2. General Market Conditions

2.1 Demand

Loads in 2005 were, by most measures, only slightly higher than those in 2004 on an overall basis. The relatively modest increase in 2005 loads is attributable to unusual weather patterns and the absence of a system-wide heat wave. While the California economy grew in 2005, weather was relatively mild throughout the year, with the notable exception of a prolonged heat wave between July 11 and August 7. In contrast, 2004 weather was fairly severe across several seasons. That year saw a very warm spring, with temperatures reaching over the 100-degree mark in inland areas, which resulted in a substantial decrease in daily peak loads between the spring months in 2004 and those in 2005. In addition, 2004 had an unusually late summer peak in September, which reached an all-time record high, also contributing to a decrease between peaks in September 2004 and September 2005.

While not the hottest on record, the July-August heat wave lasted an exceptionally long time without respite and extended to most areas across California. It resulted in four straight weeks of daily peak loads above 40,000 MW, with the exception of two Sundays, which were just shy of that level. The CAISO's 2005 peak load of 45,431 MW on July 20 was slightly lower than the 2004 peak of 45,597 MW on an absolute basis, but was effectively slightly higher than the 2004 peak when adjusted for the departure of approximately 200 MW of Western Area Power Administration (WAPA) load from the NP26 portion of the CAISO service area on January 1, 2005. Table 2.1 shows two sets of annual load statistics for the CAISO Control Area, statistics based on actual loads, and statistics based on adjusted loads that reflect changes to the CAISO Control Area and adjustments for the 2004 leap year.

Table 2.1 CAISO Annual Load Statistics for 2001 – 2005*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2001 Actual	26,004		227,795	41,155	
2002 Actual	26,572	2.2%	232,771	42,352	2.9%
2003 Actual	26,329	-0.9%	230,642	42,581	0.5%
2004 Actual	27,298	3.7%	239,786	45,597	7.1%
2005 Actual	26,992	-1.1%	236,450	45,431	-0.4%
2001 Adjusted	24,556		215,111	39,516	
2002 Adjusted	25,737	4.8%	225,456	41,890	6.0%
2003 Adjusted	26,027	1.1%	227,997	42,058	0.4%
2004 Adjusted	26,933	3.5%	235,933	45,079	7.2%
2005 Adjusted	26,947	0.1%	236,056	45,431	0.8%

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

Table 2.2 compares four metrics of load changes to the same month's levels in the previous year, adjusted for changes in the CAISO footprint. Figure 2.1 compares CAISO loads for each hour in July 2004 and July 2005

Table 2.2 Rates of Change in Load: Same Months in 2005 vs. 2004[1]

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-05	1.5%	2.6%	1.1%	5.0%
February-05	1.5%	1.8%	2.2%	0.3%
March-05	-2.3%	-2.2%	-0.6%	-5.2%
April-05	-2.2%	-3.6%	-0.3%	-22.9%
May-05	-2.5%	-2.9%	-1.1%	-9.3%
June-05	-2.5%	-3.8%	0.4%	2.7%
July-05	5.6%	6.2%	5.1%	3.9%
August-05	4.3%	5.1%	4.1%	-1.5%
September-05	-5.7%	-9.0%	-2.1%	-11.9%
October-05	2.7%	2.9%	2.4%	3.9%
November-05	1.7%	1.8%	1.5%	-2.0%
December-05	-0.9%	0.0%	-2.5%	0.4%

Figure 2.1 California ISO System-wide Actual Loads: July 2005 vs. July 2004

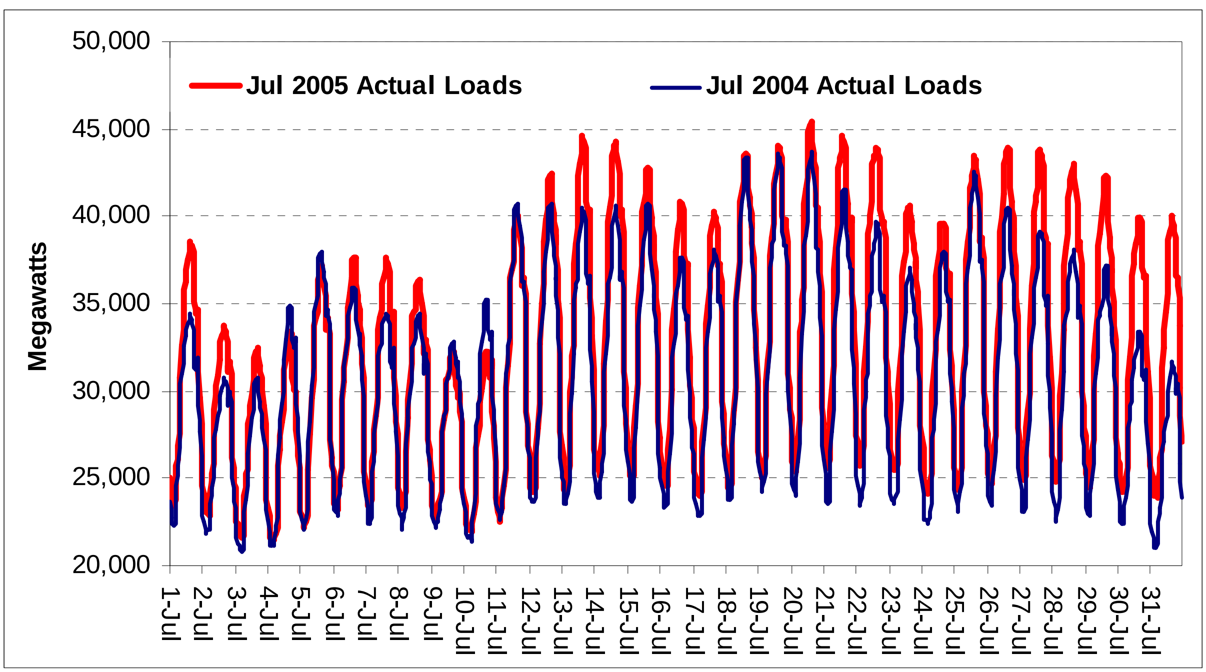


Figure 2.2 depicts load duration curves for each of the last four years, adjusted for CAISO footprint changes. Because load was generally lower in 2005 than in 2004 due to milder weather, the 2005 curve is very similar to the 2004 curve. However, the July-August 2005 heat

[1] Adjusted for change in NP26 load footprint.

wave resulted in the high portion of the 2005 curve (on the left side of the chart) being slightly above the 2004 curve. Load in 2005 was generally above that of 2003 and 2002, indicating a general trend of load growth. For example, when adjusting for the changes in the CAISO footprint, only 0.3 percent of hours between January and November exceeded 40,000 MW in 2002, while 2.5 percent did so in 2005.

Figure 2.2 California ISO System-wide Actual Load Duration Curves: 2002-2005[2]

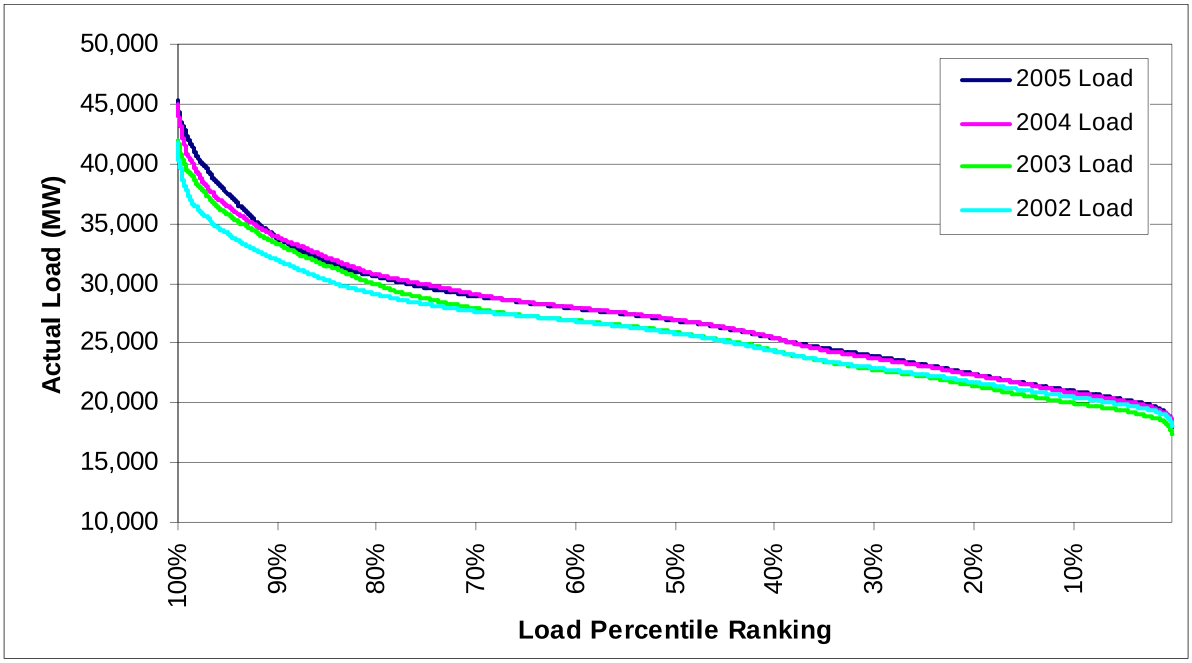


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO as a whole.

Table 2.3 CAISO Annual Load Change: 2005 vs. 2004

Zone	Avg. Hourly Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP26	0.9%	0.4%	2.3%	2.5%
SP15	-0.3%	-0.3%	-0.2%	2.8%
ISO Control Area	0.2%	0.0%	0.9%	0.7%

While NP26 load increased disproportionately in 2005, SP15 remains a greater concern going forward, as load growth in the greater Los Angeles area continues to outpace the development of transmission and generation infrastructure.

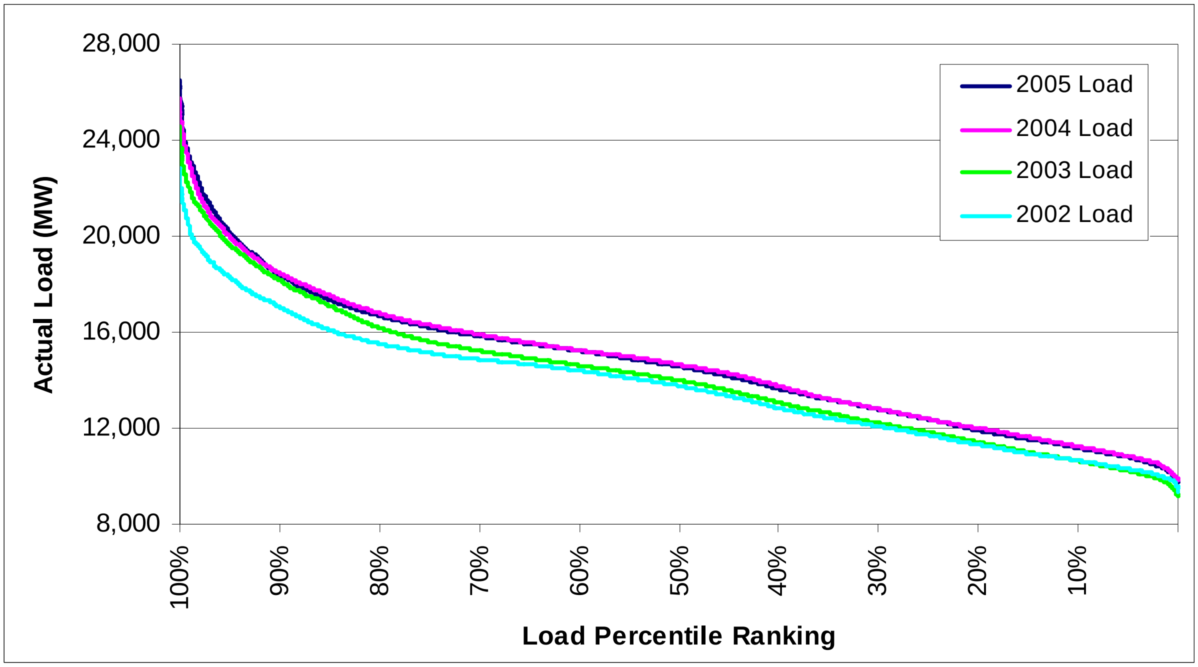
[2] All years are shown from January through November, as the CAISO NP26 load footprint changed in December 2005, and adjustment of prior years for this change was not possible. Years prior to 2005 are adjusted to account for previous footprint changes (exit of WAPA on 1/1/05, exit of SMUD on 6/19/02) and to compare similar days of the week (i.e., so that each year has the same number of Sundays, etc.)

The SP15 peak of 26,459 MW, set on July 21, was 716 MW above the previous regional peak, and SP15 load came within 20 MW of that peak again on July 22. This indicates a year-to-year increase in regional peak load of approximately 2.7 percent, continuing to reflect the population growth in inland areas such as San Bernardino and Palm Springs. Load statistics for SP15 are provided in Table 2.4 and Figure 2.3. The aforementioned extreme variations in weather patterns between 2004 and 2005 make it difficult to find any consistent trends in these data. However, the peak load increase within SP15 is evident in the load duration curves depicted in Figure 2.3. Note that loads in 0.5 percent of hours in 2002 were above 21,000 MW, while loads in 3.5 percent of hours in 2005 were above 21,000 MW.

Table 2.4 Rates of SP15 Load Change: Same Months in 2005 vs. 2004

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-05	0.2%	1.6%	-0.7%	5.3%
February-05	1.8%	2.1%	2.2%	1.2%
March-05	-2.8%	-2.8%	-1.1%	-10.7%
April-05	-2.6%	-3.8%	-1.0%	-23.6%
May-05	-3.7%	-3.7%	-4.0%	-13.3%
June-05	-2.9%	-3.4%	-2.1%	0.6%
July-05	3.9%	4.4%	2.7%	5.9%
August-05	4.6%	5.8%	3.1%	1.8%
September-05	-6.2%	-9.6%	-2.1%	-9.4%
October-05	3.3%	3.7%	3.4%	7.6%
November-05	2.3%	2.3%	1.5%	0.2%
December-05	-2.1%	-0.2%	-4.6%	-0.4%

Figure 2.3 SP15 Actual Load Duration Curves: 2002-2005[3]

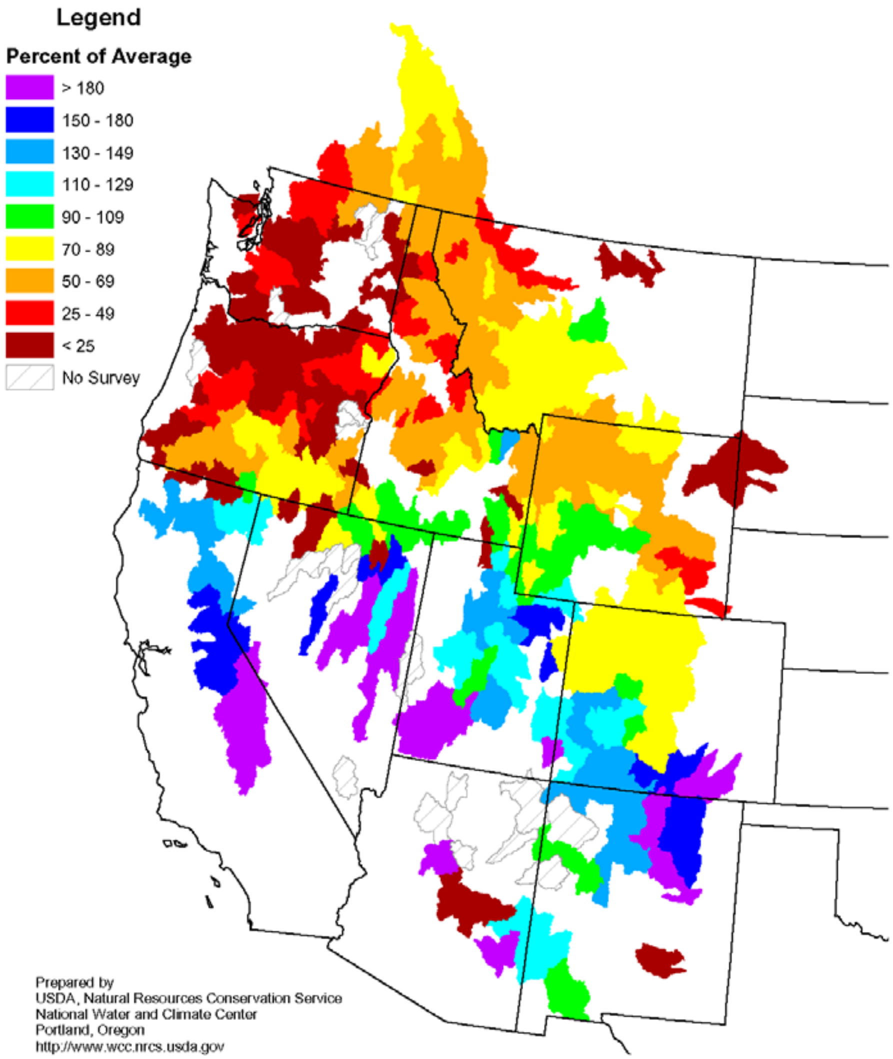


2.2 Supply

Hydroelectric. Snowfall in the California Sierra Nevada and in other Southwest ranges was generally well above average during the winter of 2005, which provided for robust runoff and storage among CAISO hydroelectric resources during the spring and summer of 2005. This largely offset the unusually low supply from the Pacific Northwest, which suffered a below-average snowpack. The graphic below shows mountain snowpack across the Western United States as of May 2005.

[3] All years are shown for all months, as there was no load adjustment within the SP15 load footprint. Previous years are adjusted to compare similar days of the week (i.e., so that each year has the same number of Sundays, etc.).

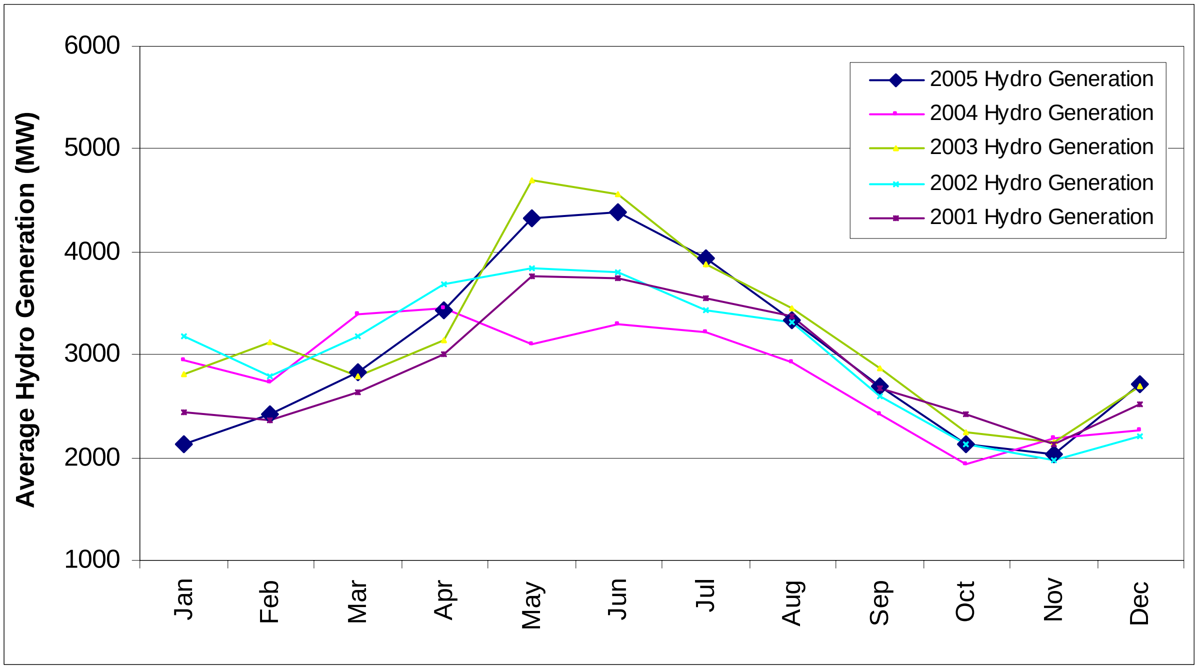
Figure 2.4 Mountain Snowpack in the Western U.S., May 1, 2005[4]



Due primarily to the robust snowpack and relatively slow melt within California, and, to a lesser extent, a wet late fall, hydroelectric production in 2005 was near the top of the recent five-year range for most of the year, as shown in Figure 2.5.

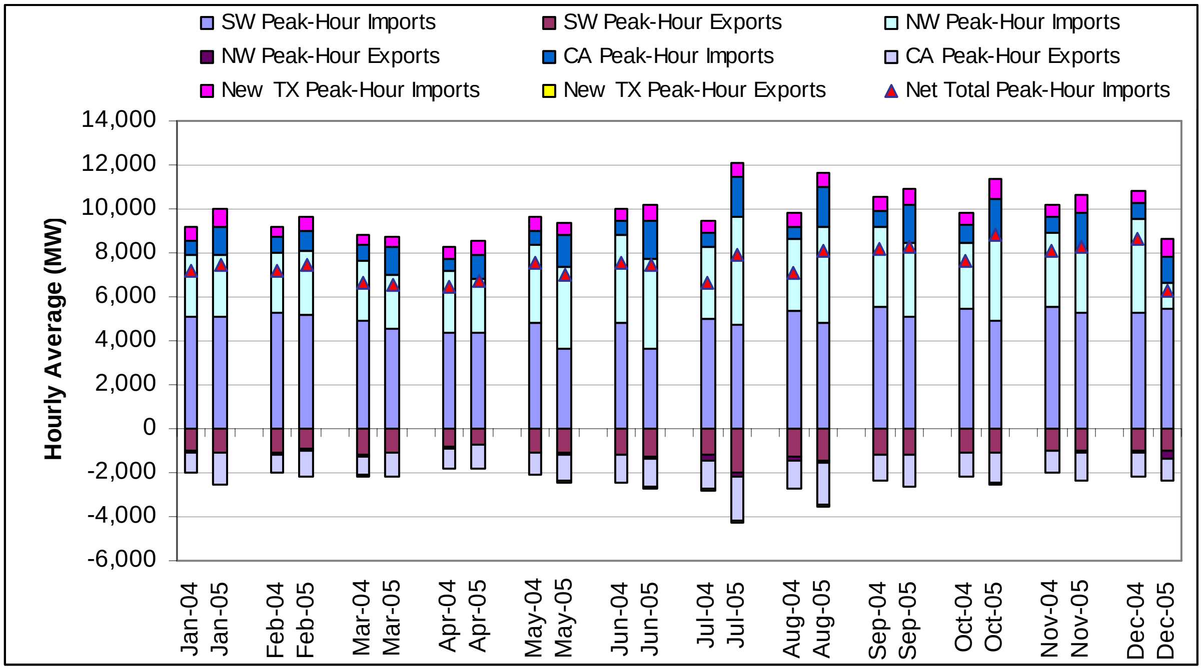
[4] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/cgibin/westsnow.pl.

Figure 2.5 Monthly Average Hydroelectric Production: 2001-2005



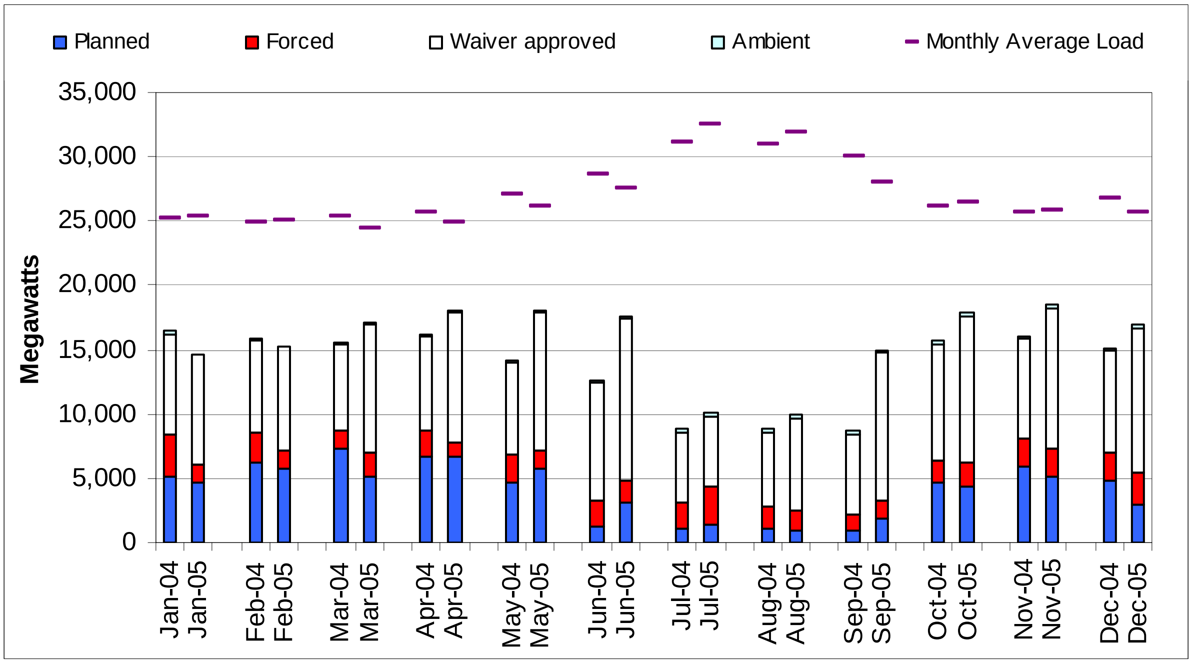
During the runoff season of May-June, the CAISO Control Area imported less power in 2005 than in 2004 overall, as its own spill condition, in addition to its other resources, was able to meet more of the load. Imports from the Northwest and other Northern California control areas increased during this period, due in part to power wheeled across the CAISO-managed grid to neighboring control areas in the Southwest. The heat wave that began in mid-July and continued through early August demanded the maximum level of imports available, resulting in year-to-year increases for those months. Figure 2.6 compares year-to-year imports and exports for each month in 2004 and 2005, and includes wheeled power.

Figure 2.6 Year-to-Year Comparison of Monthly Average Scheduled Imports and Exports: 2005 vs. 2004



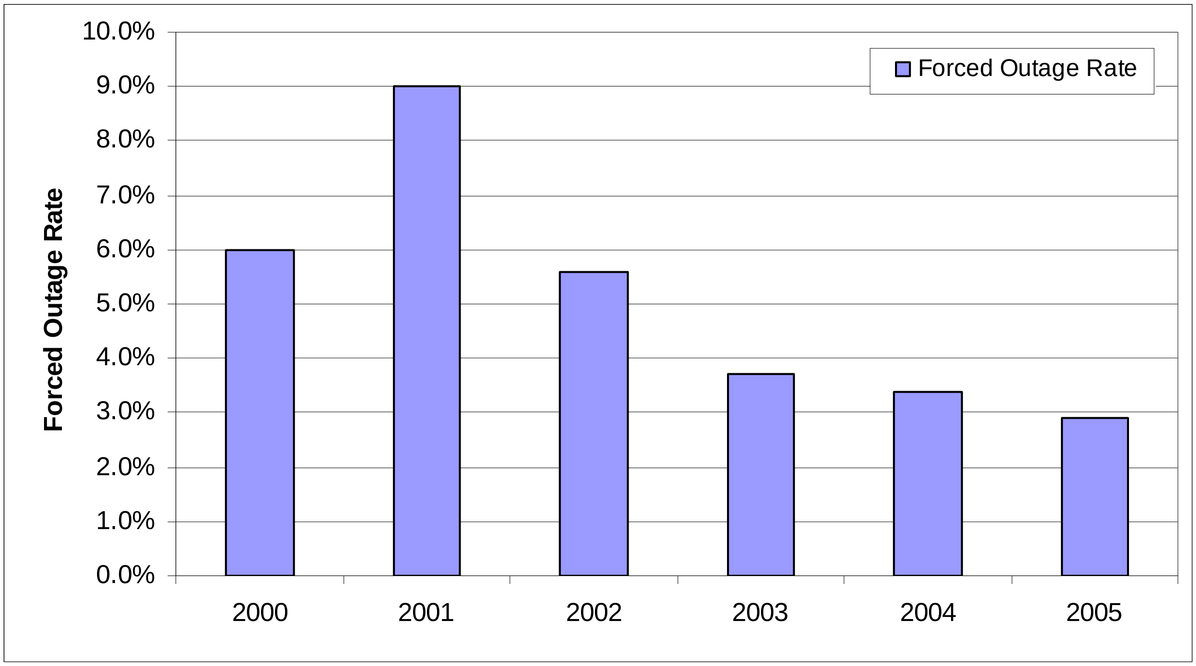
During the aforementioned July-August heat wave, the CAISO Control Area's entire generation fleet was operating seven days per week. For the entire duration of the heat wave, which lasted from July 11 to August 7, CAISO loads exceeded 40,000 MW on every day except 2 Sundays, where peaks were just shy of that level. This heat wave was unusually long, and required that generation remain on continuously, even on weekends. Consequently, typical weekend maintenance was deferred, contributing to an unusually high forced outage rate in July.

Figure 2.7 Year-to-Year Comparison of Monthly Average Outages: 2005 vs. 2004



Despite the high outage rate in July, the overall forced outage rate was the lowest since 2000. This is due primarily to the substantial increase in the generation base in 2005, which has a decreasing effect on outage rates. Figure 2.8 below compares annual forced outage rates since 2000.

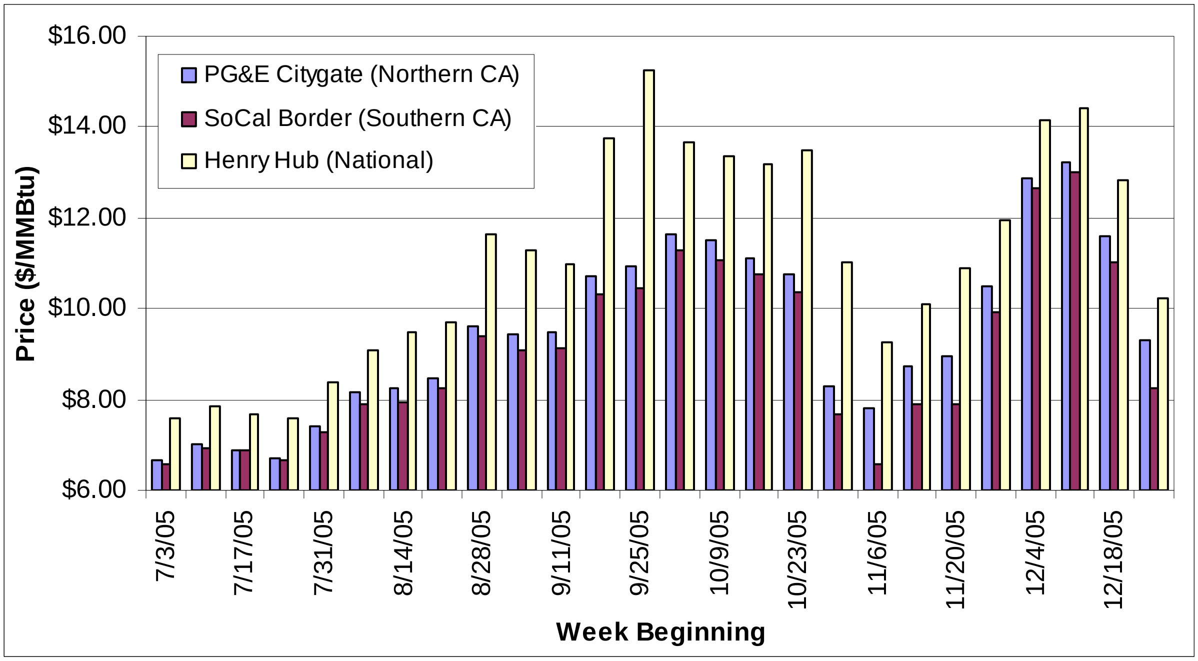
Figure 2.8 Year-to-Year Comparison of Forced Outage Rates: 2000-2005[5]



Natural gas prices increased substantially in 2005 over levels seen in 2004. Whereas gas prices in 2004 generally ranged between $5 and $7 per million British thermal units (mmBtu), national prices rose steadily in 2005, beginning in January, and peaking immediately following Hurricanes Katrina and Rita's destruction of national gas production and transportation infrastructure in the Gulf of Mexico region, during the week of August 30, 2005. As gas consumed in the West primarily comes from West Texas, New Mexico, and Canada, which were not affected by the hurricanes, Western markets traded at a discount of approximately $2/mmBtu to national prices. A cold snap across much of North America in December, coupled with limitations to the Gulf Coast transportation and production infrastructure, resulted in a second peak, with California prices reaching their highest levels since December 2000. Figure 2.9 shows weekly natural gas prices in 2005.

[5] This Annual Report now uses a methodology similar to one used by the California Energy Commission to count generation in the CAISO Control Area since 2001. As a result, forced outage rates differ slightly from those reported in previous Annual Reports.

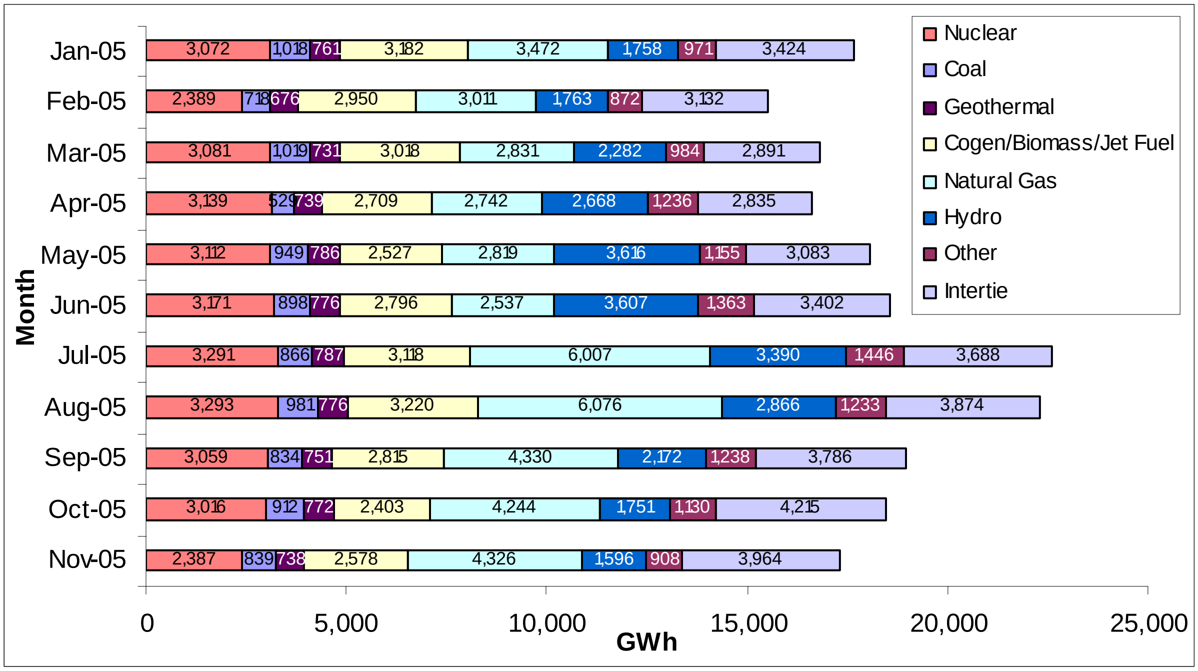
Figure 2.9 Weekly Average Gas Prices (July-06 to Dec-06)



2.2.1 Generation by Fuel

Base-load generation sources, such as nuclear, geothermal, cogeneration, and coal facilities, served between 36 and 47 percent of load each month in 2005. Between 16 and 23 percent of load was met by imports. The remaining 35 to 48 percent was served by a combination of natural gas-fired facilities, hydroelectric power, or some other generating resource. High loads in July and August resulted in substantial percentages of load being covered by natural gas-fired plants. In February and November the amount of nuclear generation decreased due to a forced outage at SONGS #2 in February and refueling outage at Diablo Canyon #1 in November. A summary of monthly energy generation by fuel type is provided in Figure 2.10.

Figure 2.10 2005 Monthly Energy Generation by Fuel Type



2.3 Total 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. This index has been updated in this report for operating years 2002-2005 to include reliability costs (must-offer minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs) with the real-time component.[6] The estimated total wholesale energy cost for 2005 was approximately $13.6 billion, compared to $13.1 billion in 2004.[7] The increase is largely due to higher natural gas prices, which were offset somewhat by lower reliability costs. The reliability costs are itemized individually below, in the All-In Cost Index. Table 2.5 shows the Wholesale Energy Cost Index by month for 2005, and annual summaries from 1998 through 2005.

[6] It was not possible to update the index to include these reliability cost components for prior years (1998-2001) due to some data limitations.

[7] This Annual Report uses an improved methodology to estimate unknown bilaterally contracted costs in 2002 through 2005. As a result, the 2002-2004 cost total reported here differs slightly from that reported in prior Annual Reports.

Table 2.5 Monthly Wholesale Energy Costs: 2005 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 ($/MWh load)	AS as % of Wholesale Cost	Avg Cost of Energy & AS ($/MWh load)
Jan-05	18,876	941	83	19	1,024	1,043	54.23	1.02	1.8%	55.25
Feb-05	16,784	831	68	16	899	915	53.54	0.97	1.8%	54.51
Mar-05	18,211	923	78	18	1,001	1,019	54.98	1.00	1.8%	55.97
Apr-05	17,900	869	63	18	932	949	52.05	0.99	1.9%	53.04
May-05	19,411	897	70	21	966	988	49.78	1.11	2.2%	50.89
Jun-05	19,866	935	60	20	994	1,014	50.05	1.01	2.0%	51.06
Jul-05	24,163	1,233	69	32	1,302	1,333	53.88	1.31	2.4%	55.19
Aug-05	23,678	1,330	61	20	1,391	1,411	58.75	0.85	1.4%	59.60
Sep-05	20,187	1,199	67	14	1,266	1,280	62.70	0.70	1.1%	63.40
Oct-05	19,665	1,231	70	15	1,300	1,315	66.12	0.74	1.1%	66.87
Nov-05	18,556	1,040	65	15	1,105	1,120	59.53	0.82	1.4%	60.35
Dec-05	19,151	1,203	28	19	1,231	1,250	64.26	1.01	1.5%	65.26
Total 2005	236,449	12,630	780	228	13,410	13,638	56.71	0.96	1.7%	57.68
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	25,410	26,756	114.63	6.07	5.3%	117.86
Total 2000	237,543	22,890	3,446	1,720	25,373	27,083	106.81	7.24	6.8%	114.01
Total 1999	227,533	6,848	562	404	7,028	7,432	30.89	1.78	5.7%	32.66
1998 (9mo)	169,239	4,704	1,061	638	4,913	5,551	29.03	3.77	13.0%	32.80

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 2005:

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 2005:

Forward energy costs revised slightly upward using a new methodology 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.

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 2.11 shows that total annual wholesale energy costs have consistently increased each year since 2002. Some of this increase can be attributable to increases in the total annual load being served. For instance, total CAISO load served increased in the 2002-2004 time frame but declined in 2005. Another important factor is the impact of natural gas prices on energy prices. Much of the variation in energy prices across years can be directly attributed to the variation in the price of natural gas.

Figure 2.11 Total Wholesale Costs: 2002-2005

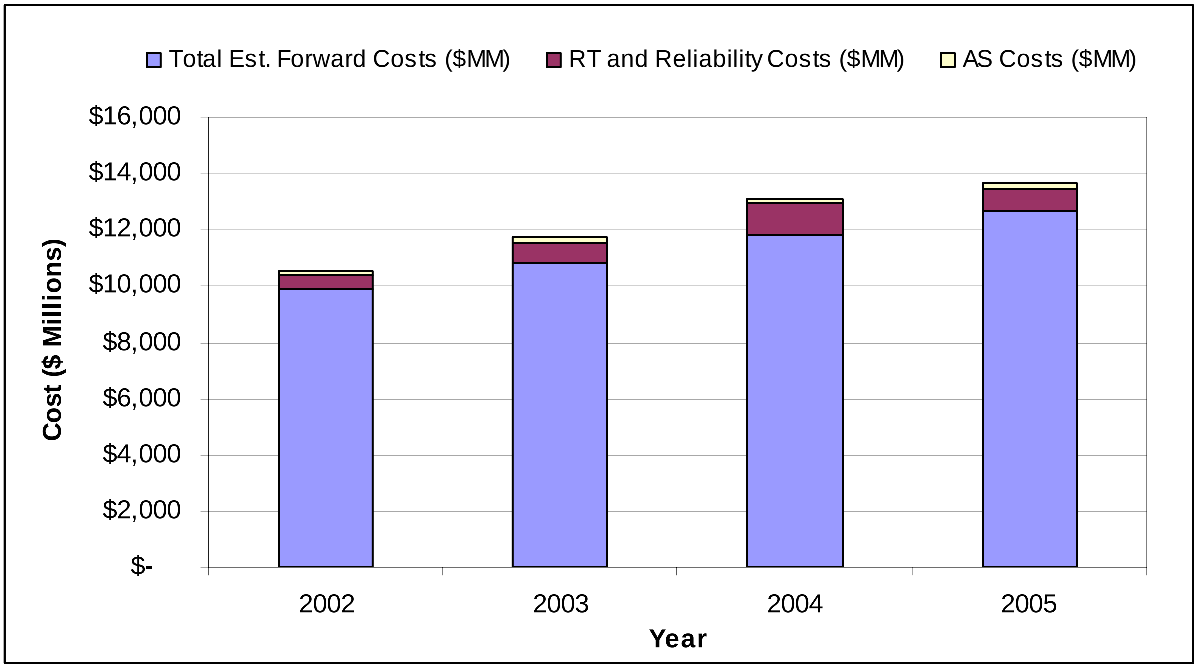
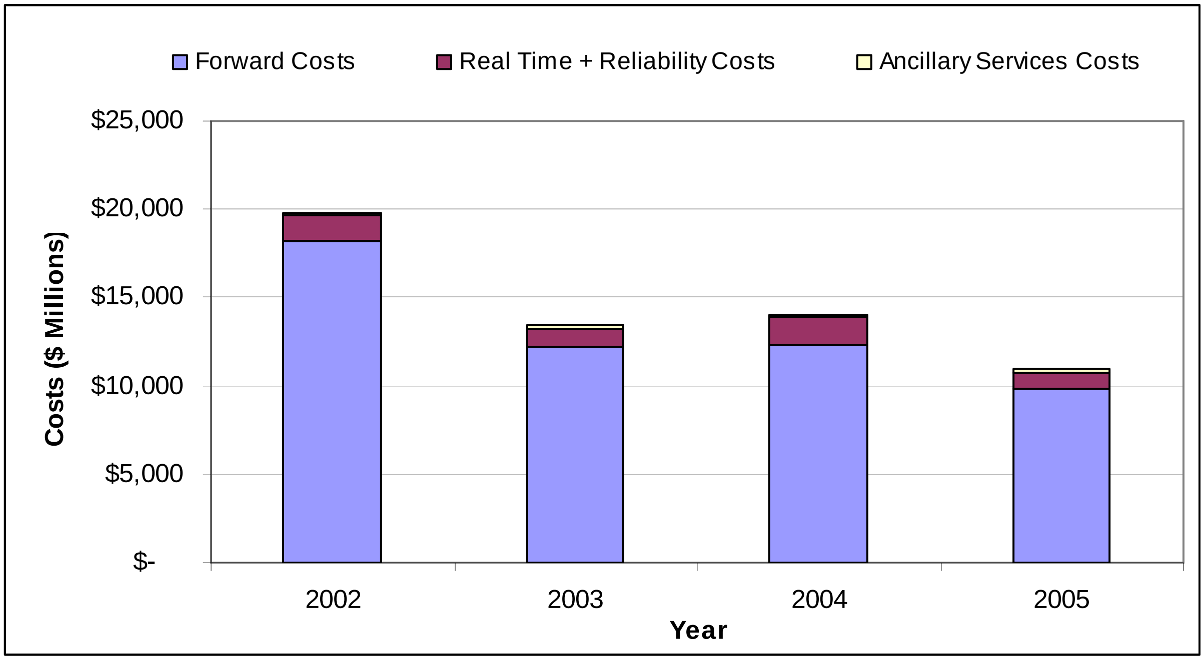


Figure 2.12 shows total annual wholesale energy costs normalizing for variations in natural gas prices[8] and indicates a general decline in total costs over this four-year period. The substantial decrease in normalized costs between 2002 and 2003 is likely due to the expiration of some costly long-term contracts entered into by the state of California in January 2001 as well as the entry of more efficient generation capacity (e.g., new combined cycle generation). Normalized costs increased slightly in 2004 due primarily to poor hydro conditions and out-of-season heat waves throughout the spring and in September, as well as by higher reliability costs for intra-zonal congestion management due to unit outages and transmission limitations. These

[8] Specific monthly energy costs (forward energy excluding grid management charges, real-time energy, MLCC, RMR pre-dispatch, and RMR real-time dispatch) were adjusted for variation in fuel price by multiplying each cost component by a monthly natural gas price index. The monthly natural gas price index was calculated by taking the simple average of the daily average spot gas price for Southern California for each month, and normalizing each month's average natural gas price by the average natural gas price for July 2004. This produces a monthly natural gas price index, such that the index value for the basis month of July 2004 is equal to one. The monthly energy costs are then divided by this monthly gas price index to produce a fuel price adjusted monthly energy cost. These adjusted costs are then added back in with the non-energy costs (grid management, fixed RMR payments, ancillary services) to produce the total adjusted monthly cost and summed for each year. A single hub price was used for the index for simplicity. Natural gas prices in the North, at PG&E Citygate, track closely with prices at the Southern California hub, with the exception of February through April of 2001.

additional costs offset any savings in 2004 due to further expirations of some state power contracts. The significant decrease in 2005 normalized costs is likely due to stronger hydro conditions in California and generally milder weather relative to 2004. The numerous transmission upgrades (described in Chapter 1) also contributed to decreased intra-zonal congestion management costs in 2005. The reduction in CAISO footprint had a small decreasing effect on 2005 costs.

Figure 2.12 Total Wholesale Costs Normalized to Fixed Gas Price: 2002-2005[9]



2.3.1 All-In Price Index

The "All-In Price Index" is a standardized metric developed by the FERC Office of Market Oversight and Investigation and several ISO market monitoring units, to provide, to the extent possible, an indicator of average wholesale energy costs that can be compared across electricity markets in several regions of the United States. The index includes adjustments to facilitate the comparison of providers with disparate features in an "apples-to-apples" manner. The All-In Price Index contains the average cost contributions of each of the following per megawatt-hour delivered to load:

- An estimate of forward energy costs, plus
- Real-time energy incremental costs, less
- Real-time decremental costs (negative), plus
- Minimum-load compensation[10] to units held on pursuant to the must-offer waiver denial process, plus
- Out-of-sequence energy costs, plus

[9] July 2004 gas price ($5.70/mmBtu) used as standard. All actual energy costs normalized; costs of grid management, ancillary services and fixed RMR component remain nominal. O&M cost not used in normalization.
[10] MLCC include start-up and no-load costs paid to generation units that are denied must-offer waivers.

- RMR costs, plus
- Market costs of ancillary services (with self-provided services estimated at market costs), plus
- Grid management charges for all services.

Table 2.6 shows the All-in Price Index values for 2002 through 2005 by contributing factor. The CAISO's All-In Price Index for 2005 was $57.68/MWh, compared to $54.70/MWh in 2004, $50.76/MWh in 2003, and $45.07/MWh in 2002, using equivalent methodologies.[11] The increase of approximately 5.4 percent since 2004 is due largely to the increases in natural gas prices. The increase in average energy costs in 2005 was moderated by a decrease in certain reliability service costs, such as RMR, out-of-sequence energy, and minimum load costs associated with the must-offer obligation (MOO). These cost elements were particularly high in 2004 due to an outage of San Onofre Nuclear Generating Station in the fall and various transmission limitations discussed in Chapter 6.

Figure 2.13 provides a comparison of the All-In Prices for 2002 through 2005. Figure 2.14 shows the all-in prices normalized against changes in natural gas prices, using the same methodology as discussed in the wholesale total costs section. The reasons for the decline in gas-normalized costs are also discussed in that section.

Table 2.6 All-In Price Index ($/MWh load): 2002-2005

	2002	2003	2004	2005	Change '04-'05
Est. Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	40.92	45.77	48.21	52.35	4.13
Interzonal Congestion Costs	0.18	0.12	0.23	0.23	(0.00)
GMC (All charge types, including RT)	1.00	1.00	0.90	0.84	(0.06)
Incremental In-Sequence RT Energy Costs	0.49	0.63	0.86	1.55	0.69
Explicit MLCC Costs (Uplift)	0.26	0.54	1.21	0.52	(0.68)
Out-of-Sequence RT Energy Redispatch Premium	0.02	0.19	0.43	0.15	(0.28)
RMR Net Costs (Include adjustments from prior periods)	1.60	1.95	2.67	1.95	(0.73)
Less In-Sequence Decremental RT Energy Savings	(0.08)	(0.29)	(0.59)	(0.87)	(0.29)
Total Average Energy Costs	**44.39**	**49.90**	**53.93**	**56.71**	**2.79**
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	0.68	0.86	0.77	0.96	0.20
Total Average Costs of Energy and A/S ($/MWh load)	**45.07**	**50.76**	**54.70**	**57.68**	**2.98**

[11] The same improvement in the estimation of unknown bilateral forward costs used in the Total Wholesale Energy Cost Index was also used in the All-In Price Index. Thus, reported indices from 2004 and earlier differ from those reported in previous Annual Reports.

Figure 2.13 Annual All-In Prices: 2002-2005

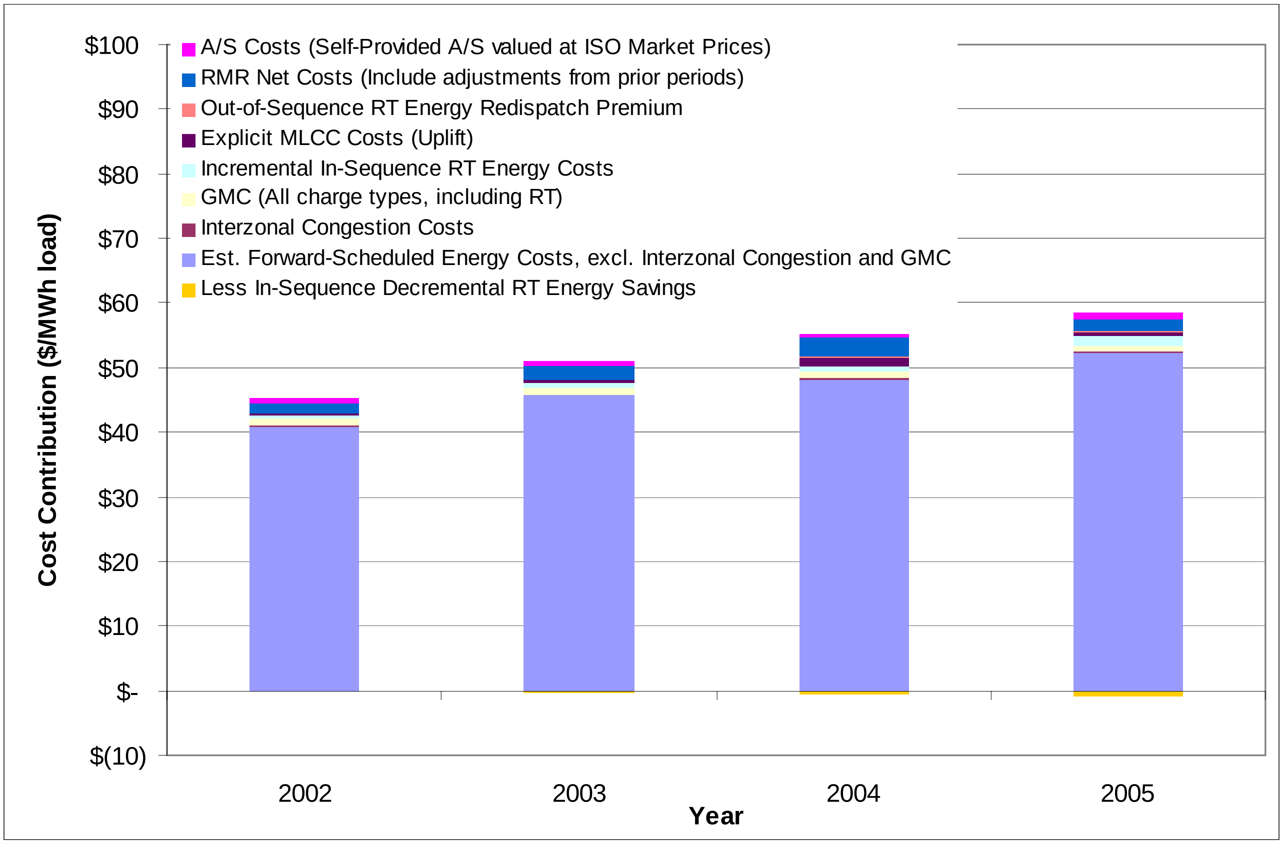
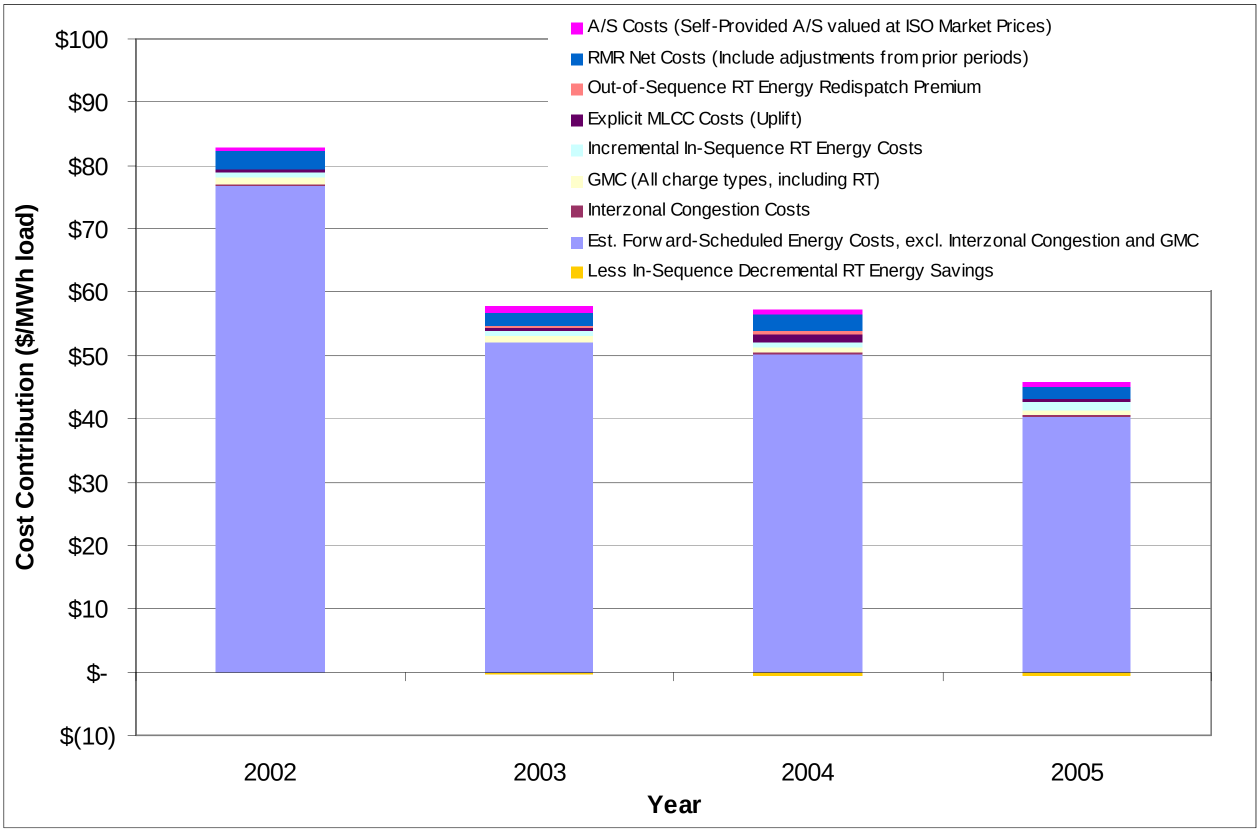


Figure 2.14 Annual All-In Prices Normalized for Natural Gas Price Changes: 2002-2005



Due to changes in data infrastructure and market structure, it was not possible to compare gas-normalized costs in recent years to the pre-crisis period of 1998 and 1999 explicitly. However, it is possible to make an approximation of gas-normalized costs based upon the annual wholesale cost figures provided in Table 2.5 for 1998 and 1999 and normalize these values using annual natural gas prices.[12] Similarly, monthly wholesale costs and gas prices from 2000 and 2001, as reported in the *Third Annual Report on Market Issues and Performance,*[13] can be used to estimate normalized costs for that period.[14] The estimated gas-normalized costs that result are summarized in Table 2.7 and Figure 2.15.

[12] Annual total energy costs in 1998 and 1999 were deflated by dividing by the ratio of Southern California border annual average gas prices to July 2004 average gas price ($5.70/mmBtu), and adding this gas price adjusted annual energy cost to the non-energy costs.
[13] California ISO Dept. of Market Analysis, January 2002.
[14] Monthly total energy costs in 1998 and 1999 deflated by dividing by the ratio of Southern California border monthly average gas prices to July 2004 average gas price ($5.70/mmBtu), and added to non-deflated non-energy costs.

Table 2.7 Annual Nominal and Gas-Normalized Wholesale Costs, 1998-2005

Year	Gas Price ($/mmBtu)	ISO Load (GWh)	Nominal Total Costs ($MM)	Average Total Nominal Costs ($/MWh load)	Normalized Total Costs ($MM)	Average Total Normalized Costs ($/MWh load)
1998	$ 2.25	169,239	$ 5,551	$ 32.80	$ 12,825	$ 75.78
1999	$ 2.33	227,533	$ 7,432	$ 32.66	$ 17,268	$ 75.89
2000	$ 6.30	237,542	$ 27,092	$ 114.05	$ 26,003	$ 109.47
2001	$ 7.74	227,023	$ 26,702	$ 117.62	$ 23,169	$ 102.05
2002	$ 3.14	232,793	$ 10,554	$ 45.07	$ 19,170	$ 82.70
2003	$ 5.09	230,668	$ 11,709	$ 50.76	$ 13,263	$ 57.31
2004	$ 5.50	239,788	$ 13,115	$ 54.70	$ 13,620	$ 56.74
2005	$ 7.55	236,449	$ 13,638	$ 57.68	$ 10,714	$ 45.26

Figure 2.15 Average Nominal and Gas-Normalized Wholesale Costs, 1998-2005

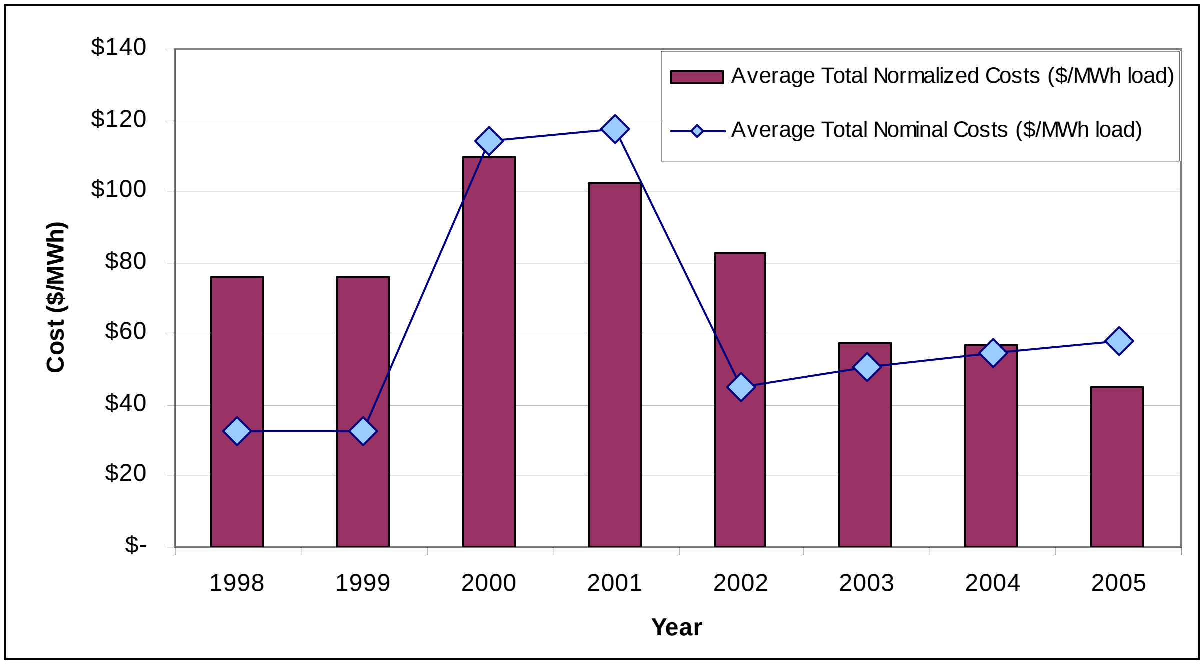


Figure 2.15 indicates that average total wholesale costs, when adjusted for changes in natural gas prices, have steadily declined since 2000, and the estimated gas-normalized average wholesale cost in 2005 is the lowest value over the entire eight-year period. As previously discussed, this trend is likely attributable to the significant amounts of new investment in efficient gas-fired generation that has occurred during the 2001-2005 period both in California and throughout the West, particularly the Southwest.

2.4 Market Competitiveness Indices

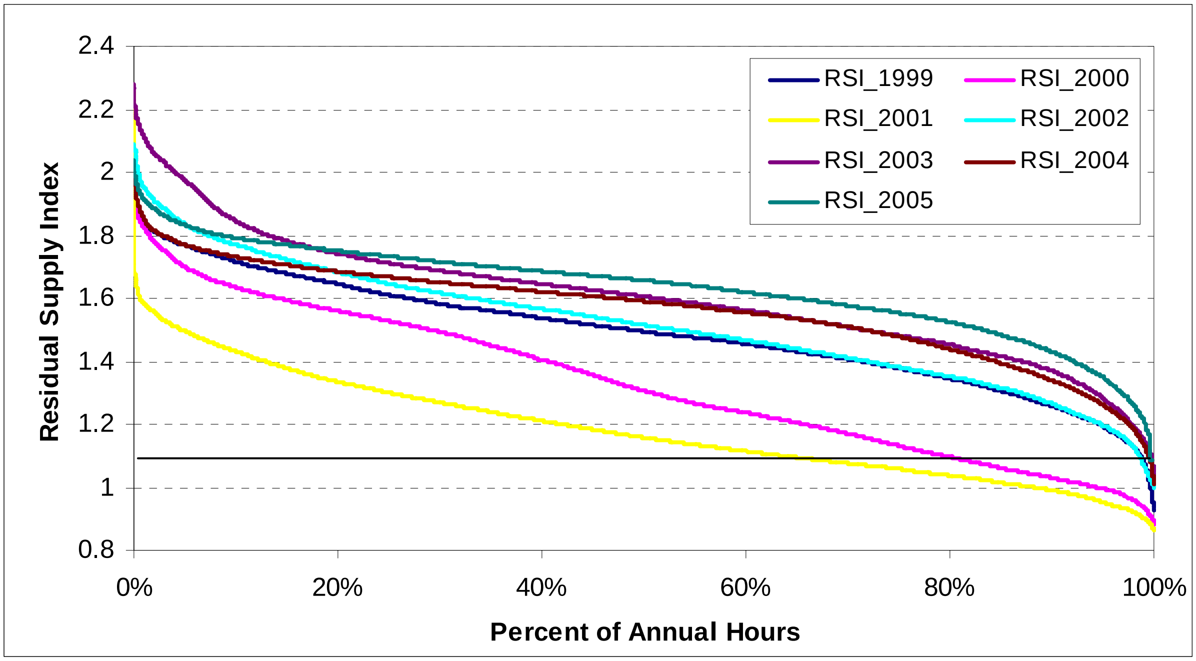
2.4.1 Residual Supplier Index: Measuring Competitiveness in Market Structure

The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2005 were generally higher than in 2003 and 2004, which were the highest of the past five years. Using an RSI level of 1.1 to compare between years,[15] in 2005 the RSI levels were less than 1.1 in less than 0.30 percent of the hours (only 5 hours out of 8,760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2005 were again significantly more competitive than in 2000 and 2001 as a result of the addition of new generation and high levels of net imports over the period. The RSI levels are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2005. The significant amount of long-term contracts entered into since 2001 have also led to more competitive market outcomes, although the impacts of contracting are not accounted for in this analysis as it is directed at reflecting the physical aspects of the market. The RSI analysis shows that the underlying physical infrastructure was much more favorable for competitive market outcomes in the period 2002 through 2005 than 2001 as reflected by the higher RSI levels. Figure 2.16 compares RSI duration curves for the past seven years (1999-2005).

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

Figure 2.16 Residual Supply Index (1999-2005)



2.4.2 Short-term Energy Price-to-Cost Mark-up Analysis[16]

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.

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 Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. The methodology 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[17] is used as a substitute.

The CAISO continues to utilize a "single resource portfolio" methodology to meet the objective of developing a competitive benchmark for short-term bilateral energy markets. The methodology depends on several assumptions: every asset in the portfolio bids competitively, all bids are at marginal cost, and the portfolio clears against the total of actual historical hour-ahead generation schedules in each hour of benchmark development.

[16] Short-term energy is defined as forward purchased energy purchased within 24 hours of real-time operation.
[17] Powerdex is an independent energy information company that surveys buyers and sellers of energy at key Western hubs and compiles hourly prices. http://www.powerdexindexes.com - 5703 Spellman Road, Houston, TX, 77096

Additional conditions were necessary to develop the competitive short-term bilateral market clearing price benchmark. All of the resources in the portfolio are assigned unit commitment levels based on historical hour-ahead schedules. Hydroelectric units in the portfolio are optimally dispatched to reflect total metered output for the given week in history. Pumped storage generation units optimally pump and generate within the bounds of storage and release constraints as well as pumping efficiency. Resources in the cogeneration, renewable and QF classes, in addition to resources with unknown variable costs, were forced to operate in direct accordance with their forward energy schedules. California imports are modeled to flow economically, bound by hourly inter-tie availability, and are priced at historical Powerdex hub price levels for the California-Oregon Border (COB) and Palo Verde (PV).

The CAISO market model utilizes PLEXOS for Power Systems™ as the market simulation tool. PLEXOS employs a linear programming based production cost model, which allows for co-optimization with ancillary service markets. PLEXOS for Power Systems™ is produced by Drayton Analytics, Pty Ltd.[18] The majority of data used by the model are sourced from CAISO market operations records. When variable cost information is not available through operations data, the CAISO attempts to obtain it from data purchased from Global Energy Decisions, Inc.[19] Global Energy Decisions is also the source for the pumped storage reservoir volumes and pump efficiency data employed in the model.

For calendar year 2005, the CAISO observed short-term mark-ups ranging from 4 to 16 percent, compared to 1.2 to 22.5 percent in the prior year. Figure 2.17 and Figure 2.18 summarize competitiveness in the short-term forward energy markets. SP15 posted eight months with mark-ups greater than 10 percent while NP15 logged five such months. Months with the greatest mark-ups were October and November, corresponding to a significant amount of generation being off-line for seasonal maintenance. On the whole, 2005 short-term forward markets functioned effectively, leading largely to competitive pricing in both the NP15 and SP15 regions.

[18] http://www.draytonanalytics.com - PO Box 13, North Adelaide, SA 5006, Adelaide, Australia
[19] http://www.globalenergy.com/ - 2379 Gateway Oaks Dr., Suite 200, Sacramento, CA, 95833

Figure 2.17 2004 Short-term Forward Market Index – NP15

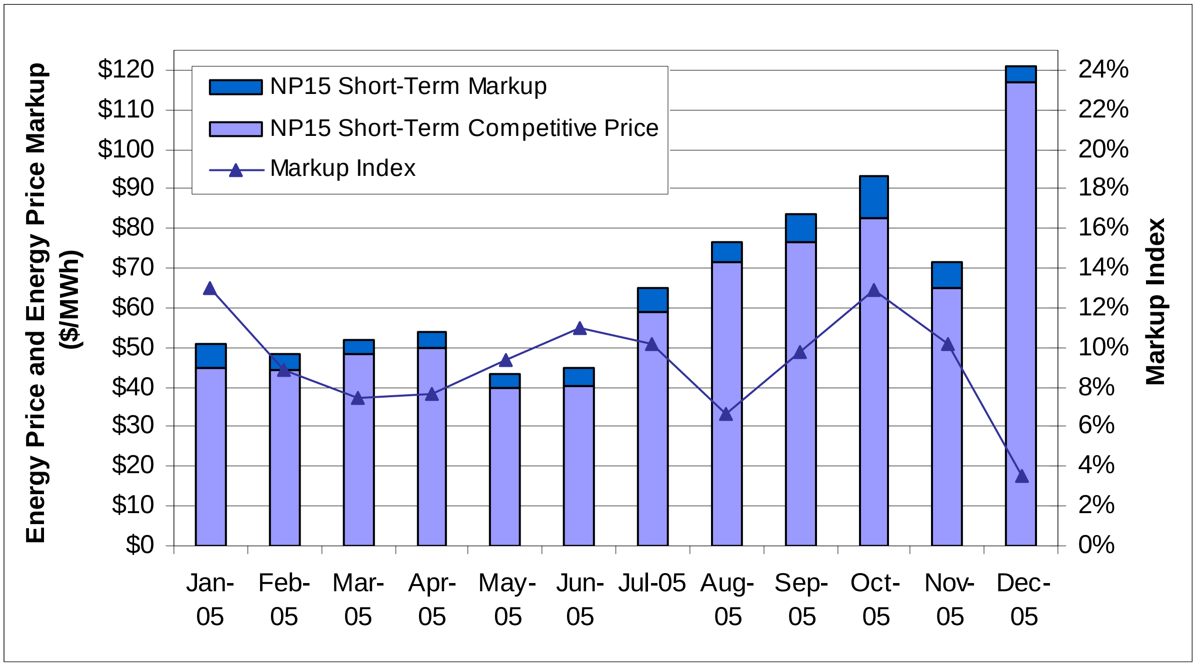
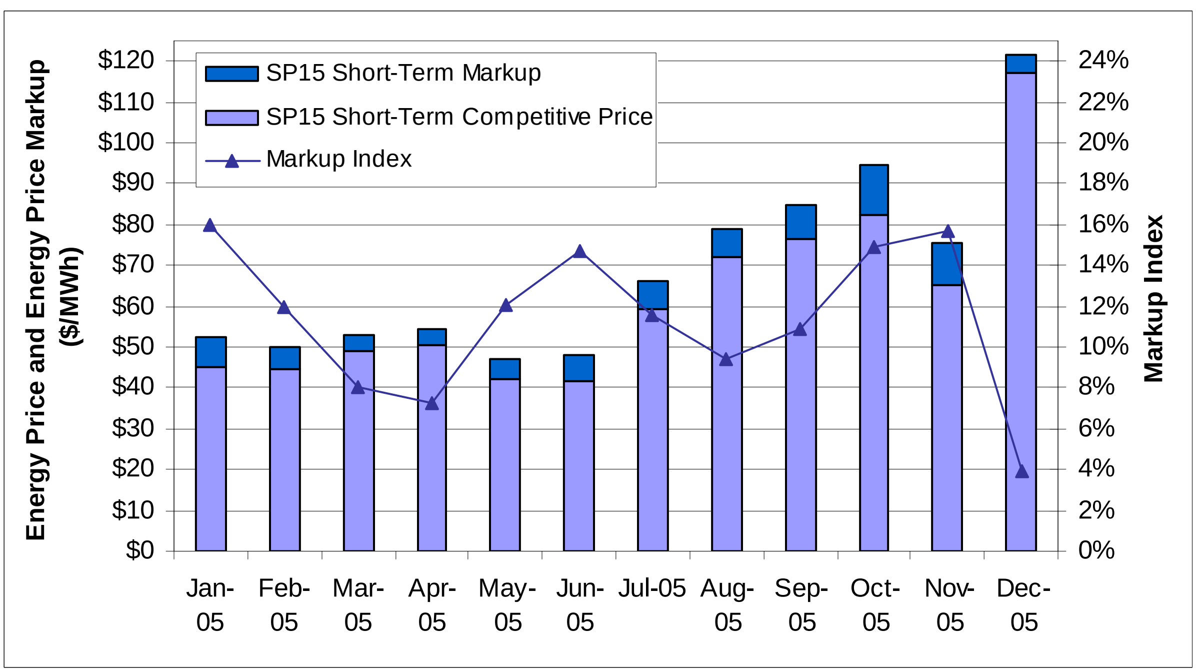


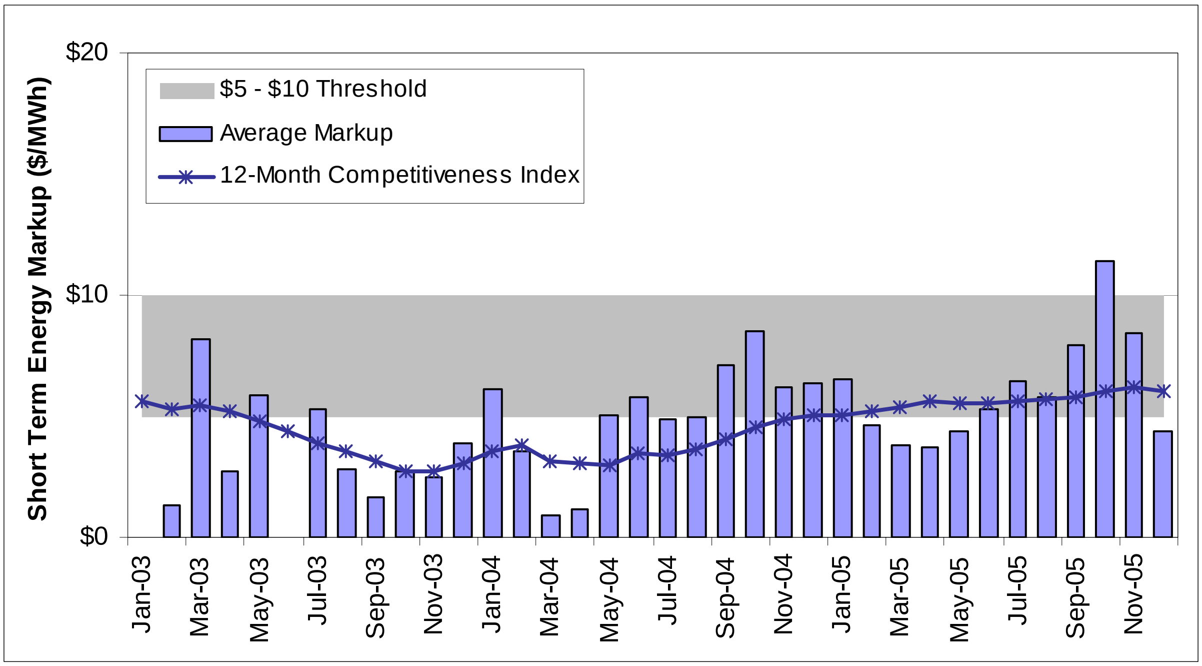
Figure 2.18 2004 Short-term Forward Market Index – SP15



2.4.3 Twelve-Month Competitiveness Index

The CAISO employs several indices during market competitiveness assessments. The index in Figure 2.19 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 approximated competitive prices. The CAISO assumes that the short-term energy market is subject to little or no exercise of market power when the index is near or below a $5 to $10 per MWh range.

Figure 2.19 Twelve-Month Competitiveness Index



2.4.4 Real-time Market Price to Cost Mark-up

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 obligations.

Figure 2.20 and Figure 2.21 show the monthly average mark-up for incremental and decremental real-time energy dispatched in 2005, respectively. As shown in these figures, the incremental Real Time Market mark-up overall is relatively stable, with estimated mark-ups ranging from 8 percent to 20 percent. However, the decremental Real Time Market mark-up seems to reflect seasonal trends. In spring and early summer, it was common to see negative (-$0.01) bids on the decremental side setting prices, reflecting certain hydro units that were operating under water management constraints. When such bids set the market clearing price, they tend to increase mark-ups in the decremental market. This is the main reason behind the high decremental mark-ups in the first half of 2005 that peaked in May and June. Starting in July, mark-ups in the decremental market returned to a range under 20 percent.

Figure 2.20 Real-time Incremental Energy Mark-up above Competitive Baseline Price

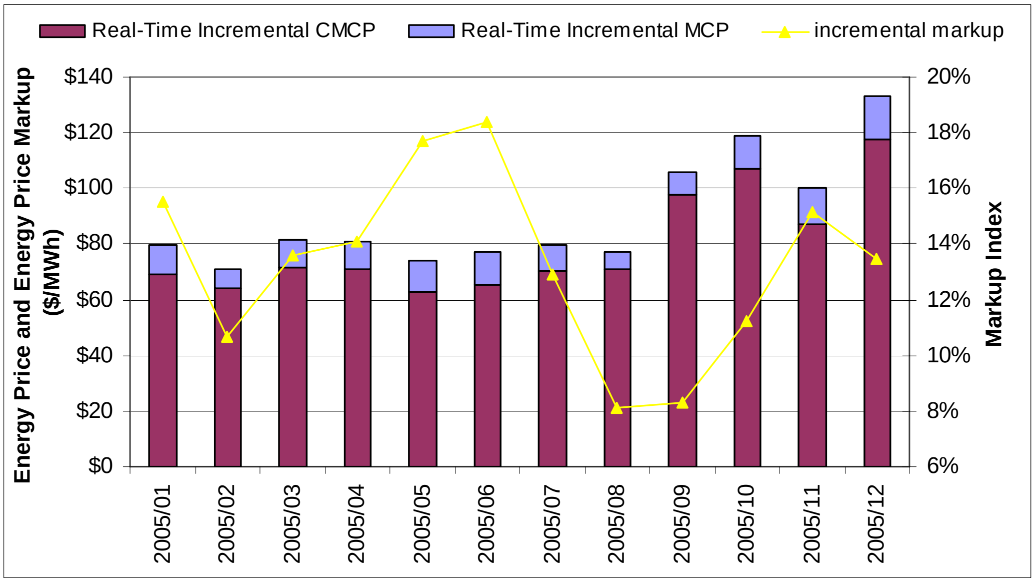


Figure 2.21 Real-time Decremental Energy Mark-up below Competitive Baseline Price

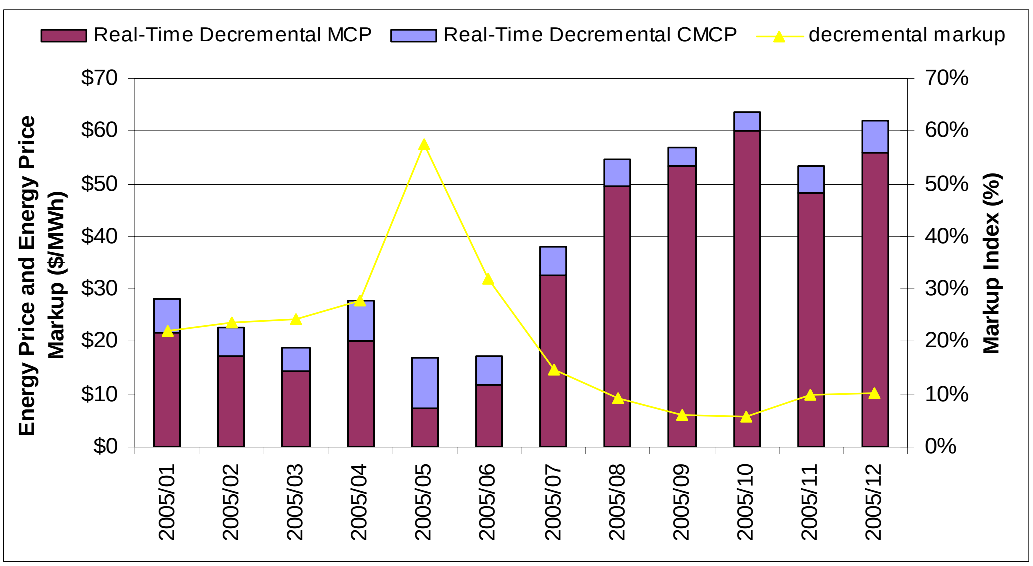
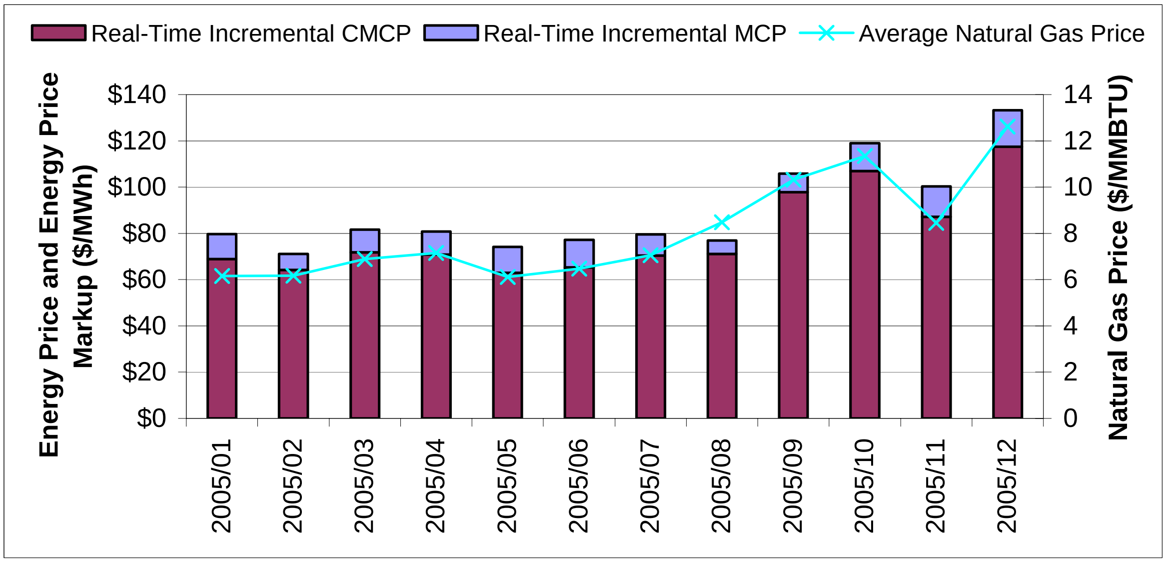


Figure 2.22 shows that the monthly weighted market clearing prices and competitive market clearing prices tend to be highly correlated with monthly averaged natural gas prices.

Figure 2.22 CMCP Relation to Natural Gas Prices



2.4.5 Real-time market Residual Supplier Index (RSI) Analysis

The DMM has also been applying the RSI to the Real Time Market to measure the competitiveness of both the incremental and decremental sides of the imbalance energy market. When the Real Time Market splits, supply and demand conditions are restricted within each individual zone. It is appropriate to calculate zonal RSIs in such circumstances. On the incremental side, when the market splits, NP15 often has abundant supply and the market is generally competitive, whereas SP15 has greater demand and relatively less supply. Figure 2.23 shows an RSI curve for the CAISO as a whole for incremental supply when the market is not split, and for SP15 when the market is split, which shows that SP15 often has lower RSI values. Figure 2.24 shows that real-time energy prices (System and SP15) are strongly negatively correlated with RSI values where lower RSI values generally result in higher real-time energy prices.

Figure 2.23 RSI Duration Curve for Incremental Energy

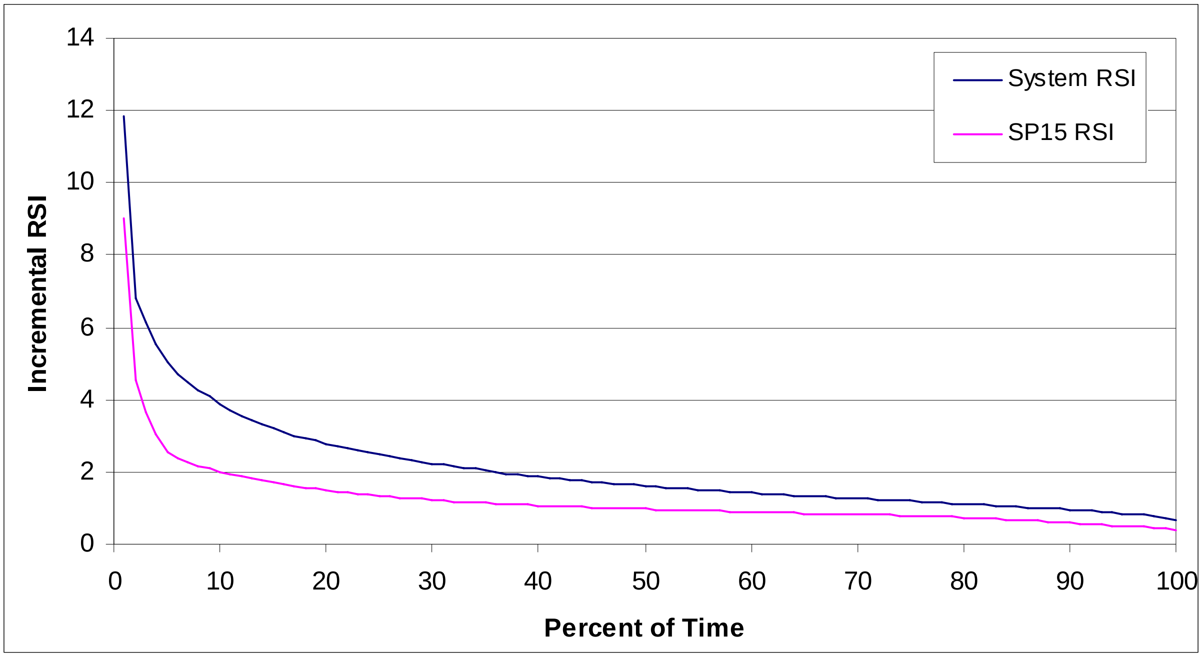


Figure 2.24 RSI Relationship to Real-time Incremental Market Clearing Prices

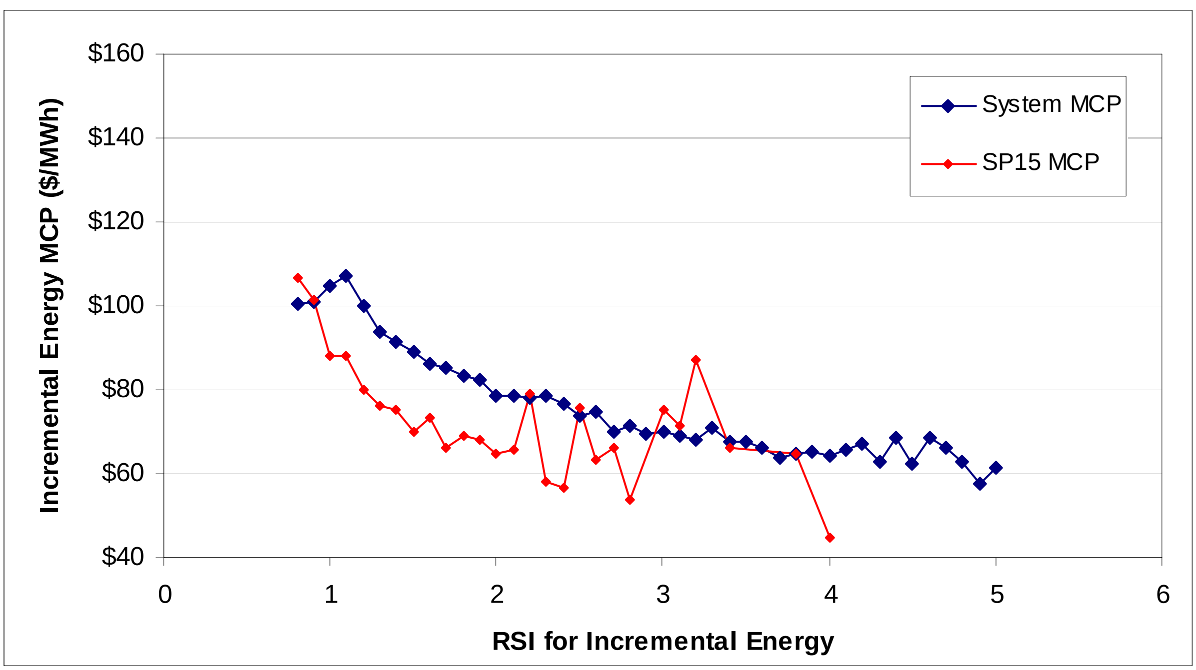


Figure 2.25 shows the RSI duration curve during decremental dispatch periods. In 2005, RSI values dipped below 1.0 in 15 percent of the periods. RSI values for decremental supply tend to be low in off-peak hours when generators are operating close to their minimum output level and unwilling or unable to offer decremental bids. On average, low RSI values result in low market clearing prices for those periods CAISO needs to dispatch decremental energy to balance the market (Figure 2.26).

Figure 2.25 RSI Duration Curve for Decremental Energy

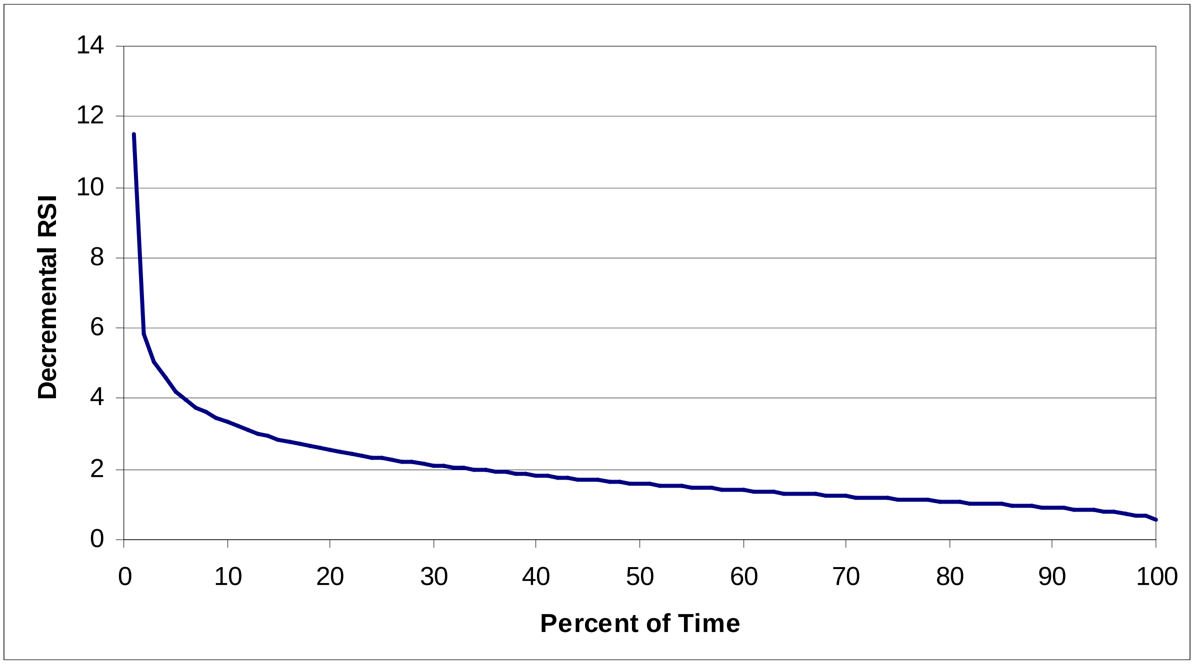
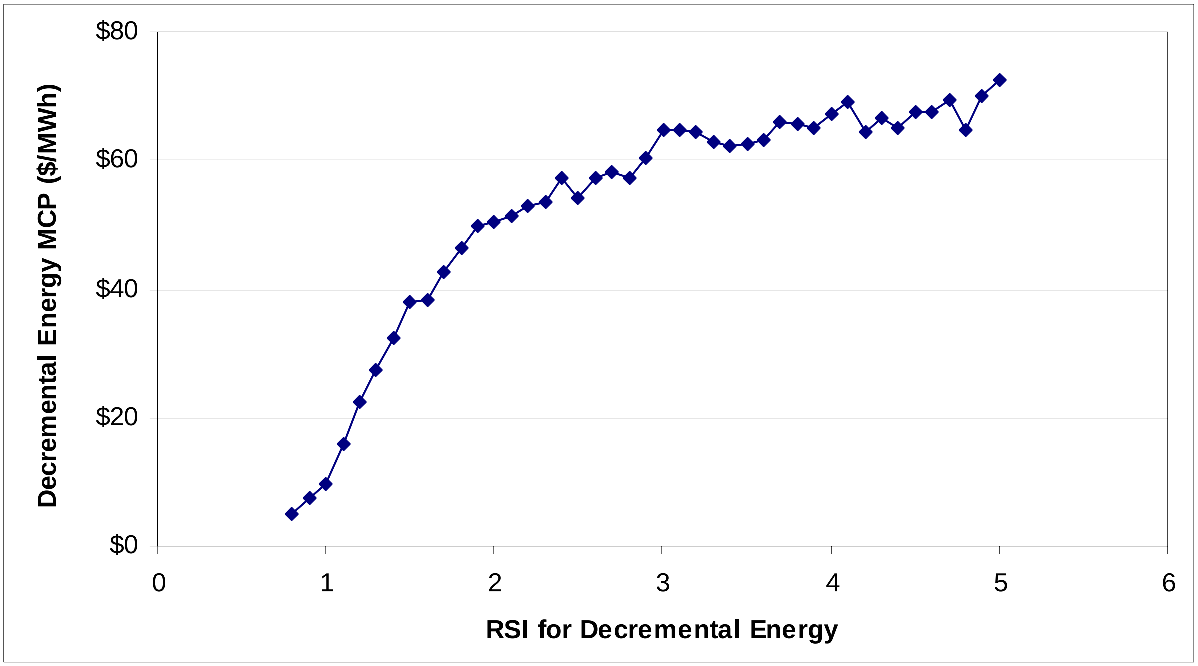


Figure 2.26 RSI Relationship to Real-time Decremental Market Clearing Prices



2.5 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past five years (2001-2005), investment in Southern California has not kept pace with unit retirements and load growth. Moreover, there is a 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 examines some of the issues that possibly affect incentives for new generation investment. It begins with an assessment of the extent to which spot market revenues in 2005 were sufficient to cover the annualized fixed cost of new generation. This is followed by an examination of the use of the Must Offer Obligation to meet reliability needs in 2005 and the potential impacts that this mechanism may have on incentives for long-term contracting. A review of the generation additions and retirements for 2001 through 2005 and projections for 2006 is provided next. This section concludes with a review of the continued reliance on older generation facilities and a discussion of the critical need for a long-term procurement framework for facilitating new investment.

2.5.1 Revenue Adequacy for New Generation Investment

This section examines the extent to which spot market prices 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 spot market revenues. Nonetheless, examining the extent to which current spot market prices alone can contribute to fixed cost recovery for new investment has proven to be an important market metric that all ISO's measure.

The annualized fixed costs used in this analysis are obtained from a California Energy Commission (CEC) report,[20] which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be $90/kW-year and $78/kW-year, respectively. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.8 and Table 2.9. It should be noted that the finance costs shown in these tables do include a rate of return on capital for equity investment.

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

Table 2.8 Analysis Assumptions: Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Heat Rates (MMBtu/kWh)	
Maximum Capacity	7,100
Minimum Operating Level	8,200
Financing Costs	$75 /kW-yr
Fixed Annual O&M	$15 /kW-yr
Other Variable O&M	$2.4/MWh
Startup Costs	
Gas Consumption	1,850 MMBtu/start
Fixed Cost Revenue Requirement	**$90/kW-yr**

Table 2.9 Analysis Assumptions: Typical New Combustion Turbine Unit

Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financing Costs	$58 /kW-yr
Fixed Annual O&M	$20 /kW/year
Other Variable O&M	$10.9/MWh
Startup Costs	
Gas Consumption	180 MMBtu
Fixed Cost Revenue Requirement	**$78/kW-yr**

2.5.1.1 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 (2002-2005). Some improvements were made to the net revenue analysis methodology used in the *2004 Annual Report* to provide a better estimate of potential spot market revenues. For consistency, these modifications were applied over the 4-year study period. Consequently, the numbers shown in this report differ from those shown in the *2004 Annual Report*, though the fundamental findings are the same.

Two methodologies were used to calculate the net revenues earned by the hypothetical combined cycle described in Table 2.8. The first was based on market participation limited to the Real Time Market with some additional revenues estimated for MLCC under the current must-offer provisions. A second was based on participation limited to the day-ahead spot energy markets and the CAISO Ancillary Service Market. The specific methods used for both of these approaches 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 from sales in the CAISO's real-time energy market are summarized below:

1. An initial operating schedule was determined based on real-time energy prices 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 2.8. The unit was scheduled up to full output when hourly prices exceed variable operating costs.

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 prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup 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. A series of simplified ramping constraints were applied to the unit's schedule to approximate the degree to which the unit would need to deviate from this schedule given the unit's ramp rate.

4. All startup 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 by 5 percent.

Potential revenues that could be earned by a typical new combined cycle unit from sales in the day-ahead bilateral spot markets were assessed using the same methodology described above, except that energy prices used in the analysis were based on the hourly spot market price index published by Powerdex on a subscription basis and ancillary service revenues were calculated by assuming the unit could provide 80 MW of non-spinning reserve each hour. Revenues from sales of non-spinning reserve were based on day-ahead market prices.

Combustion Turbine – Net Revenue Methodology

Potential revenues that could be earned by a typical new simple cycle combustion turbine in the CAISO's real-time energy market were calculated using a more simplified model, as 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 2.9. The unit was scheduled up to full output when hourly prices exceeded variable operating costs.

2. Ancillary service revenues were calculated by assuming the unit could provide 80 MW of non-spinning reserve each hour. Revenues from sales of non-spinning reserve were based on day-ahead market prices.

3. All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

4. 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.

2.5.1.2 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year's revenue analysis includes additional analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated exclusively in the day-ahead bilateral market and contrasts those estimates with net revenues earned from the same unit participating exclusively in the CAISO real-time market. These results are summarized in Table 2.10 and show a consistent downward trend in the net revenues a hypothetical combined cycle would earn from participating exclusively in the CAISO real-time energy market over the four-year period (2002-2005). The analysis is not as clear for the net revenues the unit would earn participating exclusively in the day-ahead bilateral energy market and CAISO Day Ahead Ancillary Service Market, which show fairly consistent net revenues in the 2002-2004 period with an increase in 2005. However, under all scenarios (day-ahead and real-time), the estimated net revenues are well below the $90/kW-yr annualized cost of the unit.

Table 2.11 shows the estimated net revenues that a hypothetical combustion turbine (CT) would have earned by participating exclusively in the CAISO Real Time Market. Similar to the combined cycle analysis, the estimated revenues for a hypothetical CT fall well short of the $78/kW-yr annualized costs for all years (2002-2005).

Table 2.10 Financial Analysis of New Combined Cycle Unit (2002 – 2005)

Real-Time Market Revenue Analysis

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	58%	59%	44%	47%	39%	44%	54%	57%
Energy Revenue ($/kW - yr)	$208.4	$215.0	$217.4	$233.4	$190.8	$223.3	$320.9	$339.5
MLCC ($/kW - yr)		$10.6		$22.6		$31.0		$38.5
A/S Revenue ($/kW - yr)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Operating Cost ($/kW - yr)	$135.9	$138.9	$171.3	$176.7	$163.3	$178.4	$303.8	$311.5
Net Revenue w MLCC ($/kW - yr)	$72.5	$86.7	$46.1	$79.3	$27.5	$75.9	$17.1	$66.6
Net Revenue w/o MLCC ($/kW - yr)	$72.5	$76.2	$46.1	$56.7	$27.5	$44.9	$17.1	$28.1

Day-Ahead Market Revenue Analysis

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	61%	62%	53%	54%	58%	59%	57%	59%
Energy Revenue ($/kW - yr)	$176.9	$189.8	$235.7	$246.0	$270.6	$274.6	$378.9	$386.9
MLCC ($/kW - yr)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
A/S Revenue ($/kW - yr)	$0.5	$0.4	$0.7	$0.5	$0.9	$0.8	$1.2	$1.2
Operating Cost ($/kW - yr)	$141.2	$145.1	$196.1	$196.8	$235.3	$228.6	$320.2	$322.3
Net Revenue ($/kW - yr)	$36.2	$45.2	$40.3	$49.8	$36.2	$46.8	$59.9	$65.8

Table 2.11 Financial Analysis of New Combustion Turbine Unit (2002-2005)

Components	2002		2003		2004		2005	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	34%	35%	15%	19%	9%	14%	8%	10%
Energy Revenue ($/kW - yr)	$156.5	$162.1	$118.1	$142.4	$72.8	$121.7	$87.5	$107.5
A/S Revenue ($/kW - yr)	$5.8	$5.6	$19.6	$18.2	$14.1	$27.4	$19.3	$18.5
Operating Cost ($/kW - yr)	$125.9	$129.4	$87.3	$108.0	$54.0	$81.6	$63.7	$82.0
Net Revenue ($/kW - yr)	$36.4	$38.3	$50.4	$52.7	$32.8	$67.5	$43.1	$44.1

The results shown in Table 2.10 and Table 2.11 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,[21] are $15/kW-year for a combined cycle unit and $20/kW-year for a combustion turbine unit. Net revenues sufficient to cover fixed O&M costs should be sufficient to keep a unit operating from year to year.

However, the results also 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 generally did not come close to the total fixed cost estimate of $78/kW-year, except in the case of SP15 in 2004, which was still deficient by

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

roughly $10.50/kW-year. The same result is true for combined cycle units, where the total fixed cost of $90/KW-year is never fully reached even when potential MLCC revenues are accounted for.

Given the need for new generation investment in southern California, as reflected in the relatively tight supply margins that occurred in that region during peak summer demand periods over the past two years and documented reliability concerns cited in the CAISO 2005 Summer Operations Assessment,[22] the finding that estimated spot market revenues failed to provide for fixed cost recovery of new generation investment in this region in both of these years raises two issues. First, it underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. Such a procurement framework would need to be coupled with local procurement requirements to ensure energy or capacity procurement is occurring in the critical areas of the grid where it is needed. Second, it suggests there are inadequacies in the current market structure for signaling needed investment. Future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, local ancillary service procurement, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation in November 2007, will provide some of these elements (LMP, some degree of scarcity pricing, and capability to procure ancillary services locally). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and comparable programs for non-CPUC jurisdictional entities.

2.5.2 The Must-Offer Obligation

The Must-Offer Obligation (MOO) refers to a CAISO Tariff provision that requires all non-hydroelectric generating units that participate in the CAISO markets or use the CAISO Controlled Grid to bid all available capacity into the CAISO Real Time Market in all hours. This provision originated from an April 26, 2001 FERC Order adopting a prospective monitoring and mitigation plan for real-time California wholesale energy markets and has been extended through a series of subsequent FERC orders. For long-start-time units, this obligation extends into the day-ahead time frame to enable the CAISO to issue start-up instructions (or deny shut-down requests) for units the CAISO expects to need the next day.

Use of the MOO for reliability services has been extensive over the past three years, although costs associated with this mechanism declined significantly in 2005 (see Chapter 6). While there are several notable differences between RMR and MOO, one important distinction is compensation. RMR units have a pre-negotiated compensation rate that is intended to cover all, or some portion, of the total cost of owning and operating that unit. As such, the RMR mechanism provides a very explicit and targeted revenue stream for fixed cost recovery so that these units will continue to operate and provide the needed local reliability service. Compensation has two general components under RMR: a payment to cover (all or a portion of) a unit's fixed costs and a payment to cover variable cost of production. By contrast, units that are committed by the CAISO under the MOO do not receive a pre-determined fixed payment intended to address fixed cost recovery. Instead, such units are paid for their minimum load energy using a cost-based formula and are eligible to earn market revenues on ancillary services and real-time energy sales to the CAISO. Additionally, units that are committed under

[22] See http://www.caiso.com/docs/09003a6080/35/46/09003a60803546fd.pdf

the MOO receive a second payment for their minimum load energy through receiving the real-time market clearing price for that energy. In the aggregate, this second payment has been roughly 40 percent of the MLCC payment. For perspective, total MLCC costs for 2003-2005 (in millions) were $125, $287, $119, or $531 for the entire three years. While use of the MOO has subsided in 2005, these figures demonstrate the CAISO's continued reliance on and need for the MOO to provide reliability services. The second payment on minimum load, discussed above, comes to about $214 million for the 2003-2005 period, bringing the total non-market compensation for these units to $745 million for this three-year period.

While $745 million paid out to units subject to MOO is a significant revenue source, it should be noted that the majority of these revenues go to a limited subset of units. Eighty percent of the total combined payments for 2005 (MLCC and the second energy payment) were paid to roughly 34 percent of the units committed under the MOO. In the context of providing an additional source for revenue adequacy, the concentrated distribution of payments to a smaller subset of units provides little additional revenues to the larger subset of units receiving only 20 percent of the total payments.

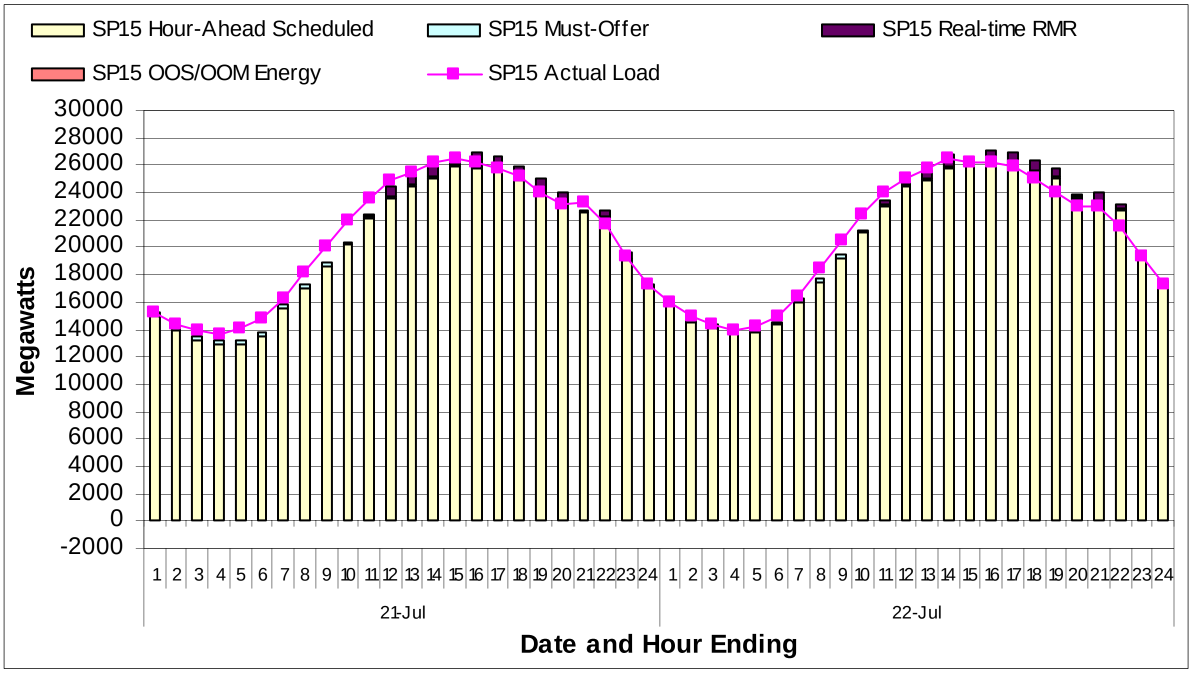
Although the MOO provides cost compensation plus a second market-based payment for minimum load as well as opportunity for market revenues from providing ancillary services and real-time energy, generation owners have argued that there is insufficient fixed cost recovery provided by the MOO provisions and that units committed via the MOO are providing a reliability service (in addition to energy and ancillary services) for which they are not being compensated.

In addition, the MOO may provide a potential disincentive to Load Serving Entities (LSEs) to enter into long-term contracts with generation owners as LSEs may find it financially advantageous to rely on the MOO for a unit's reliability service rather than contract directly for that service. Bilateral contracts with LSEs could provide generator owners with a more stable and targeted revenue source for fixed cost recovery than is provided under the current MOO structure and thus provide a better opportunity for generator owners to cover their going forward fixed costs. The concern that LSEs might rely on the MOO mechanism rather than contract with the generation resources that are frequently subject to MOO should largely be addressed by the CPUC Resource Adequacy requirements that are going into effect in 2006 – though its effectiveness may be undermined by the lack of locational capacity requirements in 2006. Additionally, the use of RMR or other potential CAISO contracting mechanisms may help to further ensure units that are critical for reliability have adequate mechanisms and opportunities for fixed cost recovery.

Though controversial, the MOO has proven to be an important tool for reliability and market competitiveness, particularly during peak summer demand periods. During the July-August heat wave in 2005, the MOO may have been a key factor in maintaining market competitiveness. In particular, during peak afternoons between July 18 and 23, the peak week of 2005, calculated system-wide residual supply indices range between 1.14 and 1.3. Had any unit withheld supply from the CAISO markets, these RSI indices would have been lower, and certain suppliers in that case likely would have been pivotal (i.e., able to exercise market power). However, whether it would have been a profitable strategy for such suppliers to exercise market power is a separate and more complicated question. Given the high level of forward contracting, profitable opportunities for the exercise of market power are much more limited than in prior years (e.g., 2000-2001).

The MOO also provided important reliability benefits in 2005. For example, on July 21, 2005, resources that were denied waivers from the MOO provided approximately 1,734 MW of generation. The Must-Offer energy plus RMR-contracted energy and other real-time energy from scheduled resources was sufficient to cover the difference between scheduled generation and load over this new SP15 peak of 26,459 MW, with only a single out-of-market transaction of approximately 1.67 MW for a system condition. The following chart compares SP15 load to zonal scheduled volume, must-offer procured generation operating at minimum load, RMR energy, and OOS/OOM procurement, for July 21 and 22, 2005.

Figure 2.27 SP15 Actual Load vs. Scheduled, Must-Offer, RMR, and OOS Energy, July 21-22, 2005



2.5.3 Generation Additions and Retirements

As discussed above, the current spot market structure coupled with a reliance on RMR and the MOO may not be providing sufficient market incentives for LSEs to enter into long-term contracts in critical areas of the grid. This apparent shortcoming may be compensated for in 2006 and beyond through regulatory means, particularly the CPUC Resource Adequacy requirements – provided this framework facilitates long-term procurement as opposed to short- to medium-term contracting. In the meantime, the continued reliance on an aging pool of generating units in California is a concerning trend. This subsection specifically addresses concerns regarding the aging pool of units in California and the potential need to either keep these units in operation or attract new investment to replace the capacity that may retire in the coming years. Table 2.12 shows generation additions and retirements, with a load growth trend figure. Note that while generation additions and retirements by zone show a net increase system-wide of 2,845 MW in 2005 and while more new generation was added to the CAISO Control Area than any other ISO in 2005[23], the total estimated net change in supply margins through 2006 is a negative 537 MW for SP15, indicating that new generation has not kept pace

[23] FERC Winter 2005-2006 Energy Market Update, February 16, 2006 (http://www.ferc.gov/legal/staff-reports/eng-mkt-con.pdf)

with unit retirements and load growth in this region.[24] One of the consequences of this is the continued reliance on older generation facilities.

Table 2.12 Generation Additions and Retirements by Zone

	2001	2002	2003	2004	2005	Projected 2006	Total Through 2006
SP15							
New Generation	639	478	2,247	745	2,376	352	6,837
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	(4,280)
Forecast Load Growth*	491	500	510	521	531	542	3,094
Net Change	148	(1,184)	565	48	1,395	(1,510)	(537)
NP26							
New Generation	1,328	2,400	2,583	3	919	89	7,322
Retirements	(28)	(8)	(980)	(4)	0	(215)	(1,235)
Forecast Load Growth*	389	397	405	413	422	430	2,456
Net Change	911	1,995	1,198	(414)	497	(556)	3,631

* Assumes 2% peak load growth using 2005 forecast from 2005 Summer Assessment.

There is a large pool of aging units in California, with 46 units built before 1979 having an average age of 42 years as seen in Table 2.13. Figure 2.28 shows the percent of hours in a year that units built before 1979 are running. While the trend is declining, this older pool of units is still relied upon, to provide either energy or reliability services, for nearly 40 percent of the hours in the year. Because of the age and relative inefficiency of these units, they are likely to have net revenues below those reported in Section 2.5.1 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.

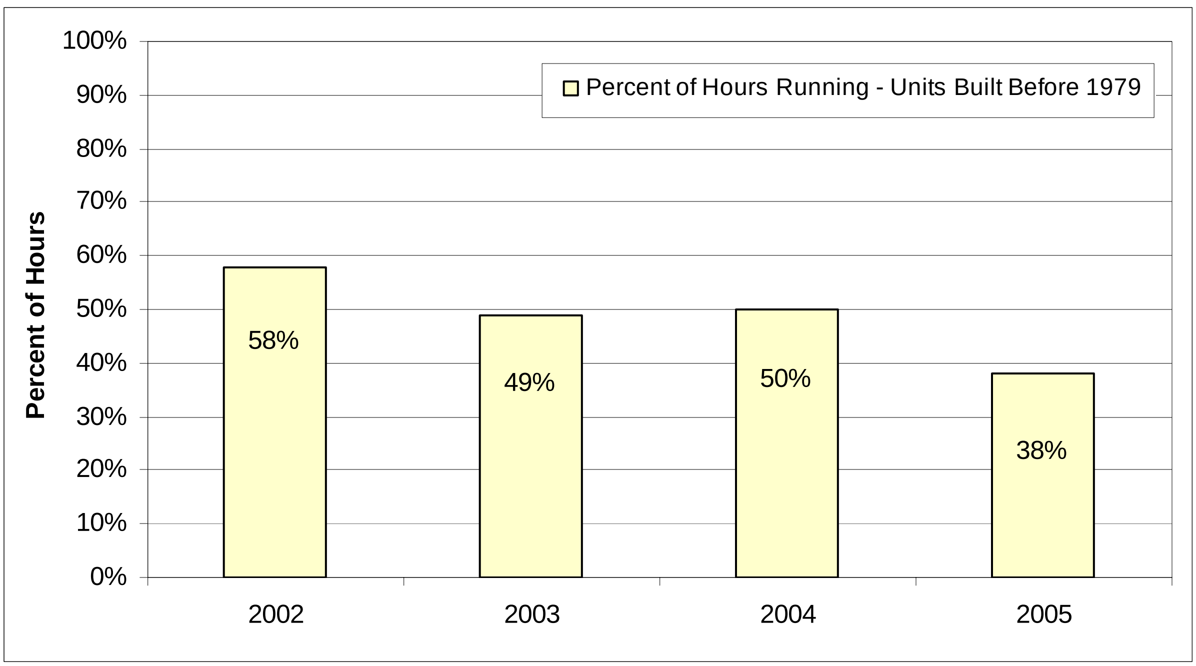
[24] It is important to note that this table only shows part of the supply picture in SP15. Some increased import capability to SP15 has also occurred. As discussed in Chapter 1, the Path 26 north-to-south rating was increased by 300 MW in 2005 and numerous other transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone. However, despite all of these improvements, meeting summer peak load demands in SP15 remains extremely challenging.

Table 2.13 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	44	17%	36%
South of Path 26	33	9,304	42	12%	35%
Total	**46**	**13,946**	**42**	**14%**	**35%**

1 Total active unit capacity as of date of publication.
2 Based on build date.
3 Based on 2005 data. Does not adjust for unit outages.
4 Based on 2005 data. Percent of all hours in year where unit showed positive metered generation.

Figure 2.28 Percent of Hours Running for Units Built Before 1979



Unfortunately, long-term energy contracting by the state's major investor owned utilities has been very limited and may therefore perpetuate the need to rely on this aging power fleet. In its 2005 Integrated Energy Policy Report (2005 Energy Report), the CEC reports that, "Utilities have released some Request for Offers (RFOs) for long-term contracts, but they account for less than 20 percent of solicitations, totaling 2,000 MW out of approximately 12,500 MW under recent solicitations,"[25] and notes that, "California has 7,318 MW of approved power plant projects

25 2005 Integrated Energy Policy Report, California Energy Commission, p. 52.

that have no current plans to begin construction because they lack the power purchase agreements needed to secure their financing."[26] The report notes that the predominance of short to medium term contracting perpetuates reliance on older inefficient generating units, particularly for local reliability needs, "Continuing short-term procurement for local reliability prolongs reliance on aging units that could otherwise be re-powered economically under the terms of longer-term contracts and thereby provide similar grid services at a more competitive price."[27]

In its report, the CEC recommends that the CPUC require the IOUs to sign sufficient long-term contracts to meet their long-term needs and allow for the orderly retirement or re-powering of aging plants by 2012. One of the major impediments to long-term contracting by the IOUs is concern about native load departing to energy service providers, community choice aggregators, and publicly owned utilities, which could result in IOU over-procurement and stranded costs. While this is a legitimate concern, it can be addressed through regulatory policies such as exit fees for departing load and rules governing returning load (i.e., load that leaves the IOU but later wants to return).

While long-term contracting is critical for facilitating new investment it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. Though the CPUC has made significant progress in 2005 in advancing its Resource Adequacy framework, delays in the development and implementation of local resource adequacy requirements could further impede new generation development in critical areas of the grid. Going forward, an effective local resource adequacy framework to facilitate needed generation investment is critical for ensuring reliable grid operation and stable markets.

2.6 Load Scheduling Practices

As discussed in Chapter 1, with the onset of peak summer demand conditions in early July, CAISO Operations staff raised concerns about load under-scheduling in the Day Ahead Market. The concern predominately relates to shortfalls between the CAISO day-ahead forecasted load and the level of final day-ahead load schedules. To the extent such shortfalls exist, the CAISO operators need to commit additional units through the MOO waiver denial process, which puts additional administrative burdens on operational staff and introduces significant commitment uplift costs to the market. More fundamentally, it raises a concern about whether LSEs have adequately planned for meeting their peak load obligations.

Throughout the initial summer months, the CAISO committed significant amounts of capacity under the MOO to cover expected shortfalls in day-ahead schedules relative to day-ahead forecasted peak load. CAISO operators commit capacity to make up this shortfall to ensure that sufficient capacity is online in time to meet the next day's peak load. During this time, day-ahead schedules had been as much as 12 percent less than the day-ahead forecast and had caused significant commitment of resources under the must-offer waiver denial process. This resulted in daily MLCC system costs in excess of $700,000 in July.

The CAISO recommendation for addressing this issue was to require LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market so that Grid Operators would not have to commit additional units in the CAISO's day-ahead must-offer process to insure enough capacity was online to meet load in the Real Time Market. In late July, the three IOUs began voluntary efforts to meet the day-ahead scheduling target of 95 percent. On September 22, the

[26] 2005 Integrated Energy Policy Report, California Energy Commission, p. 44.
[27] 2005 Integrated Energy Policy Report, California Energy Commission, p. 61.

CAISO filed Tariff Amendment 72 with the FERC to require all LSEs to schedule no less than 95 percent of their forecast load in the Day Ahead Market. FERC accepted the terms of the filing in an Order dated November 21, 2005.

Figure 2.29 and Figure 2.30 depict day-ahead under-scheduling by LSEs during peak operating hours as a percent of the CAISO day-ahead load forecast in SP15 and NP26. These figures illustrate the nature of the under-scheduling problem. The two key series in these figures are Day Ahead Forecast Load and Day Ahead Scheduled Load, which show that day-ahead under-scheduling of load was primarily a problem in NP26 and had reached twenty percent of forecast load north of Path 26 (NP26) during the peak hours in June and July of 2005.

Figure 2.29 Forecast, Schedule and Actual Load for Peak Load Hours in SP15 - June and July of 2005

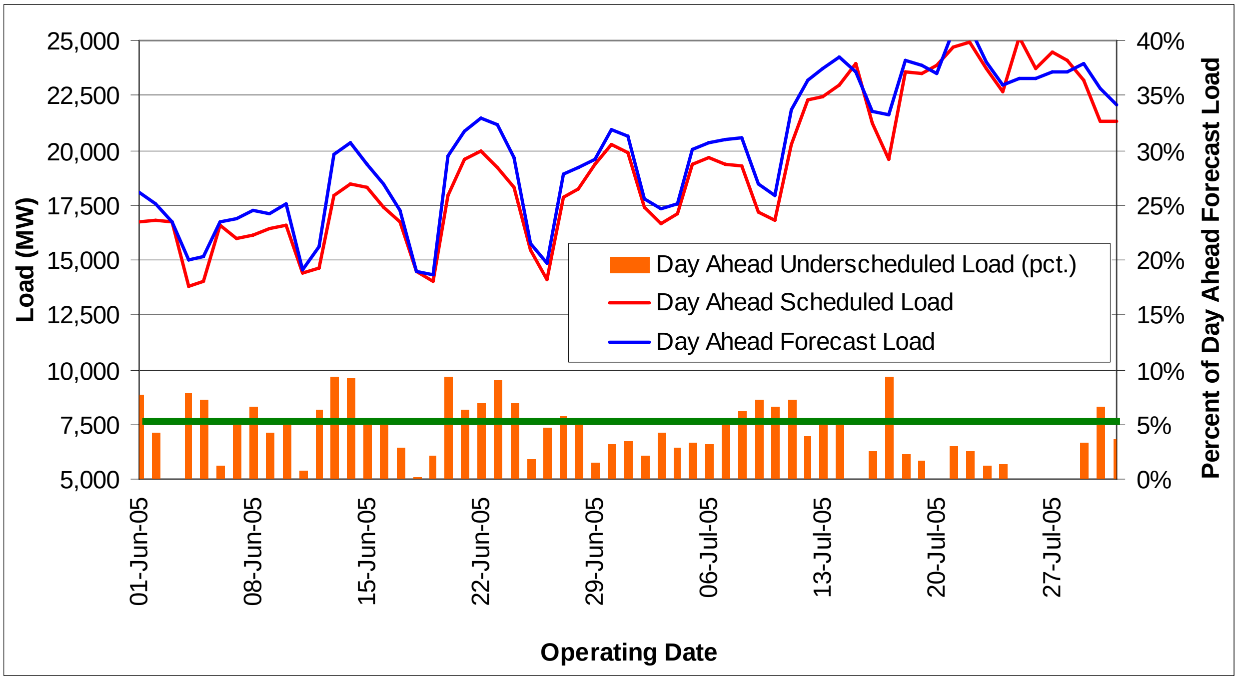
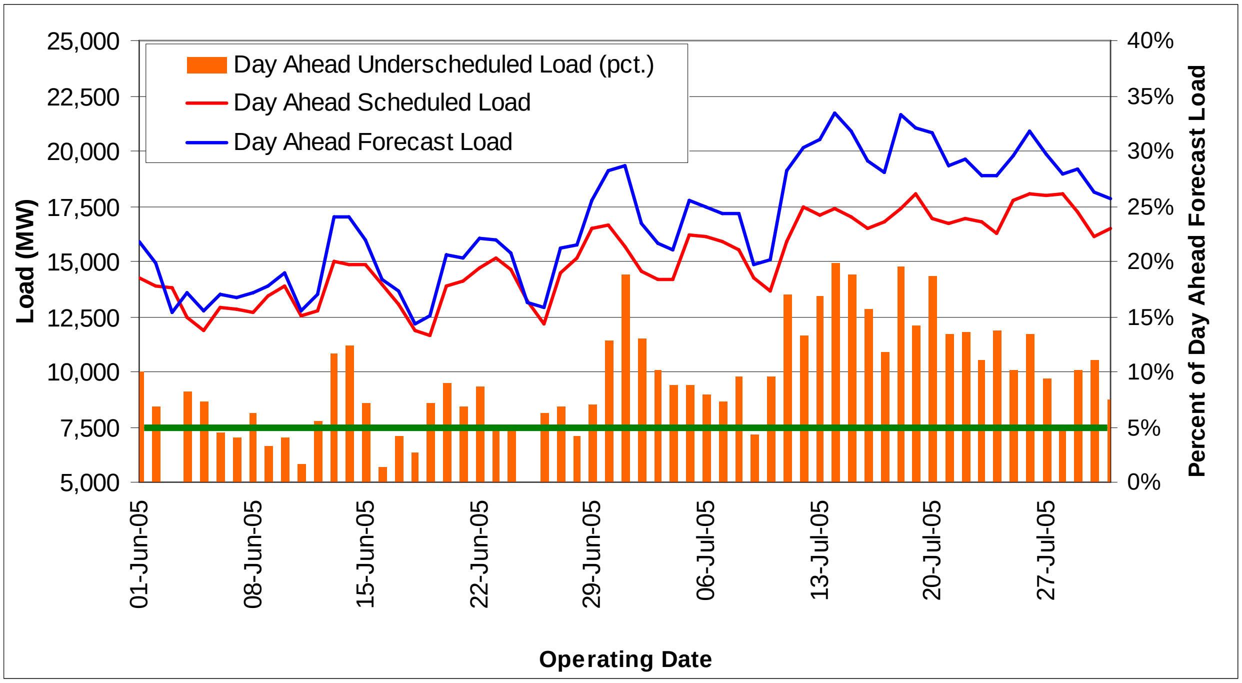
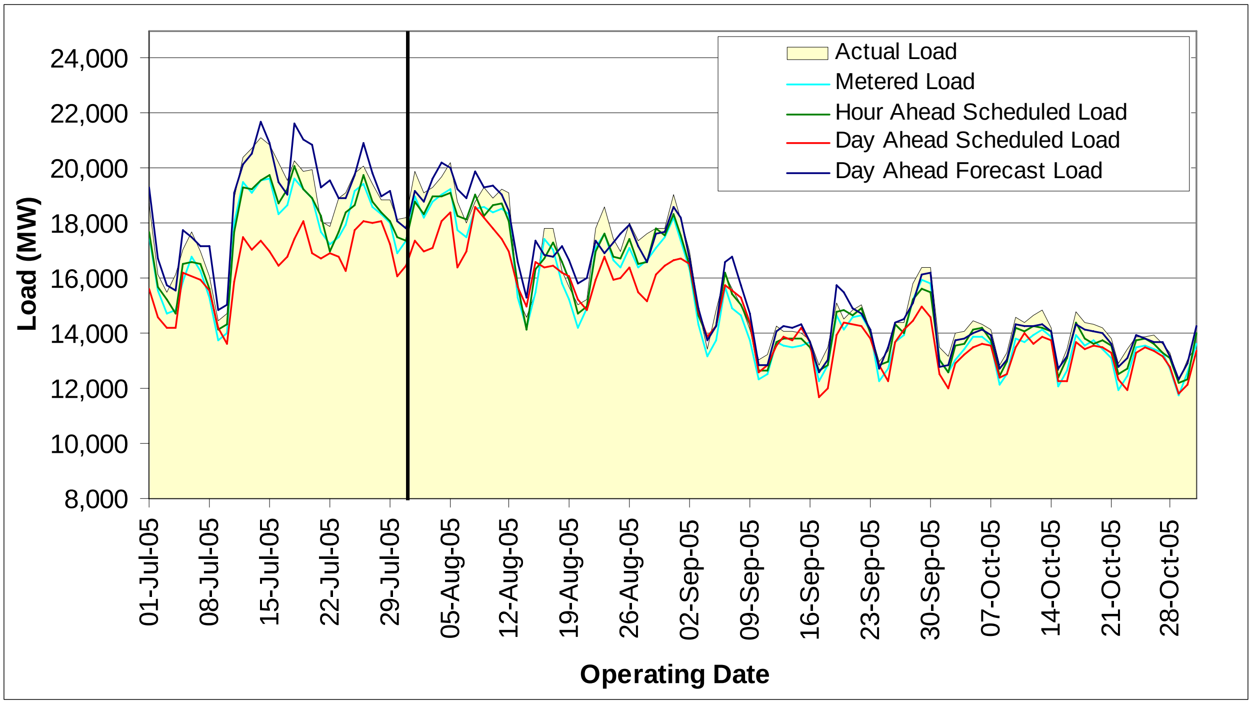


Figure 2.30 Forecast, Schedule and Actual Load for Peak Load Hours in NP26 - June and July of 2005



A more complete picture of scheduling practices in NP26 is presented in Figure 2.31 below. The day-ahead under-scheduling of load during peak summer months is still evident in this figure, however, there are two additional points to be made regarding scheduling practices by LSEs and electricity requirements to meet imbalance needs relative to metered load. Figure 2.30 illustrates that LSEs in the NP26 zone did schedule, in aggregate, nearly one hundred percent of their metered load by the hour-ahead timeframe. This shows that LSEs were not leaning heavily on the imbalance market to meet over five percent of their load served, however, leaving a significant portion of load to be scheduled after the day-ahead required Grid Operators to take measures in the Day Ahead Market to ensure there were sufficient resources to meet forecast load in real-time. The second point deals with the difference between LSEs' metered load (Metered Load series in Figure 2.31) and the amount of electricity required by the CAISO to keep the grid in balance (Actual Load in Figure 2.31). The Actual Load metric is based on telemetered data from generation and tie points and represents the amount of electricity that is required to meet load in real-time. This metric differs from actual metered load values due primarily to transmission losses and unaccounted for energy. An additional factor is that some entities schedule with the CAISO on a net basis but are metered on a gross basis. Due to these differences, the Actual Load metric is on average about 5 percent, or 815 MW, greater than actual metered load on the peak hour of the day in the NP26 region. The CAISO often uses Actual Load in its analyses due to the immediate availability of this metric compared to the availability of actual metered load values, which are often not available until 45 or more days after the fact, and because Actual Load represents the amount of electricity that is required to meet load in real-time, including line losses and unaccounted for energy.

Figure 2.31 Forecast, Schedule and Actual Load for Peak Load Hour (July - October 2005)

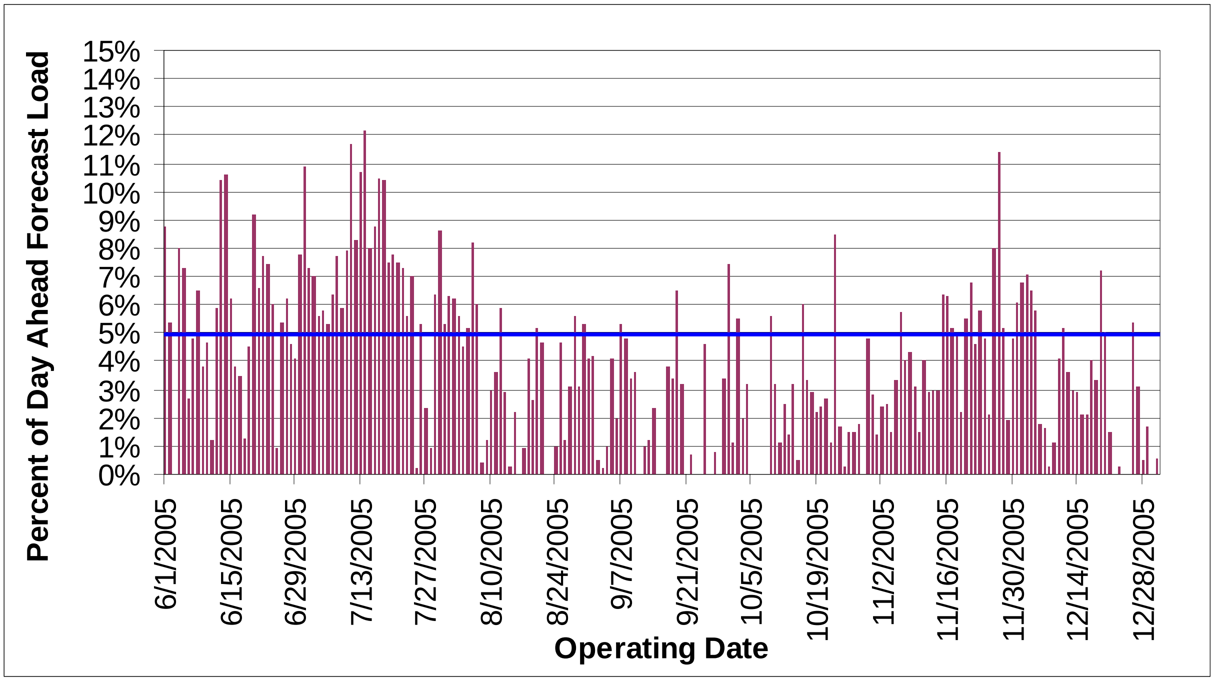


In addition to an explicit day-ahead scheduling requirement, the CAISO recognized that more timely information regarding the potential cost of under-scheduling in the Day Ahead Market would result in forward load-scheduling practices that more fully reflected the actual costs of deferring procurement to the Hour Ahead or Real Time Markets. To provide more timely information about the cost of deferring load-scheduling, the CAISO began posting estimates reflecting the per-MWh cost of under-scheduled load in the day-ahead in terms of the minimum load cost compensation (MLCC) resulting from the additional units that had to be committed to cover the under-scheduled load.

As a result of these efforts, the CAISO has observed higher proportions of total load scheduled in the Day Ahead Market, with instances in which less than 95 percent of actual load was scheduled in the Day Ahead Market declining significantly. Figure 2.32 shows this trend for the peak load hour of each day since June 1, 2005. There is a notable period, the second half of November, in which day-ahead under-scheduling was at or above the 5 percent level. This pattern coincides with abnormally high natural gas prices. These high natural gas prices may have impacted the spot bilateral procurement costs so as to shift some procurement from the Day Ahead Market to the day-of markets. As natural gas prices declined in late December and into January of 2006, load scheduled in the Day Ahead Market was predominantly above the 95 percent level.

While measuring the benefit to reliability of a higher level of load scheduled in the Day Ahead Market may not be feasible, one indicator of the benefit of implementing the 95 percent scheduling requirement is the change in must-offer waiver denials made to support system capacity requirements. An assessment of the use of the MOO to commit units to meet “System” requirements indicates that overall MOO commitments for “System” requirements are down for August-December 2005 compared to the same months in 2004. While this is not a conclusive finding (there may have been other factors affecting the need to commit units for “System” requirements), it is an indication that the 95 percent scheduling requirement has reduced the need to supplement the pool of market-committed units through the MOO. Another issue related to the scheduling requirement is whether or not the additional load scheduled in the Day Ahead Market is met by physically feasible schedules, or if the schedules are infeasible and creating additional costs through the need to manage intra-zonal congestion. An indicator for this is the use of MOO unit commitments and the use of out-of-market dispatches in real-time to relieve transmission constraints. Both of these costs have declined for August-December 2005 compared to the same months in 2004, however, again, this may be due to other factors including transmission upgrades (discussed further in Chapter 6).

Figure 2.32 Percent of CAISO Forecast Total Load Not Scheduled in the Day Ahead Market



2.7 Performance of Mitigation Instruments

2.7.1 Damage Control Bid Cap

The Damage Control Bid Cap for energy bids was binding more frequently in 2005 than in 2004, as shown in Figure 2.33. This is due largely to the increase in natural gas prices, which pushed production costs of certain gas-fired resources in the CAISO Control Area near the $250/MWh bid price cap. The $250 bid cap was binding in the real-time balancing market in approximately 0.4 percent of intervals in 2005, and in no intervals in 2004. Figure 2.33 shows interval prices within SP15 for all hours in 2004 and 2005, ordered from highest to lowest price. Figure 2.34 shows the same interval prices, normalized to the price of natural gas on January 1, 2004, which was $5.41/MMBtu. Figure 2.34 demonstrates that natural gas price increases appear to be responsible for the increased frequency of price cap hits in 2005.

Figure 2.33 SP15 Actual Interval Price Duration Curves: 2005 vs. 2004

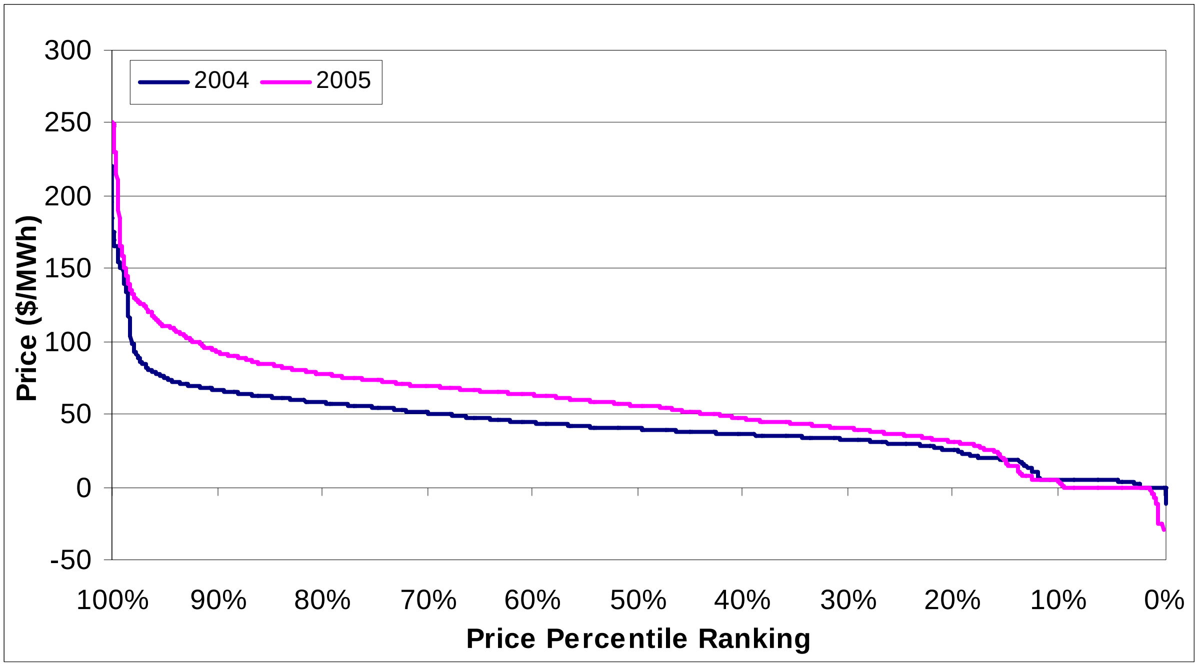


Figure 2.34 SP15 Interval Price Duration Curves, Normalized against Changes in Price of Natural Gas: 2005 vs. 2004[28]

[28] Prices adjusted for gas increases by normalizing to Southern California Border Average gas price on 1/1/04, which was $5.41/mmBtu. Assume $4/MWh operation and maintenance production cost.
Normalization formula: normalized price = (interval price - $4) * ($5.41/daily gas price) + $4

As electric production costs increased with higher gas costs, the CAISO Market Surveillance Committee (MSC) and the DMM recommended raising the maximum bid price from $250 to $400/MWh. This change was approved by FERC on January 13, 2006, and was effective the following day.

The July 22 peak is an example of the bid cap limiting price spikes. While prices increased in this hour to $249.99/MWh, the SP15 bid curve was relatively supply-inelastic ("steep") at the dispatch level during this price spike, as evidenced by the fact that SP15 load would have had to drop only 50 MW or so to pull the price below $200/MWh. Further analysis of this event is provided in Chapter 3.

The -$30/MWh price floor was binding in approximately 10 intervals in 2005 for in-sequence dispatches paid at the market-clearing price. All were in the last week of December, when gas prices were high and loads were low. Large negative prices are usually set by decremental bids. During this period, certain units faced costs for decrementing due to gas flow requirements or other operating limitations.

2.7.2 AMP Mitigation Performance

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

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

b. 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.

c. 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, the bid conduct and market impact tests are applied. The market impact test is based on the average of all four 15-minute prices.

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.

As in previous years, AMP did not mitigate any bids for incremental energy in 2005. The frequency of AMP conduct test failures increased in the fourth quarter of 2005 (Table 2.14), as natural gas prices put upward pressure on production costs. This increased conduct test failure frequency for two reasons:

1. The likelihood of the MCP to be above $91.87/MWh increased as all bids, including decremental bids, migrated upward; and

2. Production costs rose quite sharply, particularly in September, following Hurricanes Katrina and Rita. As a result, suppliers increased their bids relatively abruptly. Bid reference levels, which are what submitted bids are

compared to in applying the conduct test, are adjusted for changes in gas prices using a monthly gas index. Consequently, the reference levels may not be adequately adjusted to compensate for a rapid increase in gas prices within a month and this diversion may trigger more bid conduct violations.

Table 2.14 Frequency of AMP Conduct Test Failures

	Conduct Test Failures
Jan-05	36
Feb-05	22
Mar-05	81
Apr-05	48
May-05	15
Jun-05	4
Jul-05	11
Aug-05	38
Sep-05	195
Oct-05	328
Nov-05	173
Dec-05	371