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.[1] 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[2]

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%

[1] 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.

[2] 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

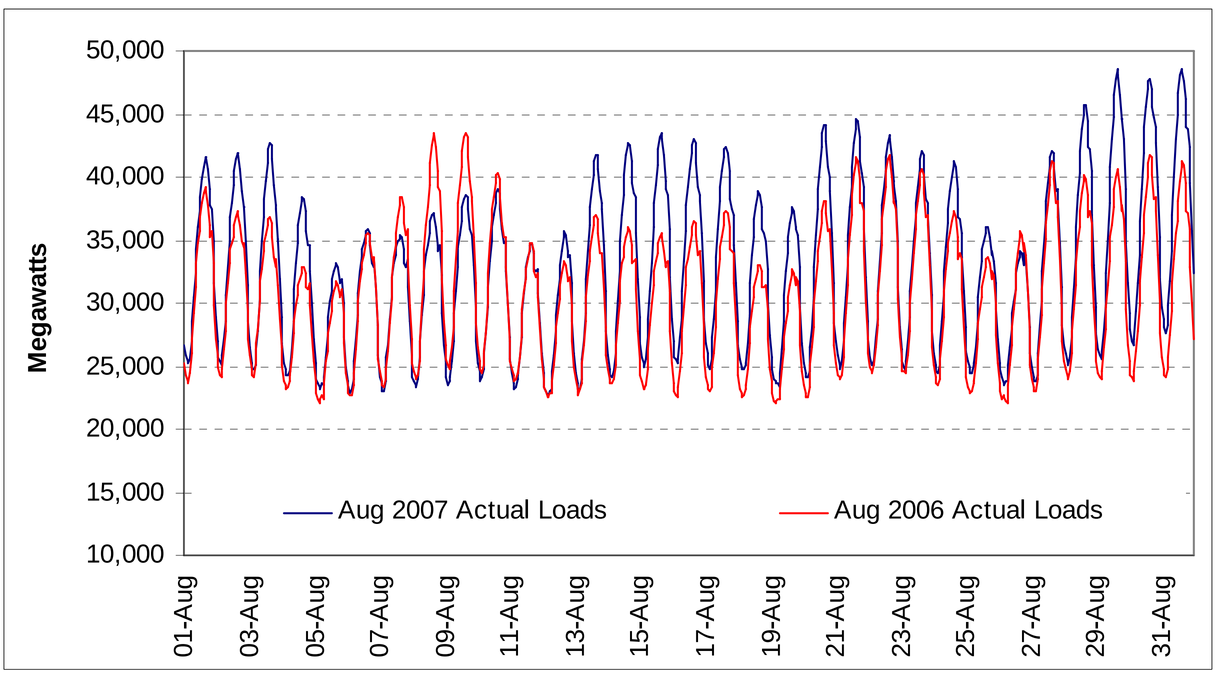


Figure 2.1 shows hourly system load for August 2007, the month in which the annual peak load occurred, compared to August 2006. August loads were higher for most days in 2007 compared with 2006, with daily peak loads well in excess of 2006 levels in all but six days. As noted

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

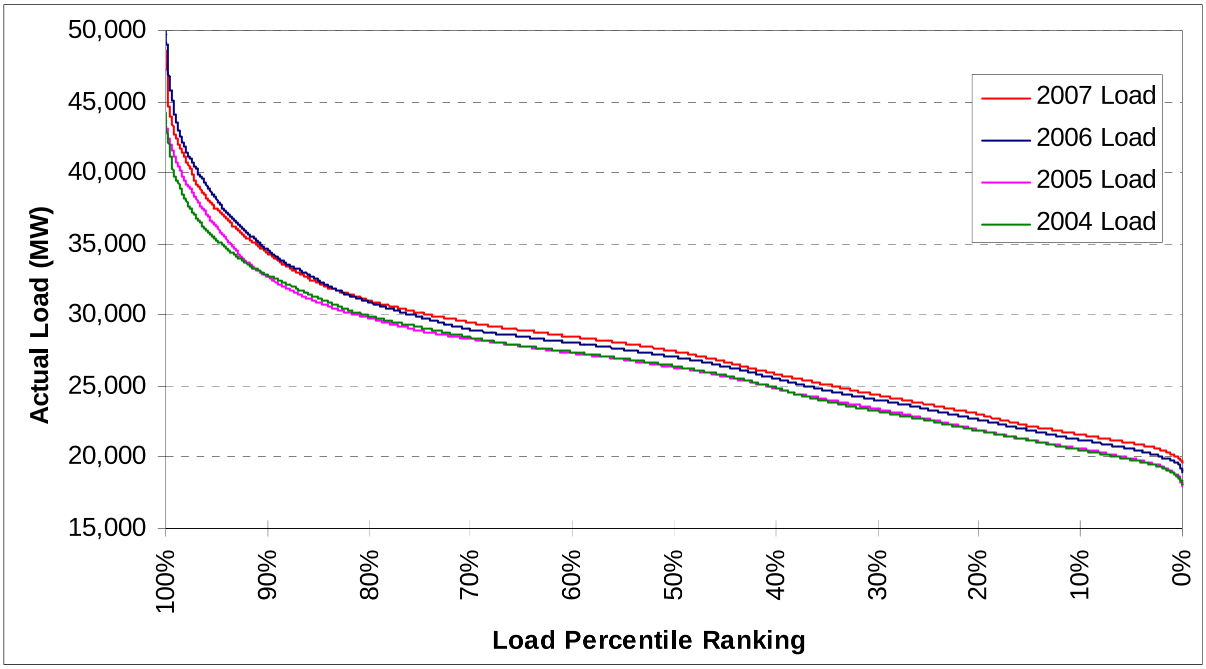


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO Control Area as a whole. NP26 and SP15 average loads were only moderately higher than 2006 levels at 1.1 and 0.6 percent, respectively. The California Energy Commission (CEC) has estimated that NP26 load grew 1.3 percent when normalized for weather.[3] 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.

[3] 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.

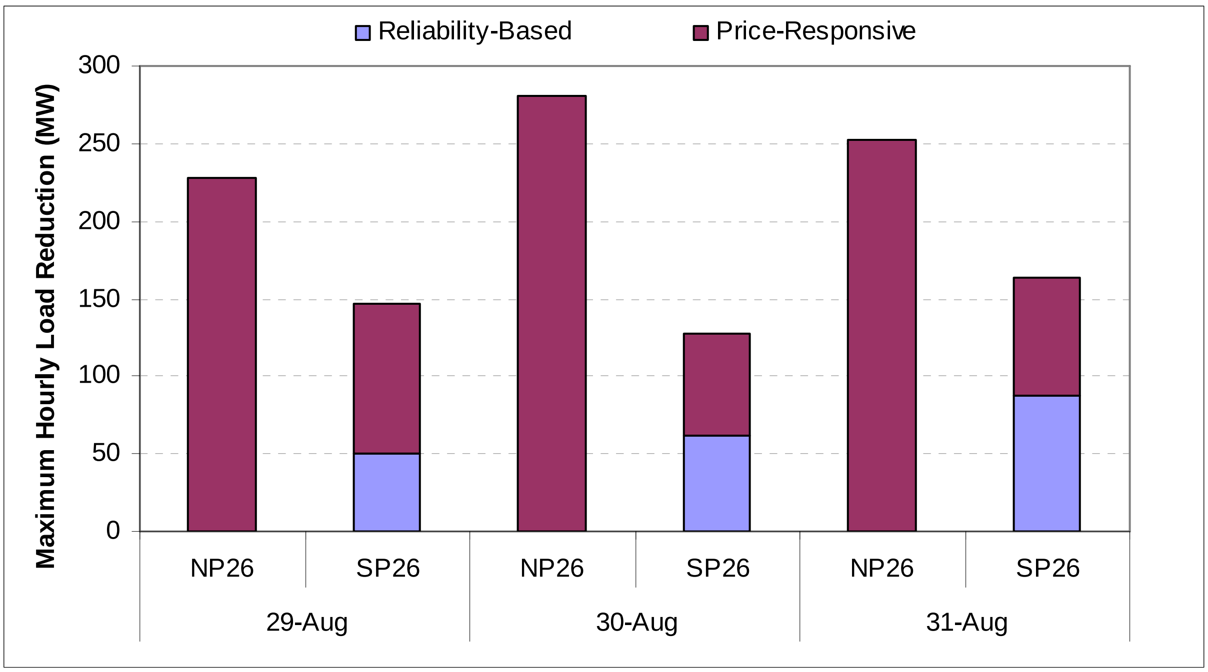
Table 2.4 Summary of Utility Operated Demand Programs[4]

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

[4] 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.

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.

Figure 2.3 Summary of IOU Programs - Actual Demand Reductions (Aug 29-31)[5]



2.2 Supply Conditions

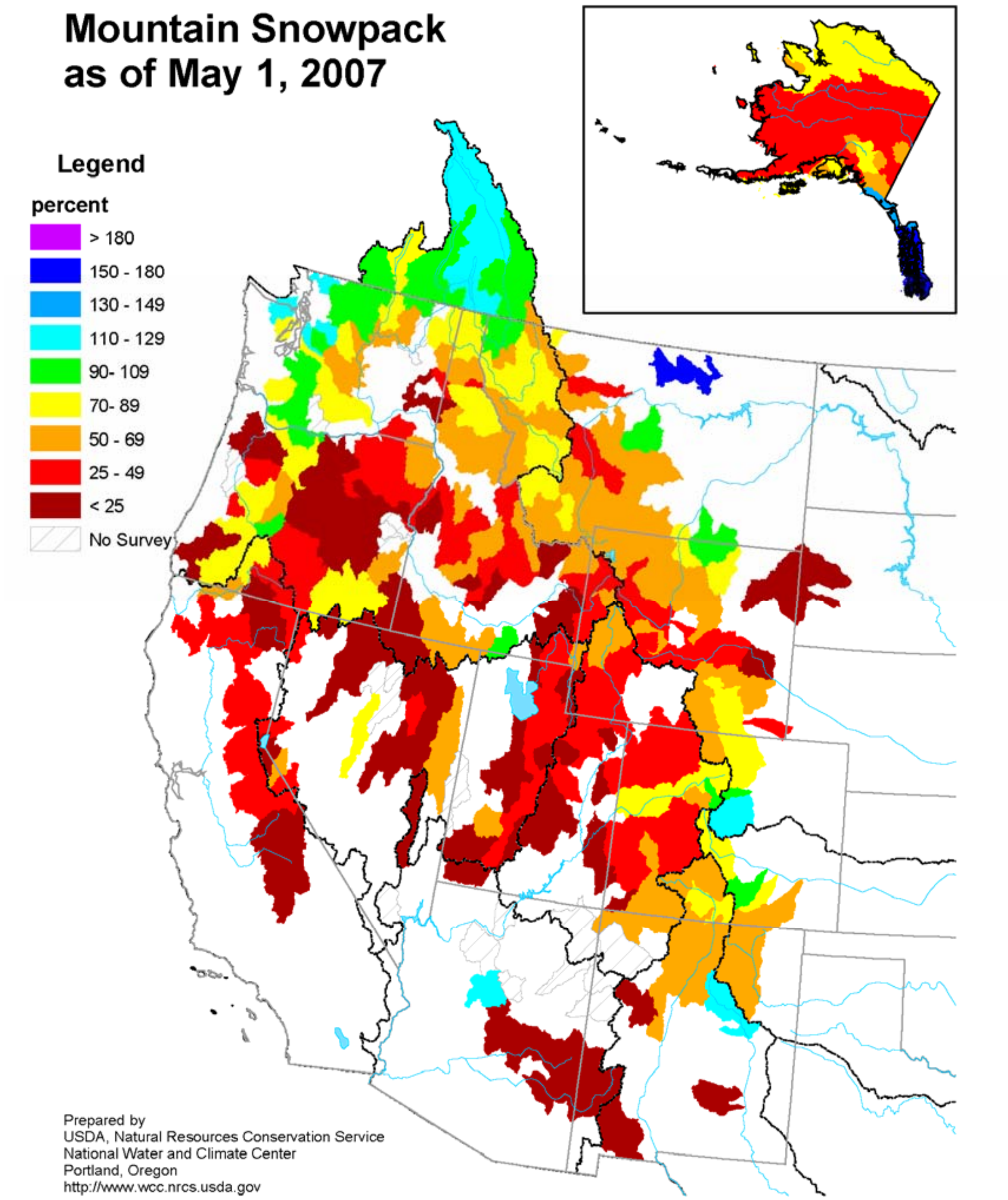
2.2.1 Hydroelectric

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

[5] 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.

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.

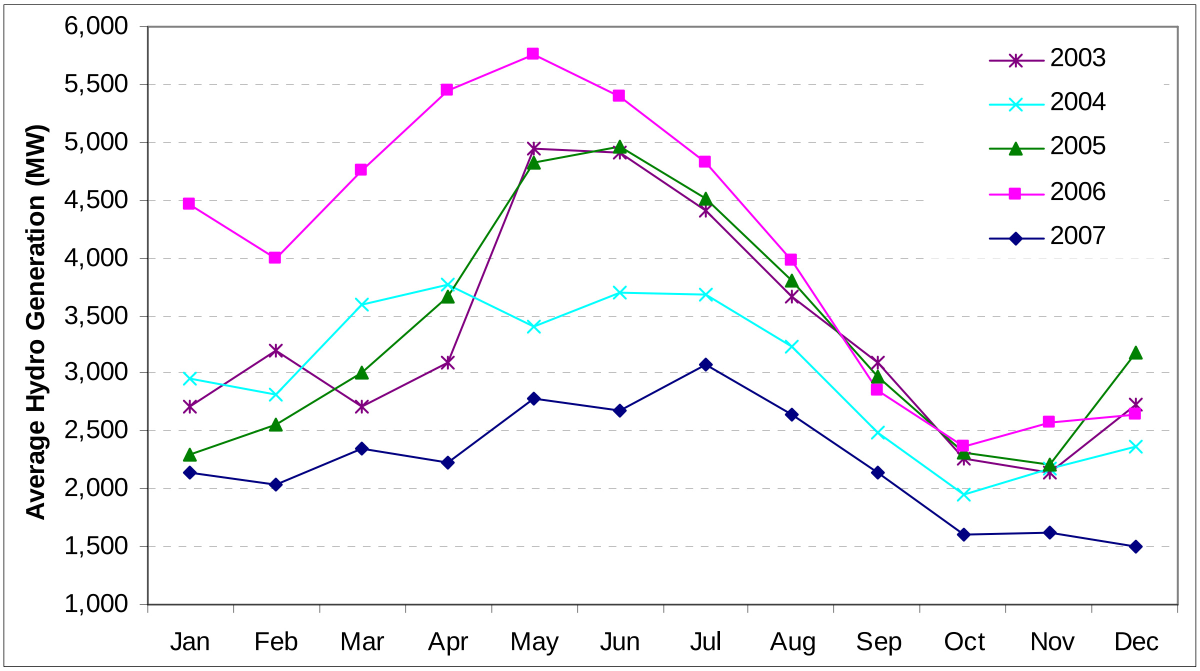
Figure 2.4 Mountain Snowpack in the Western U.S., May 1, 2007[6]



[6] 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.

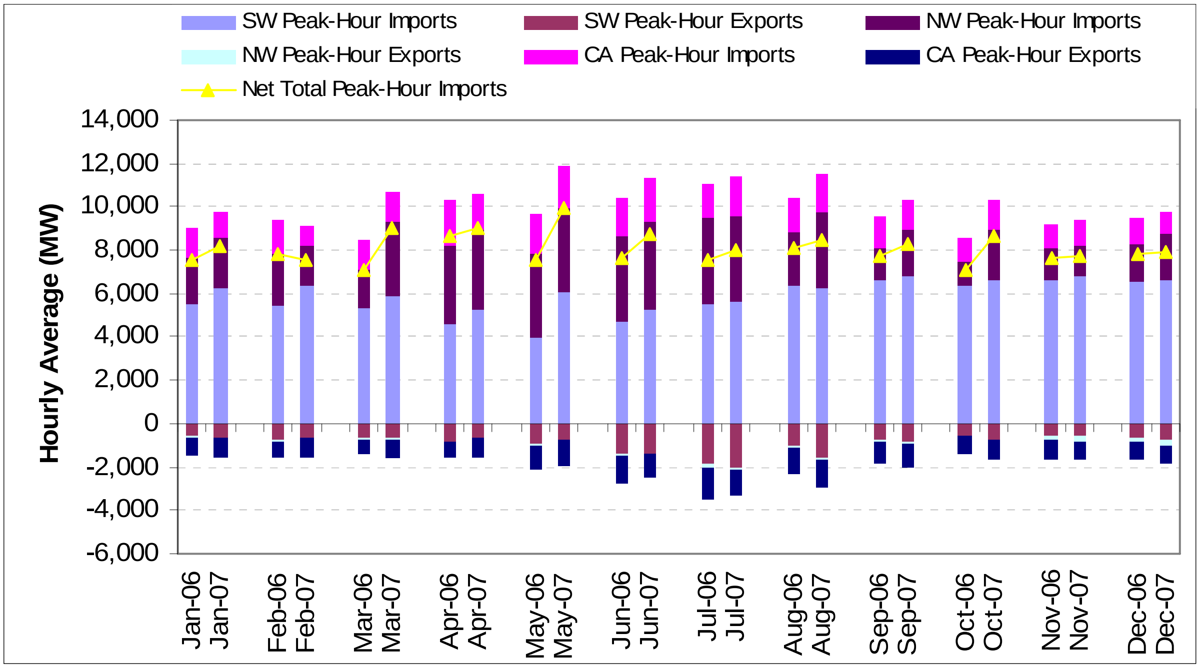
Figure 2.5 Average Hourly Hydroelectric Production by Month: 2003-2007



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.

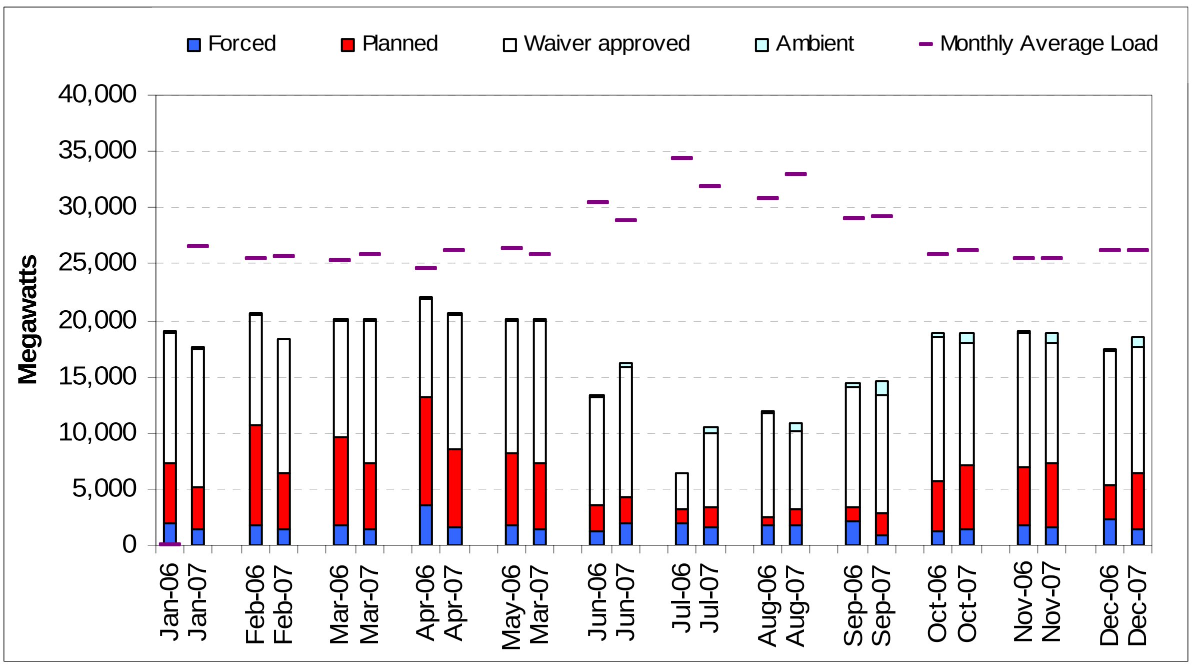
Figure 2.6 Year to Year Comparison of Hourly Average Scheduled Imports and Exports by Month: 2007 vs. 2006



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.

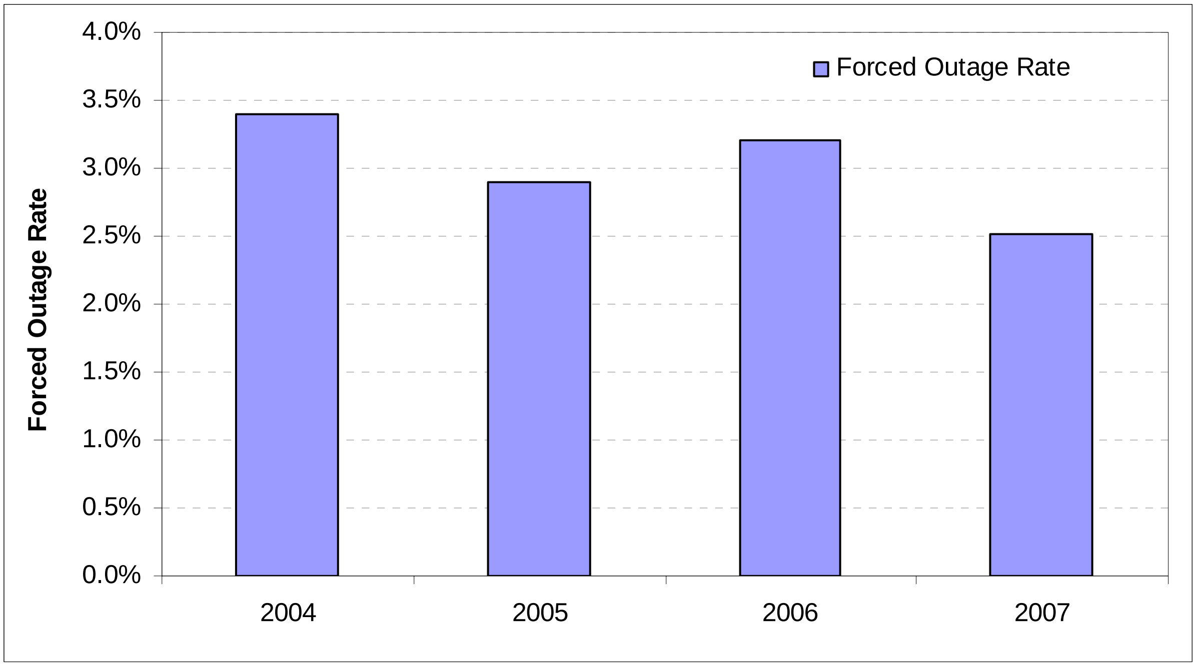
Figure 2.7 Year-to-Year Comparison of Hourly Average Outages by Month: 2007 vs. 2006



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.[7] 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.

[7] See Section 2.6.4 for more information.

Figure 2.8 Year-to-Year Comparison of Forced Outage Rates: 2004-2007[8]



[8] 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

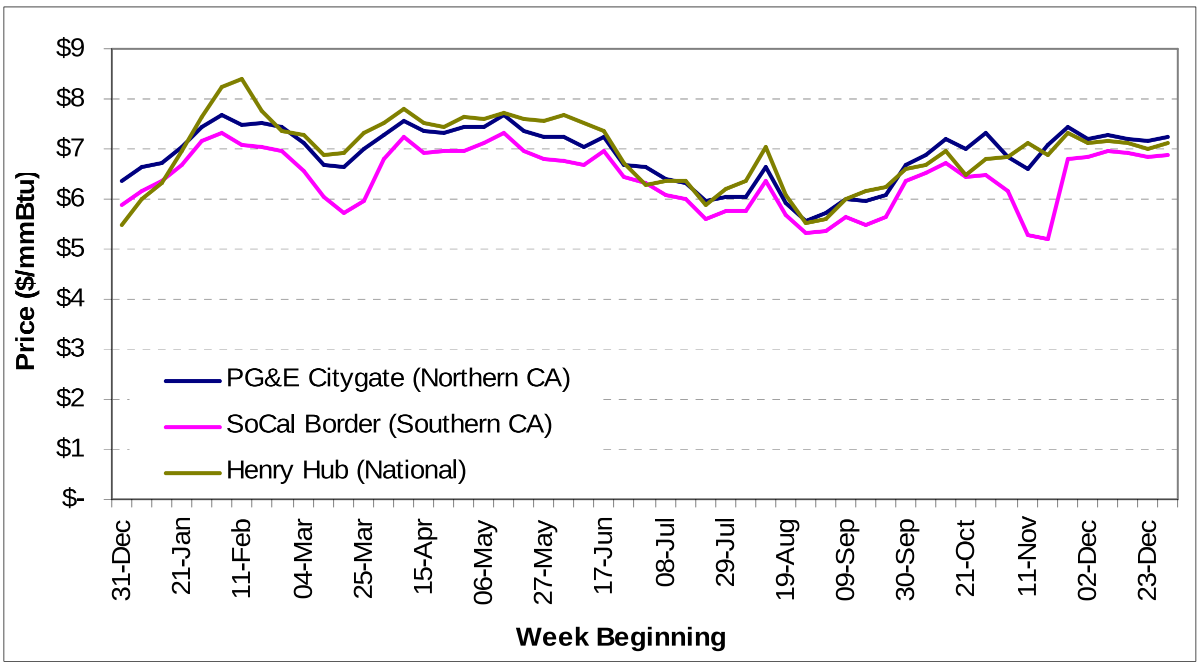
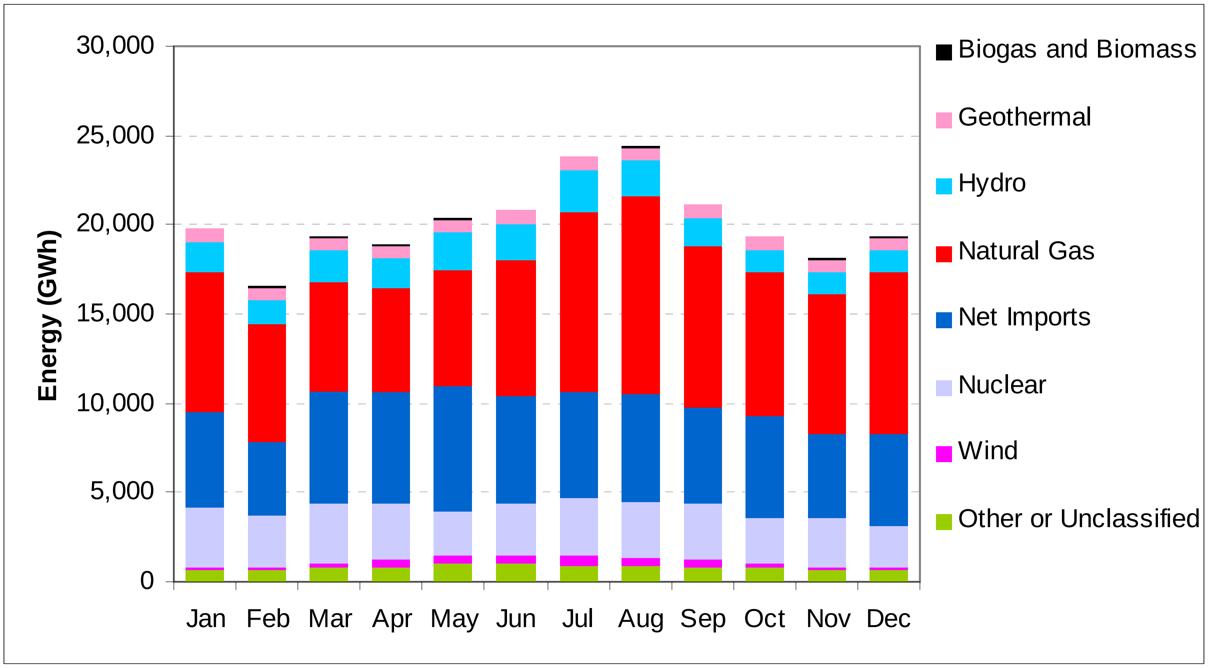


Figure 2.10 provides a profile of monthly generation by fuel type. The hydroelectric resources that had provided nearly 20 percent of total energy in the spring and summer of 2006 accounted for less than 10.5 percent of production in any month in 2007. The limited hydroelectric production was replaced 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.

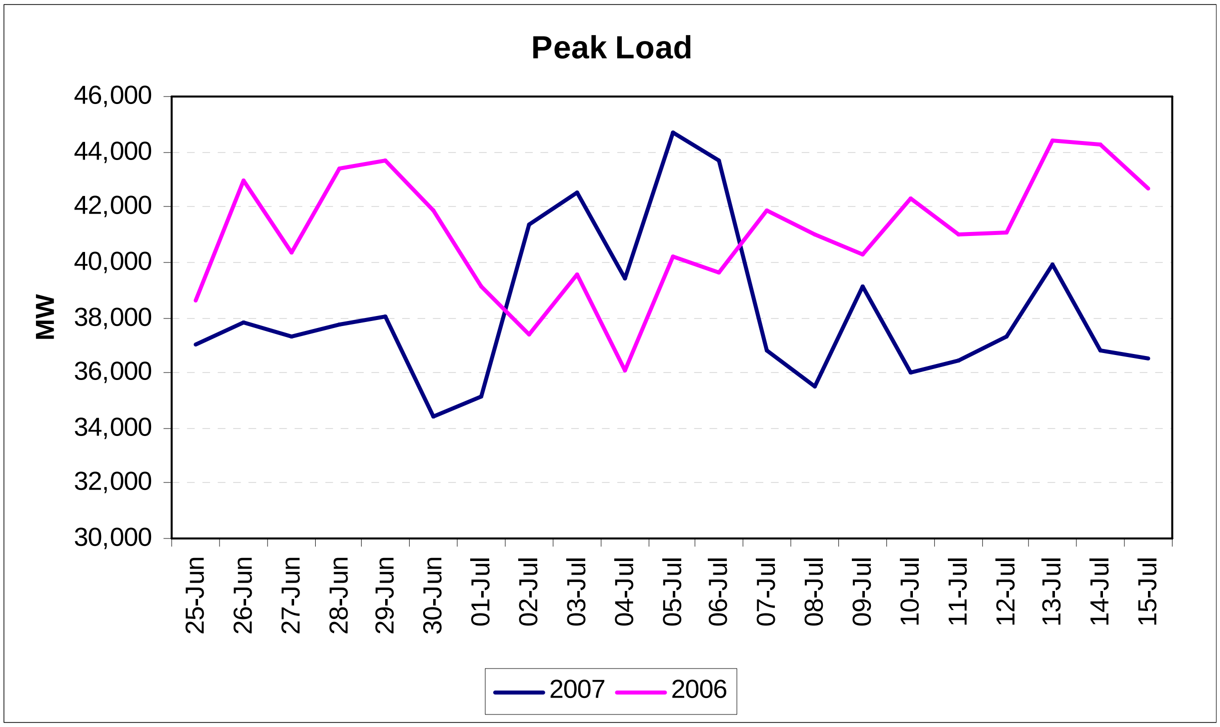
2.3.1 July Heat Wave

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.

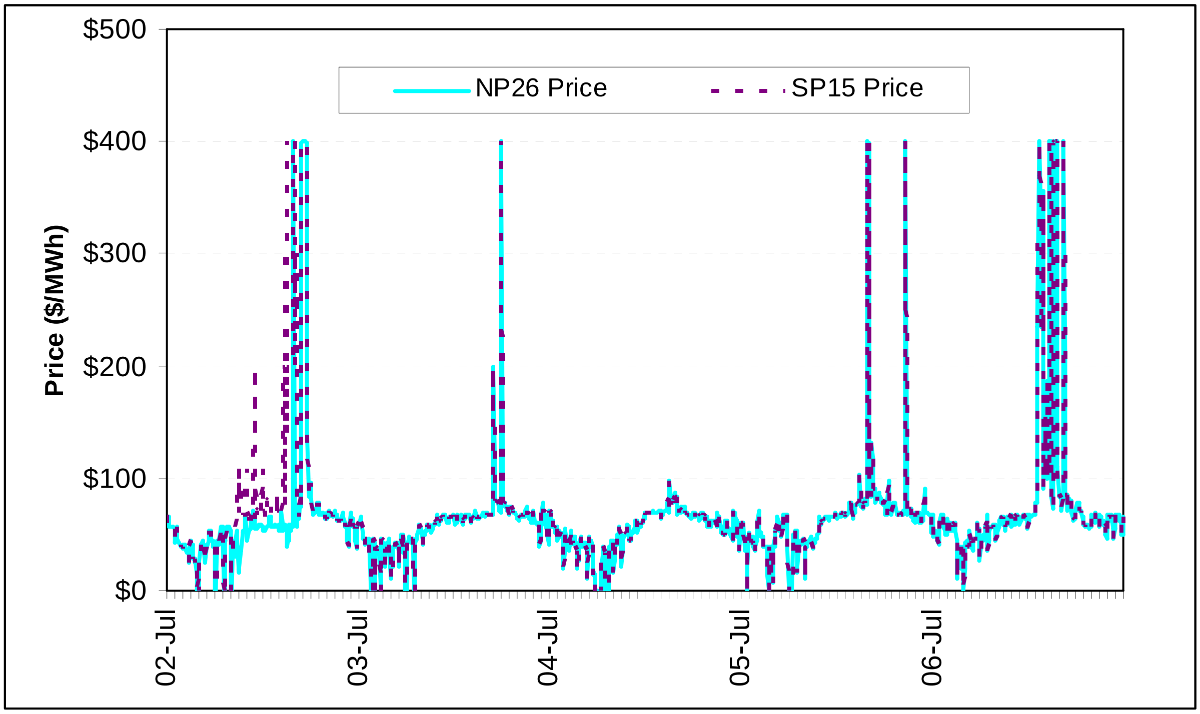
Figure 2.11 Daily Peak Load for Early Summer 2006 and 2007



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.

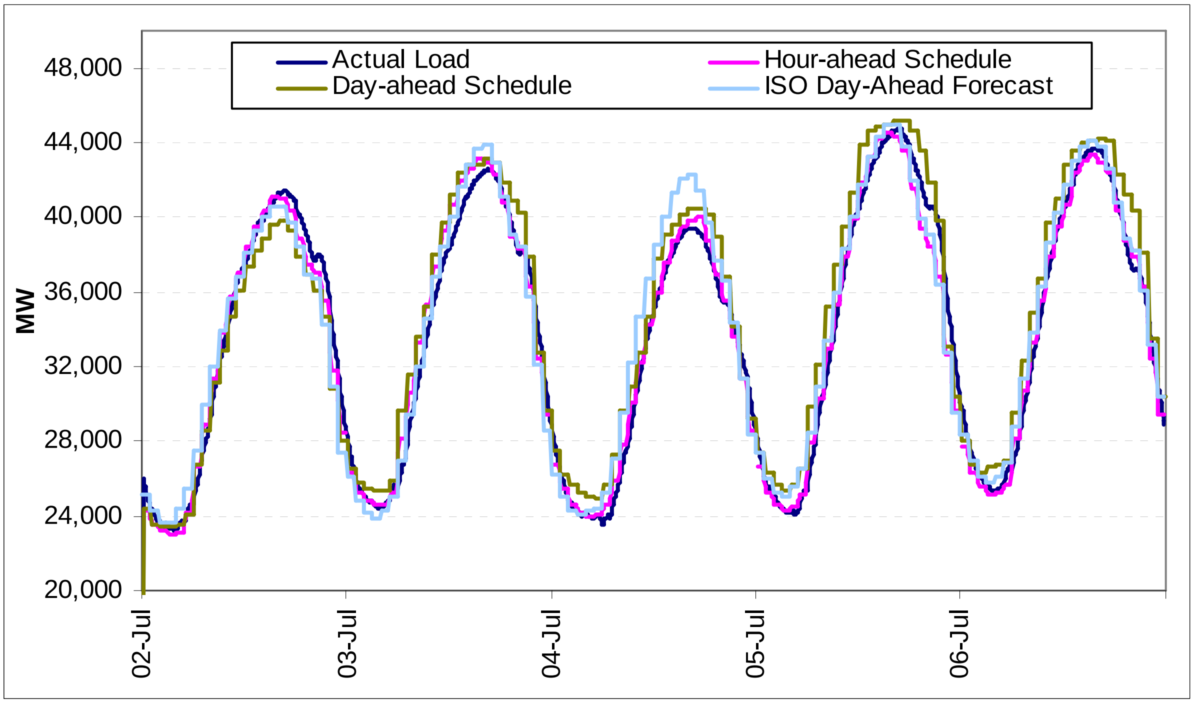
Figure 2.12 Real Time Energy Prices for July 2-5, 2007



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



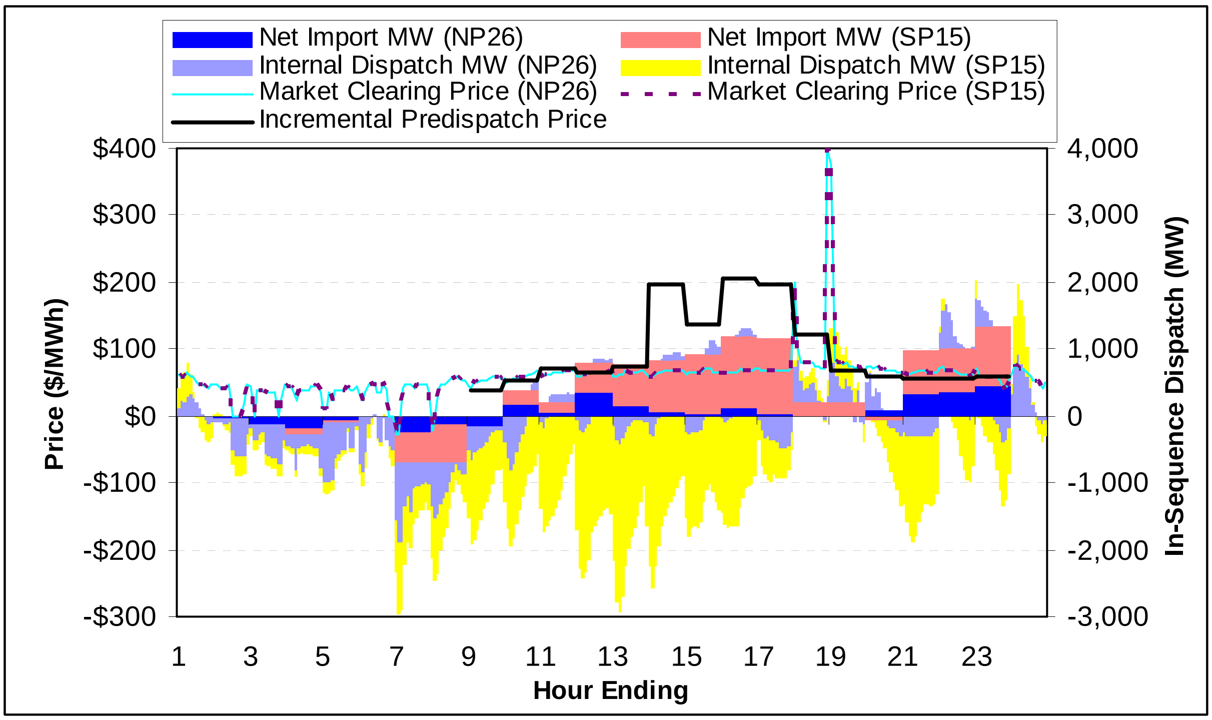
One pattern that is often observed during high load periods in the summer is an increase in the scheduling of energy from the Pacific Northwest into California to serve native load and also for export to the Southwest. During such periods, it is not uncommon to observe congestion on the transmission 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.

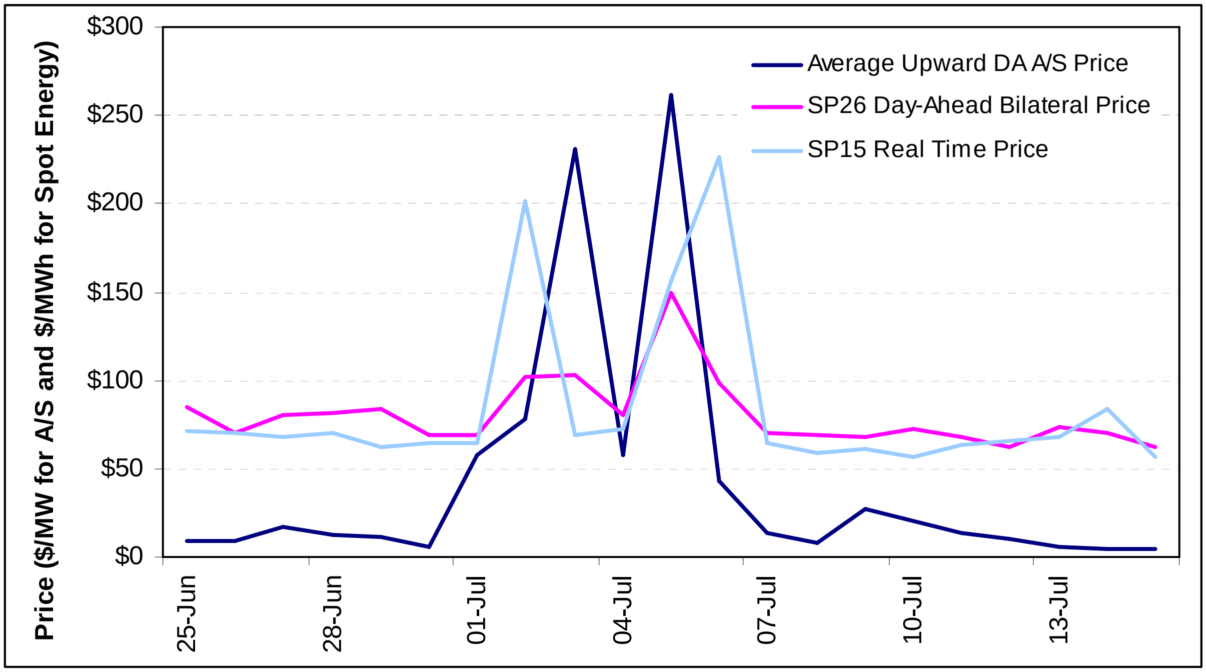
This high decline rate, and the additional imbalance requirement that had to be met by internal resources in the 5-minute market, directly impacted imbalance prices on July 2, as seen in Figure 2.12. An indirect impact of the high decline rate can also be seen on July 3. High forecast load for July 3 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



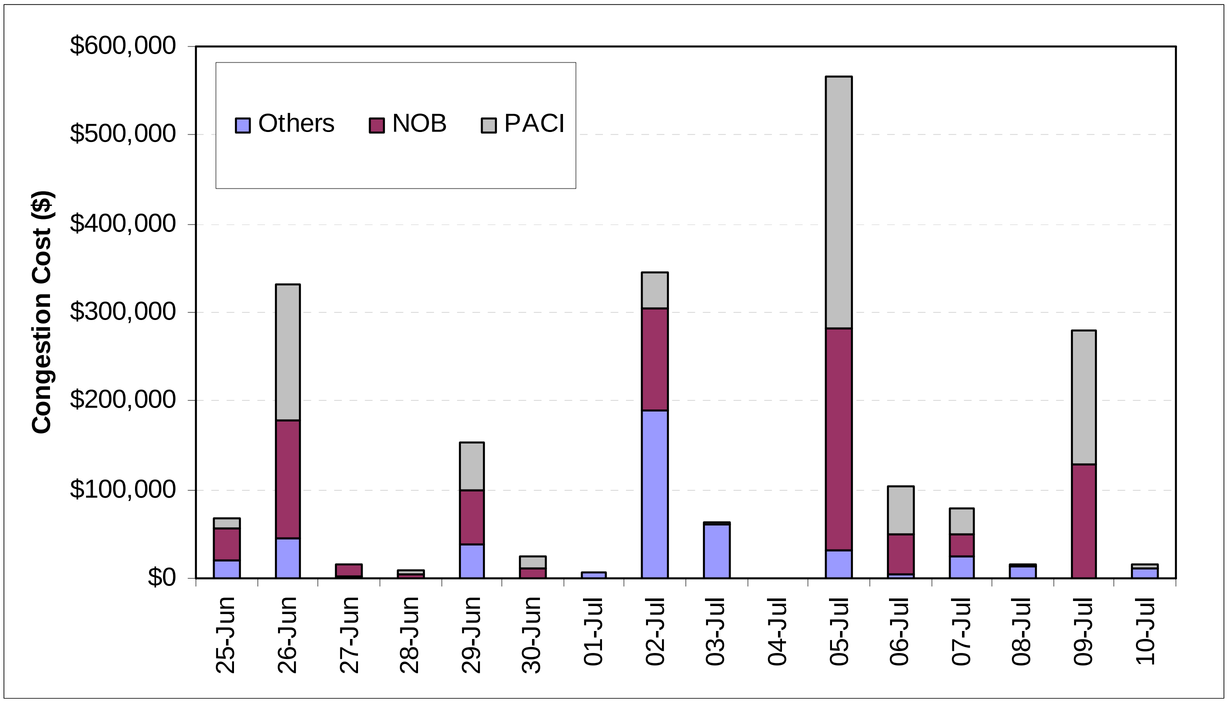
Day-ahead spot bilateral energy prices during system peak load hours can reflect scarcity and risk premiums (i.e., an aversion to not being able to cover contract positions or serve load). If markets function effectively, prices of upward Ancillary Services (Regulation-Up, Spinning Reserve, and Non-Spinning 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

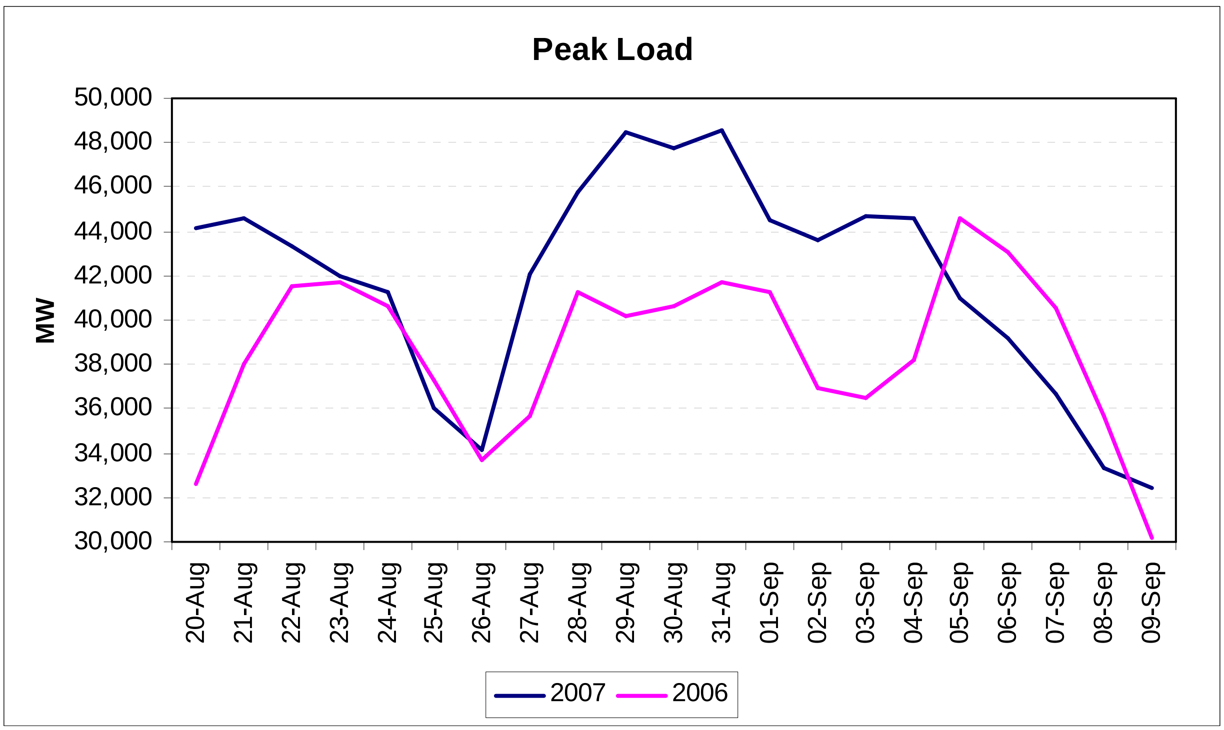
California experienced another heat wave toward the end of the summer, spanning the period August 28 through September 3, which produced the top four peak load days of 2007 on four consecutive days from August 28 through August 31. The annual peak load of 48,535 MW occurred on August 31 in HE 16, which 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

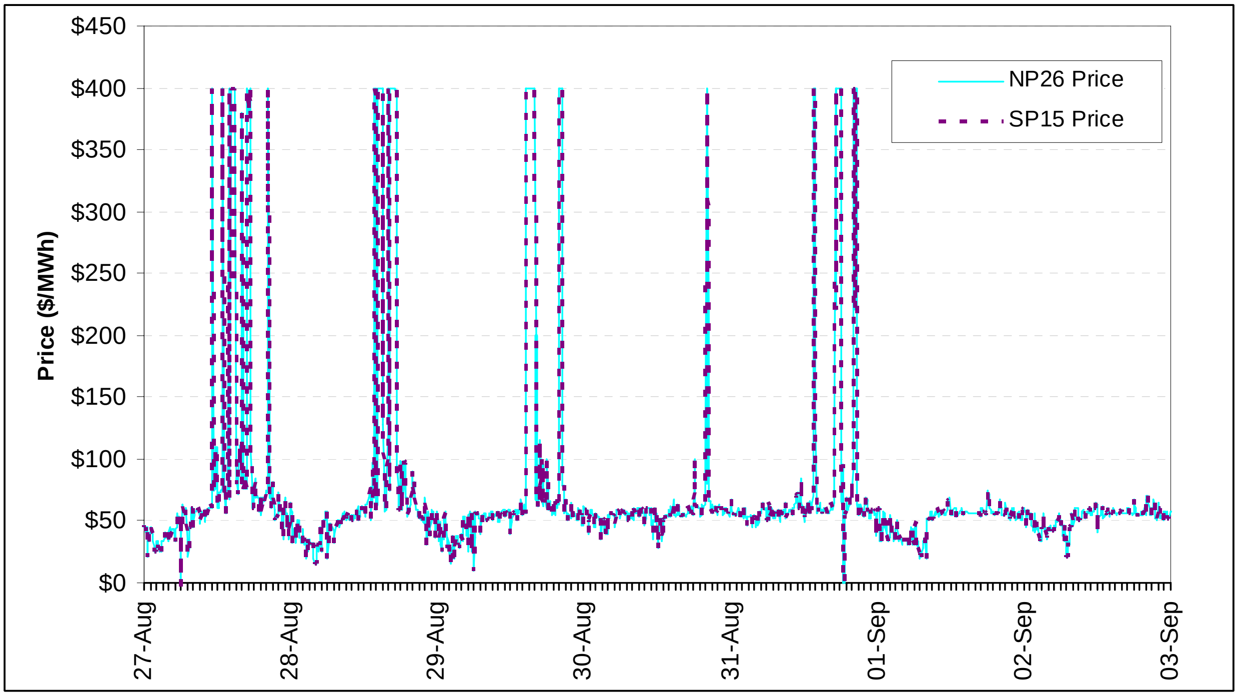


Often, with rapid increases in system load we observe coincident increases in the requirement for imbalance energy and imbalance prices. As seen in Figure 2.18, imbalance 5-minute prices were higher, on average, and more volatile during the first two days of the heat wave period with a decline in the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

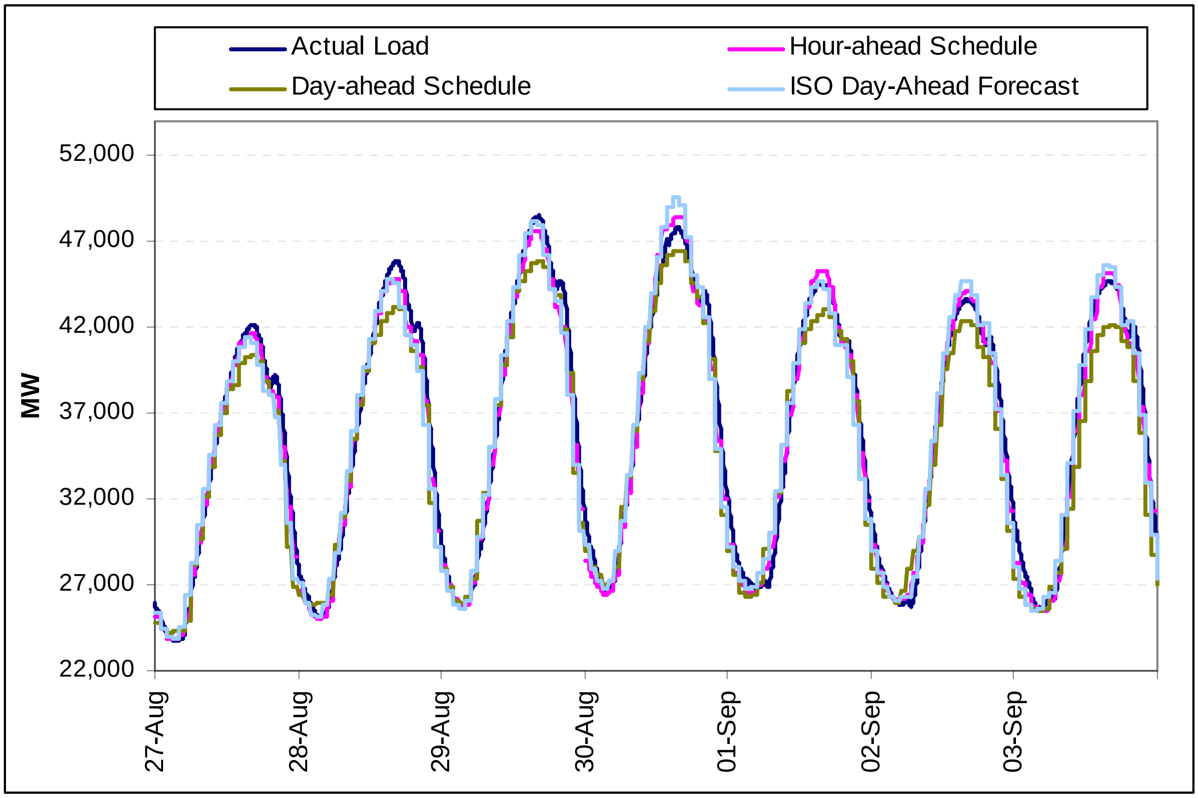
In the first few days of the heat wave, system load was under-forecasted which resulted in forward schedules that were well below actual load. When this occurs, the difference must be met in the imbalance market through the pre-dispatch of import bids and 5-minute dispatch of internal resources. In this 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

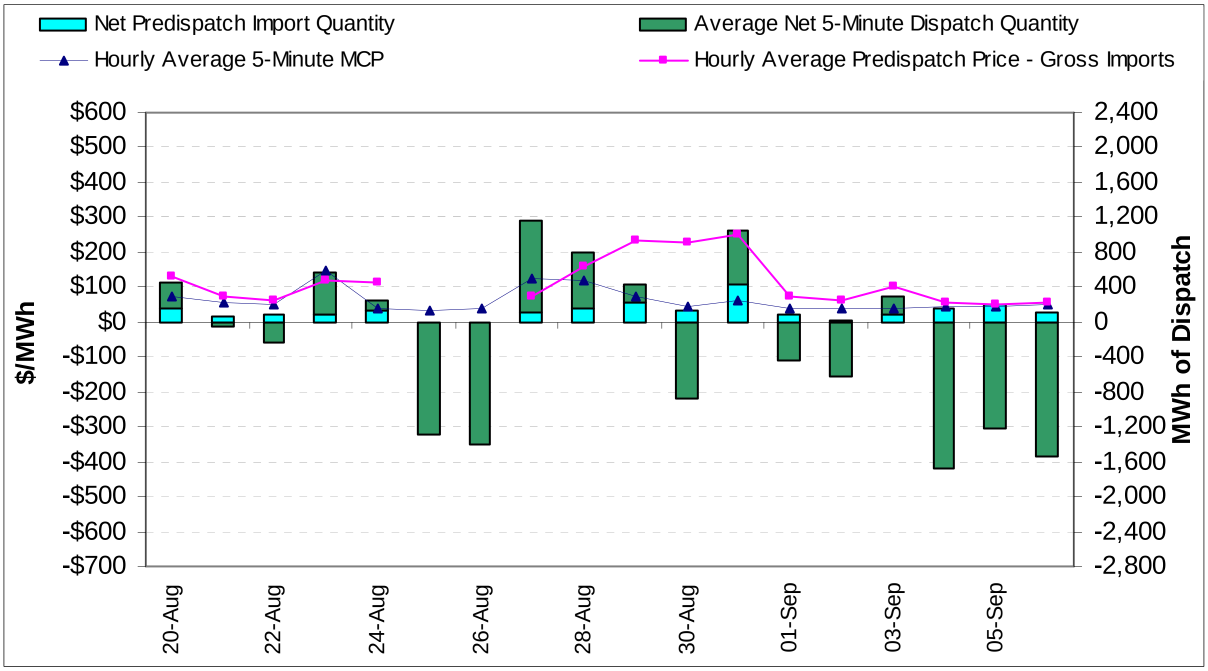
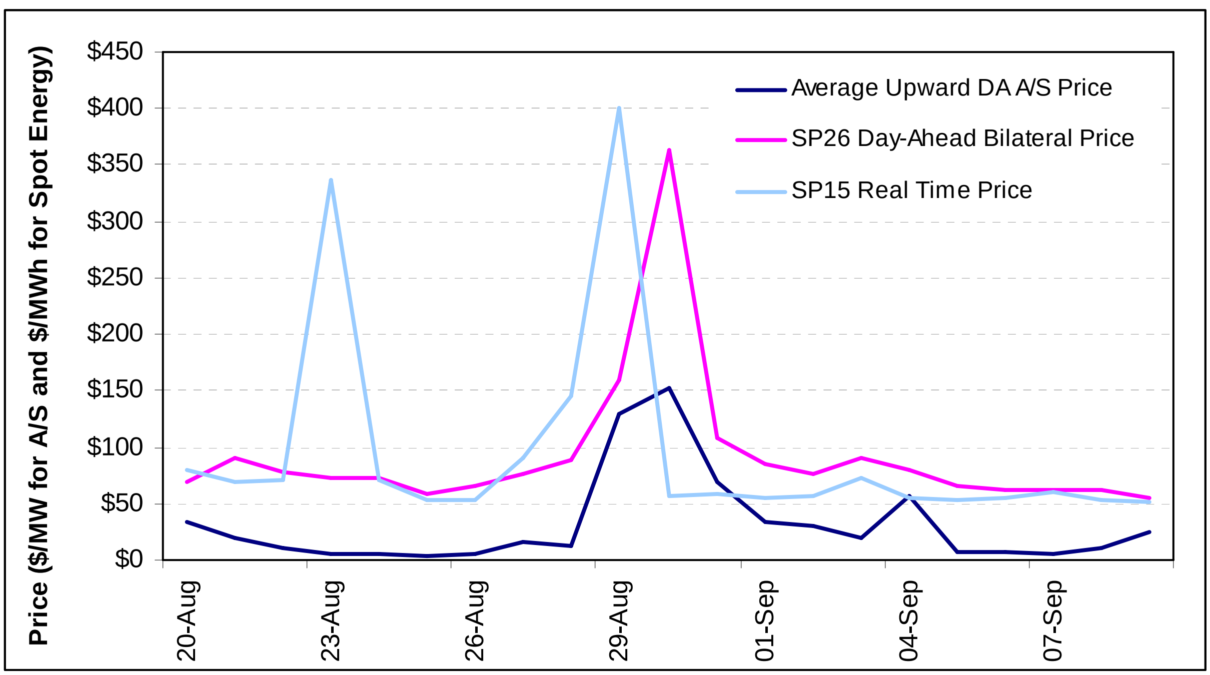


Figure 2.21 Prices for Day-Ahead Upward Ancillary Service, 5-Minute Imbalance Energy, and Spot Bilateral Energy for Aug 20 – Sep 10, 2007



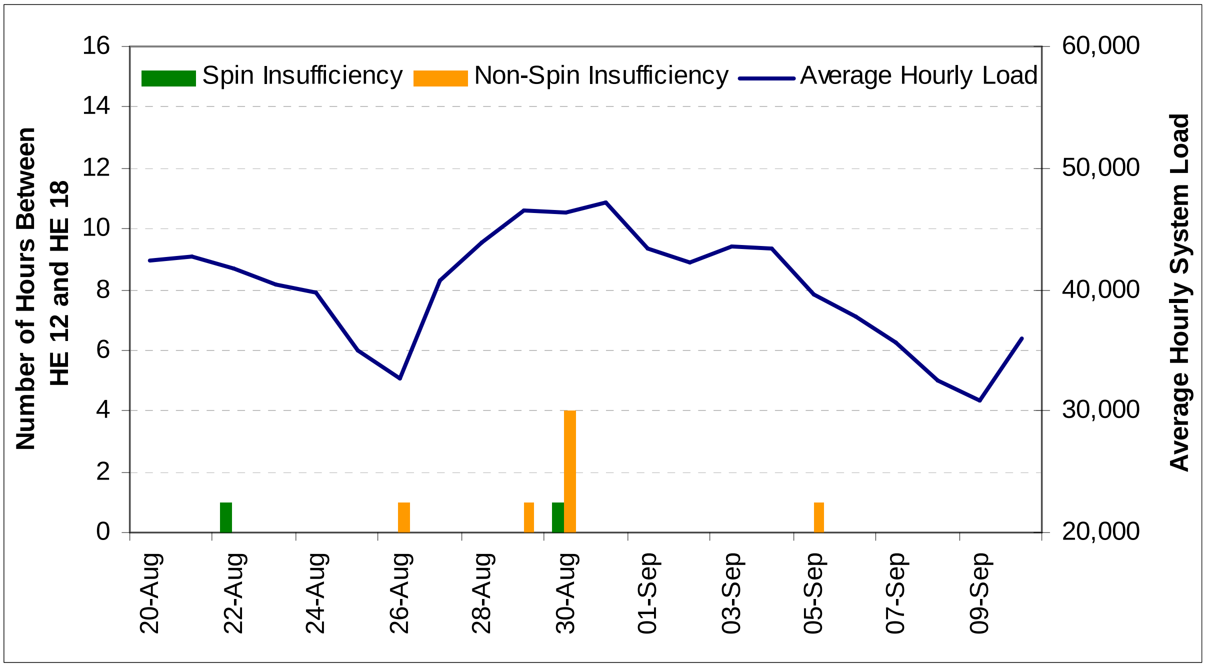
As discussed in the July heat wave section, prices of upward Ancillary Services purchased in the Day Ahead Market will reflect the opportunity cost of offering the generation capacity as reserve as opposed to selling that capacity as energy in the spot bilateral market or the imbalance market. Figure 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.[9] 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.

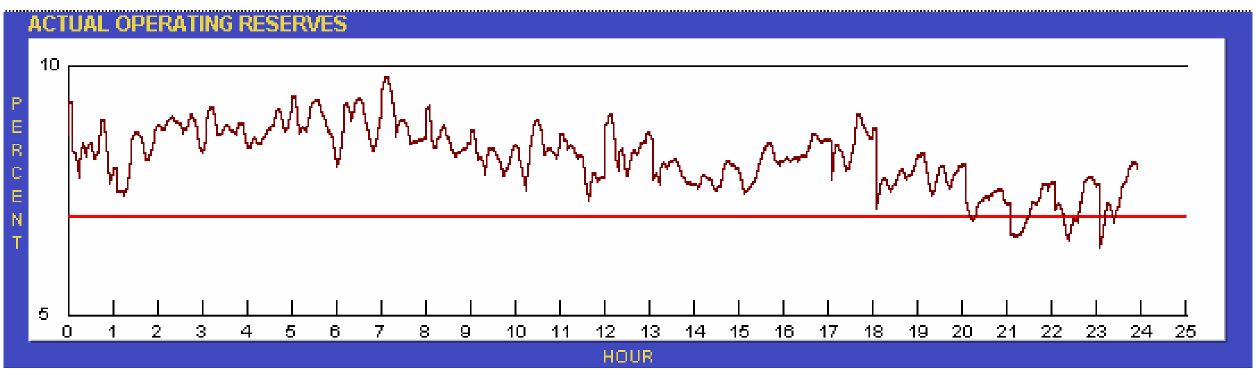
[9] The high prices observed on August 23 were the result of above average use of load bias in the imbalance market. On this day, up to 700 MW of load bias was used in the 5-minute imbalance market to adjust the 5-minute dispatch for unanticipated or unaccounted for factors that cause a discrepancy between 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.

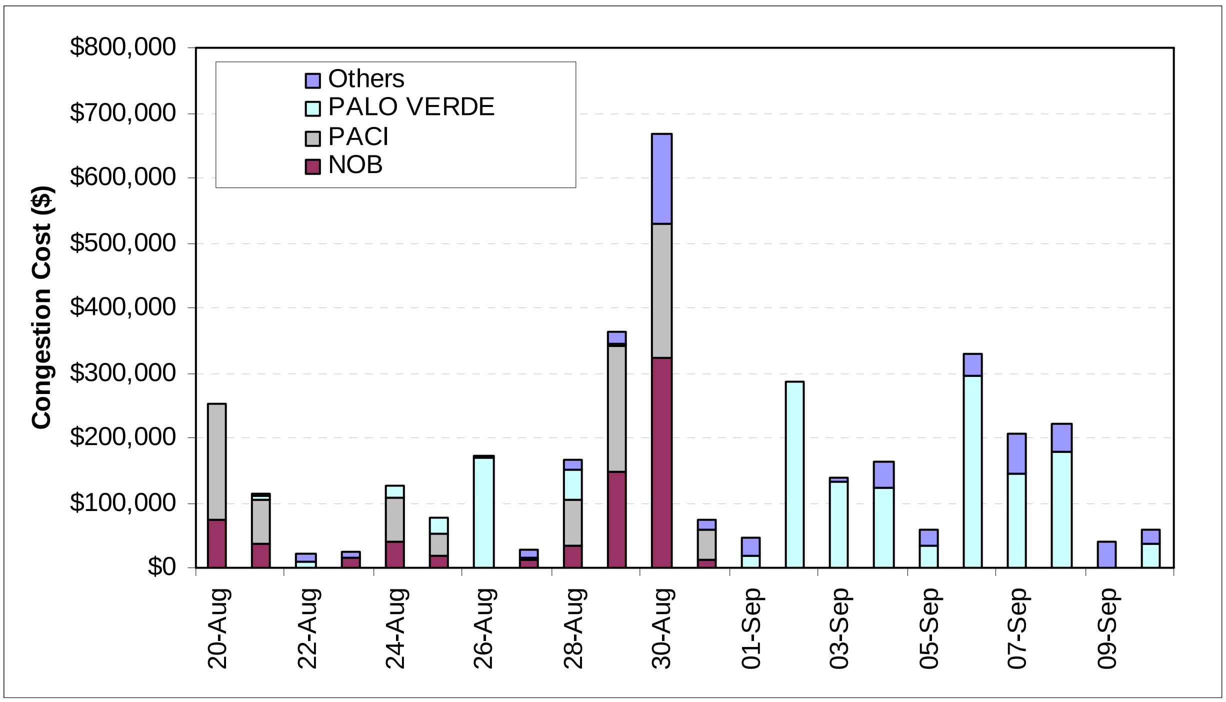
Figure 2.23 Actual Operating Reserve Levels for August 30, 2007



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.[10] As indicated in Figure 2.24, high loads throughout California and the Southwest resulted in congestion on PACI, NOB, and Palo Verde.

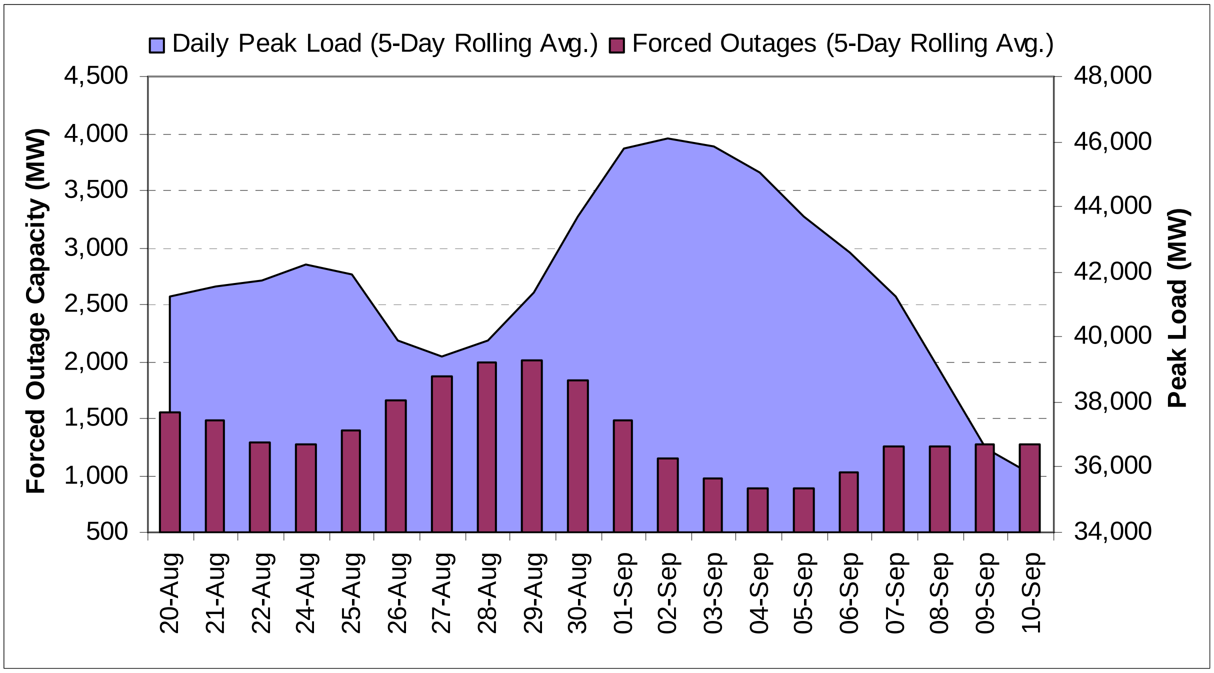
Figure 2.24 Congestion Costs on COI, PACI, Palo Verde, and the Other Branch Groups for August 20 – September 10, 2007



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.

[10] 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:

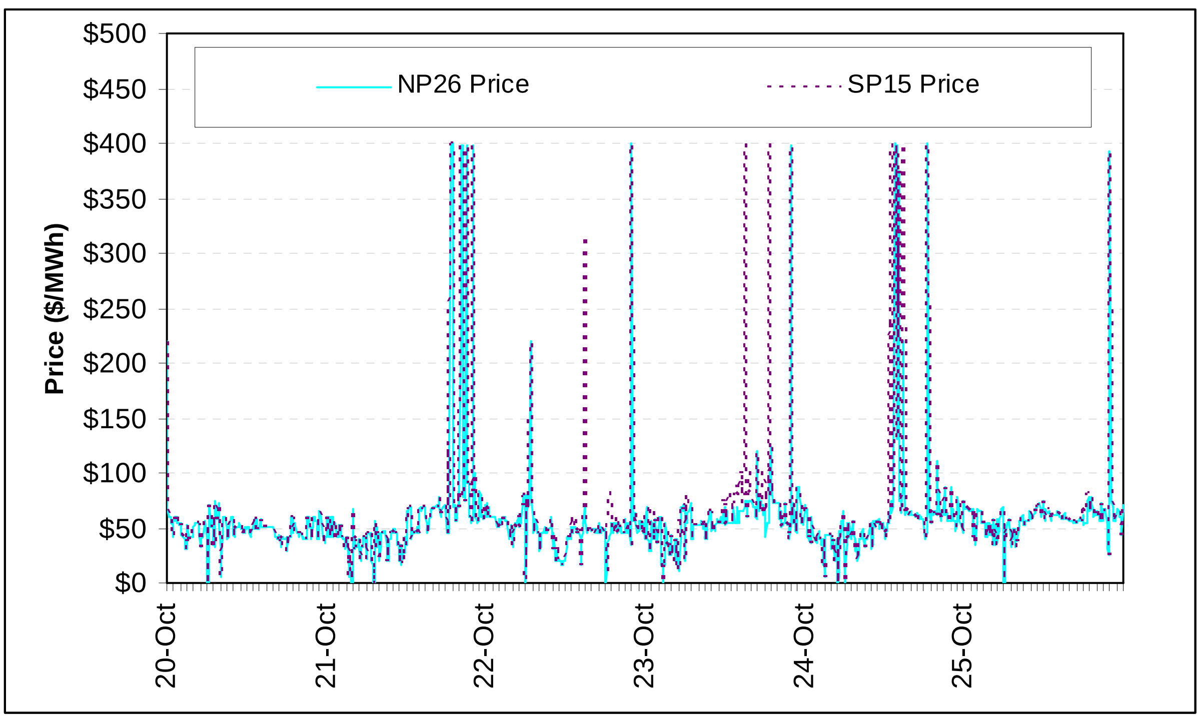
- Imbalance market prices were relatively moderate, with intermittent price spikes and market separation,
- Out-of-sequence dispatches were made frequently throughout this period to manage local reliability issues stemming from the wildfires. These dispatches occur outside the price-setting mechanism 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

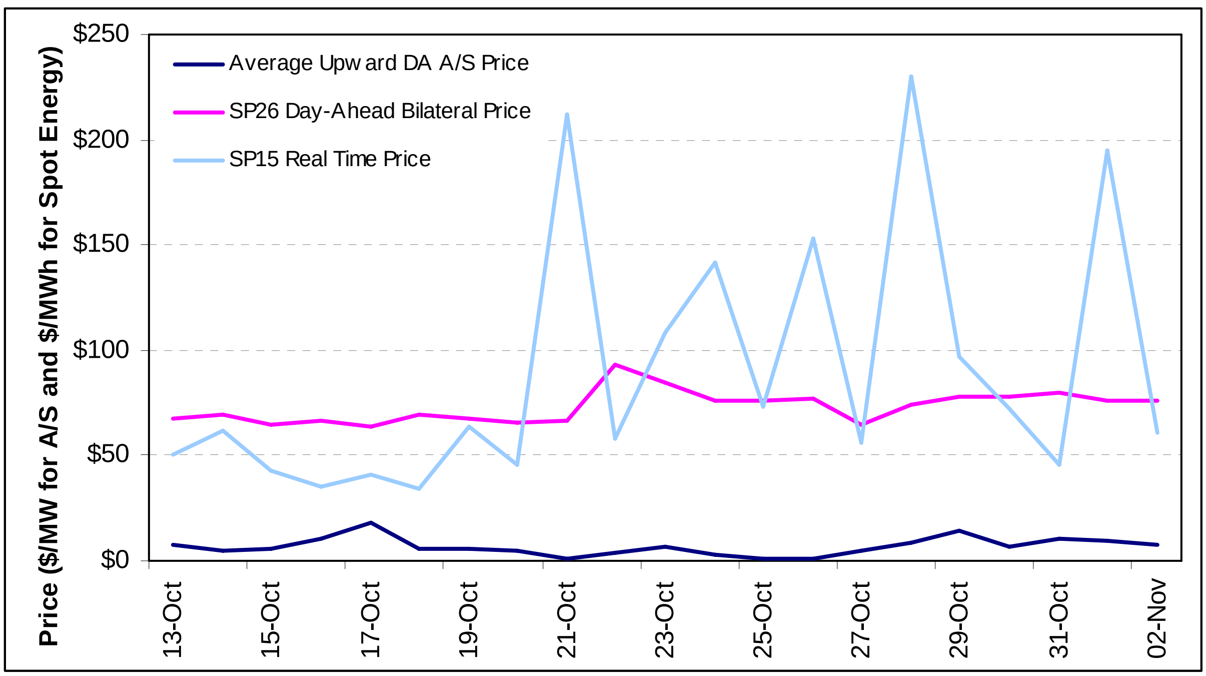


Figure 2.28 and Figure 2.29 indicate an increase in the number of resources committed on by the CAISO during the wildfire period. At the peak, seventeen units with over 5,000 MW of generation capacity were committed to mitigate grid reliability issues brought on by the wildfires. As expected, the primary 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

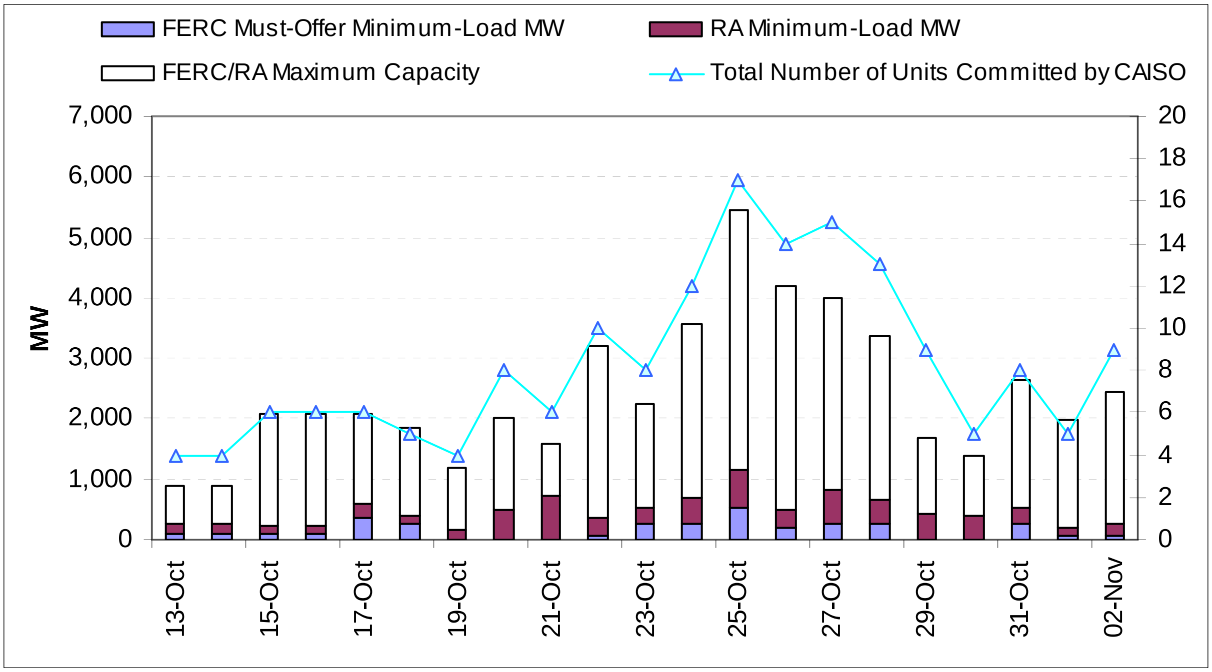


Figure 2.29 Units Committed by Commitment Type for Oct 13 – Nov 2, 2007

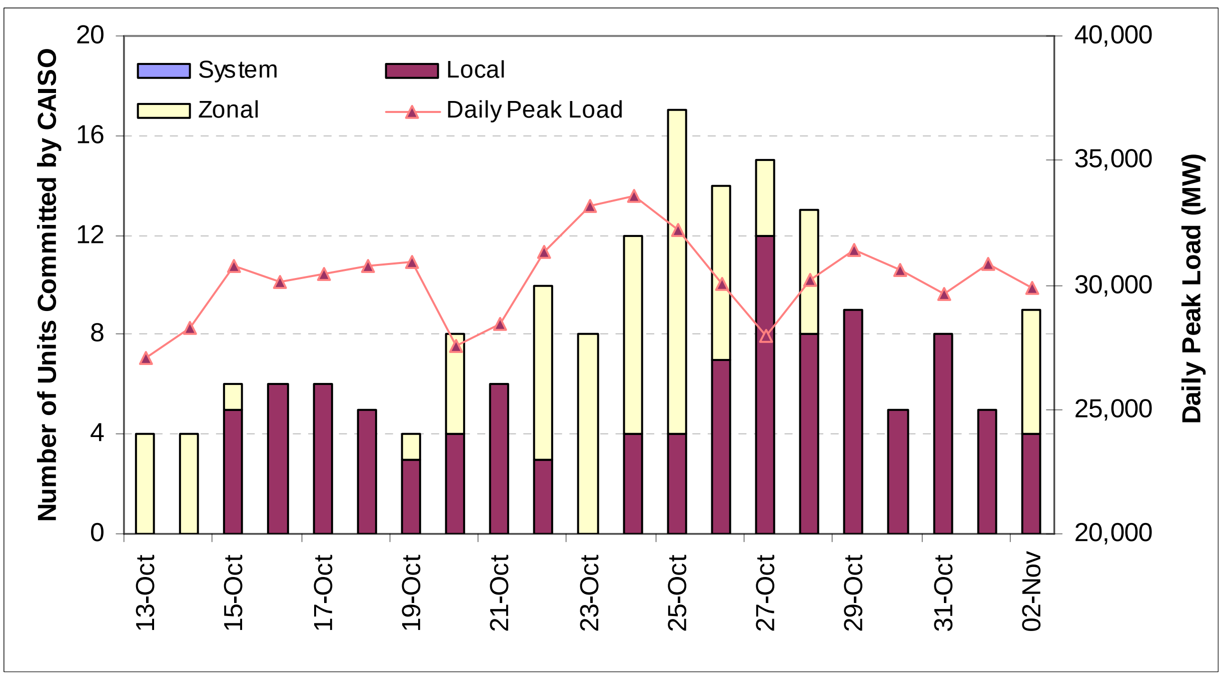
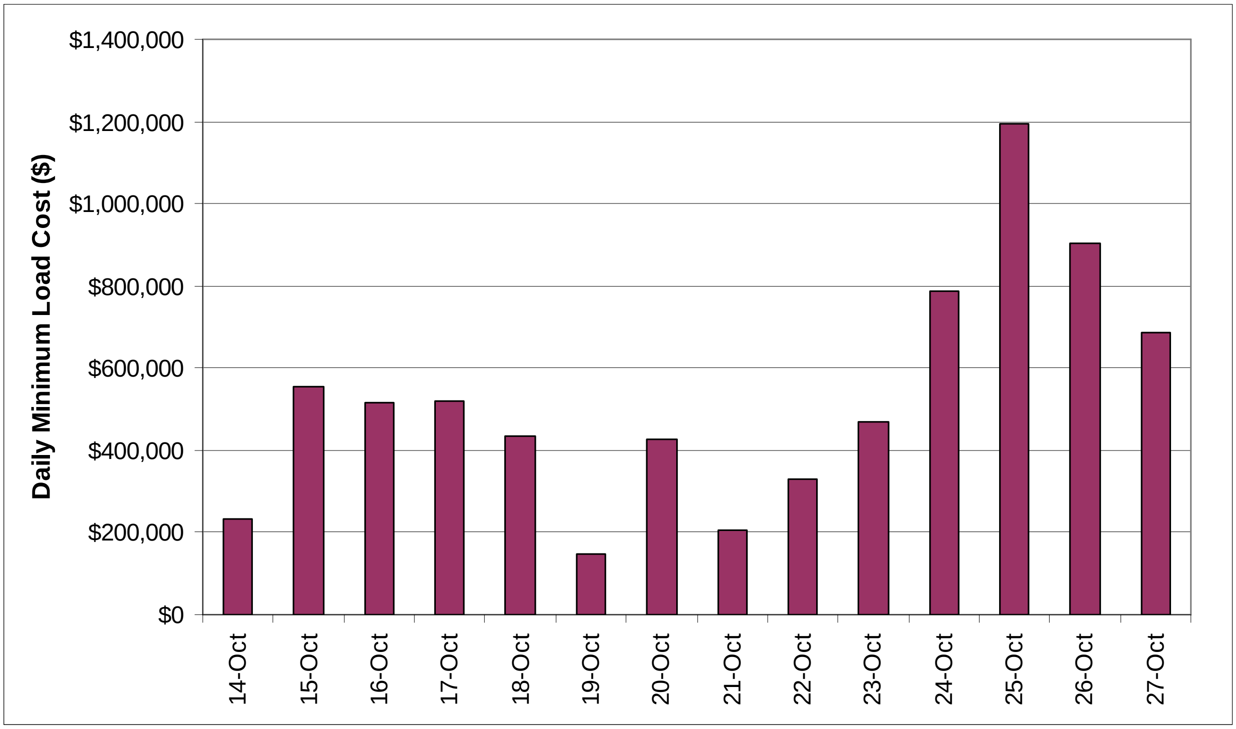
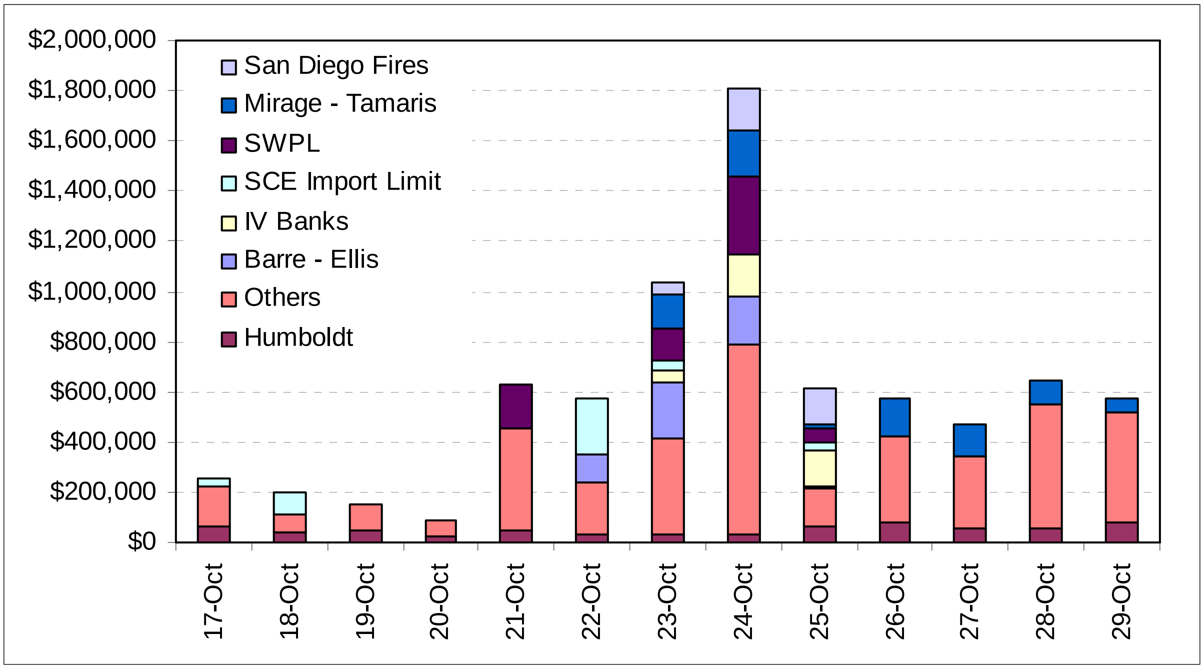


Figure 2.30 Daily Minimum Load Cost (MLCC) Associated with Day Ahead Unit Commitment for Zonal and Local Reliability Issues



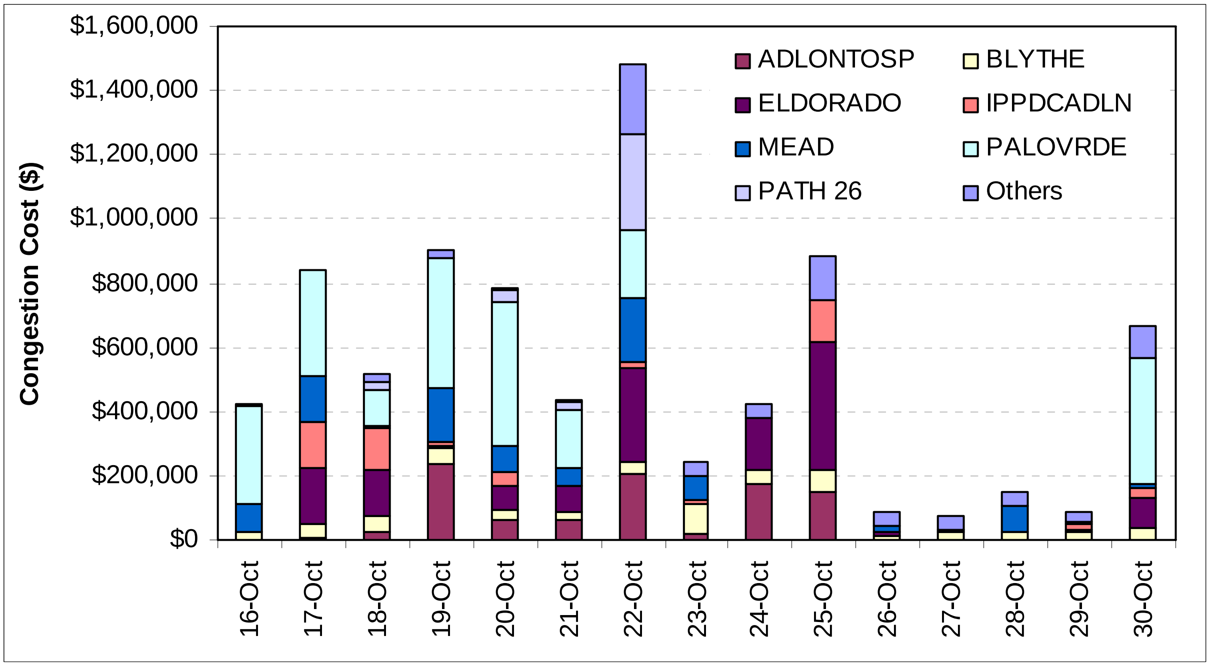
When some transmission lines were taken out of service by the wildfires, power flow shifted and other transmission lines became at risk for overload. To mitigate further threats to grid reliability resulting from additional lines being forced out of service, the CAISO relied heavily on OOS dispatches, 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.

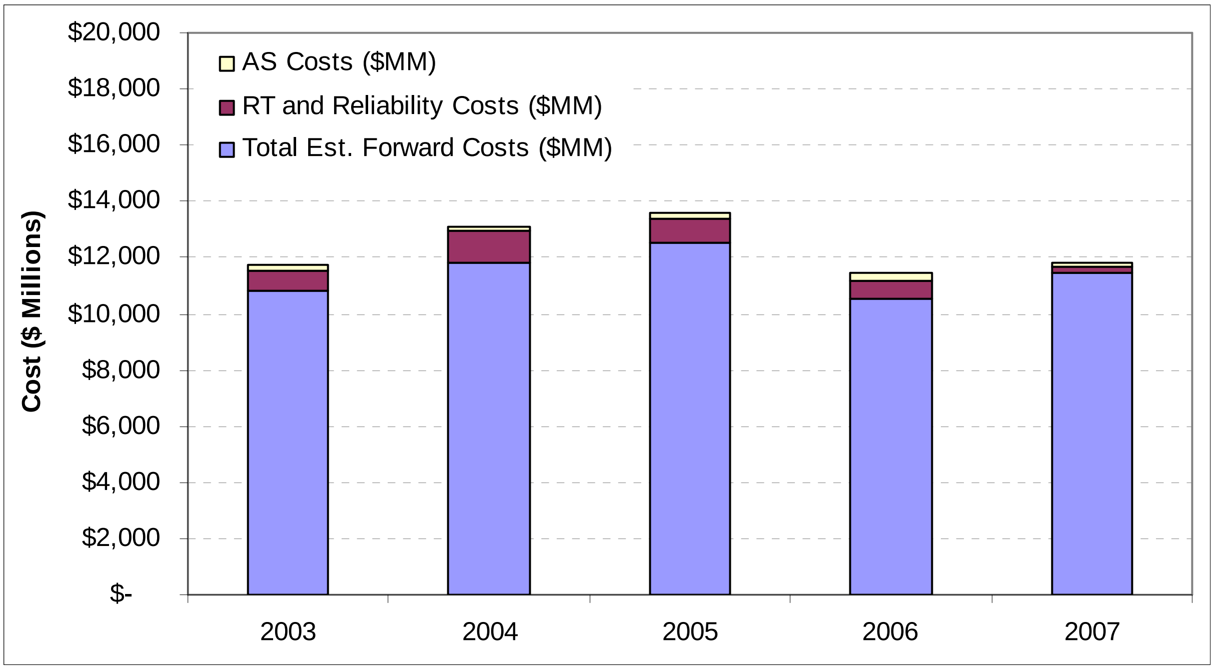
2006 and 2007 figures do not include RA capacity payments, which are not visible to the CAISO.

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.

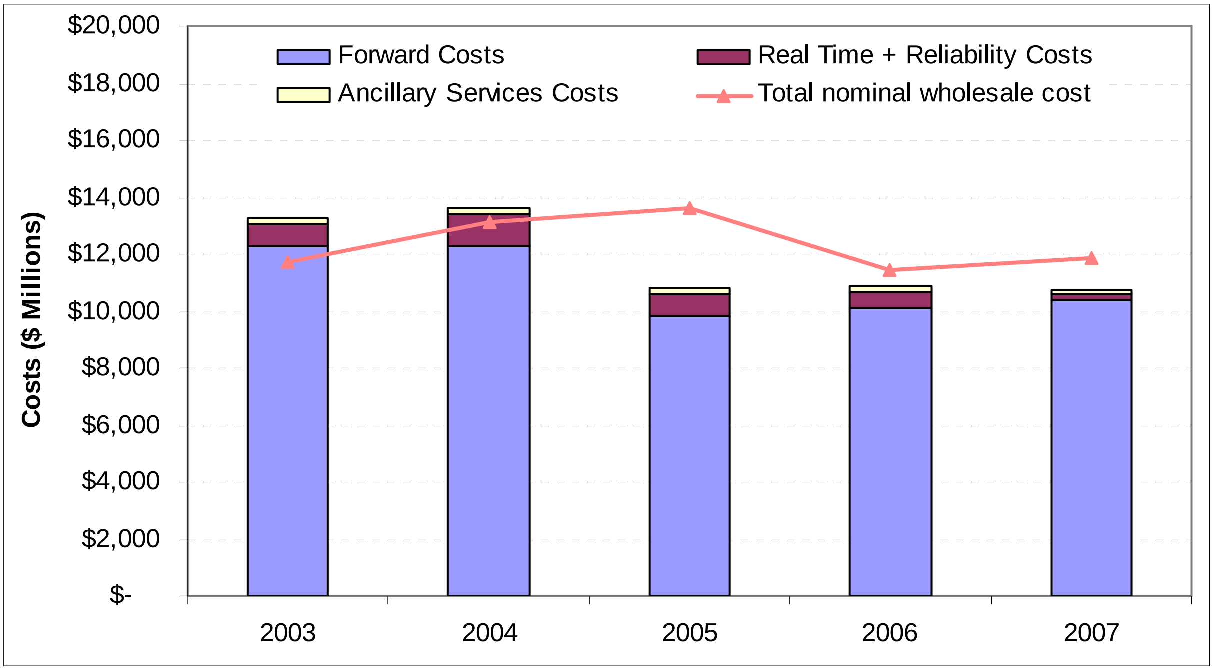
Figure 2.33 shows total wholesale costs from 2003 to 2007. With the addition of new generation and transmission infrastructure, and significant amount of forward energy procurement, costs have been stable for the past five years. Importantly, the trend in real-time balancing and reliability costs has 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[11]



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.

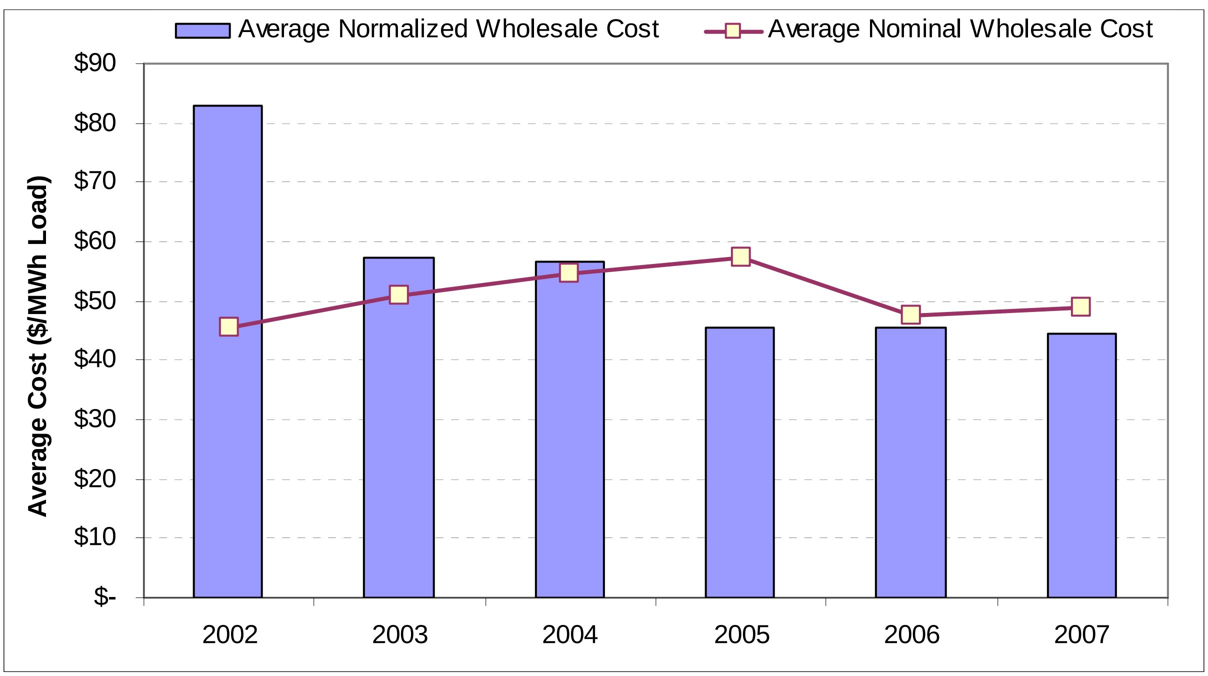
[11] July 2004 gas price ($5.70/mmBtu) is used as the basis for normalization. Energy costs were normalized separately for each month by dividing the monthly nominal energy costs by the ratio of the applicable monthly gas price and the July 2004 indexed gas price and then adding the non-energy cost components. 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[12]

	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



[12] 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.[13] 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 RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

[13] 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).

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

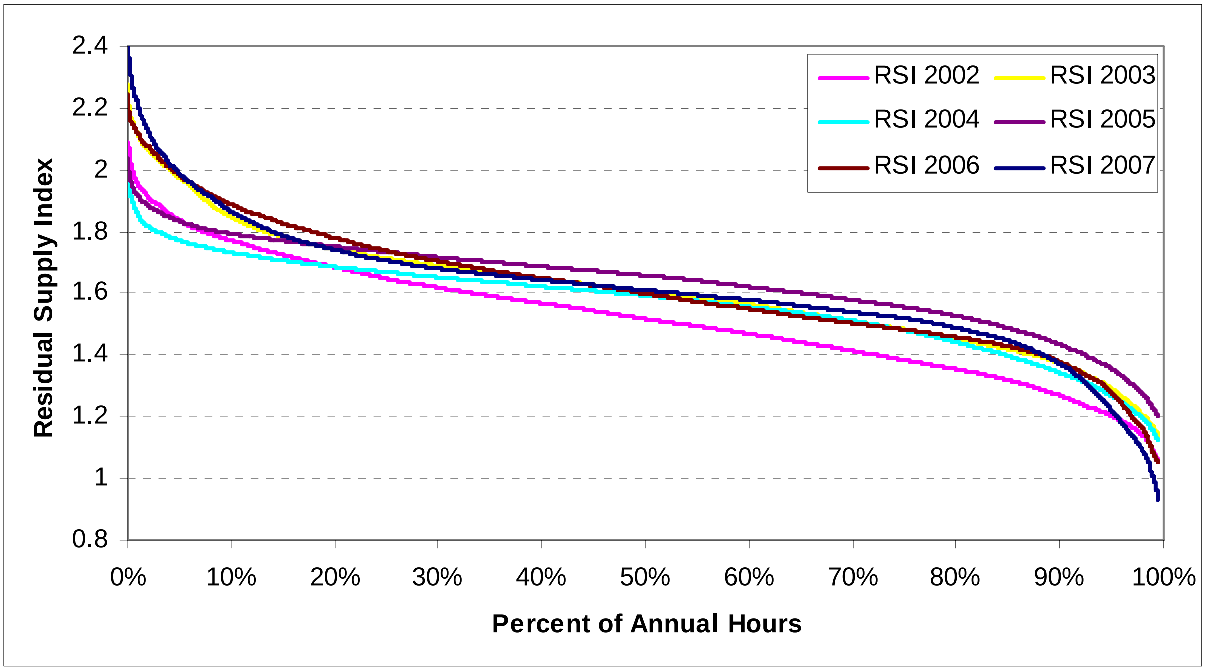


Figure 2.36 shows estimated hourly RSI values from highest to lowest values for years 2002-2007. In 2006, there were roughly 125 hours, or 1.7 percent of hours, when the RSI level dropped below 1.1.[14] This frequency was marginally higher in 2007 than in the prior four years; however, the statistic 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[15]

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

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

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

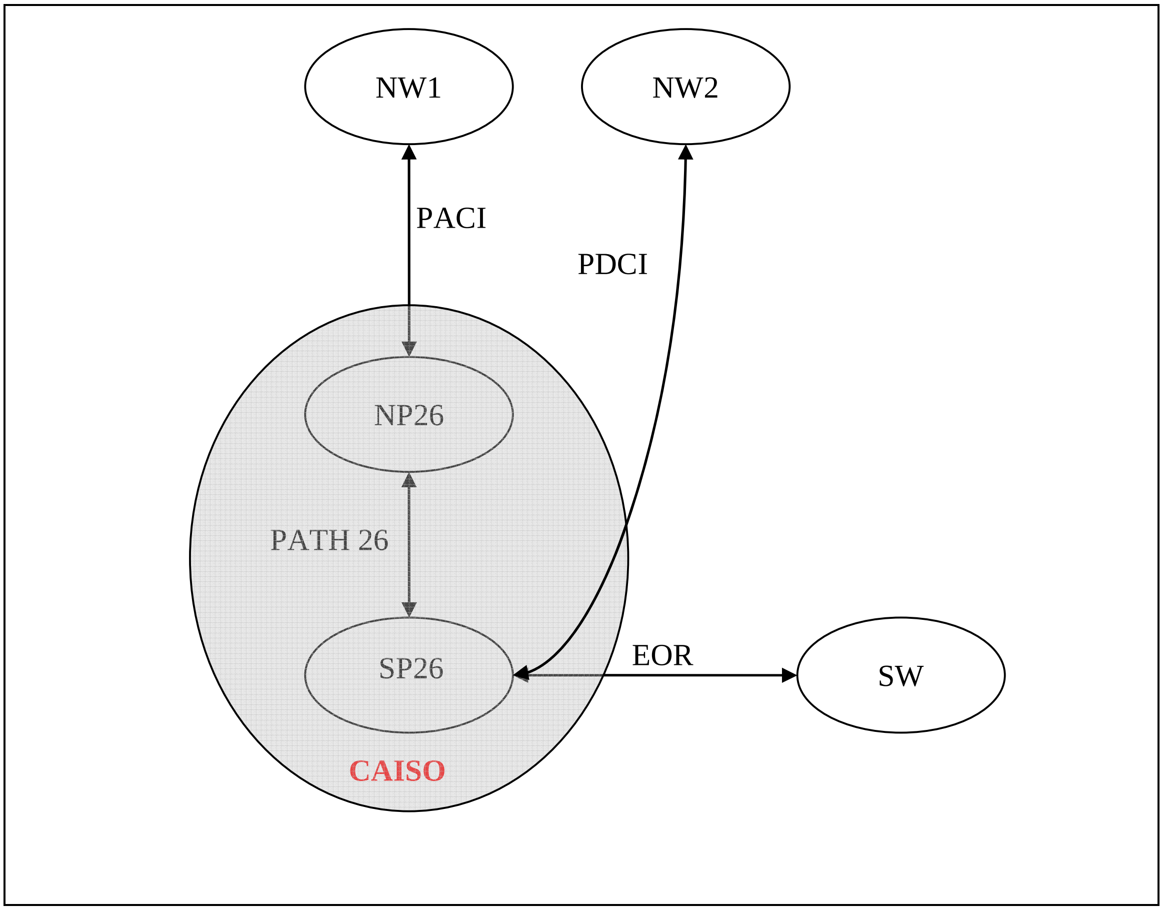
Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from the Department 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.

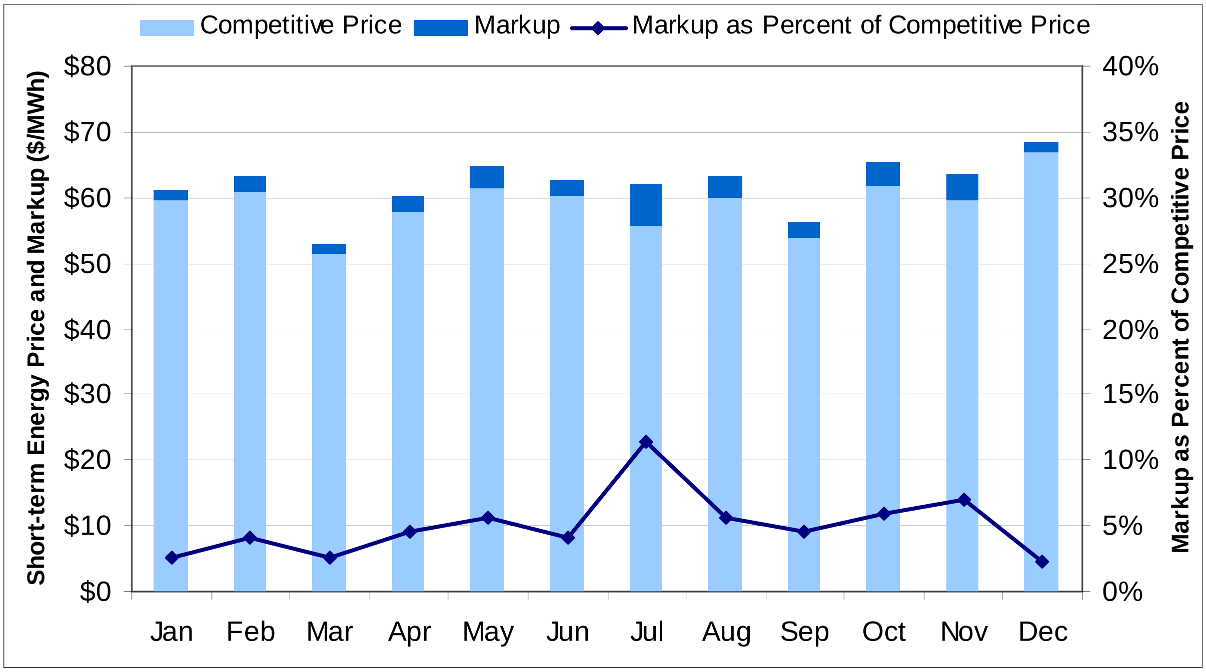
Figure 2.37 Simplified Network Topology Used in Competitive Price Simulation



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.

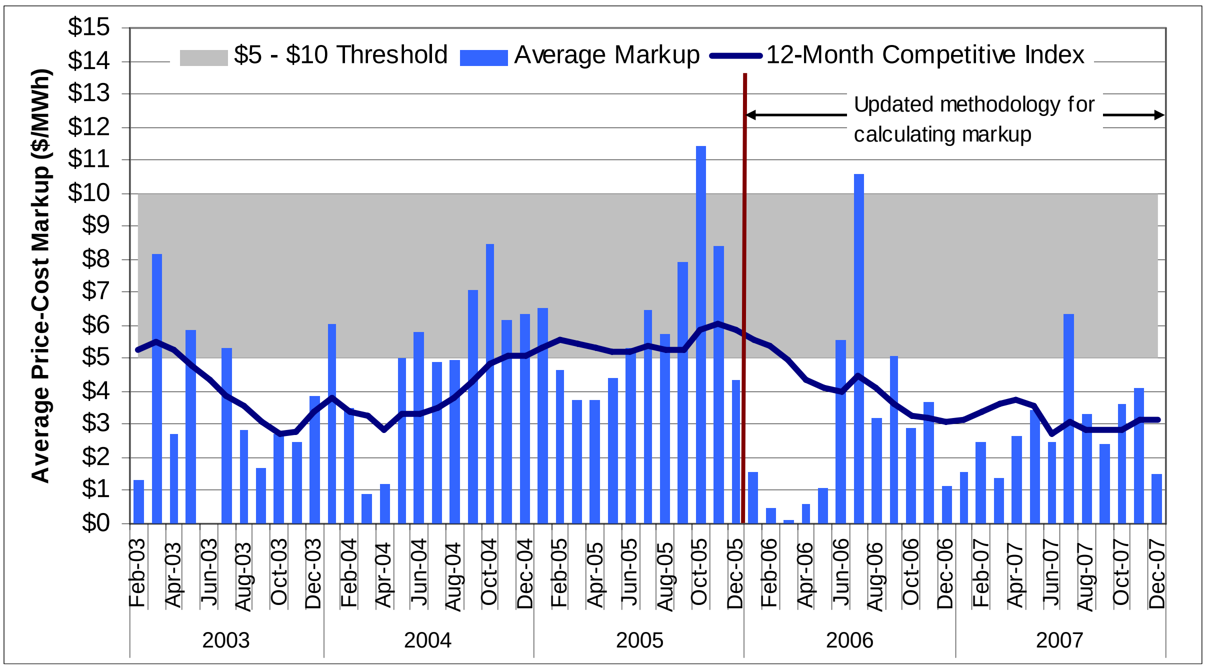
Figure 2.38 2007 Short-term Forward Market Index



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

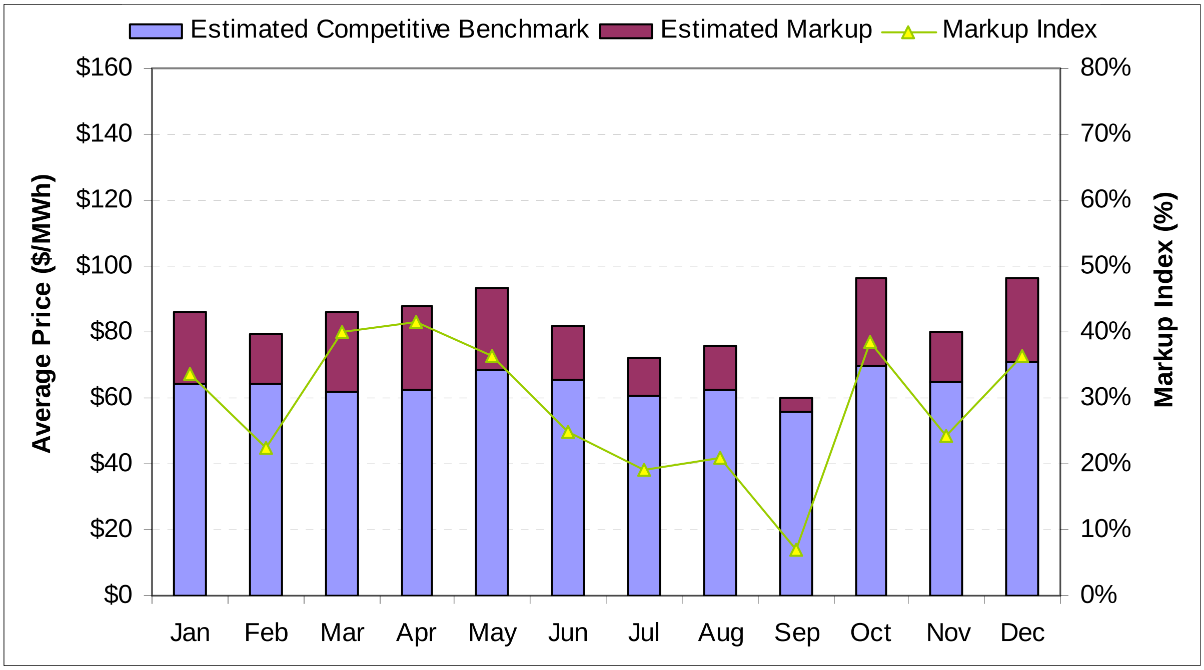
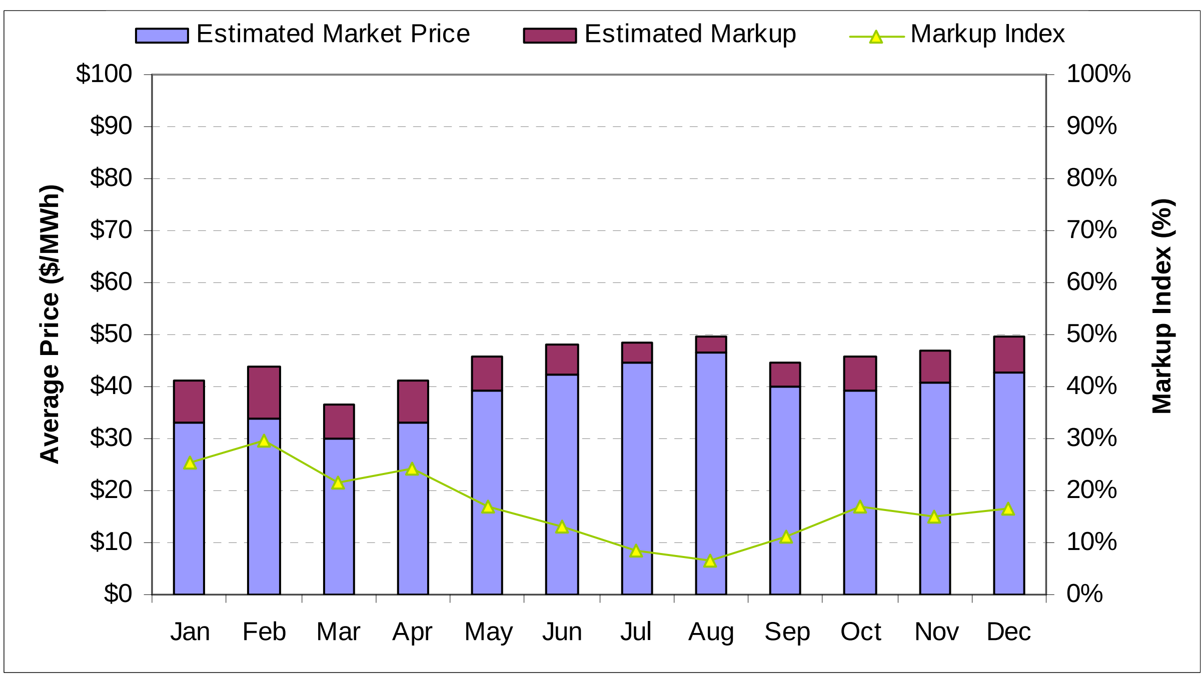


Figure 2.41 Average Hourly Real-time Decremental Energy Mark-up below Competitive Baseline Price by Month for 2007



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,[16] 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.

[16]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[17]

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[18]

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 revenues earned by the hypothetical combined cycle described in Table 2.7 is based on the

[17] 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 16, which also can be found in this presentation posted to the CAISO website: http://www.caiso.com/1c75/1c75c8ff34640ex.html.

[18] See Footnote 17

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.[19] 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[20] 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.

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

[19] 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.

[20] 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.

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.[21] 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.

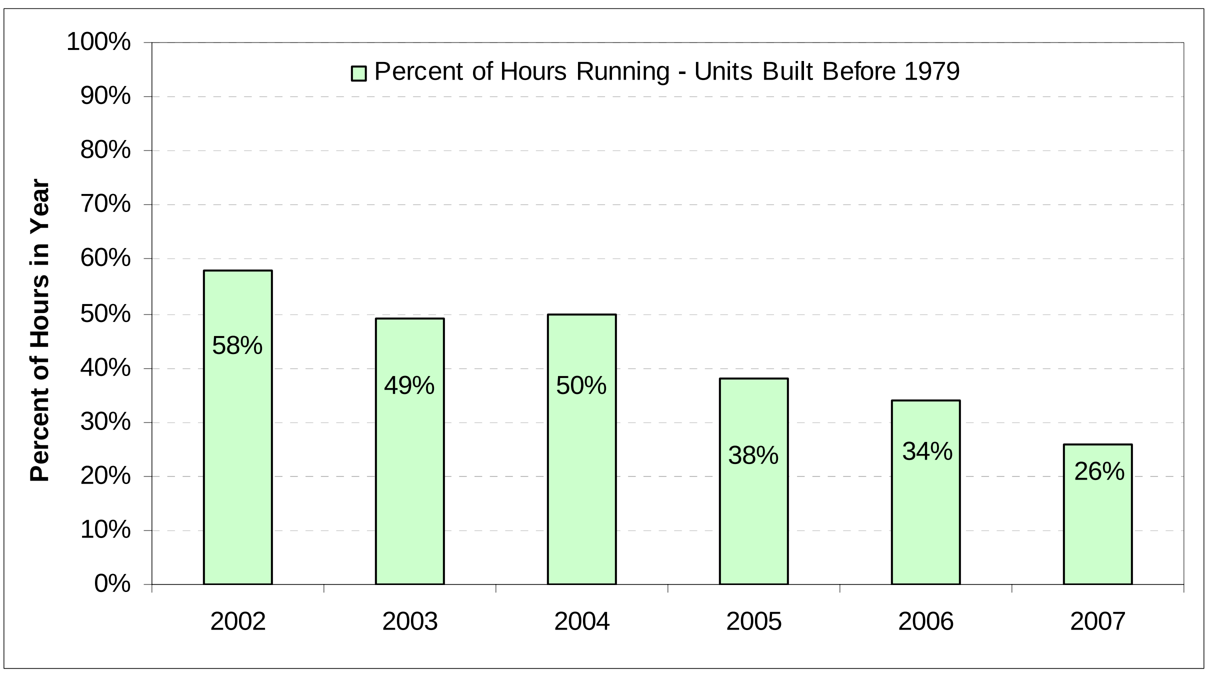
[21] It is important to note that this table only shows part of the supply picture in SP15. Numerous transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone; however, despite these improvements, meeting summer peak load demands in SP15 remains more challenging 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,[22] 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.

[22] 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

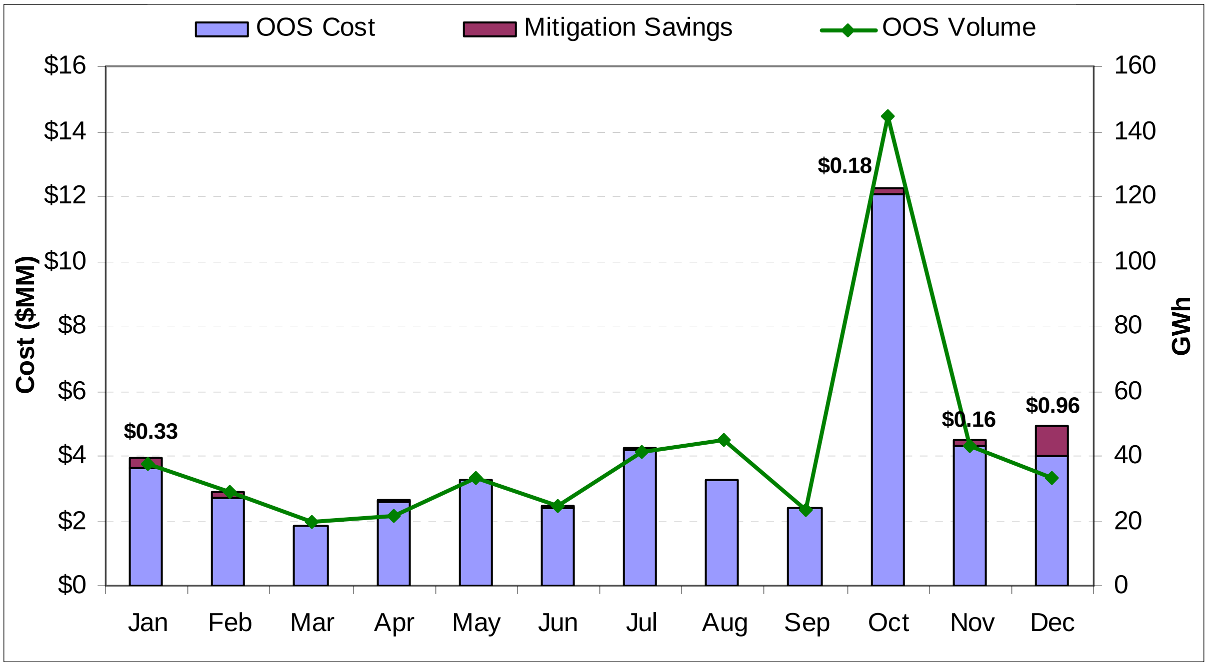
In addition to the conduct and impact tests in place to protect against the exercise of system market power, the CAISO also employs local market power mitigation (LMPM) to specific dispatches in the imbalance market that are made to support local reliability and where the energy bid price is deemed to 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.[23] 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.

[23] 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.