observed in 2006, and appear to be within acceptable limits.

The CAISO had previously proposed the Uninstructed Deviation Penalty (UDP) as a feature of the current market design as an incentive for resources to follow their schedules and CAISO dispatch instructions. UDP has not been implemented because uninstructed deviations have remained at relatively low levels and because of past concerns that generating unit operators would not have a reasonable opportunity to avoid UDP. These concerns pertained to the manner in which RTMA dispatched generating units and the ability of the CAISO outage reporting system to facilitate market participants' reporting of generating unit limitations within a 30-minute period necessary to avoid UDP. If uninstructed deviations have a significant impact on grid or market operations under MRTU, the CAISO would likely propose to implement UDP as a feature of a future release of MRTU. Under MRTU, there would likely be less concern about a generating unit operator's ability to avoid UDP than there was in the past because of the different manner that generating units will be dispatched and because of recent improvements to the CAISO's outage reporting system.

This section examines trends in uninstructed deviations based on two basic measures:

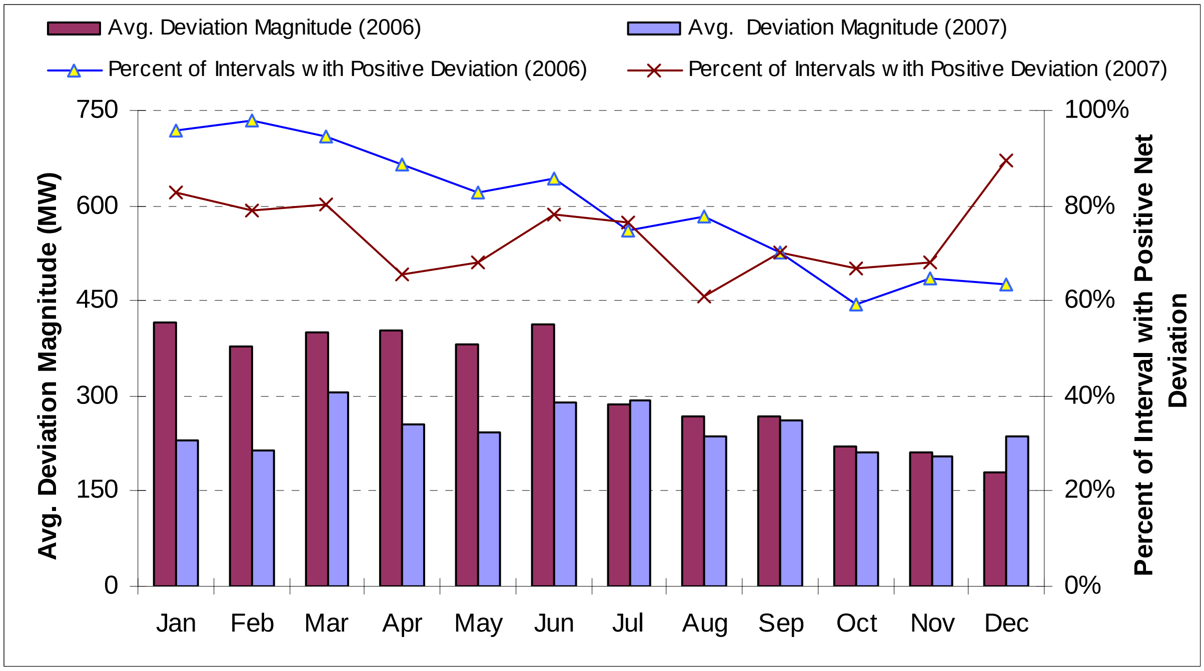
- **Volume of Uninstructed Deviations.** The total volume or magnitude of all uninstructed deviations on a system-wide level is important since this reflects the impact of uninstructed deviations on the overall quantity of incremental or decremental energy that the CAISO must dispatch to balance system loads and resources. The magnitude of system-level uninstructed deviations was based on the approximate net deviation in each 10-minute settlement interval of all generating units in the control area.

- **Volatility of Uninstructed Deviations.** The volatility of uninstructed deviations on a system-wide level from one interval to the next is also important since sudden and/or unpredictable changes in system level uninstructed deviations can have detrimental impacts on system and market operations. The volatility of uninstructed deviations was assessed based on the change in system level uninstructed deviations from each interval to the next. The analysis in this section does not include deviations resulting from pre-dispatched import or export bids that are not delivered (i.e., declined bids).

Figure 3.14 compares the magnitude of generating unit uninstructed deviations during 2007 as compared to the corresponding months in 2006.[39] Figure 3.14 also shows the percentage of 10-minute settlement intervals in which the net system level deviation was positive (i.e., net generation exceeded the total amount of energy scheduled or dispatched from these units) during each of these months.

[39] The average generating unit uninstructed deviations shown in Figure 3.14 are an average of the absolute values of the total net generating unit deviations for each 10-minute settlement interval. The approximate deviation of each unit was first calculated for each interval and the net deviation on a system level of each interval was then calculated by summing up the approximate deviation of all generating units. Since the system level deviations can be either positive or negative each interval, the system level deviation in each settlement interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net deviation over each month. These calculations exclude generating units during any settlement interval in which they were providing regulation.

Figure 3.14 Magnitude of Net Uninstructed Deviation



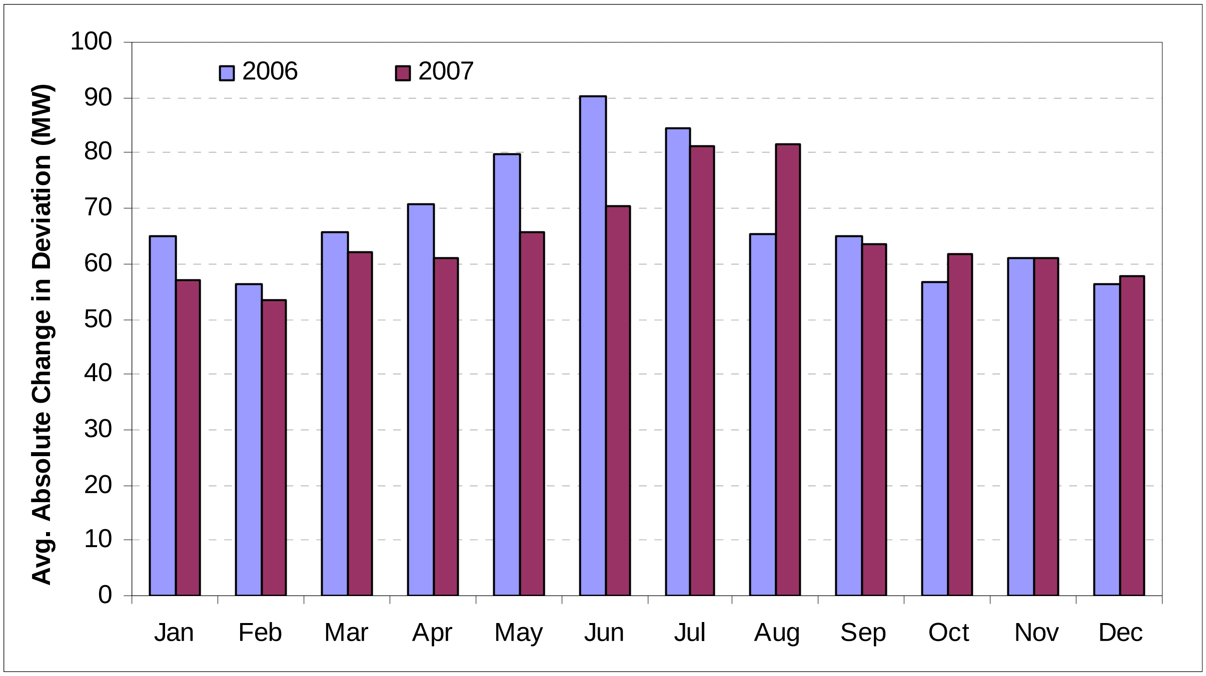
As shown by Figure 3.14, uninstructed deviations in 2007 were at a slightly lower level than 2006 – uninstructed deviations averaged 249 MW in 2007 and 319 MW in 2006. This difference was primarily attributed to lower levels of deviations during the spring months of 2007 compared to the same months of the previous year. This was likely due to a smaller amount of positive deviation of hydro units during the relatively dry 2007 spring runoff period.

Figure 3.14 also shows that uninstructed deviations were predominantly positive during 2007 (i.e., generating more than schedule plus dispatch instructions), consistent with that which occurred in 2006 – the net deviation of generating units was positive in an average of 74 percent of settlement intervals throughout 2007 and in 80 percent of settlement intervals in 2006. The prevalence of positive uninstructed deviations are likely explained by units running uninstructed, energy produced during start-up and shutdown periods, and by units that must run at levels greater than scheduled due to environmental constraints.

Figure 3.15 examines the volatility of uninstructed deviations as represented by the monthly average absolute value of the change in net generating unit deviations between 10-minute settlement intervals for 2007 compared to 2006.[40] As Figure 3.15 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2007 has been relatively consistent with 2006. The seasonal variation in the between-settlement interval net deviation change is similar in the two periods, as well as the average magnitude of the variation in the two periods, averaging 65 MW in 2007 and 68 MW in 2006.

[40] Since the system level deviations can be either positive or negative each interval, the change in system level deviation in each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net between settlement interval deviation over the month.

Figure 3.15 Average Change in Net Uninstructed Deviation between Settlement Intervals by Month for 2006 and 2007



3.5 Declines of Pre-Dispatched Inter-tie Bids

Under the CAISO's current market design, market participants may submit bids in the Real Time Market to provide incremental energy (as imports) or to purchase decremental energy (as exports). The CAISO "pre-dispatches" these inter-tie bids 45 minutes before each operating hour based on market software which seeks to optimize the dispatch of all incremental and decremental bids, based, in effect, on the assumption that all pre-dispatched bids will be accepted and delivered by market participants. However, upon receiving a pre-dispatch from the CAISO, market participants may fail to accept a pre-dispatched bid, without incurring any direct settlement consequence or financial disincentive.

During early 2007, increasing rates of declined pre-dispatches began to cause the potential for significant detrimental impacts on the CAISO Real Time Energy Market and system reliability. For example, high rates of declined pre-dispatched incremental energy bids could cause the CAISO to increase reliance on energy from within the CAISO that is dispatched on a 5-minute basis during the subsequent operating hour, and thereby increase prices or decrease reliability in the Real Time Market.

Based on DMM's discussions with market participants, it appears that high rates of declines typically occur when market participants submit real-time energy bids at the inter-ties as marketers or traders of energy, rather than bidding based on resources that they control. In this case, declines can occur due to differences in the timing between the CAISO energy dispatches at the inter-ties and the bilateral "real-time" market for the Western Interconnection, as described by the following scenarios:

- By the deadline for submission of real-time energy bids to the CAISO (i.e., 62 minutes prior to the operating hour in the current market design), these participants typically do not have a firm business arrangement to deliver incremental energy or receive decremental energy for each specific bid submitted. Rather, these participants indicated that they submit bids for energy that they expect to be able to deliver (or accept) based on their evaluation of bilateral market conditions conducted shortly before bids are due.

- Meanwhile, many transactions in the bilateral real-time market are being finalized at this same approximate time, and often completed by 60 minutes prior to the operating hour – or just beyond the deadline for submission of energy bids in the CAISO Real Time Market.

- Once a participant receives pre-dispatch instructions from the CAISO at 45 minutes prior to the operating hour, the potential supply (or sink) of energy may still not be available to the participant, due to commitments made in the bilateral market. Consequently, the participant may not be able to obtain a supply or sink necessary to perform on the CAISO pre-dispatch instruction and must decline it.

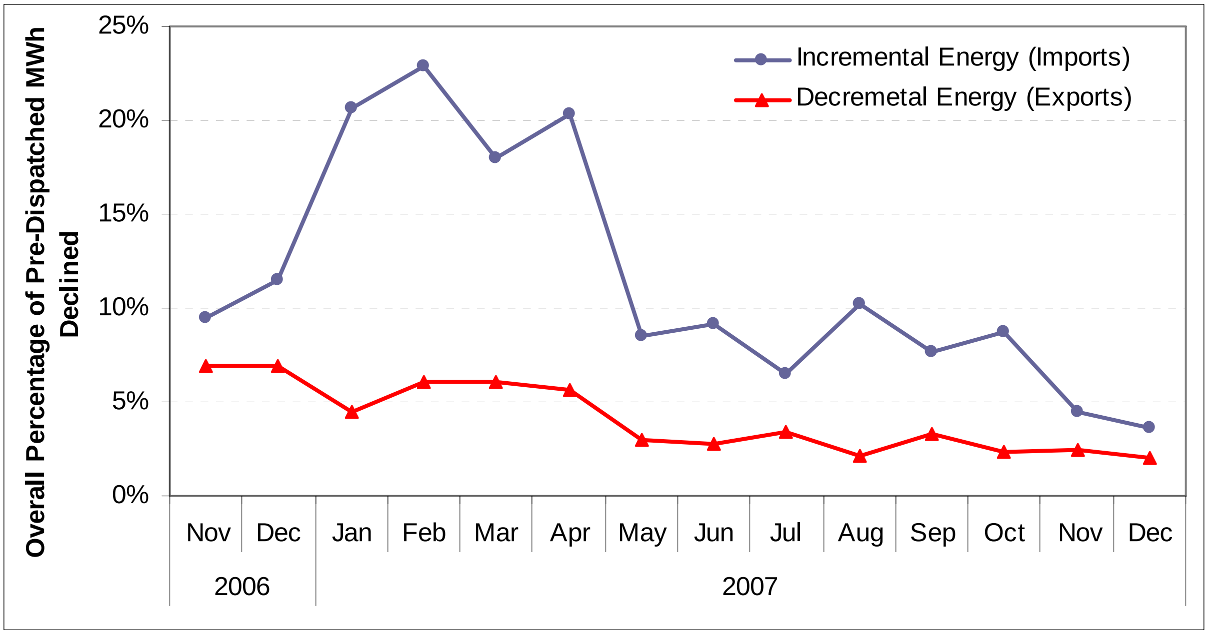
- In some cases, participants also indicated that, in addition to the availability of resources to take or receive energy, lack of available transmission once the CAISO issues pre-dispatch instructions at the inter-ties sometimes contributes to declines.

In the spring of 2007, DMM expressed concern to market participants about the potential market and reliability impacts of high rates of declined pre-dispatches, and recommended that the CAISO take steps to clarify or amend market rules to reduce declined pre-dispatches. Although modifications in the rule concerning declined pre-dispatches did not take effect in 2007, declined pre-dispatches did decrease significantly after DMM expressed concern about the potential market and reliability impacts of high rates of declined pre-dispatches in the spring of 2007, as shown in Figure 3.16.

While declined pre-dispatches can detrimentally affect reliability and market efficiency in a variety of ways, one of the concerns about any efforts or market design changes to decrease declined pre-dispatches is the potential effect this may have on the price and volume (or liquidity) of supply from imports and demand from exports in the Real Time Market. In analyzing this issue, DMM found that the reduced rates of declined pre-dispatches observed in 2007 were due largely to a drop in bids by smaller participants with relatively high rates of declined pre-dispatches, which accounted for a relatively high portion of declined pre-dispatches, but only accounted for a relatively small portion of total bids submitted and accepted in the CAISO market.

In March 2008, the CAISO filed a tariff amendment to establish a charge for declined pre-dispatches starting in May 2008. The level of the charge and “allowance” for declined pre-dispatches proposed in the CAISO’s filing are designed to balance the need to limit the potential detrimental reliability and market effects of declined pre-dispatches with the goal of maintaining a competitive supply of real-time energy bids by not deterring suppliers from offering bids that may occasionally need to be declined due to various resource and market limitations.

Figure 3.16 Pre-Dispatched Import/Export Energy Declined (CAISO System)



4 Ancillary Service Markets

4.1 Summary of Performance in 2007

Overall, average Ancillary Service (A/S) prices decreased by 35 percent in 2007 compared to prevailing prices in 2006. The total procurement cost also decreased by 35 percent while the total procurement volumes of the four A/S products stayed almost at the same level as in 2006. The decrease in the aggregate A/S price resulted from price decreases in all four types of A/S markets to various extents.

The A/S markets also experienced a significant decline in hours of bid insufficiency in 2007 compared to the previous year. With the exception of Non-Spinning Reserve in the summer, bid deficiency occurred in less than one percent of the operating hours in each month for all four services. The relatively higher frequency of bid insufficiency for Non-Spinning Reserve in July and August can be attributed to tight supply conditions and high opportunity costs of providing energy during periods of high loads.

4.2 Ancillary Services Market Background

The CAISO procures Regulation Reserve, Spinning Reserve and Non-Spinning Reserve in the Day Ahead and Hour Ahead Markets such that the total procurement volumes plus self-provision volumes meet or exceed the Western Electricity Coordinating Council's (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electricity Reliability Council (NERC) Control Performance Standards (CPS). The CAISO procures A/S at the lowest overall cost while maintaining the reliability of the system and the competitiveness of the markets. The combination of a single-price auction pricing mechanism across the control area and the Rational Buyer algorithm, which allows for economic substitution of less expensive bids in place of more expensive bids across services, facilitates a least-cost procurement approach to meeting reliability requirements.

The definitions for the actively procured Ancillary Services are:

1) Regulation Reserves: Reserved capacity provided by generating resources that are running and synchronized with the CAISO controlled grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control (AGC) to allow continuous balance between generating resources and demand. The CAISO operates two distinct capacity markets for this service, upward and downward Regulation Reserve.

2) Spinning Reserves: Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. The CAISO needs Spinning Reserve to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.

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

4) Requirement: The CAISO maintain minimum amounts of Regulation, Spinning, and Non-Spinning Reserves to meet WECC and NERC control performance criteria. The quantity of Regulation Reserve capacity needed for each Settlement Period of the Day Ahead Market and the Hour Ahead Market shall be determined as a percentage of the aggregate scheduled demand for that Settlement Period. The quantity of Spinning Reserve and Non-Spinning Reserve is calculated as (a) 5 percent of the Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) to be met by Generation from hydroelectric resources plus 7 percent of the Demand (except the Demand covered by firm purchases from outside the CAISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the CAISO may determine from time to time.

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

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

4.3 Prices and Volumes of Ancillary Services

Overall, A/S prices decreased 35 percent from a weighted average price of $11.12/MW in 2006 to $7.41/MW in 2007. Decreases in average price of each of the four Ancillary Services contributed to the overall price decrease. The prices of Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve dropped 42 percent, 12 percent, 47 percent, and 35 percent respectively compared to 2006. Despite the significant price decreases for all four A/S services in 2007, prices in 2007 for all four services were within the normal range of historical prices, as indicated in Table 4.1.

The lower prices observed in 2007 may be partially attributed to lower hydroelectric generation in 2007. As shown in Chapter 2, average hydroelectric generation in 2007 was 2,000 MW -

3,000 MW or roughly 50 percent below the 2006 levels. The extremely high hydroelectric production observed in the spring of 2006 resulted in lower offers into the A/S markets by hydro resources as they were producing at or near maximum capacity with little or no unloaded capacity for upward services and high opportunity cost for backing down production for Regulation Down. The high hydroelectric production that year also displaced gas-fired resources that may have otherwise been online and offered into the A/S markets. Both of these factors resulted in higher, and more volatile, A/S prices in 2006. Spring of 2007 had much lower hydroelectric production and as a consequence was not subject to these two seasonal issues. In addition to the hydroelectric production, loads during the summer of 2007 were relatively mild in comparison to 2006, resulting in less pressure on spot wholesale electricity prices which also helped moderate prices in the A/S markets.

Procurement volumes, in total, were essentially unchanged from 2006. The average volumes of all four types of procurements remained at the same level as last year. Table 4.1 compares prices and volumes from previous operating years.

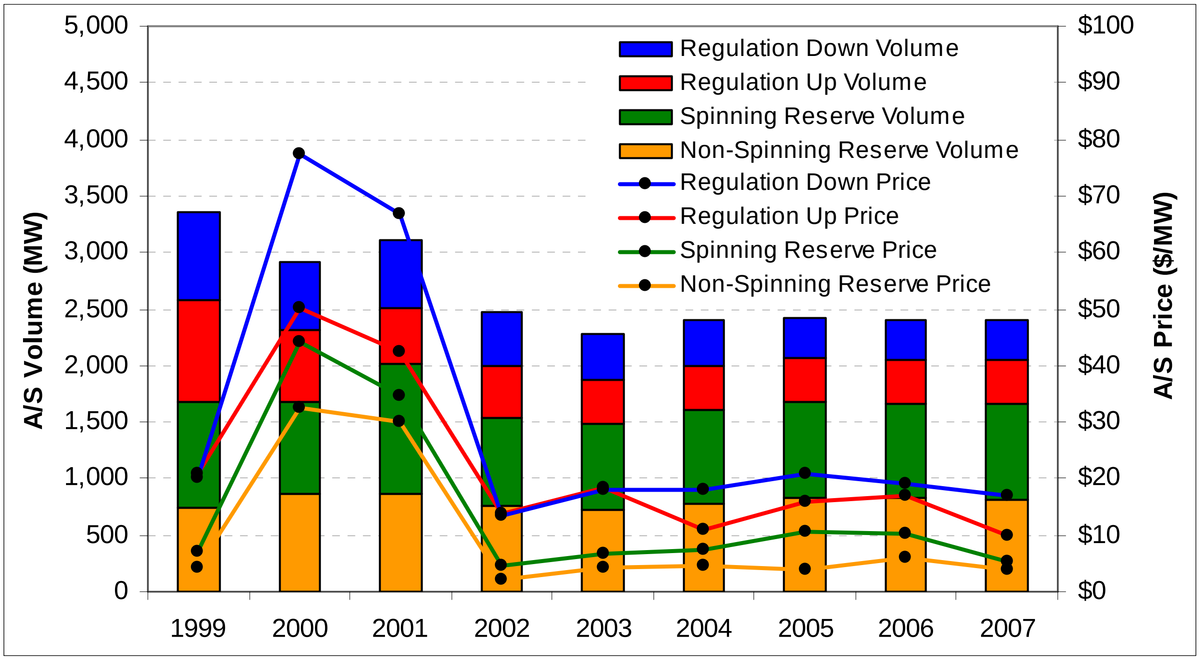
Table 4.1 Annual Hourly Average A/S Prices and Volumes

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Average A/S Price
Price ($/MW)	1999	$20.84	$20.22	$7.07	$4.35	$11.97
	2000	$50.15	$77.28	$44.07	$32.46	$41.03
	2001	$42.33	$66.72	$34.69	$30.03	$36.42
	2002	$13.76	$13.41	$4.66	$2.15	$7.08
	2003	$18.43	$18.08	$6.62	$4.20	$9.81
	2004	$10.95	$17.95	$7.25	$4.43	$8.63
	2005	$16.05	$20.94	$10.45	$3.98	$10.72
	2006	$17.01	$18.94	$10.11	$5.96	$11.12
	2007	$9.97	$16.81	$5.42	$3.98	$7.41

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Total Volume
Volume (MW)	1999	769	903	942	735	3,349
	2000	594	633	818	861	2,907
	2001	614	492	1,148	862	3,117
	2002	469	460	775	763	2,466
	2003	416	381	767	722	2,286
	2004	408	395	817	782	2,403
	2005	363	386	841	839	2,428
	2006	354	389	831	831	2,405
	2007	361	379	849	815	2,403

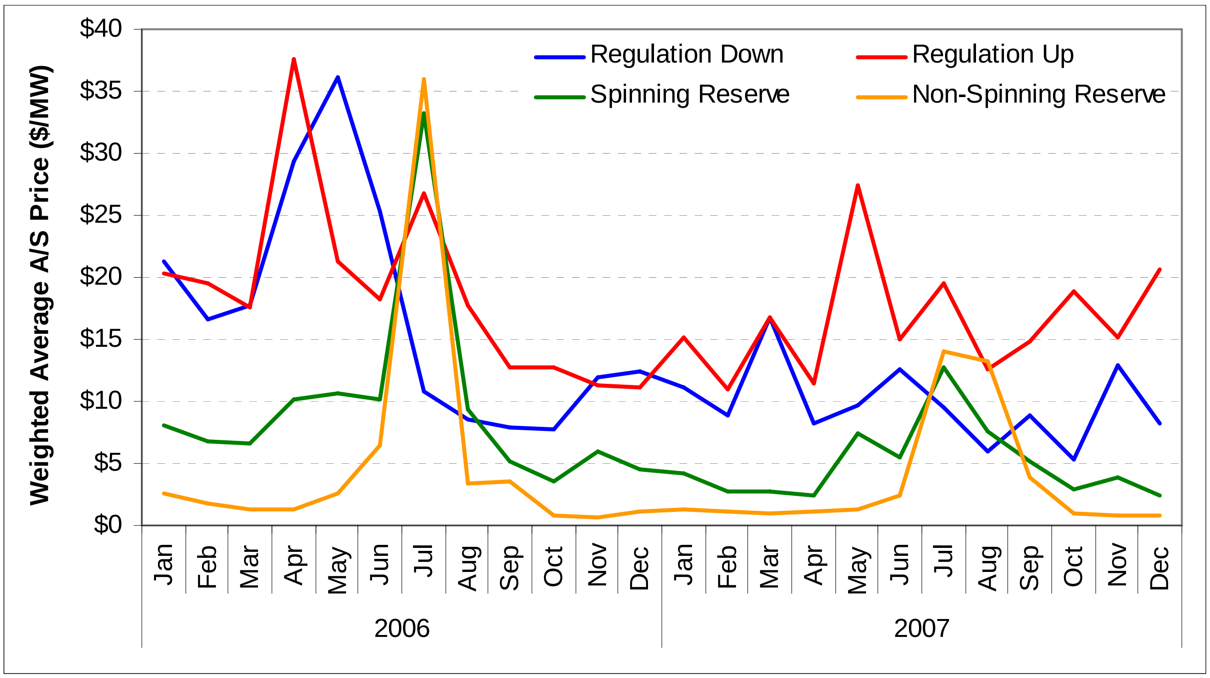
Figure 4.1 depicts the historical pattern of prices and volumes since 1999 and indicates that A/S prices and volumes have been relatively stable over the past six years (2002-2007) as compared to the period from 1999 to 2001.

Figure 4.1 Annual Average A/S Prices and Volumes



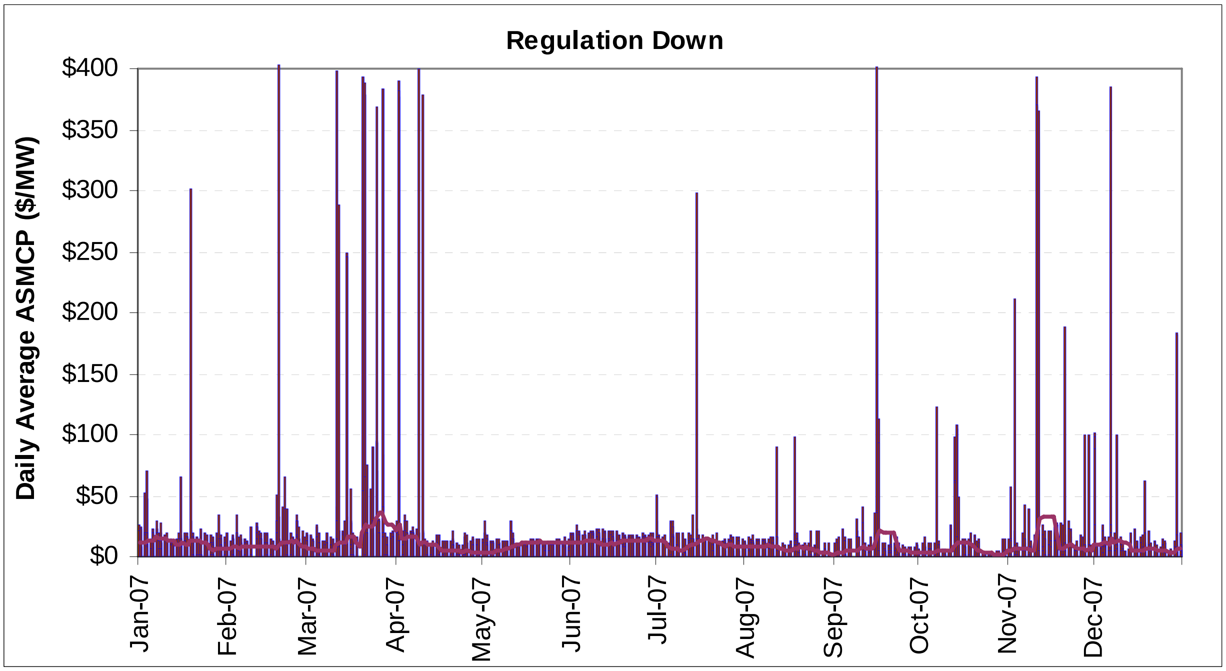
Monthly day-ahead reserve prices do tend to vary with seasonal load levels as seen in Figure 4.2. However, the volatility in monthly average A/S prices is lower in 2007 compared to 2006, as spring hydro-electric production and summer heat waves were milder in 2007 than the previous operating year. As a result of cost-minimizing economic substitution of less expensive bids for higher quality services in place of more expensive bids for lower quality services, prices of upward A/S reserves generally display a decreasing pattern in the order of Regulation, Spinning Reserve, and Non-Spinning Reserve. Notwithstanding, price reversion may still happen due to the step-wise characteristics of A/S bid patterns. As shown in Figure 4.2, the average price of Non-Spinning Reserve was higher than that of Spinning Reserve in July and August of 2007.

Figure 4.2 Monthly Weighted Average A/S Prices



Hourly average day-ahead prices are shown in Figure 4.3 and Figure 4.4 along with seven-day moving averages showing short-term price trends across the year. Compared to 2006, prices of Regulation Reserves in 2007 were lower due to lower spring hydro-electric runoff but displayed a higher volatility across the year. However, the impact of the spring hydro-electric runoff can still be seen in the pricing trends for Regulation Down Reserve. The price pattern for Operating Reserves clearly reflects the summer peak load conditions during the two heat waves in July and August.

Figure 4.3 Day Ahead Regulation Reserve Market Clearing Prices (A/S MCPs) with Seven Day Moving Averages



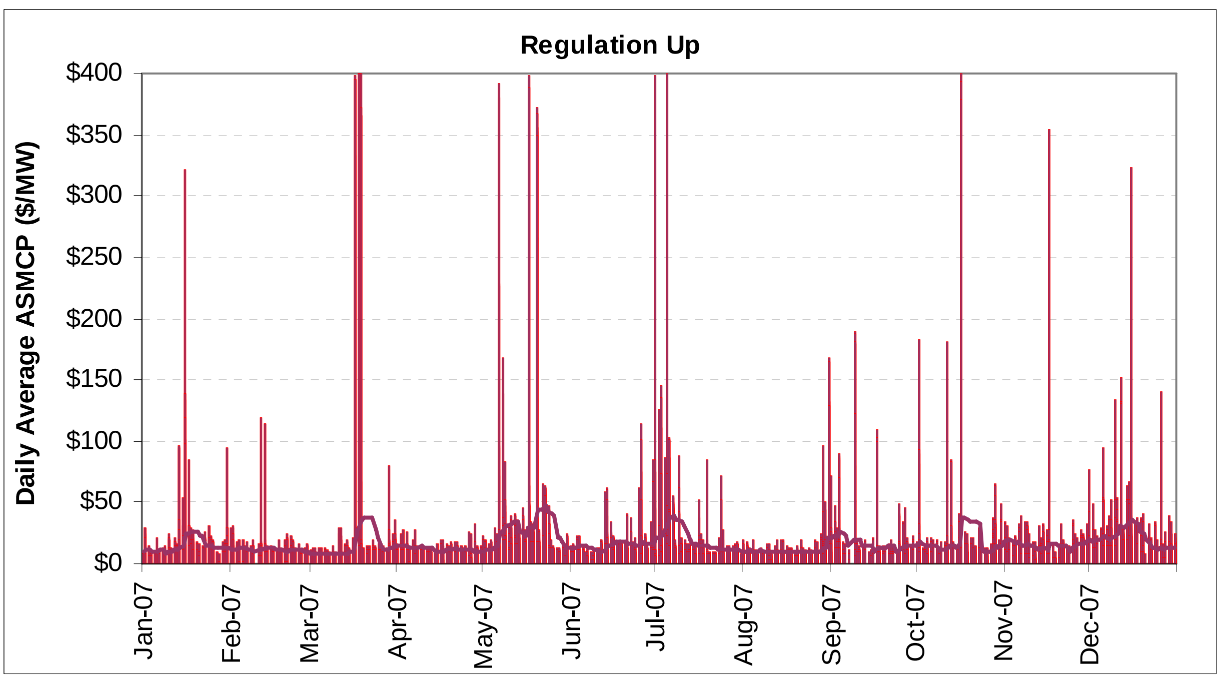
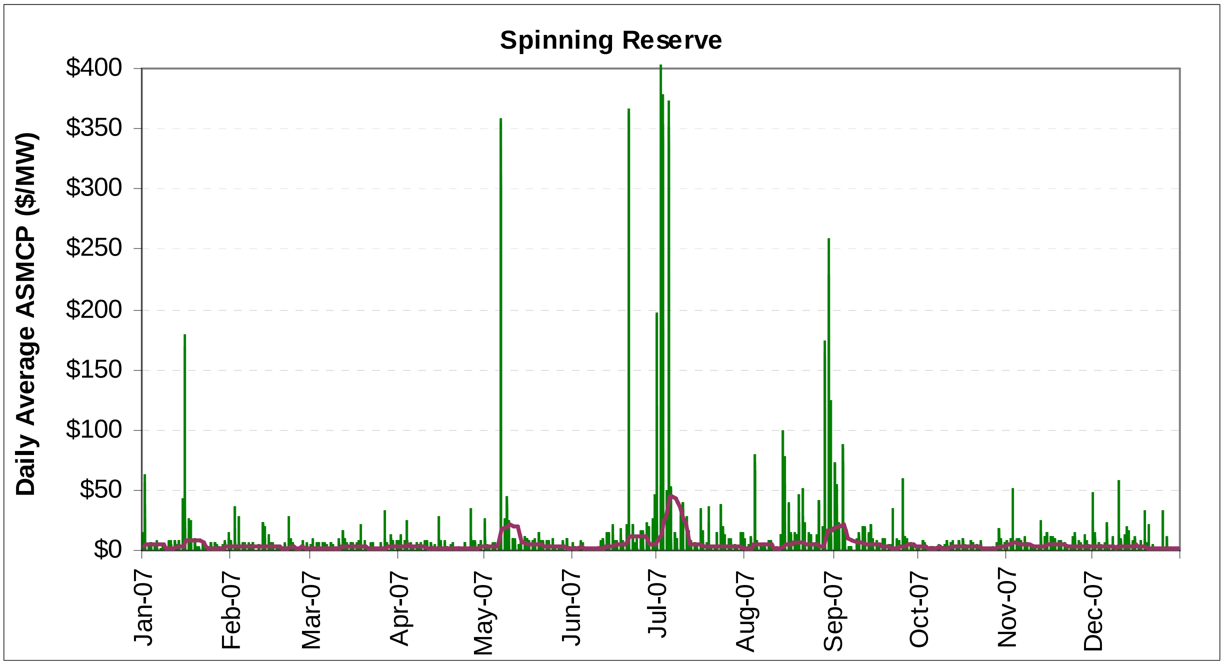


Figure 4.4 Day Ahead Operating Reserve Market Clearing Prices (A/S MCPs) with Seven Day Moving Averages



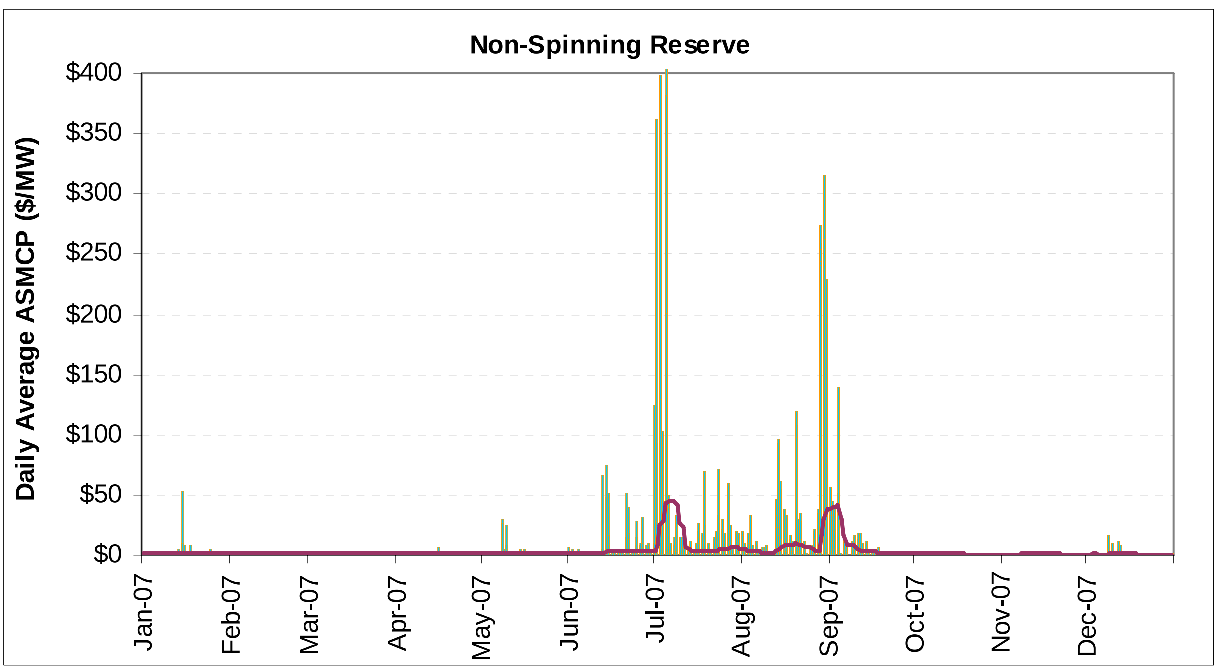


Figure 4.5 shows the variation of A/S prices across different operating hours. Prices of Upward Regulation and Operating Reserves generally follow the load pattern, with higher prices in peak load hours. However, Regulation Down Reserve prices observe an opposite trend with high prices in the early morning hours when the load is low. These high prices for Downward Regulation Reserve are especially prominent during the spring morning hours, as fewer resources are operating in a range where they can back generation down and hydro-electric resources are reluctant to reduce output due to the spill conditions that accompany spring runoff period, as illustrated in Figure 4.6. Figure 4.6 also shows the seasonal variation of Non-Spinning Reserve prices. As more resources are online and operating at high output levels in the summer peak hours, the supply of Non-Spinning Reserve is limited, resulting in higher prices. Higher energy prices in the summer peak hours also contributed to the price spikes of Operating Reserves by driving up the opportunity cost of reserving generation capacity.

Figure 4.5 Day Ahead Hourly Average A/S Prices (2007)

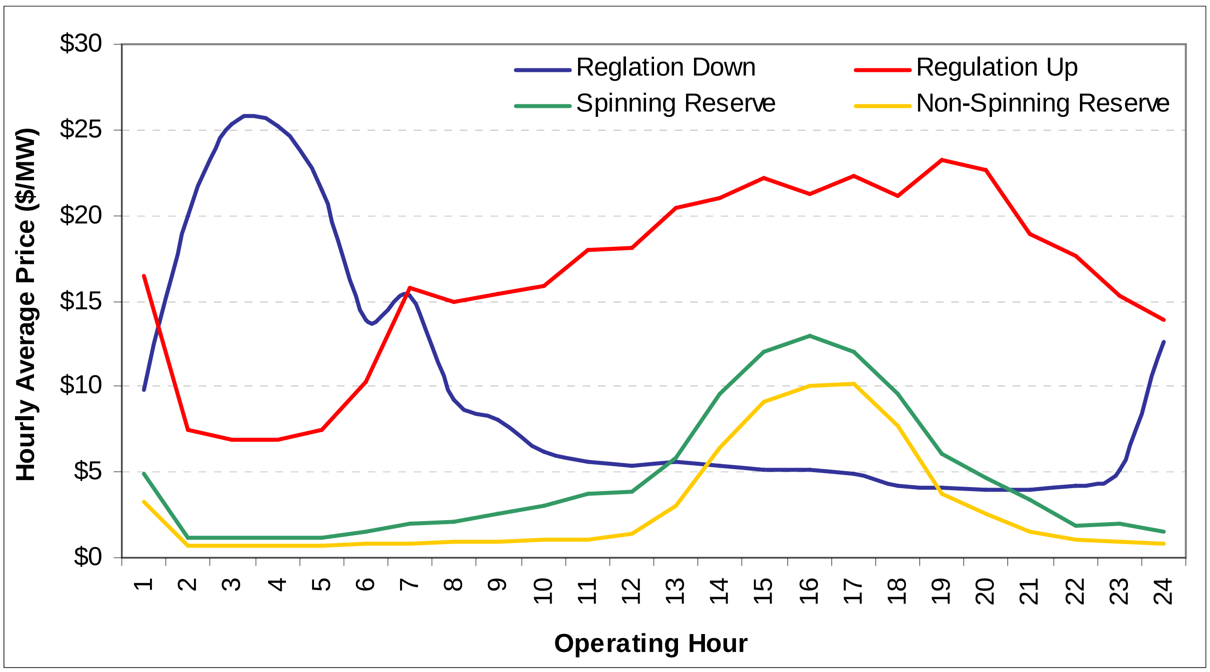
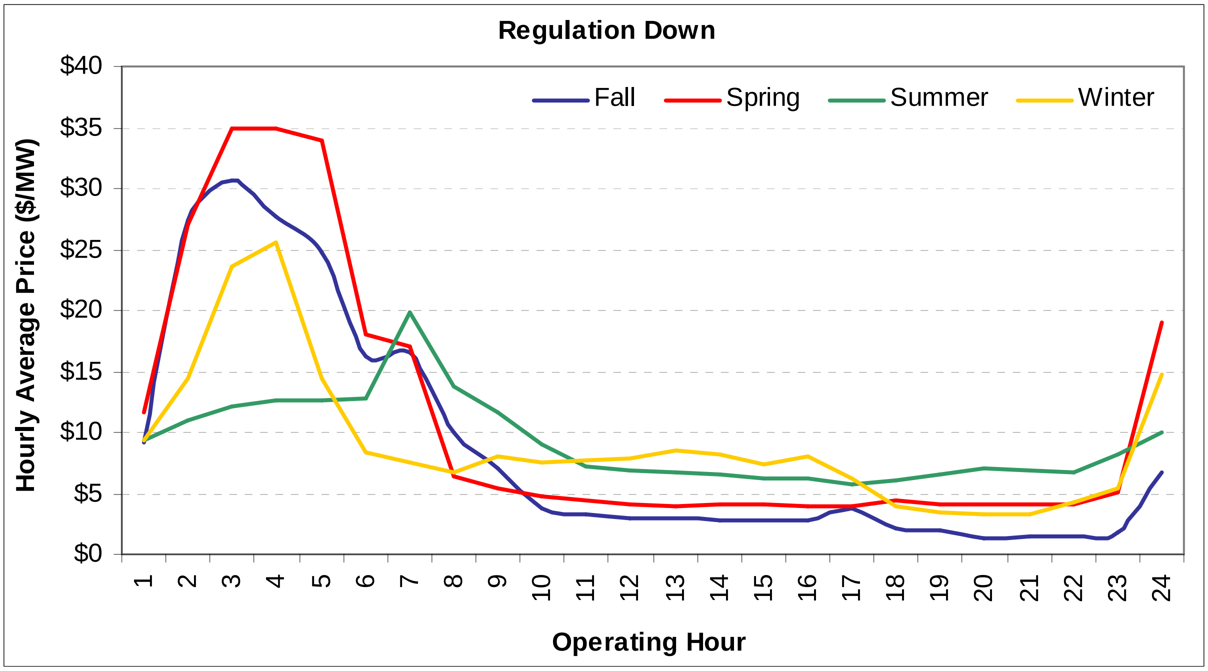
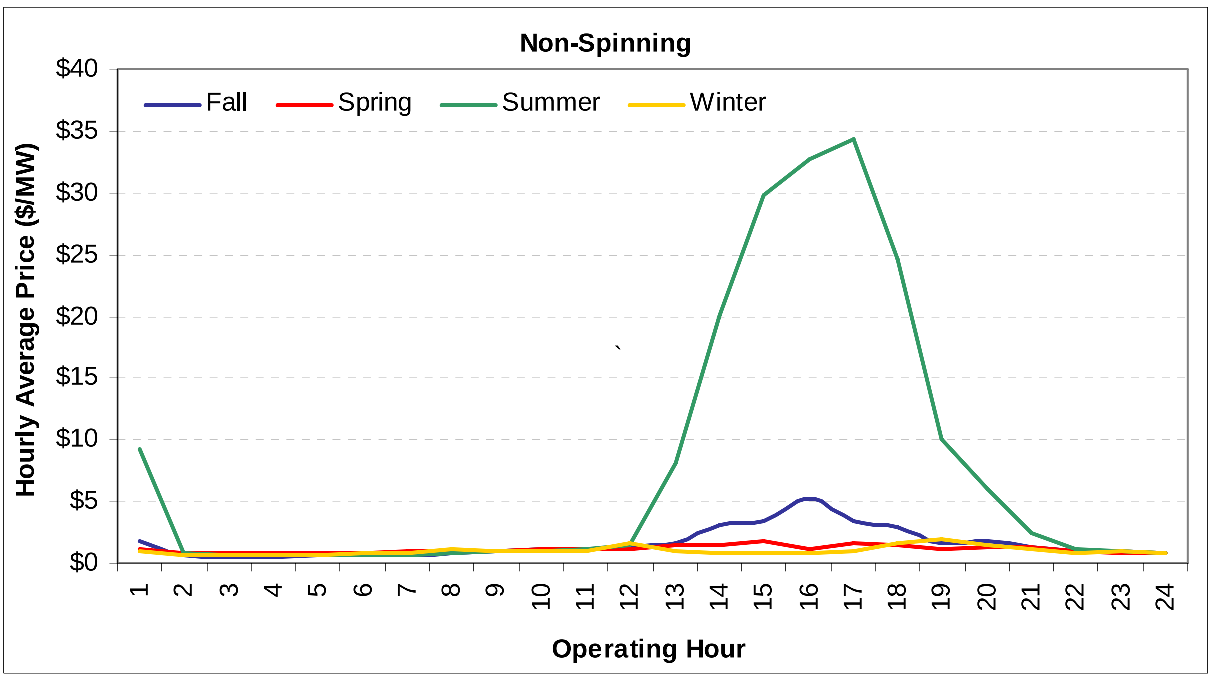


Figure 4.6 Hourly Average A/S Prices by Season (2007)





The price duration curves for the A/S Day Ahead Markets, shown in Figure 4.7 and Figure 4.8, reflect generally expected price behavior with the higher quality products exhibiting the highest sustained prices. Overall, Operating Reserve prices were at price levels above $25 in fewer than 2 percent of the operating hours in 2007, down from about 5 percent in the preceding year. At the same time the percentage hours with Regulation Reserve prices over $25 decreased from about 20 percent in 2006 to fewer than 10 percent in 2007.

Figure 4.7 Price Duration Curves for 2007 Regulation Reserve Markets

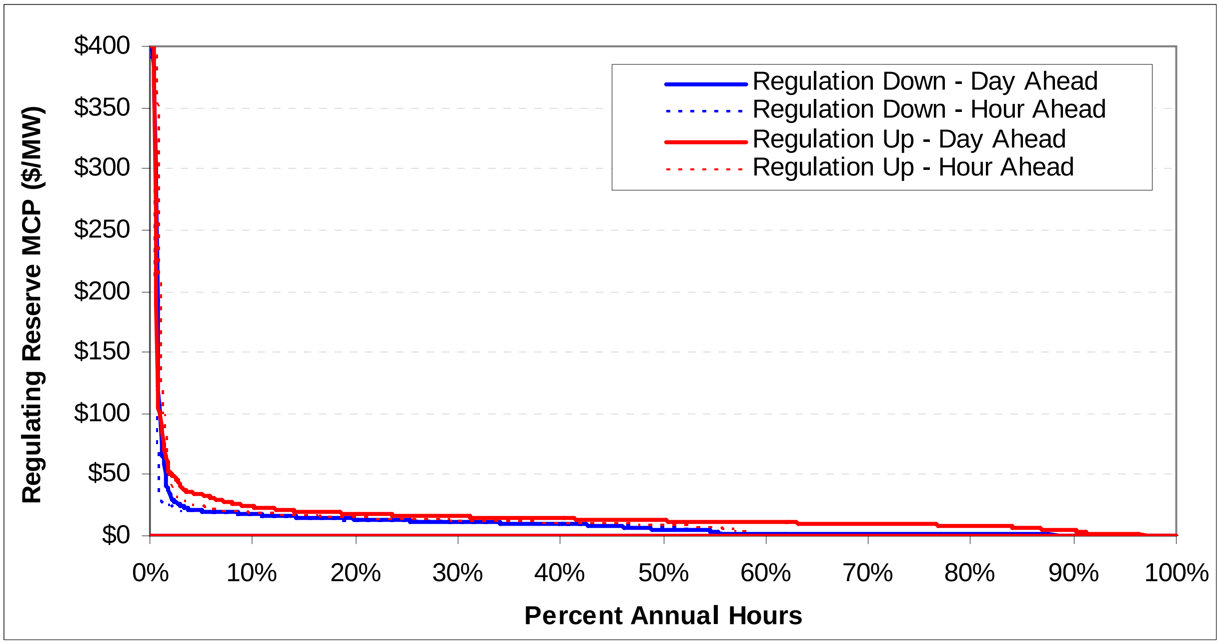
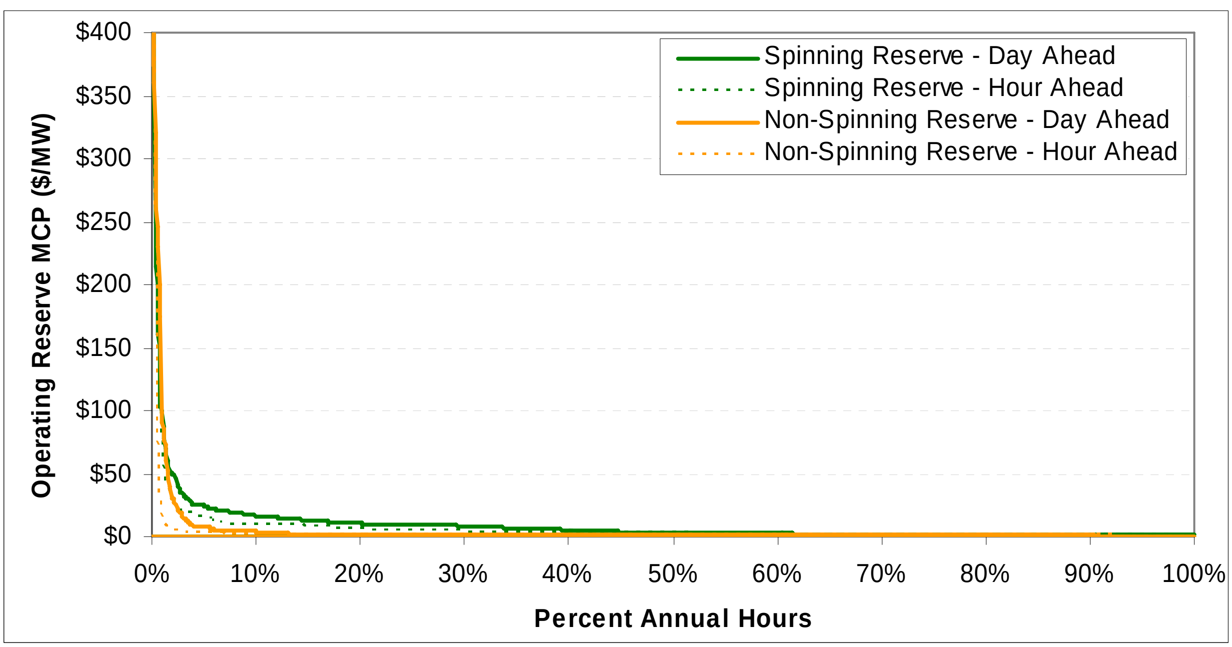


Figure 4.8 Price Duration Curves for 2007 Operating Reserve Markets

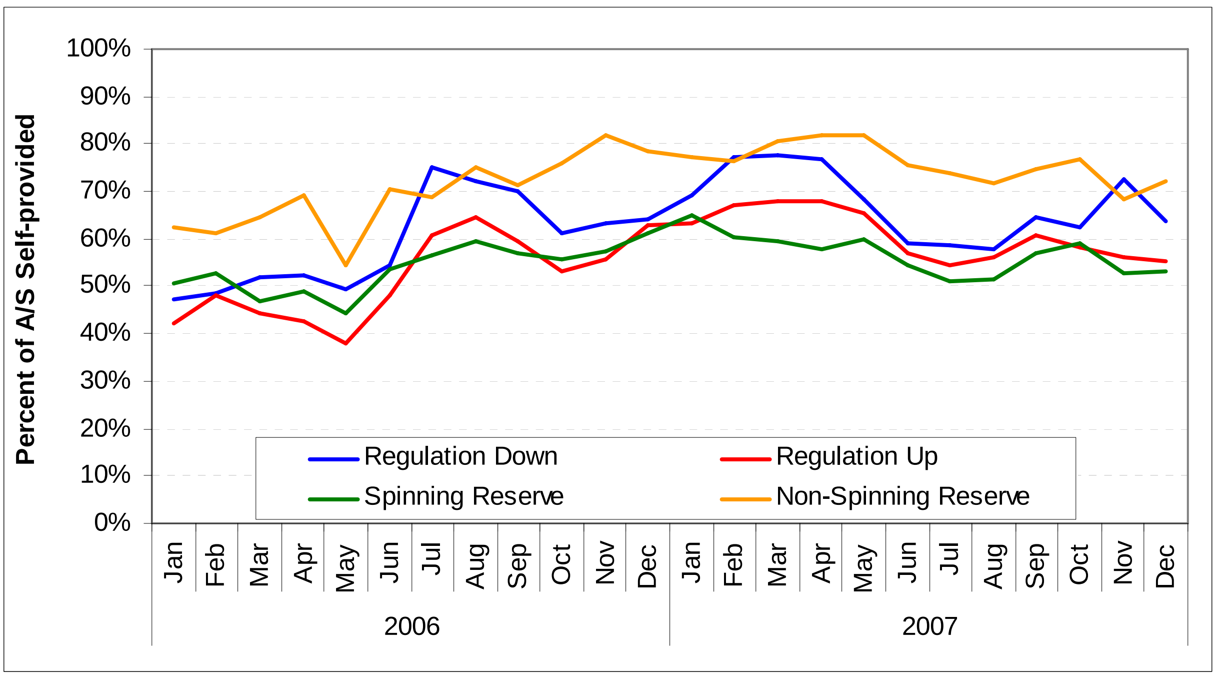


4.4 Ancillary Services Supply

4.4.1 Self-Provision of Ancillary Services

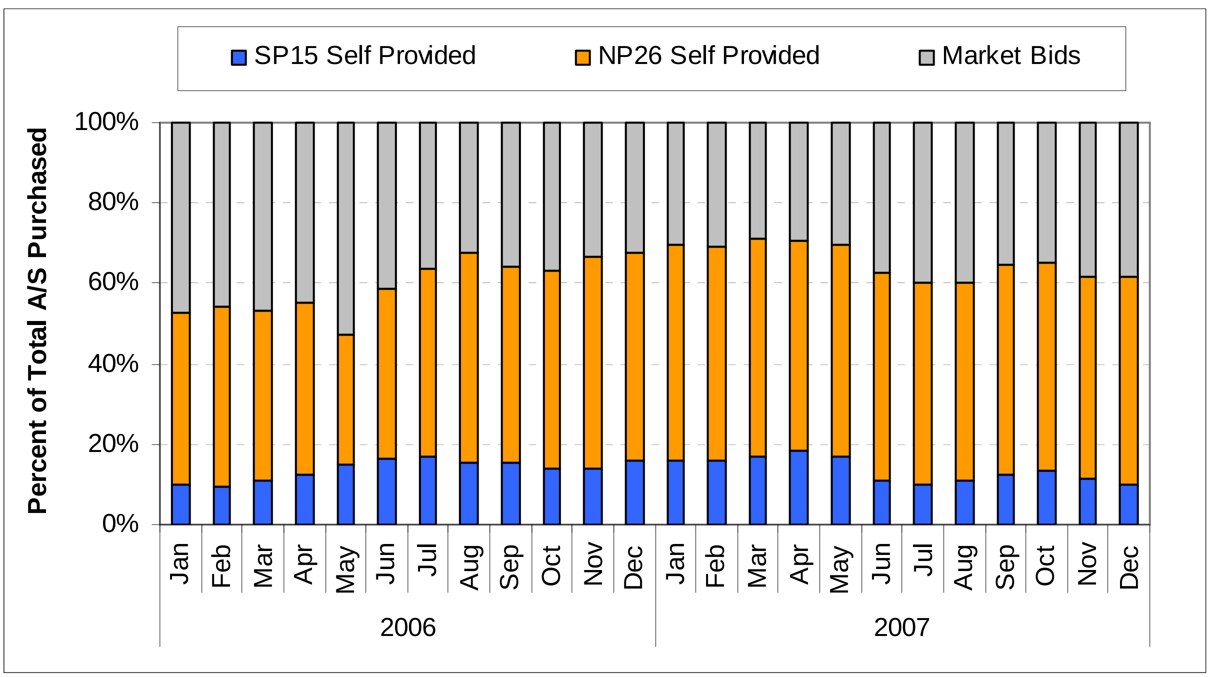
Self-provided ancillary services remained a significant share of the total supply in 2007, ranging between 50 and 80 percent for most services in most months. Self-provision on all four ancillary services, as a percent of purchases, increased in 2007, particularly for the first half of the year (Figure 4.9). This increase is likely attributable to lower levels of hydro-electric generation in the spring of 2007. Because hydro-electric resources were producing near their limit and had limited Downward Regulation capacity, higher levels of non-hydro-electric generation increased the availability of Regulation Down Reserve capacity in 2007. Summer months exhibited a relatively lower percentage of self-provision due to the fact that more generation controlled by LSEs with A/S obligations is being used to serve that LSE's load in the summer months.

Figure 4.9 Hourly Average Self-Provision of A/S



It is also interesting to view self-provision by zone. Figure 4.10 shows the breakout of total A/S procured by source (market bid, self-provided in NP26, and self-provided in SP15). During 2006 and 2007, the CAISO purchased A/S on a system-wide basis and did not practice zonal procurement. Consistent with this practice, the percentages shown in this figure are with respect to total system-wide A/S procurement. Note that hourly average self-provision in NP26 ranged from 49 percent to 54 percent during 2007 while the corresponding figure in SP15 was much lower, between 10 percent and 19 percent throughout 2007. Although the 2007 self-provision percentages in SP15 remained at similar levels as 2006, the corresponding figures in NP26, especially for the first half of 2007, generally increased. Typically, due to the distribution of load between the North and South, the calculated A/S requirement in SP15 is higher than that of NP26. Although not shown in this chapter, on average, roughly 70 percent of A/S is procured in NP26 with the remainder in SP15. However, as shown in Figure 4.8, combined procurement from resources in SP15 (procurement from market bids and self-provided A/S) is usually significantly lower than the calculated zonal A/S requirement. This disparity between the North and South is facilitated by transmission capability on Path 15 and Path 26, along which energy from A/S can be transferred from north-to-south to provide reliability support in the event of a contingency.

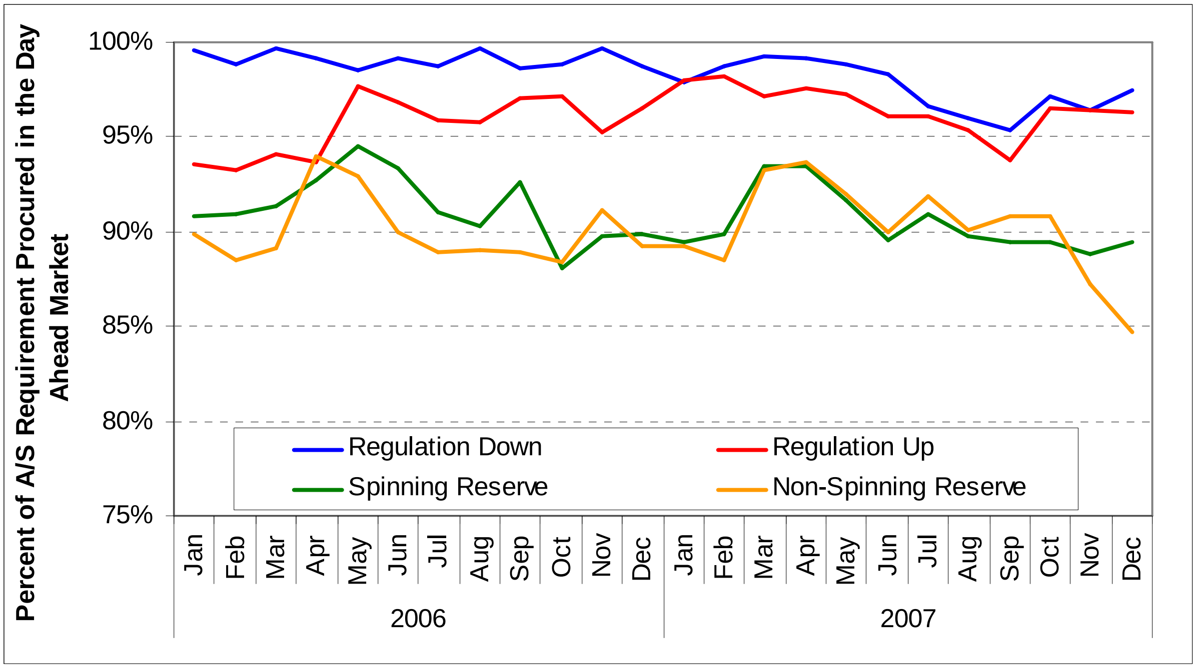
Figure 4.10 Hourly Average Self-Provision of A/S as a Percent of Total Procurement, by Zone, for All Services Combined



4.4.2 Day-ahead vs. Hour-ahead Procurement

With the exception of Non-Spinning Reserve, the percent of A/S requirement procured in the Day Ahead Market remained relatively stable at above 90 percent. The proportion of Non-Spinning Reserve procured in the day-ahead was between 85 percent and 95 percent for most of the year (Figure 4.11).

Figure 4.11 Hourly Average Day-Ahead Procurement, 2006 - 2007



4.4.3 Bid Sufficiency

Bid insufficiency occurs when there is not enough available capacity bid into the markets to meet the procurement requirements. In addition to potentially creating reliability issues, bid insufficiency in the A/S markets can result in market power concerns as essentially any supplier to the A/S market in bid deficient hours is pivotal. Additionally, market power concerns can arise if bid sufficiency exists but only marginally so. In these cases, certain suppliers may also be pivotal in the sense that the A/S requirements could not be met absent their supply. The CAISO employs several measures of bid sufficiency. Volumes of capacity shortages convey information about the magnitude of the deficiency events and the count of operating hours where bid-in capacity falls short of requirements represent commonly used metrics that provide insight into the frequency and severity of shortage events. Table 4.2 provides these two metrics for the past two operating years.

Table 4.2 Bid Insufficiency (2006 – 2007)

	Number of Hours With Shortage				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2006	159	110	145	113	527
2007	20	11	35	36	102
Percent Δ	-87%	-90%	-76%	-68%	-81%
	Average Percent of Requirement Short				
	Regulation Up	**Regulation Down**	**Spinning Reserve**	**Non-Spinning Reserve**	**All Services**
2006	21%	16%	8%	15%	13%
2007	15%	7%	6%	8%	8%

The frequency of bid insufficiency and average percent of requirement short declined significantly in 2007 compared to 2006 for all four types of reserves. The following figures (Figure 4.12 through Figure 4.15) show the frequency of hourly bid deficiencies and the average amount of deficiency (expressed as a percentage of the total requirement) by month and by service, for the past two years.

Unlike the clear pattern of bid insufficiency of Regulation Reserves during the spring months of 2006, there was no such concentration in the spring of 2007 as the bid insufficiency hours for Regulation Reserves decreased to a trivial amount. This decline in frequency of bid insufficiency for Regulating Reserves is directly attributed to the lower hydroelectric production in 2007 and the resulting impact that had on availability of Regulating Reserve from both hydro and online gas-fired resources. In comparison, hydro flows and hydro generation were significantly lower in 2007 than the preceding year, which made the provision of Regulation Reserves less restrictive and, therefore, decreased the hours of bid insufficiency for Regulation Reserves especially in the spring.

The number of hours with bid insufficiency for Operating Reserves also decreased significantly in 2007, by roughly 70 percent. The summer of 2007 was relatively mild with contrast to that of the previous year when CAISO load records were repetitively set and refreshed. Because the procurement requirements of Operating Reserves depend on load levels, a relatively mild summer in 2007 would essentially lower the demand for Operating Reserves. Moreover, relatively lower summer load levels in 2007 resulted in higher supply margins, some of which was available for providing Operating Reserves.

Figure 4.12 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Regulation Down

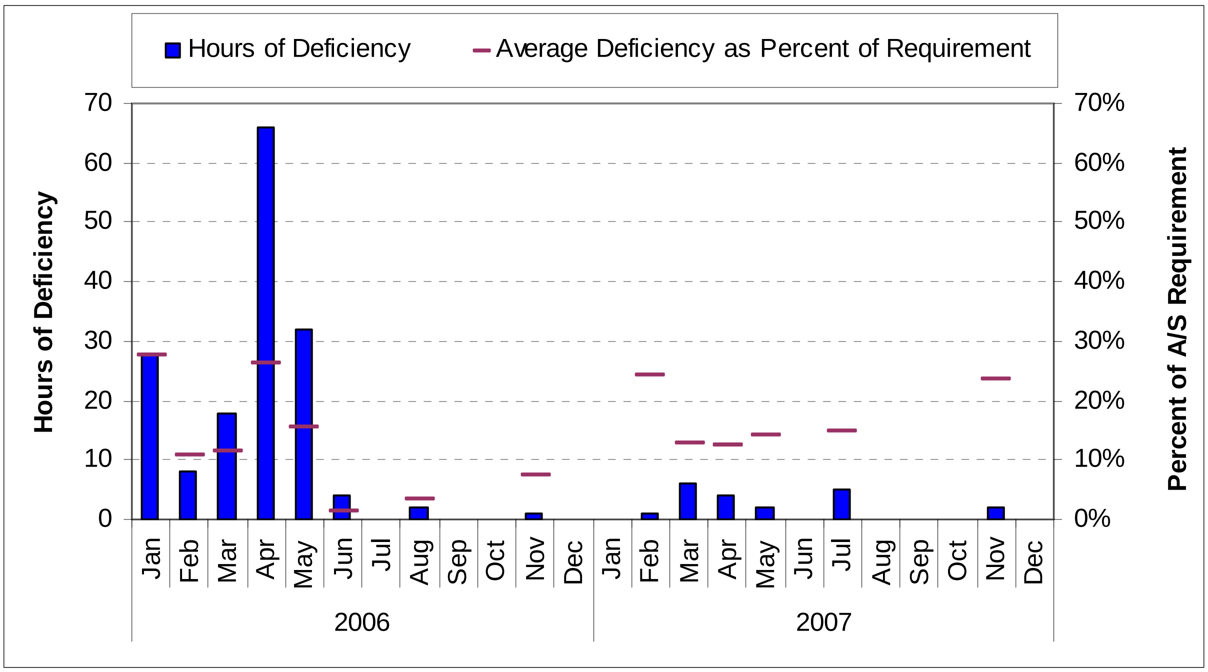


Figure 4.13 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Regulation Up

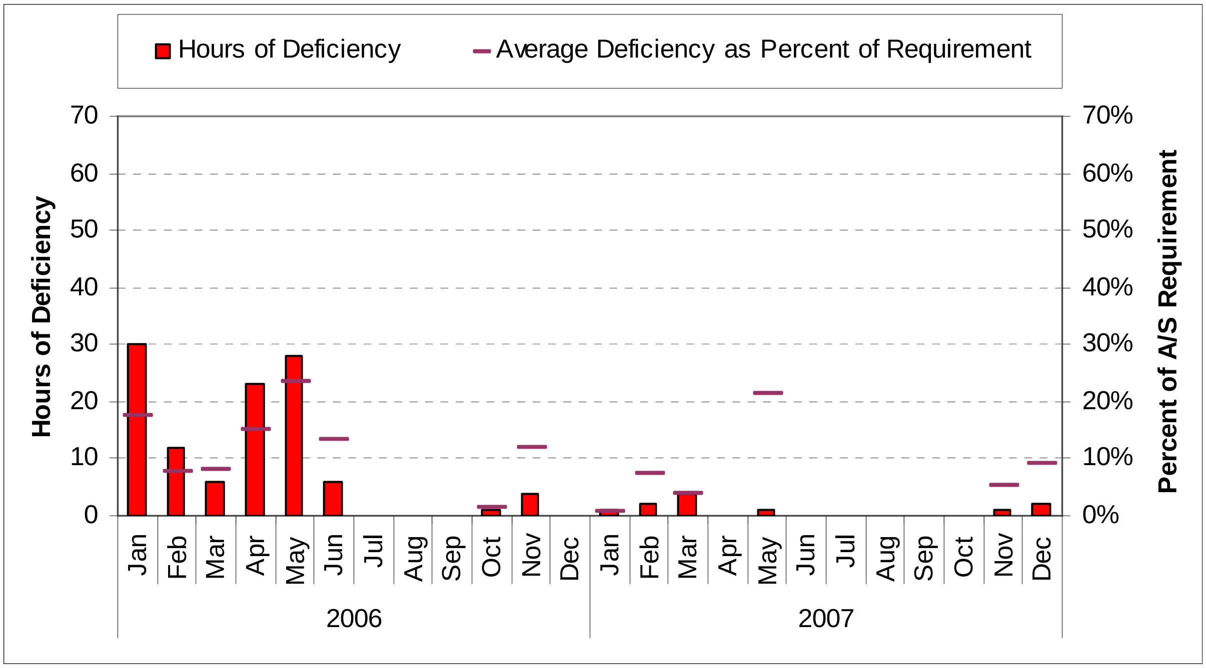


Figure 4.14 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Spinning Reserve

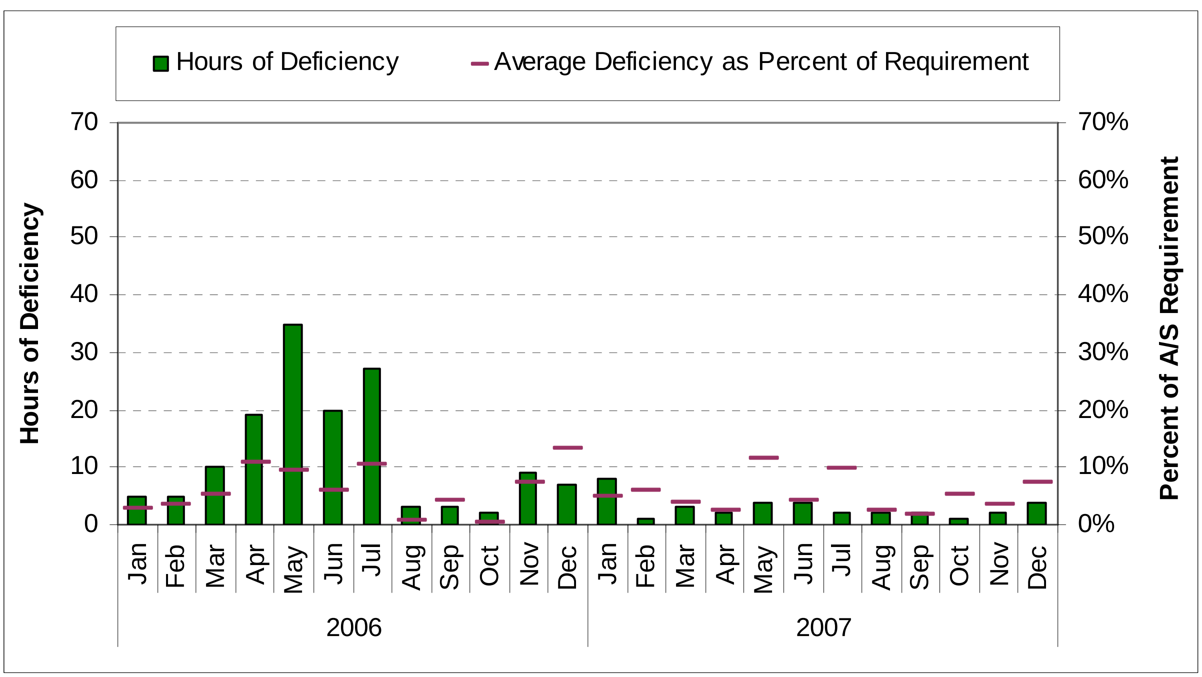
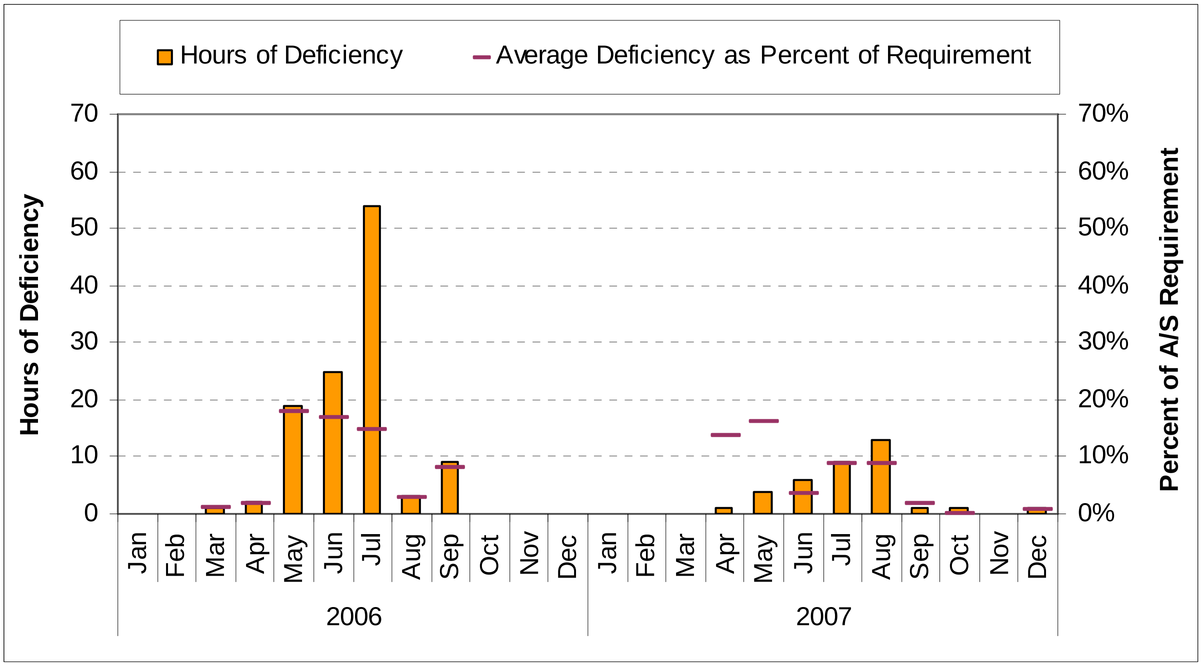


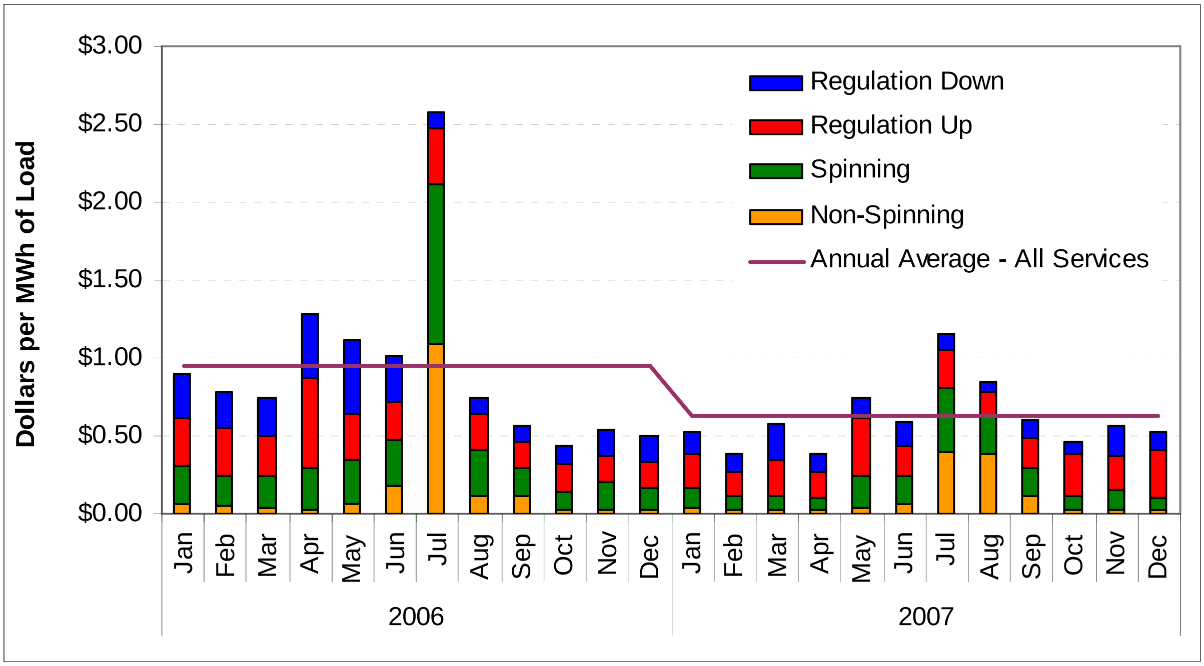
Figure 4.15 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Non-Spinning Reserve



4.5 Costs

The total cost of A/S capacity per unit of MWh load decreased in 2007 compared to 2006. The A/S procurement cost to load in 2007 averaged $0.63/MWh, which is 35 percent lower than the $0.95/MWh average the year before. Figure 4.16 provides the monthly details on these costs. With the exception of July, all monthly total cost of A/S capacity per unit of MWh load remained under $1.00/MWh in 2007.

Figure 4.16 Monthly Cost of A/S per MWh of Load



5 Inter-Zonal Congestion Management Markets

5.1 Inter-Zonal Congestion Management

Congestion occurs when the physical limits of a line, or inter-tie, prohibits load from being served with the least cost energy. The current zonal market distinguishes between inter- and intra-zonal congestion. Inter-zonal congestion refers to congestion that occurs between zones; intra-zonal congestion refers to congestion within a zone, which is discussed in the next chapter. Inter-zonal congestion is managed in forward markets on major inter-ties and two large internal paths (Path 15 and Path 26). Scheduling Coordinators (SCs) submit adjustment bids, which are dispatched to alleviate congestion while maintaining a balanced portfolio and minimizing congestion charges. The marginal adjustment bid dispatched to relieve congestion sets the congestion charge on the interface for the given period. Each SC pays a congestion charge depending on scheduled, accepted flows on the congested interface to the CAISO, which is then distributed back to holders of Firm Transmission Rights (FTRs) and Transmission Owners (TOs).

Congestion in 2007 increased in frequency and charges among almost all branch groups and inter-ties from 2006. The increase in congestion frequency and charges system-wide is mostly attributed to high north-to-south flows during the spring and early summer months coupled with transmission outages throughout the year and a few distinct events in the fall. Total congestion charges increased from $56 million in 2006 to $85 million in 2007, the first year since 2001 with charges over $60 million. The Palo Verde branch group had the highest congestion charges, accounting for 25 percent of total charges; May was the most costly month in 2007 at $12.1 million. The most frequently congested path in 2007 was the Pacific AC Inter-tie (PACI) at 32 percent of total annual hours. The spring and early summer months' congestion charges were concentrated on PACI and the Pacific DC Inter-tie (PDCI or NOB as referred to in the tables) as hydro electricity was imported from the Northwest across PACI and NOB to meet California load. The pattern of congestion transitioned to Palo Verde and Eldorado in the fall months as Northwest hydro went into the re-charge season and California shifted to rely more heavily on gas, nuclear, and coal generation from the Southwest.

Scheduling Coordinators can own FTRs to mitigate congestion charges they incur during the year. A FTR is both a financial instrument and a physical right to transmission. On the financial side, owners share in the distribution of Usage Charge revenues received by the CAISO due to inter-zonal congestion during the period for which the FTR was issued. The physical right is the priority given to FTR holders when scheduling energy across congested interfaces. FTRs are distributed to SCs through assignment, auction, secondary sales or trades, and transfers. Total revenues from the 2007-2008 FTR primary auction was $121 million, a 16 percent increase from the 2006-2007 FTR primary auction. More FTR market transactions occurred through secondary auctions in 2007, compared to previous years, due to the delay of Market Redesign and Technology Upgrade (MRTU) and the need to extend FTRs beyond an MRTU implementation date that had become obsolete.

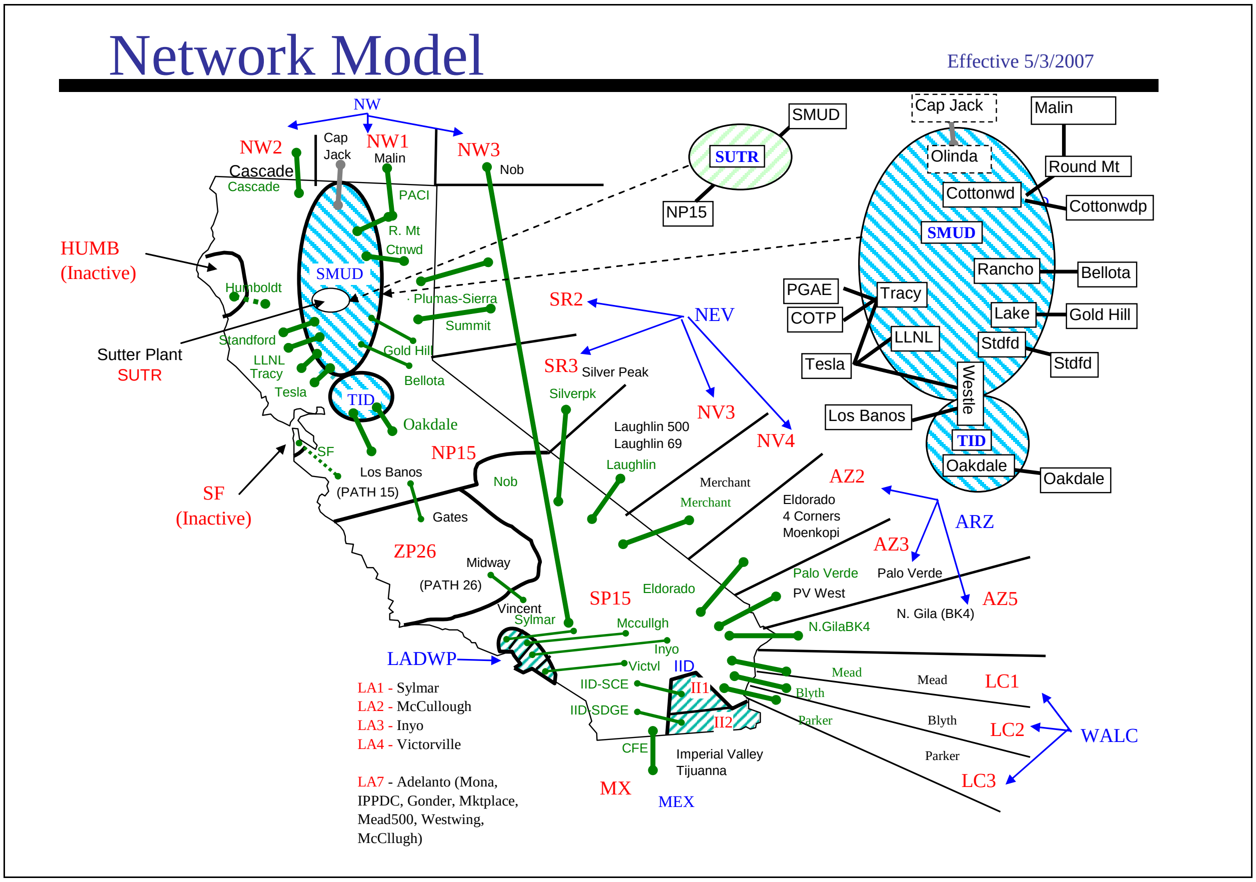
5.1.1 Overview

Under the current zonal model, the CAISO manages congestion in the forward market only on major inter-ties and two large internal paths (Path 15 and Path 26). It uses adjustment bids to mitigate congestion while minimizing the cost of schedule adjustments and keeping each SC's schedule in balance. The marginal SC establishes the usage charge for the inter-zonal interface. All SCs pay this charge based on their accepted, scheduled flow on the interface. The CAISO pays the net amount of congestion charges it collects to the Transmission Owners (TOs) and owners of FTRs. Figure 5.1 shows the active congestion zones and major inter-zonal pathways (branch groups) in the CAISO grid. The new footprint of the CAISO grid reflects several operational changes that were effective by May 3, 2007, including:

- A Pseudo Tie for Melones Plant[41]
- Modification of the Palo Verde branch group[42]
- The new Tesla to Stanford branch group (TSLASTDFD_BG)[43]
- The new Oakdale to Los Banos branch group (OAKDLSBNS_BG)[44]

[41] The pseudo tie connects the Melones plant from SMUD to PGAE control area.
[42] The modification included combining Palo Verde and Palo Verde West into one inter-tie.
[43] TSLASTDFD_BG includes the SMUD Inter-tie in Westly Los Banos and the SMUD-TID Inter-tie in Stanford Sub.
[44] OAKDLSBNS_BG includes the TID Inter-tie in Westly Los Banos and the TID Inter-tie in Oakdale CSF.

Figure 5.1 Active Congestion Zones and Branch Groups



Total inter-zonal congestion charges for the Day Ahead and Hour Ahead Markets in 2007 were $85 million, which is a 51 percent increase from 2006. Table 5.1 shows the historical annual total inter-zonal congestion charges since the year 2001. The majority of 2007 inter-zonal congestion charges (89 percent) can be attributed to 7 branch groups (Palo Verde, PACI, Eldorado, IPP (DC)-Adelanto,[45] NOB, Mead, Marketplace-Adelanto), with Palo Verde constituting the largest share. The next section provides a more detailed breakdown of congestion frequency and charges by individual branch group.

[45] IPP-Adelanto is a 500kV DC transmission line owned by the Los Angeles Department of Water and Power (LADWP).

Table 5.1 Historical Inter-Zonal Congestion Charges

Year	Total Inter-Zonal Congestion Charges ($ M)
2001	$107
2002	$42
2003	$26
2004	$56
2005	$55
2006	$56
2007	$85

5.1.2 Inter-Zonal Congestion Frequency and Magnitude

This section summarizes frequencies and average congestion charges for major inter-zonal interfaces (branch groups) in 2007. Table 5.2 shows annual congestion frequencies and average congestion charges by branch group, direction (import or export), and market type (day-ahead or hour-ahead). The frequency of congestion in 2007 was highest on several of the main branch groups between the CAISO and neighboring control areas outside California. In the Day Ahead Market, the Mead, Palo Verde, Blythe, and Eldorado branch groups, the Pacific DC (also known as the North-of-Oregon Border Inter-tie, or NOB, as listed in the table), the Pacific AC (PACI), and the IPP(DC)-Adelanto (IPPDCADLN) Inter-ties all were congested in at least 10 percent of hours. In the Hour Ahead Market, the Pacific AC and DC Inter-ties were also congested in at least 10 percent of hours. The most frequently congested branch group in 2007 was the Pacific AC Inter-tie, at 32 percent in the Day Ahead Market, up from 18 percent in 2006. The PACI was also congested 18 percent of hours in the Hour Ahead Market in 2007, with all of the congestion being in the import direction. The increased congestion on PACI and NOB may be attributed to the lower hydro conditions in the Pacific Northwest and California in 2007. Despite low overall hydro conditions, California's hydro conditions were lower than the Pacific Northwest, resulting in high north-to-south flows across PACI into the CAISO control area during the spring and early summer months. Congestion charges on PACI averaged $3/MWh in the Day Ahead Market and $17/MWh in the Hour Ahead Market, which was comparable to average charges on the Pacific DC (NOB) branch group. Average[46] day-ahead congestion charges on two major Southwest branch groups (Palo Verde and Eldorado) were higher than the Northwest, averaging $6/MWh and $8/MWh, respectively. Congestion frequency on the IPPDCADLN Inter-tie in the Day Ahead Market increased significantly from 6 percent in 2006 to 29 percent in 2007, mostly due to several transmission de-rates and outages in September and October.

[46] The Average Congestion Price is the average price only during congested hours. When the inter-tie is not congested, the congestion price is $0.

Table 5.2 Inter-Zonal Congestion Frequencies (2007)[47]

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
Branch Group	Import	Export	Import	Export	Import	Export	Import	Export
ADLANTOSP	6	0	$4	$0	2	0	$42	$0
BLYTHE	10	0	$14	$0	0	0	$57	$0
CASCADE	7	0	$0	$0	4	0	$1	$0
CFE	0	0	$0	$0	0	0	$87	$0
ELDORADO	13	0	$8	$0	6	0	$21	$0
GONDIPPDC	0	0	$0	$0	0	1	$0	$38
IID-SCE	0	0	$0	$0	0	0	$10	$0
IID-SDGE	0	0	$0	$0	0	0	$30	$0
IPPDCADLN	29	0	$6	$0	8	0	$58	$0
MEAD	18	0	$4	$0	9	0	$21	$0
MERCHANT	0	0	$0	$0	0	0	$0	$0
MKTPCADLN	5	0	$18	$0	1	0	$43	$0
MONAIPPDC	0	2	$0	$7	0	1	$0	$67
NOB	17	0	$5	$17	10	0	$24	$5
PACI	32	0	$3	$0	18	0	$17	$0
PALOVRDE	19	0	$6	$0	9	0	$34	$0
PARKER	8	0	$9	$0	0	0	$46	$0
PATH15	0	0	$16	$0	0	0	$52	$0
PATH26	0	1	$0	$4	0	1	$1	$19
SILVERPK	0	0	$15	$0	1	0	$9	$0
SUMMIT	2	0	$0	$0	1	0	$9	$84
TRACYCOTP	0	0	$2	$0	0	0	$13	$0
TSLASTDFD	0	0	$0	$30	0	0	$0	$0
WSTWGMEAD	5	0	$13	$0	1	0	$9	$15

5.1.3 Inter-Zonal Congestion Usage Charges and Revenues

Table 5.3 shows the total annual congestion charges for the major CAISO branch groups in 2007. Total congestion charges system-wide of $85.1 million represents a 51 percent increase above the 2006 total. Twenty five (25) percent of total congestion charges were incurred on the Palo Verde branch group in the import direction in 2007, compared to 30 percent in 2006. Another 18 percent was incurred on the Pacific AC Inter-tie (PACI), all in the import direction, compared to the 21 percent of total congestion charges incurred in 2006. Both Palo Verde and PACI had a decrease in their share of total congestion charges, while actual congestion charges increased $4.5 million and $3.4 million respectively. Other branch groups with significant increases in congestion charges over 2006 include: the Pacific DC Inter-tie (NOB), which increased 119 percent in congestion charges from 2006; the IPP(DC)-to-Adelanto (IPPDCADLN) branch group increased 93 percent in congestion charges; the Blythe branch group congestion charges increased more than sixteen times; and the Marketplace-to-Adelanto branch group congestion charges increased more than twenty times from 2006. The only branch group that experienced a decline in congestion charges from 2006 was Path 26, which

[47] In all tables, north-to-south congestion on Path 26 is represented as “Exports”. South-to-north congestion on Path 15 is represented as “Imports”.

incurred $3.36 million in 2006 and only $1.3 million in 2007, representing a 60 percent decrease.

Table 5.3 Inter-Zonal Congestion Charges (2007)[48]

Branch Group	Day-ahead		Hour-ahead		Total Congestion Charges		Total Congestion Charges		Total Congestion Charges	Total Charges Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
ADLANTOSP	$2,124,792	$0	$117,527	$0	$2,242,318	$0	$2,124,792	$117,527	$2,242,318	3%
BLYTHE	$2,085,431	$0	$64,922	$0	$2,150,353	$0	$2,085,431	$64,922	$2,150,353	3%
CASCADE	$1,949	$0	$3,668	$0	$5,617	$0	$1,949	$3,668	$5,617	0%
CFE	$577	$0	$23,046	$0	$23,623	$0	$577	$23,046	$23,623	0%
ELDORADO	$9,146,578	$0	$239,013	$0	$9,385,591	$0	$9,146,578	$239,013	$9,385,591	11%
GONDIPPDC	$0	$0	$0	$41,230	$0	$41,230	$0	$41,230	$41,230	0%
IID-SCE	$0	$0	$2,193	$0	$2,193	$0	$0	$2,193	$2,193	0%
IID-SDGE	$0	$0	$3,631	$10	$3,631	$10	$0	$3,641	$3,641	0%
IPPDCADLN	$8,060,476	$0	$209,315	$0	$8,269,791	$0	$8,060,476	$209,315	$8,269,791	10%
MEAD	$4,497,756	$0	$340,338	$0	$4,838,094	$0	$4,497,756	$340,338	$4,838,094	6%
MERCHANT	$206	$0	$0	$0	$206	$0	$206	$0	$206	0%
MKTPCADLN	$3,257,325	$0	$31,310	$52	$3,288,635	$52	$3,257,325	$31,362	$3,288,687	4%
MONAIPPDC	$1,032	$253,267	$0	$84,836	$1,032	$338,103	$254,300	$84,836	$339,136	0%
NOB	$12,046,166	$68,066	$62,778	-$4,643	$12,108,944	$63,422	$12,114,232	$58,135	$12,172,367	14%
OAKDALSU	$0	$0	$0	$1	$0	$1	$0	$1	$1	0%
PACI	$15,175,369	$0	$262,535	$0	$15,437,905	$0	$15,175,369	$262,535	$15,437,905	18%
PALOVRDE	$22,549,528	$0	-$936,166	$0	$21,613,362	$0	$22,549,528	-$936,166	$21,613,362	25%
PARKER	$938,557	$0	$9,708	$0	$948,265	$0	$938,557	$9,708	$948,265	1%
PATH15	$2,108,667	$0	$85,915	$0	$2,194,582	$0	$2,108,667	$85,915	$2,194,582	3%
PATH26	$0	$1,049,190	$656	$292,414	$656	$1,341,604	$1,049,190	$293,070	$1,342,260	2%
SILVERPK	$4,087	$0	$10,380	$0	$14,467	$0	$4,087	$10,380	$14,467	0%
STNDFDSTN	$0	$0	$0	-$17	$0	-$17	$0	-$17	-$17	0%
SUMMIT	$0	$0	$13,622	$24,794	$13,622	$24,794	$0	$38,416	$38,416	0%
TRACYCOTP	$4,981	$0	$38,661	$0	$43,642	$0	$4,981	$38,661	$43,642	0%
TSLASTDFD	$0	$53,527	$0	$0	$0	$53,527	$53,527	$0	$53,527	0%
WSTWGMEAD	$603,578	$0	$21,130	$2,361	$624,708	$2,361	$603,578	$23,491	$627,070	1%
Total	**$82,607,055**	**$1,424,050**	**$604,181**	**$441,037**	**$83,211,236**	**$1,865,087**	**$84,031,105**	**$1,045,218**	**$85,076,323**	**100%**

The combined congestion charges for the two internal paths managed in the inter-zonal congestion market, Path 15 and Path 26, account for less than 5 percent of total congestion charges in 2007, compared to 9 percent in 2006. Path 26 was the only branch group with a decrease in total congestion charges, from $3.4 million in 2006 down to $1.3 million in 2007, $0.4 million of which occurred during the wildfires in October. The majority of congestion on Path 15 occurred in November mainly due to a dynamic de-rate based on Midway generation as a result of work on Moss Landing-Los Banos 500kV and Diablo Canyon Unit #2 being out of service.

Exports from the CAISO Control Area resulted in only $523,483 in congestion charges – 65 percent on Mona-IPP (DC) branch group, which connects to the Intermountain Power Project and is physically located in Utah.

Hour-ahead congestion accounted for 1.2 percent of congestion charges, or approximately $1.05 million. This small proportion is due to the fact that hour-ahead congestion typically occurs after SCs have adjusted their day-ahead schedules or as the result of changes in line ratings after the closure of the Day Ahead Market. Only those SCs whose schedules change to help relieve congestion in the Hour Ahead Markets are required to pay hour-ahead congestion charges. Thus, the volume of transactions in the Hour Ahead Market is much lower than that in the Day Ahead Market.

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[48] In all tables, north-to-south congestion on Path 26 is represented as “Exports”. South-to-north congestion on Path 15 is represented as “Imports”.

5.1.3.1 Significant Transmission Events

There were several significant transmission events, forced outages, and scheduled outages that contributed to congestion charges on one or more major inter-ties or internal paths. Following is a brief description of selected major events that may have had a significant impact on congestion charges.

Adelanto 500kV was forced out of service on May 9 for equipment repairs. The line tripped and was out of service on May 10-May 11, and May 18. Due to the outages, Southern California Inter-ties were de-rated.

Captain Jack – Olinda was forced out of service from October 1 to October 3 and on October 12 to repair equipment, de-rating and contributing to congestion on the Pacific AC Inter-tie (PACI).

Celilo was out of service from October 1 to October 9 for annual maintenance, curtailing 1,000 MW. The outage de-rated the Pacific DC Inter-tie (PDCI) 1,900 MW north-to-south and 900 MW south-to-north, and added to congestion on PDCI in the import direction during October.

Celilo – Sylmar was out of service for maintenance work from October 9 to October 20, de-rating PDCI. On October 9, PDCI was de-rated to 500 MW in both directions and de-rated to approximately 1,000 MW in both directions from October 10 to October 20. For a few hours on December 6, PDCI was de-rated to zero in both directions when Celilo to Sylmar was forced out of service.

Eldorado – Moenkopi was forced out of service from May 7 to May 11, de-rating West of River, Westwing to Mead, and Eldorado to Moenkopi. The outage may have contributed to congestion on the de-rated lines as well as on several other Southwest inter-ties as flows across parallel lines were increased to meet load.

Malin – Round Mountain #1 line cleared and was forced out of service from April 30 to May 5, de-rating PACI by almost 2,000 MW north-to-south and adding to congestion on PACI and possibly on the PDCI as flows across those lines had to be increased to meet load.

Marketplace 500kV was de-energized and forced out of service from March 28 to March 29. The outage de-rated Southern California Inter-ties and East of River Inter-ties, leading to congestion on those lines.

Marketplace – Adelanto was out of service for scheduled work from December 1 to December 15, de-rating several branch groups and nomograms which include: Marketplace-Adelanto, Westwing-Mead, and Eldorado-Moenkopi branch groups and Southern California Inter-ties, East of River, and West of River nomograms.

Mira Loma 500kV was out of service from November 2 to November 3, de-rating South of Lugo by 2,000 MW. De-rating South of Lugo caused imports on other Southern inter-ties to increase, adding to congestion on those lines.

North Gila – Hassayampa was out of service from January 22 to January 25 due to scheduled work. The outage de-rated several Southwest inter-ties and nomograms, notably Palo Verde. Palo Verde was derated to 1,100 MW and 1,300 MW in the Day Ahead and Hour Ahead Markets respectively, resulting in approximately $2 million in congestion charges.

Palo Verde #2 unit tripped on February 7, curtailing 220 MW, and returned to service on February 9. During the outage, the Southern California Inter-ties were de-rated, which increased flows on other parallel importing lines and led to congestion on the Palo Verde branch group.

Palo Verde – Devers 500kV relayed on November 30 and was forced out of service through December 1, curtailing 500 MW. The outage de-rated all Southwest inter-ties, which may be attributed to almost $1 million in congestion charges on Palo Verde.

San Onofre Units #2 and #3 were both out of service for several days in October. Prior to the fires, San Onofre Unit #3 was out of service for maintenance. On October 20, which was at the beginning of the Southern California Wildfires, San Onofre Unit #2 was forced out of service. With no San Onofre generation online, imports from the Southwest had to be increased to account for the 2,200 MW of lost internal generation. Increasing the Southwest imports added to the congestion on Palo Verde, and exacerbated the impact from the wildfires.

South West Power Link (SWPL) is a major importing line from Arizona into Southern California. During the October Southern California Wildfires, SWPL was forced out of service from October 24 to October 28, de-rating the Palo Verde tie, East of River, and West of River transfer capabilities. The loss of SWPL naturally causes power flow to increase on Palo Verde, a parallel importing line, which in this situation led to congestion on Palo Verde.

5.1.3.2 Significant Changes in Congestion Cost

As a result of the major transmission events and other system conditions (e.g., hydroelectric availability, regional energy demands), congestion charges on almost all major inter-ties and paths increased from 2006. Figure 5.2 compares congestion charges in 2006 and 2007 on selected major paths. Congestion charges increased on the Pacific AC Inter-tie (PACI) and the Pacific DC Inter-tie (NOB), which could be due to high north-to-south hydroelectric flows in the Pacific Northwest during the spring and summer and numerous transmission de-rates. Congestion charges also increased on Eldorado, Mead, and IPPDCADLN branch groups, most of which can be attributed to the Southern California wildfires and various transmission de-rates. The increased congestion charges on the Marketplace-Adelanto (MKTPLADLN) branch group is mostly due to two unrelated events, which are discussed below.

Figure 5.3 shows the seasonal pattern of congestion charges on major paths. High monthly congestion charges on several of the branch groups correspond with the timing of several major transmission events previously discussed. The highest cost month was May, which may be due to high north-to-south power flows on PACI and NOB in combination with maintenance work. October through December also had notably high congestion charges on Palo Verde and Eldorado, primarily due to the Southern California wildfires, transmission de-rates, and increased reliability on Southwest imports. Following is a brief discussion of events that led to increased congestion charges by branch group.

Figure 5.2 Congestion Charges on Selected Paths (2006 vs. 2007)

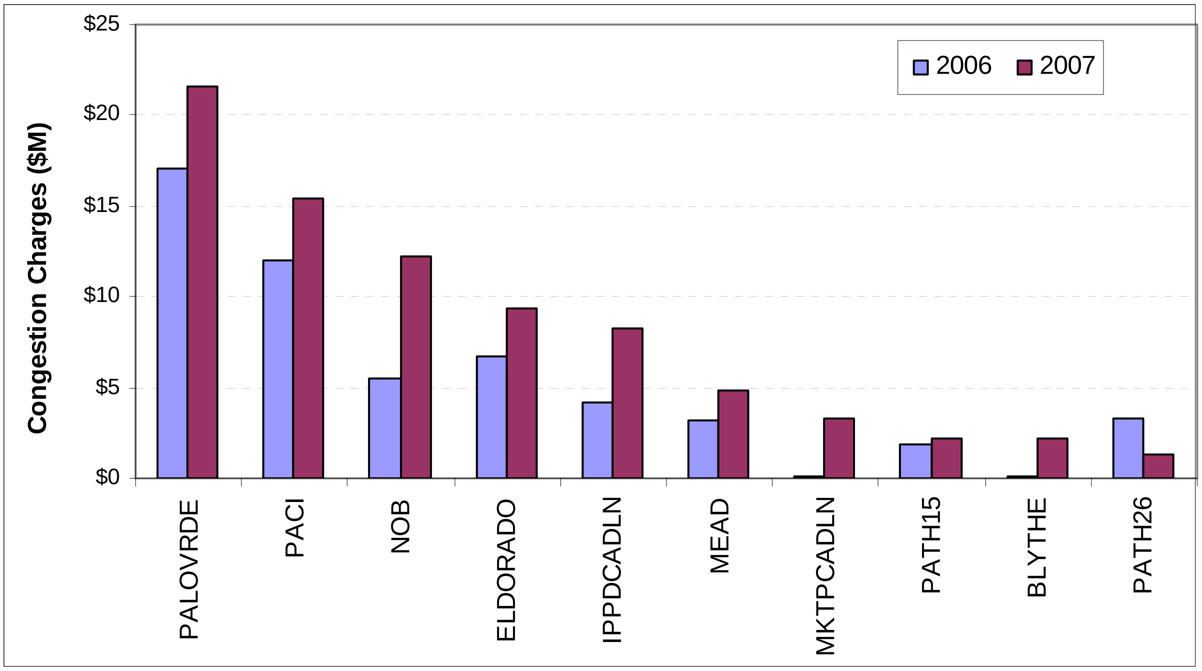
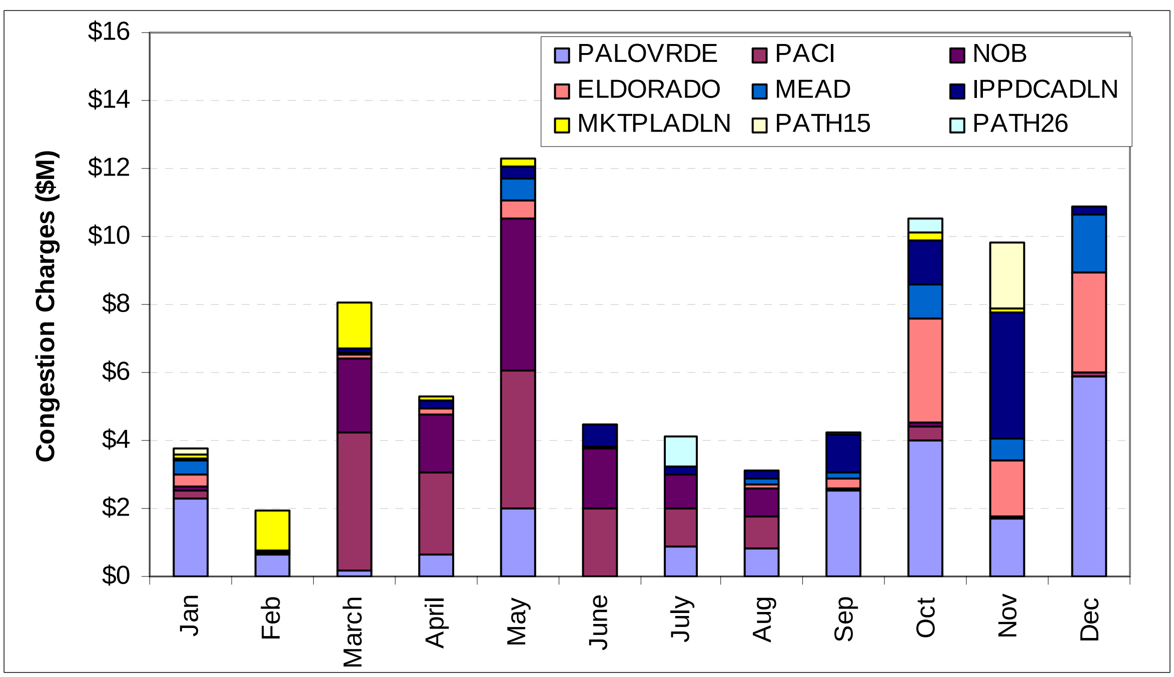


Figure 5.3 Monthly Congestion Charges on Selected Major Paths (2007)



Palo Verde had the highest total congestion charges in 2007 of $21.6 million, a 26 percent increase from 2006. Four months (January, September, October, and December) account for 70 percent of the congestion charges on Palo Verde, which was all in the import direction.

January congestion charges totaled $2.3 million, most of which was incurred from January 22 to January 25 when Palo Verde was de-rated due to work on North Gila to Hassayampa. The loss of SWPL and both San Onofre Units can also be attributed to congestion charges on Palo Verde in October, along with Mead being de-rated to zero from October 1-October 15. December's congestion charges on Palo Verde reached $5.9 million, $4.1 million of which occurred in the first week when Palo Verde to Devers 500kV was out of service, de-rating the Palo Verde branch group. The Marketplace-Adelanto and Celilo-Sylmar outages in December may have also added to the congestion as they both increased the reliance on the Palo Verde branch group. A significant portion of the day-ahead congestion charges on Palo Verde are hedged through Firm Transmission Rights, which are not accounted for in the figures represented here, making the actual congestion charges less than what is shown.

Pacific AC Inter-tie (PACI) congestion charges increased $3.4 million from 2006, most of which can be attributed to high north-to-south flows in conjunction with several transmission outages throughout the year. High north-to-south flows were most likely a result of the increased imported hydroelectric generation from the Northwest into the CAISO Control Area on PACI due to Northern California's low hydro conditions during the spring months. The Captain Jack-Olinda outage in October as well as the Southern California Wildfires also contributed to the congestion charges on PACI.

Pacific DC Inter-tie (PDCI or NOB as in table) congestion charges increased $6.6 million from 2006, most of which occurred during the spring months. Congestion charges in the spring are attributable to the high north-to-south flows as a result of Northern California's low hydro conditions. The wildfires and work on Celilo and Celilo-Sylmar also added to congestion charges on PDCI in October.

Eldorado congestion charges increased to $9.4 million from $6.7 million in 2006, most of which were incurred during the fall months, October to December; congestion charges incurred in May were a result of the Eldorado – Moenkopi outage. During the fall months, energy flows were from the Southwest to the Northwest to meet peak loads in the Northwest. In addition to the directional change of energy flows, the October wildfires, loss of SWPL, loss of two San Onofre Units, and work on Celilo-Sylmar added to congestion charges on Eldorado. Most of the December charges can be attributed to the Marketplace-Adelanto outage.

Intermountain Power Project DC to Adelanto (IPPDCADLN) congestion charges nearly doubled from 2006, reaching $8.3 million. IPPDCADLN incurred congestion charges throughout the year, with the majority in November when South of Lugo was de-rated as a result of the Mira Loma 500kV outage. On November 5, the Intermountain Power Project (IPP) #1 was offline, accounting for approximately $1 million in congestion charges.

Mead congestion occurred in several months, with the majority occurring during the fall. The congestion charges can mostly be attributed to the October wildfires, and work on Marketplace-Adelanto and Palo Verde-Devers. In December the Mead branch group was de-rated 600 MW on two days as a result of work on Navajo to West Wing, adding to the December congestion on Mead.

Marketplace to Adelanto congestion charges reached $3.3 million, up from $0.1 million in 2006. February and March were the high congestion months for MKTPLADLN. The increased congestion charges can mostly be attributed to two events. Palo Verde Unit #2 tripped on February 7, leading to high congestion prices on MKTPLADLN, and the Marketplace 500kV line was out of service in March, both of which can account for the majority of congestion charges on MKTPLADLN.

5.2 Firm Transmission Rights Market Performance

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

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

5.2.1 Primary Auction Results

The CAISO creates a primary market for FTRs by auctioning them each year for a 12-month period beginning in April and ending in March. Due to the planned release date of the Market Redesign and Technology Upgrade (MRTU) market design of February 1, 2008, the 2007-2008 FTR primary auction was for a 10-month period from April 1, 2007, to January 31, 2008.[49] The FTR Auction is a simultaneous, multi-round clearing price auction conducted separately and independently across specified CAISO inter-zonal interfaces. The FTR Auction proceeds are distributed to Participating Transmission Owners (PTOs), based upon their respective ownership interest in each auctioned path. Owners of FTRs can use their FTRs as a hedge against congestion costs.

Table 5.4 provides a summary of the 2007-2008 FTR primary auction results. In the 2007-2008 primary auction, FTRs on 33 directional branch groups were auctioned. Total revenue earned in the 2007-2008 primary auction was approximately $121 million for the 10 month period. The 2006-2007 primary auction, which spanned a 12 month period, generated $104 million in revenue. Auction results for the 2006-2007 Primary Auction can be found in the 2006 Annual Report on Market Issues and Performance.

During the 10-month FTR period, various exchange agreements and existing transmission contracts (ETCs)[50] expired on July 31, 2007, impacting the available megawatts to be auctioned

[49] FTR revenues for the 2006-2007 and 2007-2008 primary auction results cannot be directly compared as a result of the temporal differences due to the planned release date of MRTU. The 2006-2007 FTRs were for a 12 month period while the 2007-2008 FTRs only spanned a 10 month period.

[50] Existing Transmission Contract (ETC) owners are given scheduling priority on the associated branch group for a predetermined capacity. When an ETC expires, the corresponding megawatts that had scheduling priorities are released and become available in the FTR auction.

off on several branch groups. The Los Angeles Department of Water and Power (LADWP) exchange agreement expired on July 31, 2007, increasing available megawatts on PACI, Path 15, and Path 26, and decreasing megawatts on NOB; the Pacific Gas and Electric (PGAE)-Pacific Corp exchange agreement expired, also impacting available megawatts on PACI. Two Palo Verde ETCs expired, releasing an additional 25 MW in both directions. In addition to the LADWP exchange agreement releasing 320 MW on Path 26, the Vernon exchange agreement also expired, reducing available megawatts on Path 26 by 121 MW. FTRs on Tracy COTP were eliminated on July 31, 2007 when the PGAE-Vernon exchange agreement expired. To accommodate the change in available megawatts, FTRs on PACI, Palo Verde, NOB, Path 15, Path 26, and Tracy COTP were auctioned off in two separate time blocks, April 1, 2007 to July 31, 2007 and August 1, 2007 to January 31, 2008. FTRs auctioned off for August 1, 2007 to January 31, 2008 reflect the changes in available megawatts. The FTR auction results for both time blocks are listed independently for each branch group by direction in Table 5.4.

Table 5.4 Summary of 2007-2008 FTR Auction Results (FTRs – April 1, 2007 through January 31, 2008)[51]

Branch Group	Direction	Total FTRs Sold (MW)	Auction Clearing Price ($/MW)	Auction Revenue ($)
BLYTHE	Export	127	$154	$19,558
BLYTHE	Import	171	$5,751	$983,421
CFE	Export	408	$142	$57,936
CFE	Import	400	$137	$54,800
CTNWDRDMT	Export	305	$83	$25,315
CTNWDRDMT	Import	305	$83	$25,315
CTNWDWAPA	Export	703	$83	$58,349
CTNWDWAPA	Import	703	$83	$58,349
ELDORADO	Export	704	$108	$76,032
ELDORADO	Import	704	$23,755	$16,723,520
IID-SCE	Import	600	$300	$180,000
IID-SDGE	Export	57	$362	$20,634
IID-SDGE	Import	62	$237	$14,694
MEAD	Export	767	$83	$63,661
MEAD	Import	598	$10,975	$6,563,050
NOB*	Import	472	$13,138	$6,201,136
NOB**	Import	398	$2,855	$1,136,290
PACI*	Export	833	$33	$27,489
PACI**	Export	575	$50	$28,750
PACI*	Import	841	$15,951	$13,414,791
PACI**	Import	791	$10,796	$8,539,636
PALOVRDE*	Export	1,475	$25	$36,875
PALOVRDE**	Export	1,258	$58	$72,964
PALOVRDE*	Import	1,850	$3,187	$5,895,950
PALOVRDE**	Import	1,875	$27,443	$51,455,625
PARKER	Import	160	$2,967	$474,720
PATH15*	Import	2,700	$106	$286,200
PATH15**	Import	3,020	$1,267	$3,826,340
PATH26*	Export	1,827	$2,143	$3,915,261
PATH26**	Export	2,026	$123	$249,198
RNCHLAKE	Export	753	$83	$62,499
RNCHLAKE	Import	642	$83	$53,286
SILVERPK	Export	10	$1,708	$17,080
SILVERPK	Import	10	$688	$6,880
TRACYCOTP*	Export	79	$93	$7,347
TRACYCOTP*	Import	34	$103	$3,502
TRACYPGAE	Export	1,067	$83	$88,561
TRACYPGAE	Import	1,208	$83	$100,264
VICTVL	Export	450	$83	$37,350
VICTVL	Import	1,222	$83	$101,426
Total				**$120,964,054**

[51] * Indicates FTR auction results for the April 1, 2007 to July 31, 2007 time block.
** Indicates FTR auction results for August 1, 2007 through January 31, 2008 time block.

5.2.2 2007-2008 FTR Market Performance

FTR Revenue

The 2007-2008 FTR market cycle begins on April 1, 2007 and ends on January 31, 2008. Table 5.5 summarizes the FTR revenues from the current market cycle. The primary auction price for those directional Branch Groups that were auctioned off in two time blocks, as noted in Table 5.4, is a quantity weighted average price. FTR market revenues for the 2006-2007 FTR Auction can be found in the 2006 Annual Report.

During the current FTR cycle, five paths (Blythe (import), Parker (import), Path 15 (south-to-north), Silver Peak (import), and Tracy COTP (import)) had total pro-rated FTR revenue greater than their auction prices. However, pro-rated FTR revenues on most paths were well below the auction price. This is not surprising. As mentioned earlier, the FTR holders of major paths are also transmission owners. The FTR auction revenues are used to reduce the Transmission Revenue Requirement (TRR). As a result, the FTR purchase cost for these entities is to a large extent offset by a corresponding reduction in the TRR. Also, the FTR provides additional benefits to the holders beyond FTR revenue. Schedules with FTR rights are entitled to scheduling priority in the Day Ahead Market and FTRs can serve as insurance to hedge against possible high congestion charges.

Table 5.5 FTR Revenue Statistics ($/MW) (April 2007 – January 2008)

Branch Group	Direction	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Cum. Net $/MW FTR Rev.	Prorated Net $/MW FTR Rev.	Primary Auction Price	Value Ratio
ADLANTOSP	Import	$ -	$ 231	$ 15	$ 3	$ -	$ 3	$ 1,234	$ 158	$ 34	$ 1,678	$ 2,237	N/A	N/A
BLYTHE	Import	$ -	$ 563	$ 98	$ 0	$ -	$ 194	$ 4,437	$ 2,632	$ 3,829	$ 11,753	$ 15,671	$ 5,751	272%
CFE	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53	$ 53	$ 71	$ 137	52%
ELDORADO	Import	$ 227	$ 480	$ 12	$ 60	$ 159	$ 222	$ 2,781	$ 1,618	$ 3,244	$ 8,803	$ 11,737	$ 23,755	49%
GONDIPPDC	Export	$ 30	$ 194	$ -	$ 60	$ 6	$ 4	$ 730	$ 764	$ -	$ 1,788	$ 2,384	N/A	N/A
IID-SDGE	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30	$ 30	$ 40	$ 237	17%
IPPDCADLN	Import	$ 356	$ 511	$ 959	$ 286	$ 437	$ 1,754	$ 1,975	$ 5,759	$ 347	$ 12,383	$ 16,511	N/A	N/A
MEAD	Import	$ 21	$ 985	$ 17	$ 0	$ 238	$ 270	$ 1,493	$ 955	$ 2,523	$ 6,503	$ 8,670	$ 10,975	79%
MKTPCADLN	Import	$ 246	$ 588	$ -	$ -	$ -	$ 65	$ 494	$ 168	$ 55	$ 1,615	$ 2,154	N/A	N/A
MONAIPPDC	Export	$ -	$ -	$ 217	$ 879	$ 177	$ -	$ -	$ -	$ -	$ 1,272	$ 1,697	N/A	N/A
MONAIPPDC	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ 3	$ 4	N/A	N/A
NOB	Import	$ 865	$ 2,407	$ 1,018	$ 496	$ 566	$ 13	$ 98	$ -	$ -	$ 5,464	$ 7,285	$ 8,434	86%
NOB	Export	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70	$ -	$ 70	$ 93	N/A	N/A
PACI	Import	$ 1,325	$ 2,798	$ 971	$ 506	$ 422	$ 32	$ 219	$ -	$ 44	$ 6,318	$ 8,425	$ 13,452	63%
PALOVRDE	Import	$ 341	$ 798	$ 8	$ 357	$ 320	$ 1,011	$ 1,608	$ 683	$ 2,394	$ 7,520	$ 10,026	$ 15,396	65%
PARKER	Import	$ -	$ 179	$ 0	$ -	$ 0	$ 33	$ 1,604	$ 837	$ 3,240	$ 5,894	$ 7,858	$ 2,967	265%
PATH15	South-to-North	$ -	$ -	$ -	$ -	$ -	$ 0	$ -	$ 559	$ 0	$ 559	$ 746	$ 719	104%
PATH26	North-to-South	$ 1	$ -	$ 20	$ 380	$ 0	$ -	$ 166	$ -	$ -	$ 566	$ 754	$ 1,081	70%
SILVERPK	Import	$ -	$ -	$ 11	$ 240	$ 9	$ -	$ 579	$ -	$ -	$ 838	$ 1,118	$ 688	162%
TRACYCOTP	Import	$ 51	$ 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 160	$ 213	$ 103	207%
WSTWGMEAD	Import	$ 103	$ 689	$ -	$ 0	$ 5	$ -	$ -	$ 1,153	$ -	$ 1,951	$ 2,601	N/A	N/A
WSTWGMEAD	Export	$ -	$ 5	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 18	$ 24	N/A	N/A

FTR Trades in the Secondary Markets

In California, the successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary markets. The FTR transactions in the secondary markets have been minimal, as shown in Table 5.6. One notable exception was a 121 MW trade of Path 15 imports from the City of Vernon back to CAISO on August 9, 2007. All but one of these exchanges (121 MW Path 15 exchange) occurred between Southern Participating Transmission Owners (SPTOs) (i.e., the City of Pasadena, the City of Anaheim, and the City of Riverside) and the CAISO, due to either the transfer of FTRs owned by SPTOs to CAISO, or the revision of SPTOs entitlements.

Table 5.6 FTR Trades in the Secondary Market (April 2007 – December 2007)

Branch Group	Direction	Date of Trade	Buyer	Seller	Quantity Sold (MW)	First Effective Date	Last Effective Date
GONDIPPDC	Import	21-Sep-07	PASA	CISO	3	25-Sep-07	31-Mar-08
GONDIPPDC	Export	21-Sep-07	PASA	CISO	2	25-Sep-07	31-Mar-08
GONDIPPDC	Import	21-Sep-07	ANHM	CISO	9	25-Sep-07	31-Mar-08
MONAIPPDC	Import	21-Sep-07	PASA	CISO	12	25-Sep-07	31-Mar-08
MONAIPPDC	Export	21-Sep-07	PASA	CISO	11	25-Sep-07	31-Mar-08
MONAIPPDC	Import	21-Sep-07	ANHM	CISO	46	25-Sep-07	31-Mar-08
MONAIPPDC	Export	21-Sep-07	ANHM	CISO	39	25-Sep-07	31-Mar-08
MONAIPPDC	Import	24-Sep-07	RVSD	CISO	26	26-Sep-07	31-Mar-08
MONAIPPDC	Export	24-Sep-07	RVSD	CISO	22	26-Sep-07	31-Mar-08
PATH15	Import	9-Aug-07	CISO	VERN	121	11-Aug-07	31-Jan-08

5.2.3 Supplemental Auction Results (February 1 – March 31, 2008)

As noted above, the FTR Primary Auction for 2007-2008 covered an FTR time period from April 1, 2007 to January 31, 2008, assuming a February 1, 2008 MRTU release date, at which time Congestion Revenue Rights (CRRs)[52] would be implemented. As the release date was delayed to April 1, 2008, the 2007-2008 FTR time period was extended to cover the lapse between the start date for CRRs (April 1, 2008) and the initial FTR expiration date (January 31, 2008). A supplemental auction was held to extend the 2007-2008 FTRs through March 31, 2008 and successfully auctioned off FTRs on 52 directional branch groups. The results of this auction are shown in Table 5.7.

[52] Congestion Revenue Rights (CRRs) will be implemented with MRTU and are similar to the current market's Firm Transmission Rights (FTRs) with a few design differences. For example, CRRs are only financial instruments that are associated with a source and sink rather than a line.

Table 5.7 Summary of FTR Supplemental Auction Results (2007 Auction Year)

Branch Group	Direction	Quantity Sold (MW)	First Effective Date	Last Effective Date
ADLANTOSP	Export	502	1-Apr-07	31-Mar-08
ADLANTOSP	Import	1,036	1-Apr-07	31-Mar-08
BLYTHE	Export	127	1-Feb-08	31-Mar-08
BLYTHE	Import	123	1-Feb-08	31-Mar-08
CFE	Export	408	1-Feb-08	31-Mar-08
CFE	Import	400	1-Feb-08	31-Mar-08
CTNWDRDMT	Export	320	1-Feb-08	31-Mar-08
CTNWDRDMT	Import	320	1-Feb-08	31-Mar-08
CTNWDWAPA	Export	1,117	1-Feb-08	31-Mar-08
CTNWDWAPA	Import	1,117	1-Feb-08	31-Mar-08
ELDORADO	Export	704	1-Feb-08	31-Mar-08
ELDORADO	Import	704	1-Feb-08	31-Mar-08
GONDIPPDC	Export	4	1-Apr-07	31-Mar-08
GONDIPPDC	Import	13	1-Apr-07	31-Mar-08
IID-SCE	Import	600	1-Feb-08	31-Mar-08
IID-SDGE	Export	57	1-Feb-08	31-Mar-08
IID-SDGE	Import	62	1-Feb-08	31-Mar-08
IPPDCADLN	Export	471	1-Apr-07	31-Mar-08
IPPDCADLN	Import	647	1-Apr-07	31-Mar-08
MCCLMKTPC	Export	686	1-Apr-07	31-Mar-08
MCCLMKTPC	Import	686	1-Apr-07	31-Mar-08
MEAD	Export	34	1-Apr-07	31-Mar-08
MEAD	Export	767	1-Feb-08	31-Mar-08
MEAD	Import	70	1-Apr-07	31-Mar-08
MEAD	Import	598	1-Feb-08	31-Mar-08
MEADMKTPC	Export	369	1-Apr-07	31-Mar-08
MEADMKTPC	Import	369	1-Apr-07	31-Mar-08
MEADTMEAD	Export	182	1-Apr-07	31-Mar-08
MEADTMEAD	Import	182	1-Apr-07	31-Mar-08
MKTPCADLN	Export	423	1-Apr-07	31-Mar-08
MKTPCADLN	Import	423	1-Apr-07	31-Mar-08
MONAIPPDC	Export	268	1-Apr-07	31-Mar-08
MONAIPPDC	Import	279	1-Apr-07	31-Mar-08
NOB	Export	69	1-Apr-07	31-Jan-08
NOB	Export	27	1-Apr-07	31-Mar-08
NOB	Export	82	1-Apr-07	31-Jul-07
NOB	Import	73	1-Apr-07	31-Mar-08
NOB	Import	93	1-Apr-07	31-Jul-07
NOB	Import	421	1-Feb-08	31-Mar-08
PACI	Export	778	1-Feb-08	31-Mar-08
PACI	Import	791	1-Feb-08	31-Mar-08

Branch Group	Direction	Quantity Sold (MW)	First Effective Date	Last Effective Date
PALOVRDE	Export	25	1-Apr-07	30-Jun-07
PALOVRDE	Export	1,300	1-Feb-08	31-Mar-08
PALOVRDE	Import	10	1-Apr-07	30-Jun-07
PALOVRDE	Import	1,875	1-Feb-08	31-Mar-08
PARKER	Import	160	1-Feb-08	31-Mar-08
PATH15	Import	2,845	1-Feb-08	29-Feb-08
PATH15	Import	175	1-Feb-08	31-Mar-08
PATH15	Import	2,511	1-Mar-08	31-Mar-08
PATH26	Export	121	1-Aug-07	31-Jan-08
PATH26	Export	1,371	1-Feb-08	29-Feb-08
PATH26	Export	703	1-Feb-08	31-Mar-08
PATH26	Export	1,383	1-Mar-08	31-Mar-08
RNCHLAKE	Export	917	1-Feb-08	31-Mar-08
RNCHLAKE	Import	994	1-Feb-08	31-Mar-08
SILVERPK	Export	10	1-Feb-08	31-Mar-08
SILVERPK	Import	10	1-Feb-08	31-Mar-08
SYLMAR-AC	Export	25	1-Apr-07	30-Jun-07
SYLMAR-AC	Import	35	1-Apr-07	30-Jun-07
SYLMAR-AC	Import	10	1-Jul-07	31-Mar-08
TRACYPGAE	Export	121	1-Aug-07	31-Mar-08
TRACYPGAE	Export	1,894	1-Feb-08	29-Feb-08
TRACYPGAE	Export	1,200	1-Mar-08	31-Mar-08
TRACYPGAE	Import	121	1-Aug-07	31-Mar-08
TRACYPGAE	Import	1,200	1-Feb-08	31-Mar-08
VICTVL	Export	560	1-Feb-08	31-Mar-08
VICTVL	Import	1,355	1-Feb-08	31-Mar-08
WSTWGMEAD	Export	126	1-Apr-07	31-Mar-08
WSTWGMEAD	Import	126	1-Apr-07	31-Mar-08

6 Reliability Costs

Observable reliability costs – Minimum Load Cost Compensation (MLCC), Reliability Must Run (RMR) costs, and Out-of-Sequence (OOS) redispatch costs – were dramatically lower in 2007 than in previous years, totaling approximately $101 million, a decrease of 51 percent from the 2006 level. However, these costs do not include Reliability Capacity Service Tariff (RCST) charges[53] or capacity payments to meet Resource Adequacy (RA) requirements. Upgrades to the Southern California transmission grid in 2006 and termination of RMR contracts both appear to have contributed significantly to the decrease in reliability costs. In addition, 2007 was a year of relatively few construction outages and relatively mild weather, in which the grid required minimal workarounds to ensure reliability, save for two weeks in late October when wildfires swept through Southern California and caused numerous transmission outages. In contrast, 2006 saw multiple outages, as key transmission upgrades were completed, and an extraordinarily hot summer, in which loads were estimated to be in the top two percentile of probability.

6.1 Overview

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

Intra-zonal congestion costs are comprised of three components:

1) Minimum Load Cost Compensation (MLCC).[54] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[55]

2) Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.

3) Costs of Out-of-Sequence (OOS) dispatches.

[53] See Chapter 1 and Section 6.3.2 for discussion of Resource Adequacy (RA) and Reliability Capacity Services Tariff (RCST).

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

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

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated, where transmission within the zone is not sufficient to allow access to lower-priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within it. Intra-zonal congestion can also occur due to pockets in which generation is clustered together, without the transmission necessary for the energy to flow out of that pocket to load. 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. Such congestion is inefficient if the market costs due to the transmission congestion (i.e., the cost imposed by the fact that load cannot be served by the lowest-cost supplier(s), and instead must be served by higher-cost suppliers) exceed the cost of a transmission upgrade that could alleviate the congestion.

Typically, there is limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal congestion is often coupled with locational market power. Consequently, methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise local market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often constrains-on or commits long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments and/or RA capacity payments. This forward unit commitment process helps to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO Real Time Market.[56] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids OOS;[57]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-of-Market (OOM).

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

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

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

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

6.2 Points of Intra-Zonal Congestion

Both NP26 and SP15 experienced intra-zonal congestion in 2007. The largest congestion point within NP26 was the Humboldt area on the North Coast of California. Intra-zonal congestion within SP15 was predominately at locations where intra-zonal congestion has been an issue in recent years. These include the following:

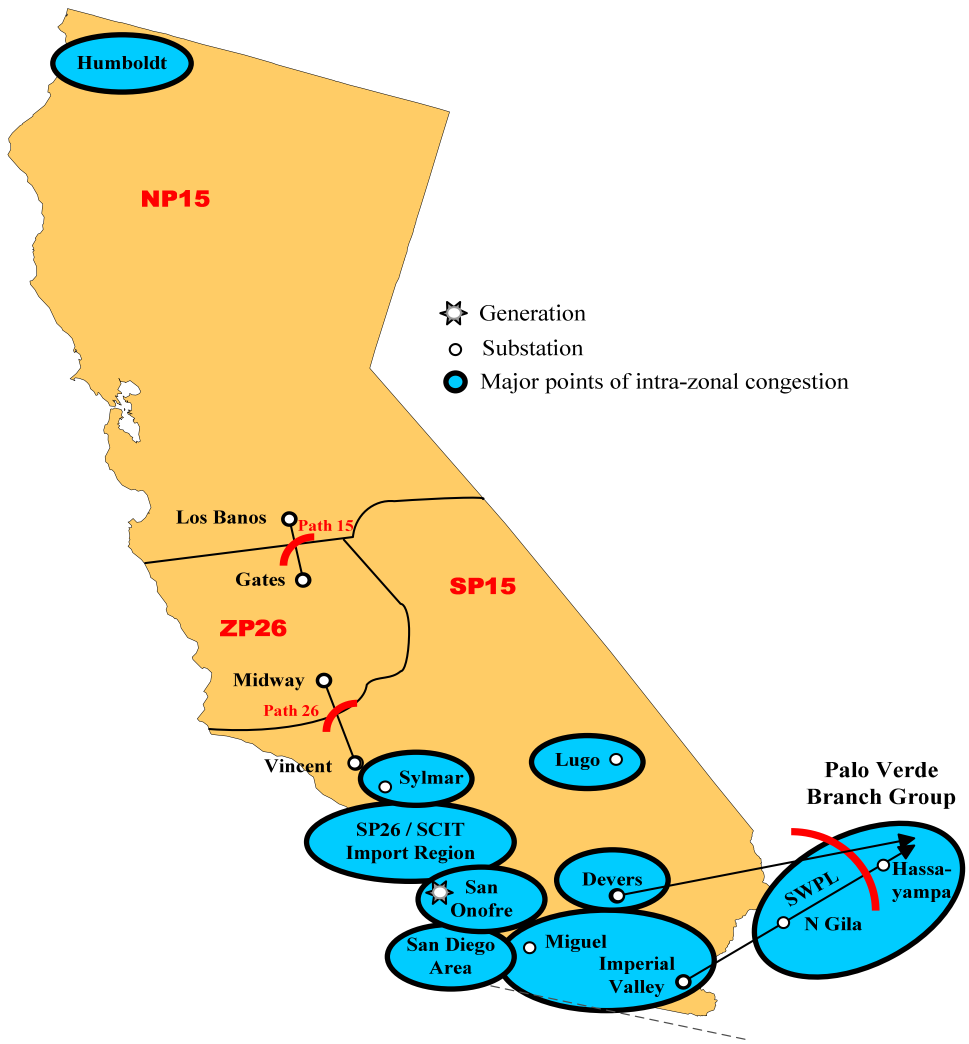
- Miguel, Imperial Valley Banks, and SWPL, which are considered in the San Diego Transmission Network Analysis (TNA) procedure that manages flows through the greater San Diego area that also impact the greater SP15 area. The Miguel and Imperial Valley substations provide transmission of power to Southern California load from generation facilities located in Mexicali, Baja California, Mexico, and imports on the Southwest Power Link (i.e., North Gila to Imperial Valley).

- South of the Lugo substation, near Hesperia. Power from the Hoover Dam in Nevada and newer combined-cycle facilities in California and Nevada interconnect to the Southern California grid at this point, often resulting in congestion.

- Palo Verde / Devers Branch Group. This was impacted in October by shifts in power flow due to the wildfires and SWPL outage, and was also forced out of service in late November and early December. While this is an inter-zonal, not intra-zonal, transmission corridor, the CAISO did rely on non-market mechanisms to manage reliability on this facility in the fourth quarter.

Figure 6.1 provides a representation of the CAISO Control Area's key historical intra-zonal congestion locations.

Figure 6.1 Key Points of Intra-Zonal Congestion



6.3 Reliability Management Costs

Intra-zonal congestion and reliability costs were significantly lower in 2007 than in previous years, due largely to new infrastructure improvements that were completed in previous years. For example, a key upgrade to the Lugo-Serrano transmission corridor, which brings power from Las Vegas area generation into the Los Angeles and Orange County metropolitan areas, was completed in mid-2006. While CAISO customers incurred approximately $15 million in MLCC costs for this path in 2006 due to construction outages, the work contributed significantly to the 51 percent decrease in reliability management costs between 2006 and 2007.

Measurable intra-zonal congestion management costs include three components: Minimum-Load Cost Compensation for intra-zonal (non-system) reasons, Reliability Must Run variable costs associated with real-time congestion management, and Out-of-Sequence redispatch costs. Table 6.1 shows monthly and annual total estimated intra-zonal congestion management costs for 2005 through 2007, itemized by these three components. While MLCC costs and RMR costs declined in 2007 by approximately $65 million and $54 million, respectively, these savings were offset to some extent by an increase in redispatch costs of approximately $13 million.

Table 6.1 Total Estimated Intra-Zonal Congestion Costs for 2005-2007 ($MM)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**	**2005**	**2006**	**2007**
Jan	$ 8	$ 10	$ 3	$ 3	$ 13	$ 2	$ 6	$ 4	$ 2	$ 17	$ 27	$ 6
Feb	$ 4	$ 8	$ 2	$ 3	$ 15	$ 1	$ 3	$ 2	$ 2	$ 10	$ 25	$ 4
Mar	$ 3	$ 11	$ 2	$ 5	$ 13	$ 1	$ 3	$ 3	$ 1	$ 11	$ 27	$ 4
Apr	$ 6	$ 27	$ 2	$ 5	$ 8	$ 2	$ 3	$ 6	$ 2	$ 14	$ 41	$ 6
May	$ 14	$ 12	$ 2	$ 5	$ 3	$ 1	$ 2	$ 1	$ 2	$ 21	$ 16	$ 4
Jun	$ 7	$ 15	$ 3	$ 2	$ 4	$ 1	$ 0	$ 0	$ 1	$ 9	$ 19	$ 5
Jul	$ 13	$ 14	$ 7	$ 5	$ 2	$ 1	$ 1	$ 0	$ 2	$ 19	$ 17	$ 10
Aug	$ 14	$ 5	$ 2	$ 9	$ 3	$ 1	$ 1	$ 0	$ 1	$ 24	$ 8	$ 4
Sep	$ 8	$ 3	$ 2	$ 6	$ 2	$ 0	$ 3	$ 0	$ 1	$ 17	$ 5	$ 4
Oct	$ 13	$ 1	$ 10	$ 8	$ 3	$ 6	$ 4	$ 1	$ 8	$ 25	$ 5	$ 25
Nov	$ 12	$ 1	$ 5	$ 5	$ 6	$ 3	$ 6	$ 0	$ 4	$ 23	$ 7	$ 12
Dec	$ 11	$ 2	$ 5	$ 16	$ 7	$ 8	$ 5	$ 0	$ 4	$ 32	$ 9	$ 17
Total	**$ 114**	**$ 109**	**$ 44**	**$ 72**	**$ 80**	**$ 26**	**$ 36**	**$ 17**	**$ 30**	**$ 222**	**$ 207**	**$ 101**

6.3.1 Minimum Load Cost Compensation

Pursuant to a FERC Order issued May 25, 2001,[58] and subsequent Orders, the CAISO provides Minimum Load Cost Compensation to generators that apply for waivers of the Must-Offer Obligation but are denied, and thus are required to be on-line at minimum load for the following operating day. In such cases, the CAISO compensates the generators for their minimum load costs, based upon unit operating costs and natural gas prices, where applicable. In addition, generators that are neither RA nor RCST resources, and whose waiver requests are denied, are also entitled to receive the real-time price for energy supplied while operating at minimum load. Units subject to the Must-Offer Obligation are required to bid all unloaded capacity into the CAISO Real Time Market. To encourage units subject to must-offer to bid into the Ancillary Services Market, the CAISO filed and FERC approved Amendment 60. This tariff change enables generators to keep both ancillary services revenues and MLCC.

Table 6.2 shows average must-offer and RA waiver denial capacity and total monthly costs in 2006 and 2007, as well as the imbalance energy payments that these generators received for their minimum-load energy based on real-time market prices. The costs shown in Table 6.2 also include MLCC costs for “system” reliability reasons in addition to intra-zonal reasons; these system commitments account for the differences among the totals in Table 6.1 and Table 6.2. Note that all costs exclude resource adequacy contract payments, which are negotiated bilaterally between utilities and generation owners, and thus are not visible to the CAISO.

[58] 95 FERC 61,275; 95 FERC 61,418, etc. (2001).

Table 6.2 Must-Offer Waiver Denial Capacity and Costs

	2006			2007		
Month	Average MW*	MLCC ($MM)	Imbalance ML Energy Payments ($MM)**	Average MW*	MLCC ($MM)	Imbalance ML Energy Payments ($MM)**
Jan	1,065	$ 10.9	$ 4.0	1,054	$ 3.3	$ 0.5
Feb	965	$ 8.6	$ 2.8	848	$ 1.9	$ 0.2
Mar	1,323	$ 11.6	$ 4.7	797	$ 2.3	$ 0.5
Apr	2,444	$ 27.3	$ 13.7	846	$ 2.5	$ 0.2
May	1,331	$ 12.7	$ 6.8	697	$ 1.7	$ 0.0
Jun	2,478	$ 18.3	$ 2.9	1,541	$ 5.6	$ 1.1
Jul	2,150	$ 19.6	$ 7.1	1,951	$ 8.8	$ 2.2
Aug	879	$ 4.9	$ 0.5	1,484	$ 4.0	$ 0.5
Sep	796	$ 2.8	$ 0.2	1,120	$ 3.7	$ 0.5
Oct	309	$ 0.8	$ 0.0	1,844	$ 10.7	$ 3.3
Nov	391	$ 1.1	$ 0.1	1,254	$ 4.8	$ 0.4
Dec	445	$ 2.1	$ 0.1	975	$ 5.4	$ 0.0
Annual Total	**1,215**	**$ 120.7**	**$ 42.8**	**1,201**	**$ 54.7**	**$ 9.6**

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

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

CAISO operators issued unit commitments for a variety of reasons in 2007, with no one particular reason predominating across the year. Certain commitment reasons have been cited consistently for several years, particularly during summer and high-load periods. These reasons include:

- System capacity requirements, which are charged proportionally to all LSEs.
- Southern California capacity requirements, which are charged proportionally to SP15 zonal customers.
- Southern California area capacity to ensure sufficient resources are available when the Southern California Import Transmission (SCIT) nomogram, a physical limitation on power imports into Southern California, is binding. These commitment costs are generally charged to zonal customers.
- Local Los Angeles and Orange County area requirements when flows through the Lugo Substation, through which energy from the Las Vegas and Hoover Dam areas pass, are constrained. This was prevalent June through September of 2007. Costs for this capacity typically are allocated locally to area load.

A key transmission upgrade to route power between the Lugo and Serrano substations through the Mira Loma substation was completed in April 2006. This work required multiple clearances and commitment costs over several months in 2005 and early 2006. Its completion resulted in a decrease in MLCC for Lugo-area reasons to approximately $6.9 million in 2007, from $35.2 million in 2006.

Other reasons were event-specific in 2007 and tended to occur over short periods of time. As these happened to occur later in the year, the bulk of costs were incurred between July and December. For example:

- Commitments for the Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) load-serving areas for reliability in those areas were issued during the winter and spring. As discussed below, the CAISO was able to eliminate several RMR contracts in this region due to the fact that generation capacity needed for reliability needs was procured by LSEs in meeting the resource adequacy requirements imposed by the CPUC. Reliability requirements for these resources are particularly high in the winter and spring, when Southern California load relies heavily on relatively inexpensive imports, and conserves internal high-cost and emission-constrained resources for summer use. Costs for these commitments are primarily charged to zonal (SP15) customers.

- Beginning November 2007, the CAISO frequently has made additional unit commitments for regional requirements based on a transmission network analysis of the transmission facilities generally in or around the SDG&E service territory (San Diego TNA) and other power flow analysis which jointly indicated additional resources were required to support reliability at Miguel Banks. Because these commitments are required to mitigate regional reliability issues at Miguel Banks, costs for these unit commitments are allocated to zonal (SP15) customers pursuant to FERC Order on Rehearing on Amendment 60.[59]

- Wildfires in October 2007 across Southern California resulted in significant transmission losses, and necessitated primarily local commitment of resources. At certain points, fires nearly or completely eliminated high-voltage transmission, and local generation supplied all load. Commitment costs were primarily local.

- A forced outage of one bank at the Vincent substation resulted in Path 26 being derated intermittently between July 11 and August 8. This resulted in approximately $6 million in primarily zonal costs within the SP15 region in July, for both zonal capacity and SCIT management.

- Other outages, derates, and clearances for transmission work, the costs of which typically are allocated locally.

[59] *Cal. Indep. Sys. Operator,* 121 FERC ¶ 61,193 (2007).

Figure 6.2 Annual MLCC Costs by Reason, 2006-2007

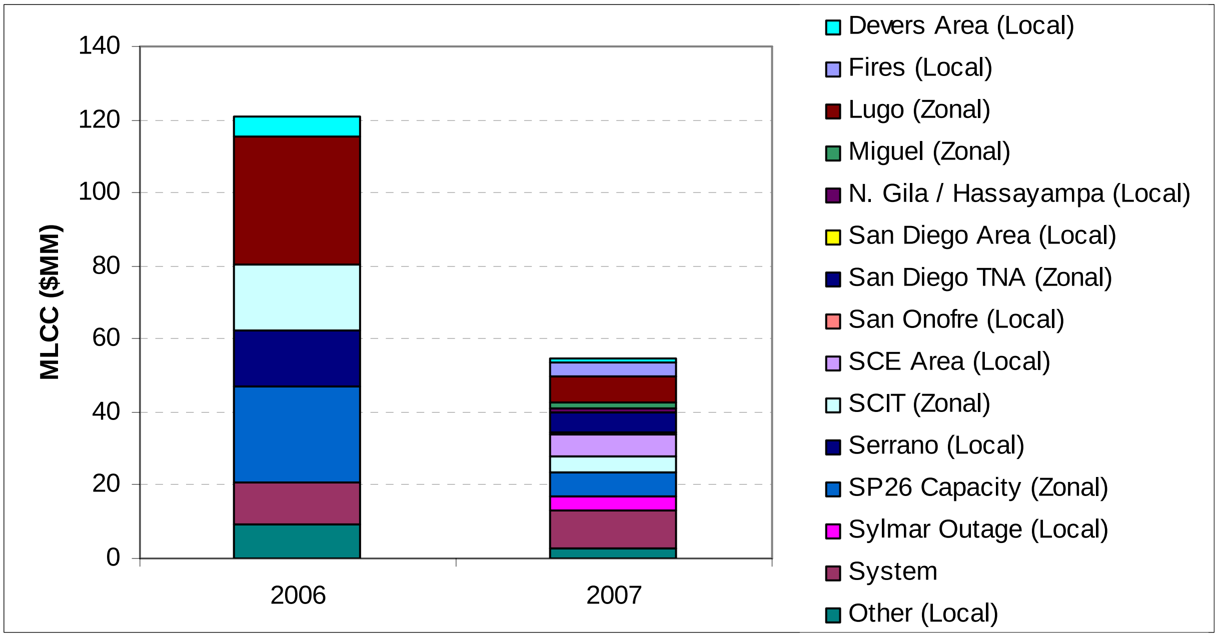


Figure 6.3 Monthly MLCC Costs by Reason, 2007

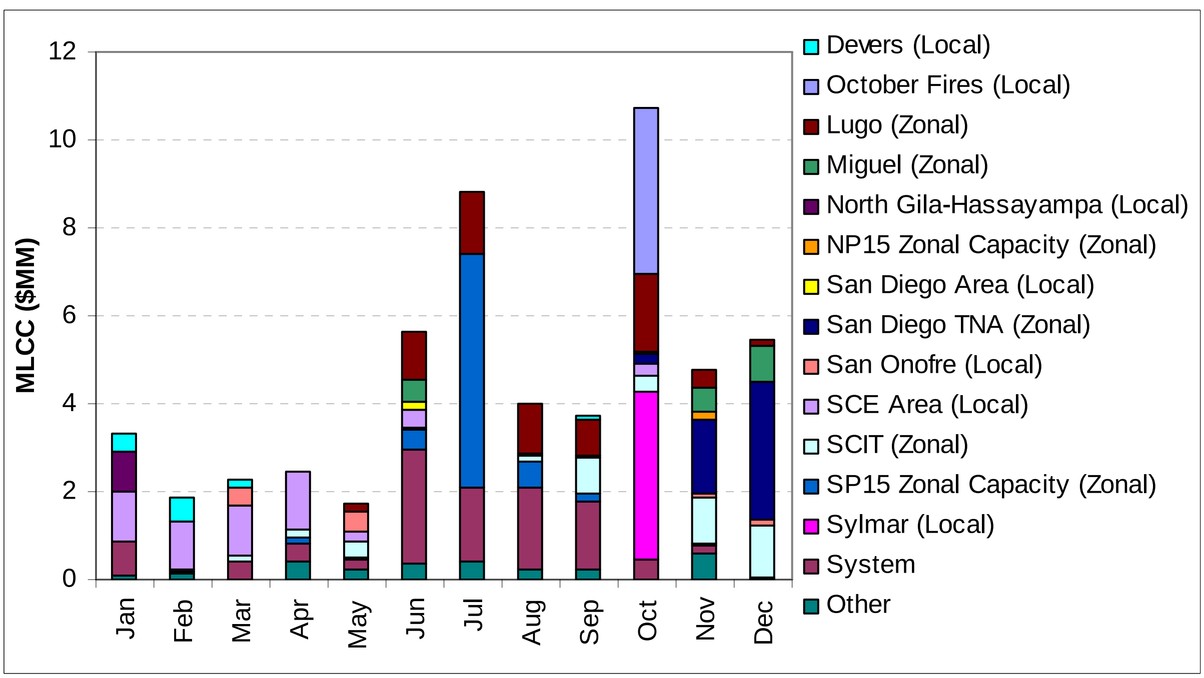
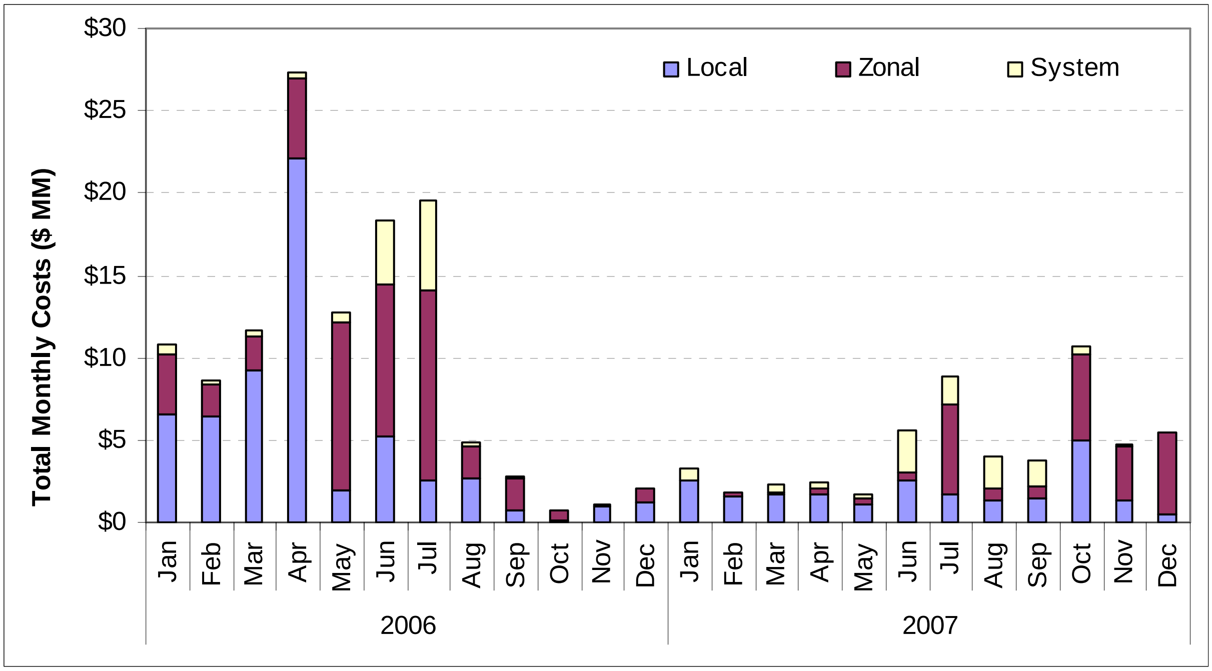


Figure 6.4 shows average daily capacity cost of waiver denials by commitment charge type (local, zonal, and system). The monthly totals of all three reason categories equals the values

shown in Table 6.2. The sharp decline in zonal requirements following the summer of 2006 was due largely to the completion of the aforementioned Southern California transmission upgrade projects.

Figure 6.4 Total Monthly MLCC Payments for All Reasons (Local, Zonal, and System), 2006-2007

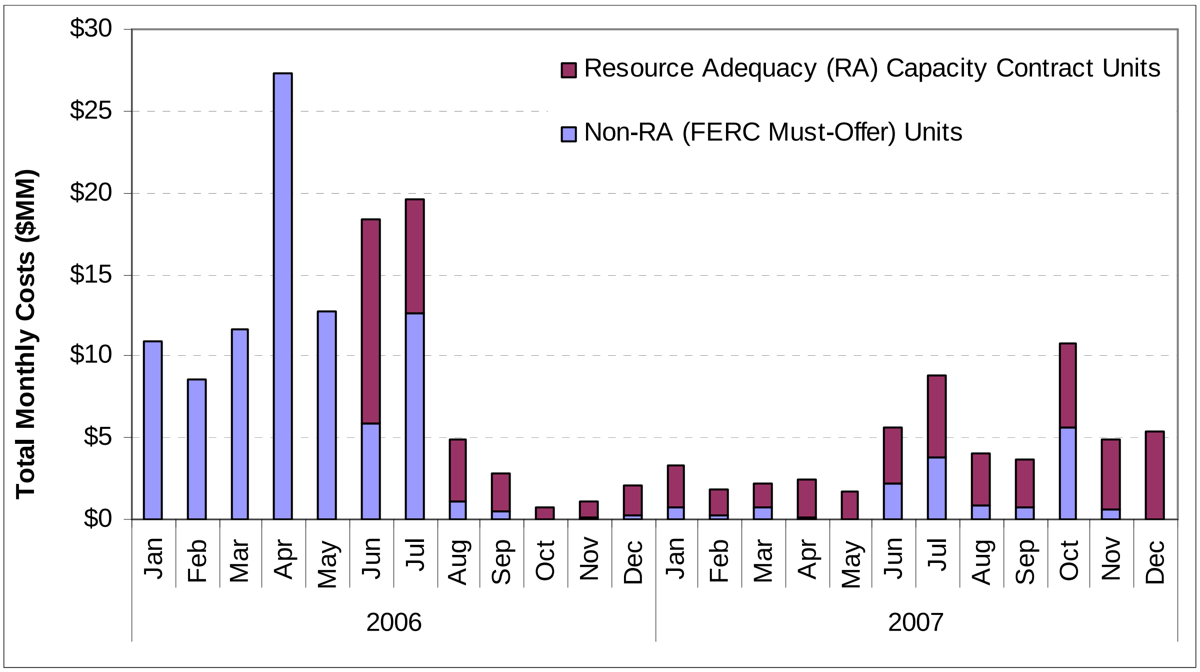


In 2006, the Resource Adequacy (RA) programs developed by the CPUC became effective. This program requires that LSEs procure sufficient resources to meet their peak load along with appropriate reserves. In addition to the CPUC RA program, non-CPUC jurisdictional LSEs have also instituted similar capacity reserve margins. 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 the way 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 forecasted load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined for each CPUC-jurisdictional LSE load forecast based on an allocation of each LSE's coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE's forecast load was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation. Most frequently-committed units are now covered under RA capacity contracts. Non-RA units were committed under the Must-Offer Obligation in 2007 occasionally, usually to meet system requirements and when needed in October during the series of wildfires. Figure 6.5 shows the breakdown of costs between commitment of units with and without RA contracts. As noted previously, these costs do *not* include RA contract payments, which are bilateral and outside the purview of the CAISO, nor do they include RCST payments which are covered in the next section of this chapter.

Figure 6.5 Total Monthly MLCC Payments to Must-Offer vs. RA-Contracted Units in 2006-2007



6.3.2 Reliability Capacity Service Tariff (RCST) Charges

Beginning June 1, 2006, the CAISO implemented 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 also provides the CAISO with the authority to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

The purpose of the RCST, which was ultimately approved by the FERC, was to provide a mechanism by which the reliability needs of the CAISO were met and that ensured generators providing reliability services would be appropriately compensated, thereby reducing the likelihood that units critical for reliability will be mothballed or shut down. 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. The 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. The net payment was designed to reflect a reasonable price for "backstop" capacity and encourage LSEs and generators to engage in longer term contracting and not rely on the must-offer mechanism. This net RCST capacity payment is calculated on a monthly basis by allocating these annual fixed costs 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 for 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.

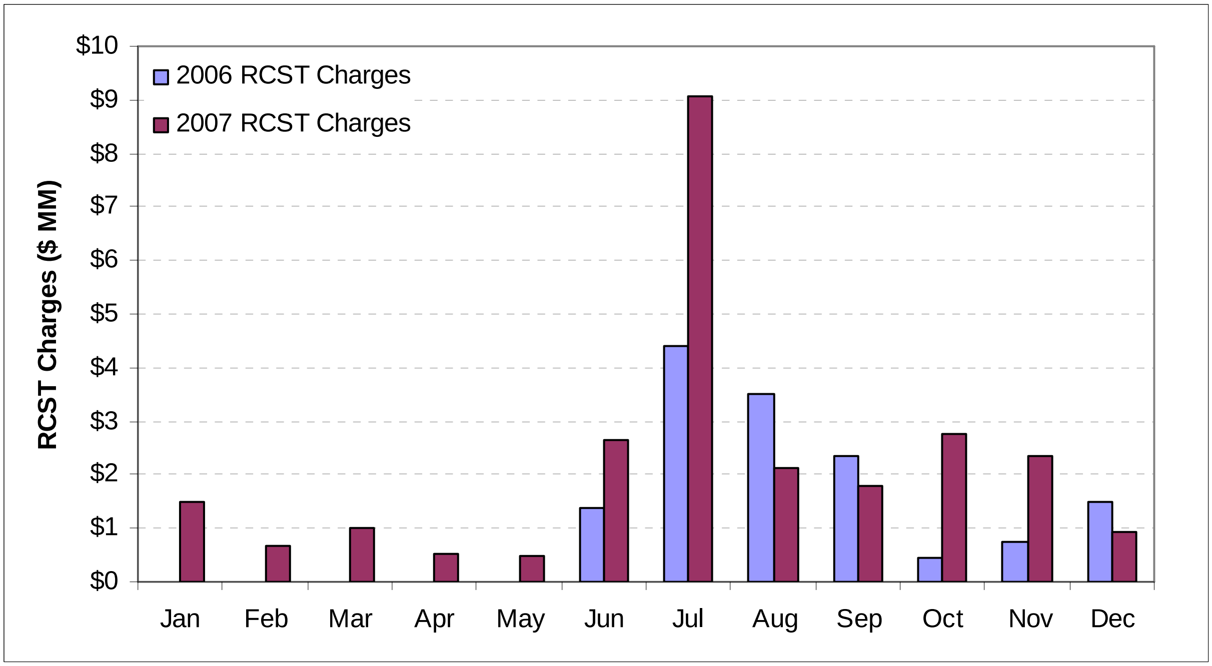
- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. As discussed below, 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 more than 75 percent 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 CAISO's current local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[60]

For 2006 and 2007, there was only one instance where the RCST Capacity Payment (not the Daily RCST Capacity Payment) was warranted, which occurred in 2006 and totaled just over $600,000 in total payment. The vast majority of costs associated with the RCST have been in Daily RCST Capacity Payments, which can be seen in Figure 6.6.

[60] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs which are in excess of $50 or 200 percent of the interval MCP are mitigated to their reference price and settled on the greater of the mitigated bid or the interval MCP. Under the RCST tariff provisions, bids mitigated under these LMP 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.

Figure 6.6 Daily RCST Capacity Payments by Month for 2006-2007



The RCST was in effect only for the last six months of 2006. During this period, the Daily RCST Capacity Payments totaled $14.3 million. In 2007, the comparable RCST payments totaled $25.9 million for the full twelve months, with $21.7 million of that occurring in the last six months. Comparing the June – December periods for 2006 and 2007, the Daily RCST Capacity Payments increased 52 percent. The increase in daily RCST capacity payments in 2007 can be attributed to a number of factors, including increased use of short-start units to provide system energy, increased use of resources to provide capacity in SP15, and increases in the basis of the 1/17th capacity payment, resulting in lower Peak Energy Rents in the summer months in 2007.

6.3.3 Reliability Must-Run (RMR) Costs

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

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[61]

Since 2006, the CAISO has significantly reduced its portfolio of RMR resources. This has resulted in a decline in total RMR costs of approximately 70.7 percent between 2006 and 2007. Table 6.3 shows fixed and variable RMR costs by month in 2007, and further divides variable cost payments into costs associated with pre-dispatch RMR energy for local reliability, and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[62] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy.

Table 6.3 Monthly RMR Contract Energy and Costs in 2007*

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Pre-Dispatch Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan	61	29	$ 8	$ 4	$ 2	$ 13
Feb	41	20	$ 7	$ 2	$ 1	$ 10
Mar	32	31	$ 8	$ 2	$ 1	$ 11
Apr	21	23	$ 6	$ 1	$ 2	$ 9
May	57	7	$ 5	$ 3	$ 1	$ 8
Jun	36	31	$ 5	$ 2	$ 1	$ 8
Jul	60	16	$ 5	$ 2	$ 1	$ 8
Aug	84	24	$ 5	$ 3	$ 1	$ 9
Sep	64	12	$ 6	$ 3	$ 0	$ 8
Oct	98	201	$ 5	$ 3	$ 6	$ 15
Nov	55	126	$ 5	$ 2	$ 3	$ 9
Dec	66	154	$ 5	$ 3	$ 8	$ 16
2007 Total	**675**	**676**	**$ 70**	**$ 29**	**$ 26**	**$ 125**
% ∆ from 2006	-76.1%	-63.7%	-73.1%	-66.9%	-67.3%	-70.7%

* Includes only dispatches under contract option.

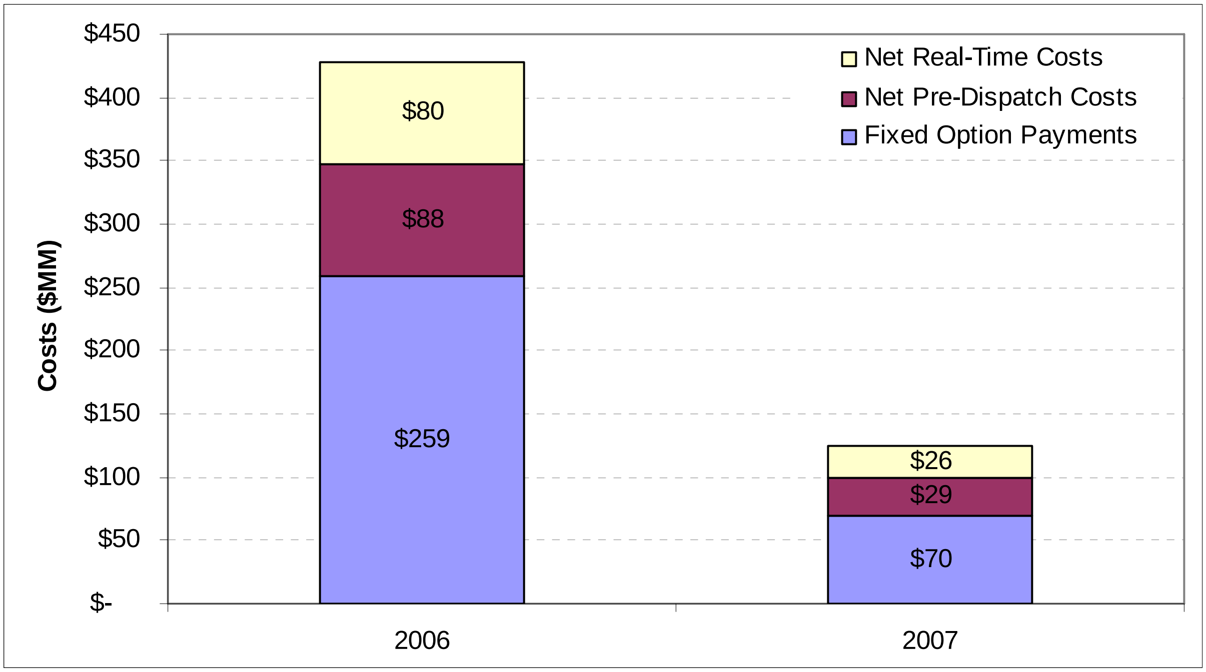
Most of the savings in RMR contract costs is attributable to a large reduction in the amount of generation capacity under RMR contracts, from approximately 9,300 MW in 2006 to 3,300 MW in 2007. As previously discussed in Chapter 1, the significant decline in the amount of generation capacity under RMR contracts was brought about through the introduction of Local Resource Adequacy requirements. With more local resources being procured through Resource Adequacy contracts, the CAISO was able to significantly decrease its RMR designations, which in turn resulted in a significant decrease in RMR fixed option payments, from approximately $259 million in 2006 to $70 million in 2007. In addition, the reduction in RMR contracted units, as well as grid upgrades and milder weather, resulted in substantially lower RMR variable cost payments (pre-dispatch and real-time dispatch). RMR variable costs

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

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

totaled approximately $55 million in 2007, compared to $168 million in 2006. In sum, total RMR costs decreased in 2007 to approximately $125 million, from approximately $428 million in 2006 (Figure 6.7). This continued a trend of declining RMR costs that has persisted since 2004.

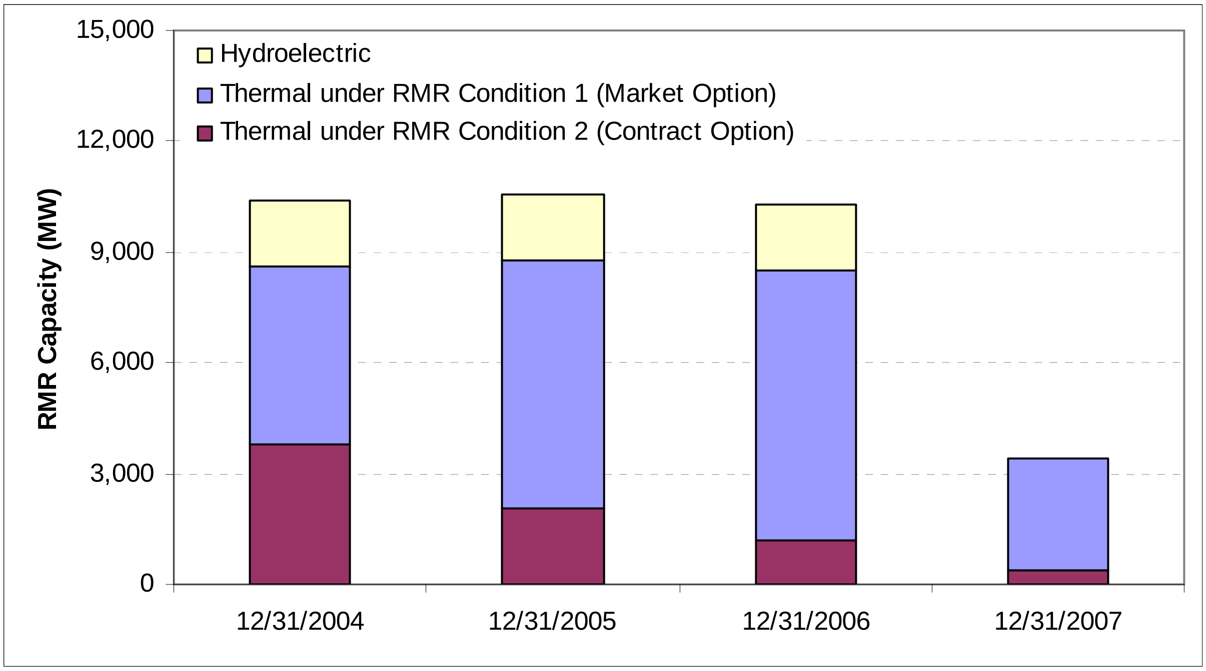
Figure 6.7 Total RMR Costs, 2006-2007



The portion of RMR unit capacity selecting Condition 2 (non-market) of the pro forma RMR contract continued to decrease, which also contributed to lower variable cost payments. RMR-providing generation owners may select either Condition 1 or 2 contracts. Condition 1 designations entitle the generation owner to participate in the market, and, if dispatched for RMR, to select on a daily basis whether to collect variable contract-based rates (Contract Path) or market revenues (Market Path). Because Condition 1 units have market opportunities, they receive a lower monthly FOP.[63] Condition 2 effectively is a tolling agreement between the CAISO and the generation owner, where the owner receives a higher FOP, but receives cost-based payments for its energy and cannot participate in the market unless given an RMR dispatch. Condition 2 unit capacity accounted for approximately 10.3 percent of total RMR-contracted unit capacity by the end of 2007, compared to 11.8 percent at the end of 2006 (Figure 6.8).

[63] RMR Condition 1 revenues from dispatch under the Market Path are not included in the calculation of reliability costs, but are included as real-time market costs in the calculation of total wholesale market costs in Chapter 2.

Figure 6.8 RMR Capacity by Resource and Contract Type, 2004-2007



6.3.4 Out-of-Sequence (OOS) Costs

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is the difference between the price paid to the resource for OOS energy (generally, their bid price) less the market clearing price (the cost of balancing the OOS energy). For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental OOS energy.[64]

As shown in Table 6.4, net redispatch costs of incremental dispatches to LSEs, or the costs in excess of real-time market prices, were approximately $20.8 million in 2007, compared to $4.3 million in 2006. In all, the CAISO procured 365 GWh of incremental OOS energy at an average price of $107.36/MWh, or $56.89/MWh above market.

Table 6.5 shows decremental OOS statistics. Decremental redispatch costs, or the amount of money below the market price that resources save when the CAISO reduces their output in order to avoid intra-zonal congestion, totaled approximately $9.7 million in 2007, compared to

[64] This discussion excludes OOS and OOM dispatches for system conditions, which totaled approximately $4.9 million in redispatch costs in 2007. These dispatches were largely incremental dispatches to RMR Condition 2 units during the summer heat wave, which under the RMR contract are not required to bid, and decremental dispatches to pump storage units to offset over-generation during the spring months.

$13.2 million in 2006. In all, the CAISO decremented 480.8 GWh of OOS energy at an average price of $45.19/MWh, or $20.22/MWh below market.

Table 6.4 Incremental OOS Congestion Costs in 2007

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Mitigation Savings ($)	Average Price	Average Net Cost ($/MWh)
Jan	33.0	$ 3.4	$ 1.9	$ 436,369	$ 102.03	$ 57.74
Feb	23.8	$ 2.5	$ 1.4	$ 225,168	$ 103.45	$ 60.62
Mar	13.5	$ 1.5	$ 0.9	$ 32,607	$ 111.38	$ 68.80
Apr	14.3	$ 2.2	$ 1.6	$ 30,945	$ 155.79	$ 109.06
May	27.1	$ 2.9	$ 1.4	$ 30,854	$ 105.43	$ 50.71
Jun	15.7	$ 1.9	$ 1.0	$ 129,924	$ 123.79	$ 64.45
Jul	28.6	$ 3.4	$ 1.9	$ 94,811	$ 118.76	$ 65.07
Aug	29.0	$ 2.7	$ 0.9	$ 105,756	$ 91.60	$ 30.82
Sep	18.1	$ 2.1	$ 1.2	$ 268,150	$ 113.03	$ 63.71
Oct	108.7	$ 9.4	$ 4.1	$ 191,202	$ 86.26	$ 37.65
Nov	30.6	$ 3.5	$ 1.9	$ 221,467	$ 113.78	$ 63.03
Dec	22.6	$ 3.9	$ 2.6	$ 416,144	$ 170.99	$ 115.47
2006 Total	**365.0**	**$ 39.2**	**$ 20.8**	**$ 2,183,396**	**$ 107.36**	**$ 56.89**

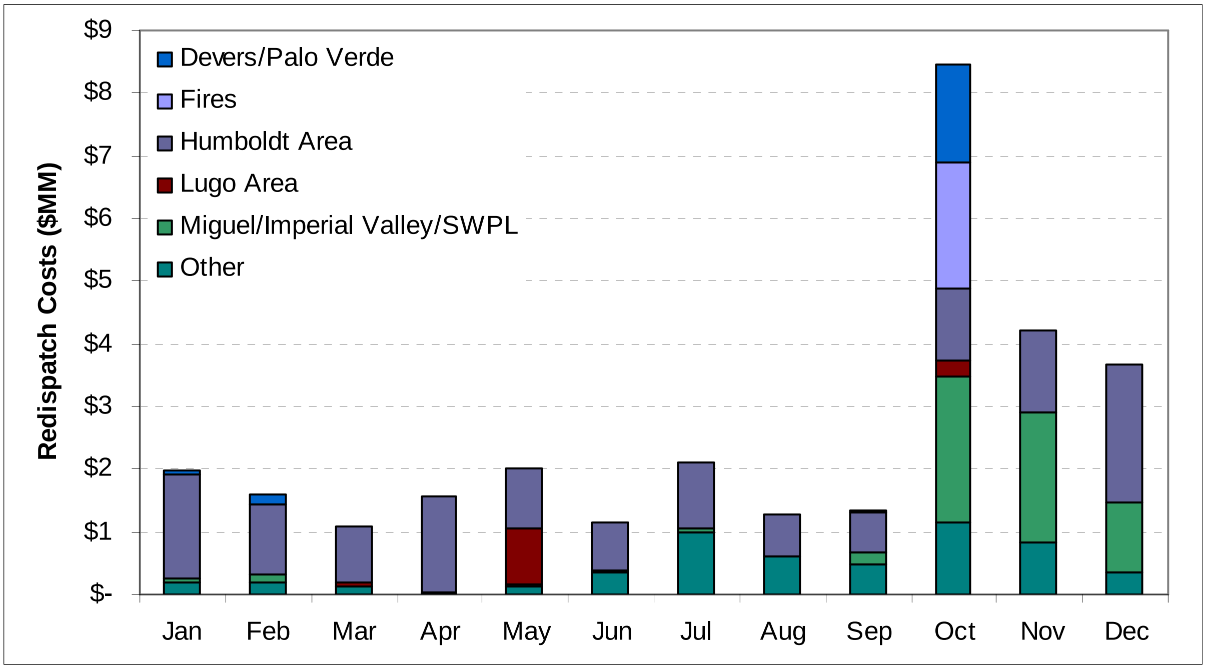
Table 6.5 Decremental OOS Congestion Costs in 2007

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Average Price	Average Net Cost ($/MWh)
Jan	(20.0)	$ (1.0)	$ 0.1	$ 49.67	$ 4.27
Feb	(25.6)	$ (1.5)	$ 0.2	$ 58.03	$ 6.12
Mar	(7.6)	$ (0.3)	$ 0.2	$ 45.91	$ 22.31
Apr	(0.7)	$ (0.0)	$ 0.0	$ 42.18	$ 14.09
May	(16.2)	$ (0.6)	$ 0.6	$ 39.45	$ 39.96
Jun	(7.3)	$ (0.4)	$ 0.1	$ 54.42	$ 19.21
Jul	(10.6)	$ (0.5)	$ 0.3	$ 51.65	$ 23.83
Aug	(5.7)	$ (0.2)	$ 0.4	$ 29.28	$ 67.63
Sep	(15.4)	$ (0.6)	$ 0.2	$ 42.04	$ 11.49
Oct	(165.1)	$ (7.1)	$ 4.4	$ 42.84	$ 26.44
Nov	(128.5)	$ (5.4)	$ 2.3	$ 41.80	$ 17.74
Dec	(78.1)	$ (4.0)	$ 1.1	$ 51.56	$ 13.51
2007 Total	**(480.8)**	**$ (21.7)**	**$ 9.7**	**$ 45.19**	**$ (20.22)**

The increase in OOS redispatch costs in 2007 over the 2006 level was due primarily to the increased need for management of local congestion in Humboldt County, a rural region in Northern California connected to the CAISO grid by two relatively small transmission lines. Until December 31, 2006, the Humboldt area was supported by RMR contracts covering the region's four generators, rated at a total of 135 MW. Beginning January 1, 2007, the CAISO managed reliability in this transmission-constrained region through OOS redispatches. Humboldt-area local OOS dispatches are typically in the incremental direction, while the dispatch in the remainder of the NP15 zone is generally decremental to manage over-scheduling in that region.

Of the $30.49 million in intra-zonal congestion redispatch costs, $14 million are due to uplifts to support local reliability in the Humboldt area.

Figure 6.9 Monthly Contribution to Intra-Zonal Congestion OOS Redispatch Costs by Reason in 2007



7 Market Surveillance Committee

7.1 Market Surveillance Committee

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

7.1.1 Current Members

In 2007, the Committee was comprised of the following members: Frank Wolak of Stanford University, Benjamin Hobbs of Johns Hopkins University and James Bushnell of the University of California Energy Institute at Berkeley. Frank Wolak served as the chairman of the Committee.[65] The following is a brief description of each member's background.

Since April of 1998 Dr. Wolak has been Chairman of the MSC. In this capacity, he has testified numerous times at the FERC, and at various Committees of the US Senate and House of Representatives on issues relating to market monitoring and market power in electricity markets. Dr. Wolak has also worked on the design and regulatory oversight of the electricity markets internationally, including markets in Europe, Australia/Asia, Latin America, and the US (CAISO, NY-ISO, PJM, ISO-NE). He lectures internationally on issues related to electricity market monitoring and regulatory oversight. He has contributed to the design of market monitoring and regulatory oversight protocols in a number of electricity markets.

Dr. Frank Wolak is a Professor of Economics at Stanford University. He received his undergraduate degree from Rice University, and an S.M. in Applied Mathematics and Ph.D. in Economics from Harvard University. His fields of research are industrial organization and empirical economic analysis. He specializes in the study of privatization, competition and regulation in network industries such as electricity, telecommunications, water supply, natural gas and postal delivery services. He is the author of numerous academic articles on these topics. He is a Research Associate of the National Bureau of Economic Research and a Visiting Researcher at the University of California Energy Institute in Berkeley. Professor Wolak has served as a consultant to the California and U.S. Departments of Justice on market power issues in the telecommunications, electricity, and natural gas markets. He has also served as a consultant to the Federal Communications Commission and Postal Rate Commission on issues relating to regulatory policy in network industries.

Dr. Benjamin F. Hobbs, a member of the MSC since 2002, is a Professor of Geography & Environmental Engineering and Applied Mathematics & Statistics in the Whiting School of Engineering, at Johns Hopkins University since 1995. He is a former Professor of Systems Engineering and Civil Engineering at Case Western Reserve University. He has previously held

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[65] More information is available at http://www.caiso.com.

positions at Brookhaven National Laboratory and Oak Ridge National Laboratory. He is presently Scientific Advisor to The Energy Research Centre of the Netherlands and a member of the Public Interest Advisory Committee for the Gas Technology Institute. His research interests include stochastic electric power planning models, environmental and energy systems analysis and economics, multi-objective and risk analysis, ecosystem management, and mathematical programming models of imperfect energy markets. Dr. Hobbs has published numerous journal articles and magazine articles on these topics and has co-authored two books. Dr. Hobbs has a Ph.D. in Environmental Systems Engineering from Cornell University, and is a Fellow of the IEEE.

Dr. James Bushnell, a member of the MSC since 2002, is currently the Research Director of the University of California Energy Institute at Berkeley. He also serves as Lecturer at the Haas School of Business at UC Berkeley. He is a former member of the Market Monitoring Committee of the California Power Exchange (CALPX). His research interests include industrial organization and regulatory economics, energy policy, and environmental economics. He has published numerous articles on the economics of electricity deregulation and has testified extensively on energy policy issues. Much of his research has focused on examining market incentives in particular; market rules and structures created; and in developing empirical methods for measuring the impact of market power on deregulated electricity markets. Dr. Bushnell has a Ph.D. in Industrial Engineering and Operations Research with a B.S. in Economics and Industrial Engineering.

7.1.2 Accomplishments

Members participated in several formal stakeholder meetings and worked closely with CAISO staff on a number of market design issues. Their efforts have culminated in the preparation and adoption of numerous MSC opinions in 2007, addressing a wide range of market design and policy issues, including the following:

- Various policy aspects of Congestion Revenue Rights under MRTU.
- Interim measures to address potential load under-scheduling under MRTU.
- Market power mitigation for start-up and minimum load bids under MRTU.
- Long-term policy framework for ensuring resource adequacy.
- CAISO backstop capacity procurement mechanisms.
- Design options for carbon dioxide emissions trading in California – implications to the wholesale energy market.

The actual MSC Opinions on these items can be found at the following web page: http://www.caiso.com/docs/2000/09/14/2000091416100025714.html.

7.1.3 MSC Meetings

In 2007, the MSC conducted numerous public meetings and teleconferences to hear CAISO staff presentations and stakeholder comments on various market design issues. Two of these meetings were held at state agencies.

In June 2007, the MSC held a technical workshop at the California Air Resources Board to discuss methods for best achieving California's Greenhouse Gas policy goals while minimizing potential adverse impacts to the wholesale electricity market in California. Stakeholders were given the opportunity to raise the major issues followed by questions and comments by the MSC. The MSC continued to follow this issue, and developed a written position entitled, "Opinion on Load-Based and Source-Based Trading of Carbon Dioxide in California," that was adopted in late November 2007.

In October 2007, the MSC held a meeting at the California Public Utilities Commission headquarters in San Francisco to discuss the design elements/issues associated with a long-term resource adequacy framework for California. Through panelist discussions, the goal of the meeting was to identify deficiencies and strengths of the current resource adequacy process and to further identify potential enhancements to that process.

During 2007, the MSC continued to work with CAISO staff on a number of topics. Various members moderated stakeholder meetings on Capacity Market Design and how to best involve demand in the ISO's energy and ancillary services.