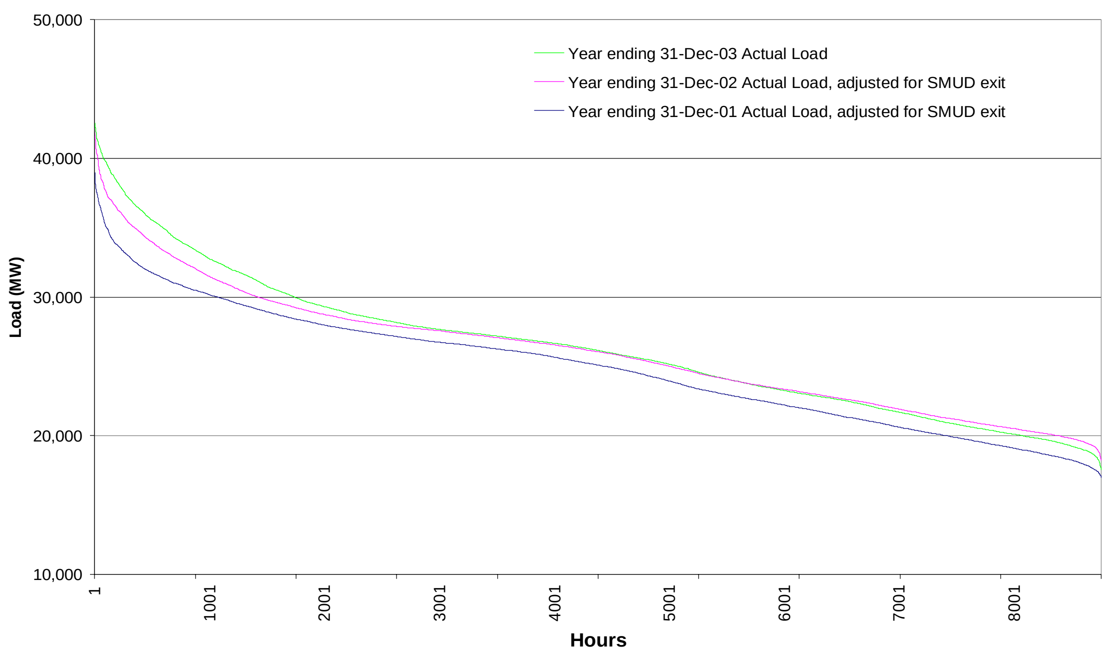
# 2. Summary of 2003 Energy Market Performance

## 2.1 Supply and Demand Conditions

### *2.1.1 Loads*

Average loads increased by 1.0 percent during 2003. The 2003 average load was 26,329 MW, compared to 26,065 MW in 2002. The peak load increased by 0.5 percent to 42,581 MW up from 42,352 MW in 2002. Loads during the first half of the year were lower than in 2002 due to mild weather conditions. However, average loads from June through December were 3.7 percent higher than during the same period in 2002. This increase, in large part, is due to economic growth resulting from a recovering economy. Figure 2.1 shows CAISO system-wide load duration curves for 2001 through 2003. Table 2.1 presents load trends for 2001-2003.

**Figure 2.1 Load Duration Curves, 2001-2003**



### Table 2.1 Hourly Actual Load Metrics, 2001-2003[1]

| Year | Avg. Load | % Chg. | Annual Min. Load | % Chg. | Annual Max. Load | % Chg. | St. Dev. of Load | % Chg. |
|---|---|---|---|---|---|---|---|---|
| 2001 | 25384 | | 17282 | | 38975 | | 4263.61 | |
| 2002 | 26065 | 2.7% | 18209 | 5.4% | 42352 | 8.7% | 4335.07 | 1.7% |
| 2003 | 26329 | 1.0% | 17515 | -3.8% | 42581 | 0.5% | 4941.47 | 14.0% |

## *2.1.2 Supply*

Supply conditions were robust during 2003. This was due to a number of reasons:

- Favorable hydroelectric conditions lasting into the summer peak season, both within the CAISO control area and in the Pacific Northwest; and
- Significant amounts of new generation added in California over the past three years; and
- Few units experiencing protracted outages during the summer months.

High natural gas prices, however, increased generation costs throughout the year, particularly in February and December.

### 2.1.2.1 Imports and Exports[2]

Primarily as a result of near-normal hydroelectric production in the Pacific Northwest since 2002 and significant new generation additions in the southwest, net imports into California were substantial in 2002 and 2003. 2003 net imports averaged 6,552 MW, nearly the same as 2002's 6,580 MW. Imports increased 1 percent from 2002 to 2003 while exports increased 8.8 percent. Figure 2.2 shows the annual average system-wide imports, exports, and net imports 2001 through 2003. Table 2.2 on the following page shows imports and exports between the CAISO and neighboring regions in 2003.

1 Loads through 6/18/02 are calculated excluding SMUD loads, in order to compare properly to loads after SMUD exited the ISO Control Area on 6/19/02. Loads through 7/10/03 are measured instantaneously at top of hour. Loads beginning 7/11/03 are measured as integrated hourly averages. These methodologies may differ from those used to calculate load statistics in other documents reported by the ISO, such as Summer and Winter Assessments, or reported by other entities.

2 SMUD left the CAISO system in late June of 2002. Therefore, to provide comparable year-to-year comparisons, the figures reported here were adjusted to exclude SMUD imports and exports from January 2002 through June 2002.

**Figure 2.2 2001-2003 Annual Average System Wide Imports and Exports**

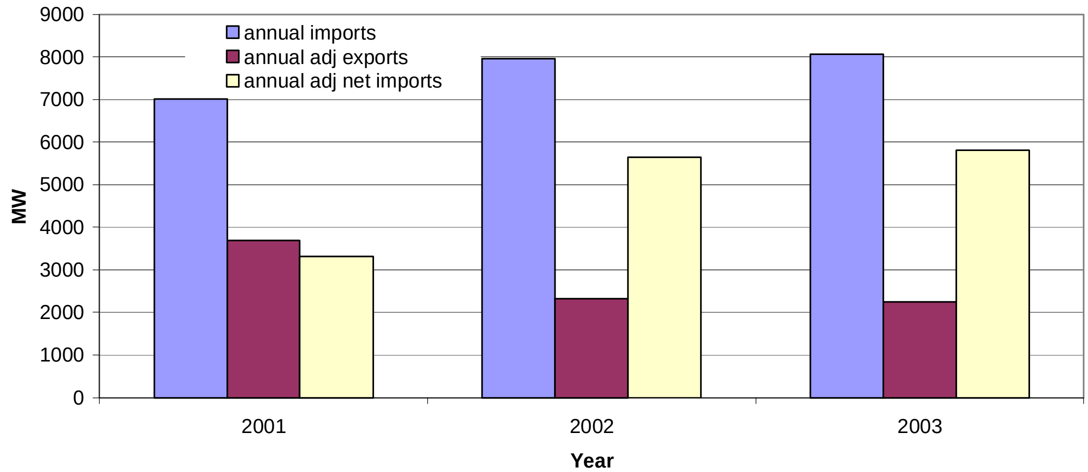



**Table 2.2 Average Scheduled Imports and Exports (MW) by Interface in 2003**

| Region | Scheduled Imports | Scheduled Exports | Net Imports |
|---|---|---|---|
| Arizona | 2970 | -219 | 2751 |
| Imperial | 437 | -132 | 305 |
| LADWP | 353 | -530 | -176 |
| Mexico | 116 | -5 | 111 |
| Nevada | 328 | -26 | 302 |
| Northwest | 2592 | -133 | 2458 |
| SMUD | 51 | -788 | -737 |
| SP/Northern Nevada | 14 | -21 | -7 |
| WALC | 790 | -356 | 434 |
| Other/Undetermined | 503 | -10 | 493 |

### 2.1.2.2 Hydro Generation

Cool and wet weather in California during April 2003 significantly improved hydro conditions and reduced the supply deficit of the preceding three months. As a result, April through July hydro production increased from near average to above average. Hydro supplies were at normal levels in the Pacific Northwest where California receives much of its imported energy. As of May 1, 2003, Pacific Northwest reservoir storage levels were near seasonal averages. This was similar to 2002 where storage levels were near to slightly below average.

The healthy hydro conditions in the west contributed to the ample energy supply in California in 2003 as they did in 2002. Adequate hydro production is a significant factor in the stability of the western wholesale power markets.

#### 2.1.2.3 Thermal Generation

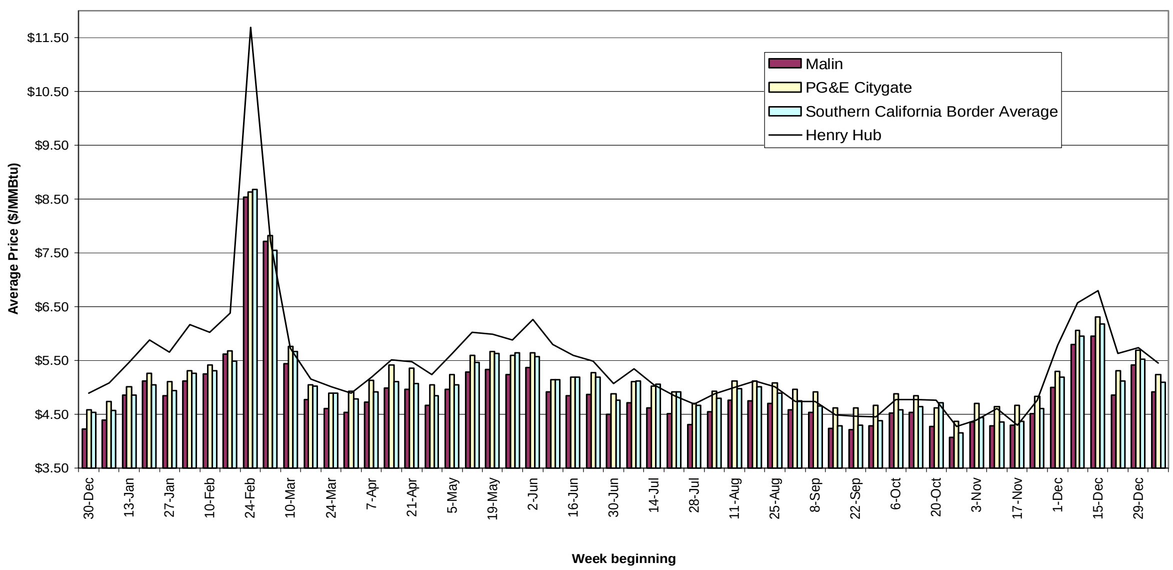
The net addition of 2,678 MW of natural gas-fueled thermal generation units added to California's resource portfolio resulted in the provision of 22 percent of the energy supplied to meet 2003 loads. The forced outage rate of all units within the CAISO control area also decreased to approximately 4 percent from over 5 percent in 2002 (see Section 2.1.2.4). Natural gas fueled units are system marginal units during the vast majority of the time and, therefore have a great impact on wholesale energy prices. Thermal generation unit's production costs increased significantly in 2003 due to a 64 percent increase in natural gas prices in 2003 compared to average 2002 levels.

***Natural Gas***

While natural gas prices in the west remained between $4.00 and $5.75/MMBtu for much of 2003, there were two prominent increases in prices. The first increase occurred in the latter half of February. Cold temperatures in the east, combined with tight storage conditions across the country, resulted in prices at Henry Hub exceeding $12/MMBtu. Natural gas storage dropped significantly below both 2002 levels and 5-year average. These levels are shown in Figures 2.4 and 2.5. Low storage levels impact natural gas prices in two ways. First, reduced storage may result in higher spot purchases of natural gas to serve demand, in turn causing a price increase. Second, reduced storage levels may induce gas marketers to purchase natural gas to replenish those reserves, thereby directly increasing demand for natural gas and causing a price increase.

Efforts to replenish depleted storage levels combined with a recovering economy served to increase natural gas demand throughout the year. The increased demand during that period led to significantly higher prices. In 2002, gas demand and resulting prices were much lower due to a mild winter, slow economy, and high storage levels. The second significant price increase in 2003 occurred in December when cold temperatures and decreasing storage levels caused prices to increase, albeit with less impact than in February. Prices remained stable during the summer peak load season.

## Figure 2.3 Weekly Average Daily Natural Gas Prices




## Figure 2.4 Total United States Natural Gas Storage Levels (billion $ft^3$)

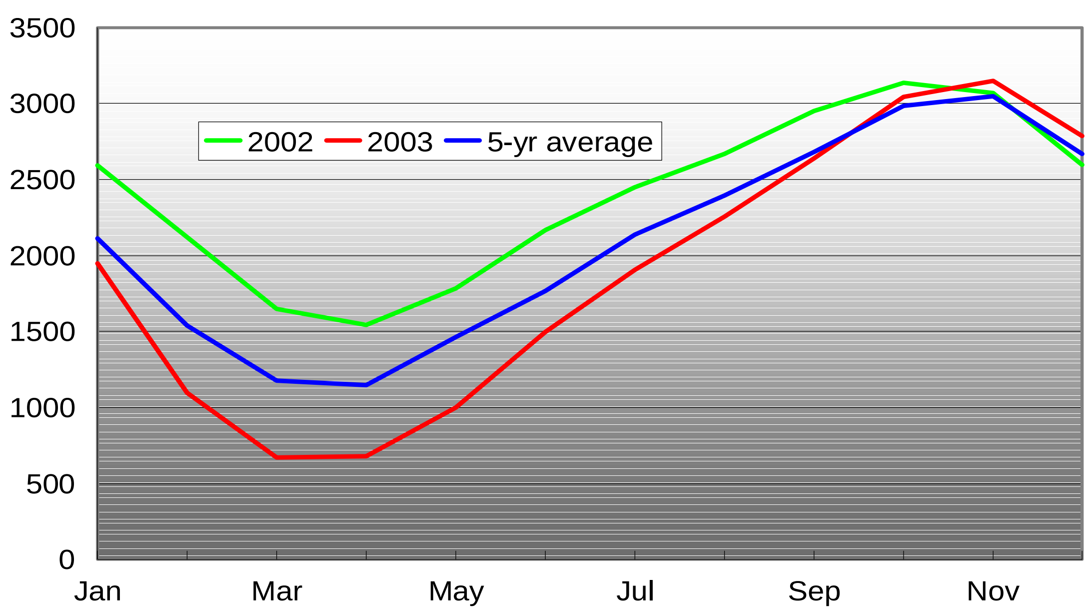
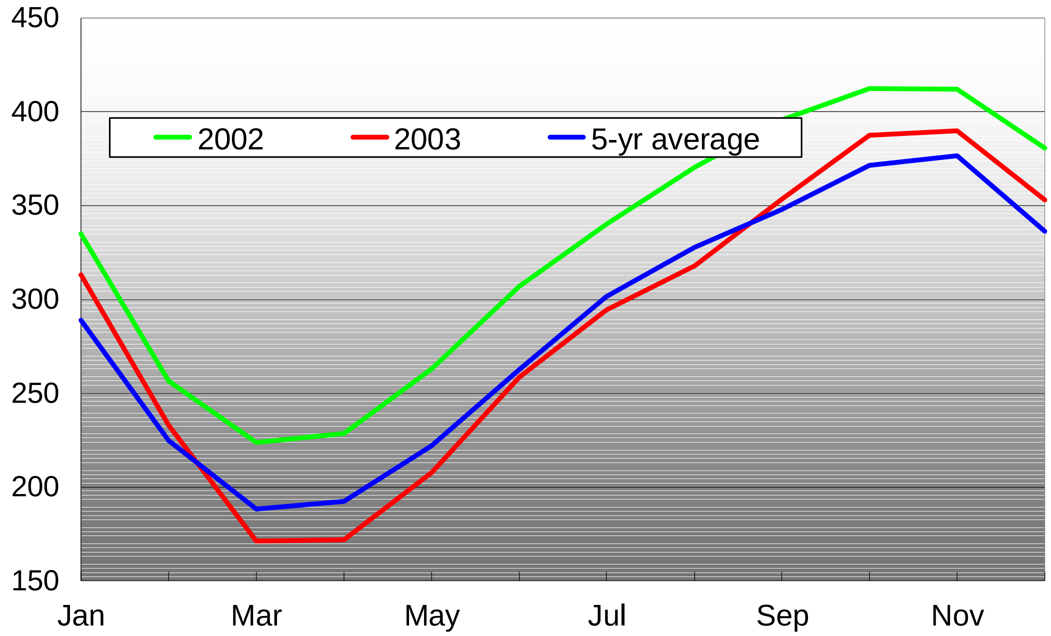


**Figure 2.5 Western United States Natural Gas Storage Levels (billion ft$^3$)**




### *Sources of Energy*

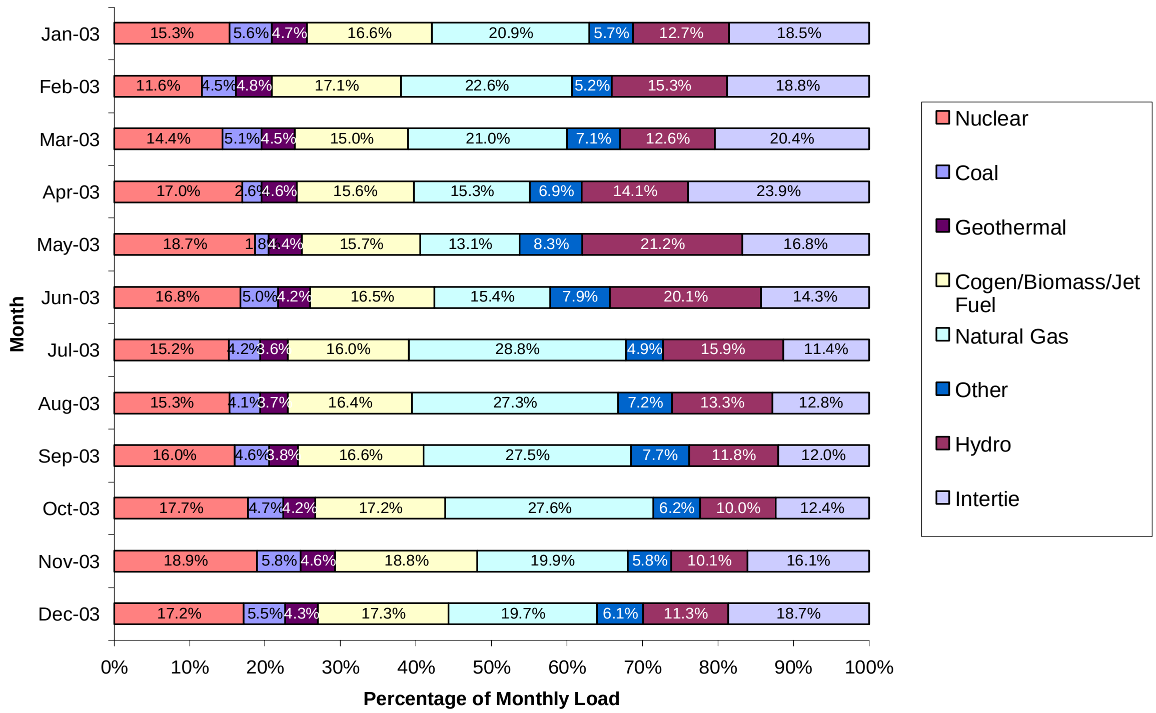
Load insensitive generation sources[3] such as nuclear, cogeneration, and coal facilities, served 40 to 45% of load each month, while between 10 and 25% of load was served by imports. The remaining 30 to 40% of load was met by a combination of natural gas-fired facilities and hydroelectric power.

The majority of the CAISO's loads are from investor-owned utilities whose procurement patterns govern how those loads are served. Testimony by the investor-owned utilities in the CPUC procurement proceeding[4] suggests that the utilities dispatch their retained generation in economic order to serve load. Since retained nuclear, coal, and hydroelectric generation are usually cheaper than contracted natural gas-fired generation, those facilities are usually fully utilized before natural gas-fired generation, making natural gas the marginal fuel. Figure 2.6 shows the monthly percentage contribution of energy by fuel type to serve load.

[3] These generation sources are characterized as load-insensitive because of the inefficiencies associated with changing the operating levels of the facilities in conjunction with hourly load fluctuations. Economic dispatch would suggest that nuclear facilities, with a production cost of between $10-$20/MW, and coal facilities, with a production cost of between $20-$30/MW, would be dispatched before natural gas, with a production cost of between $45-$60/MW. Cogeneration facilities are often subject to constraints more binding than those of system-wide load, e.g. wind, sunlight, facility loads, so that the energy provided by cogeneration facilities is often fixed.

[4] R.01-10-024.

**Figure 2.6 2003 Average Monthly Energy Percentage by Fuel Type**




## 2.1.2.4 Outages

Figure 2.7 shows outage trends during 2003. Generation unit outages during 2003 followed the traditional seasonal patterns. Maintenance (planned outages) and economic outages (higher cost units shutting down due to market prices less than their cost) usually increase in the spring and autumn during low load periods, but decrease during the high load summer periods. During the summer, there is usually a small increase in forced outages as power plants run for longer durations and become more susceptible to unscheduled maintenance issues. The forced outage rate, the annual average percentage of generation out due to unplanned reasons, fell in 2003 to approximately 4 percent down from just over 5 percent in 2002 as shown in Figure 2.8.

**Figure 2.7 2003 Weekly Average Outage Levels**

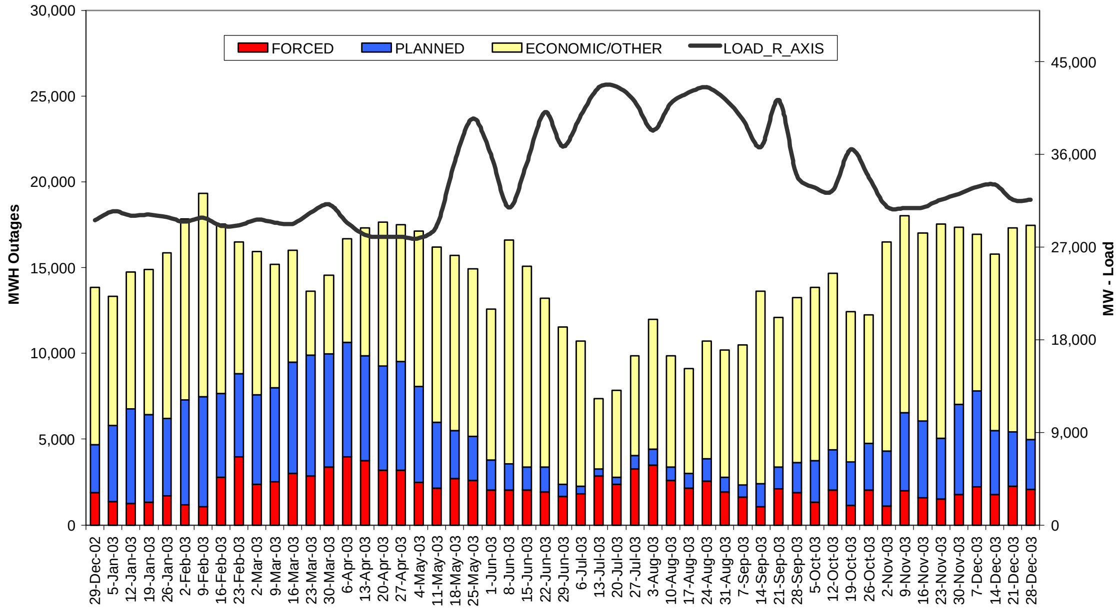
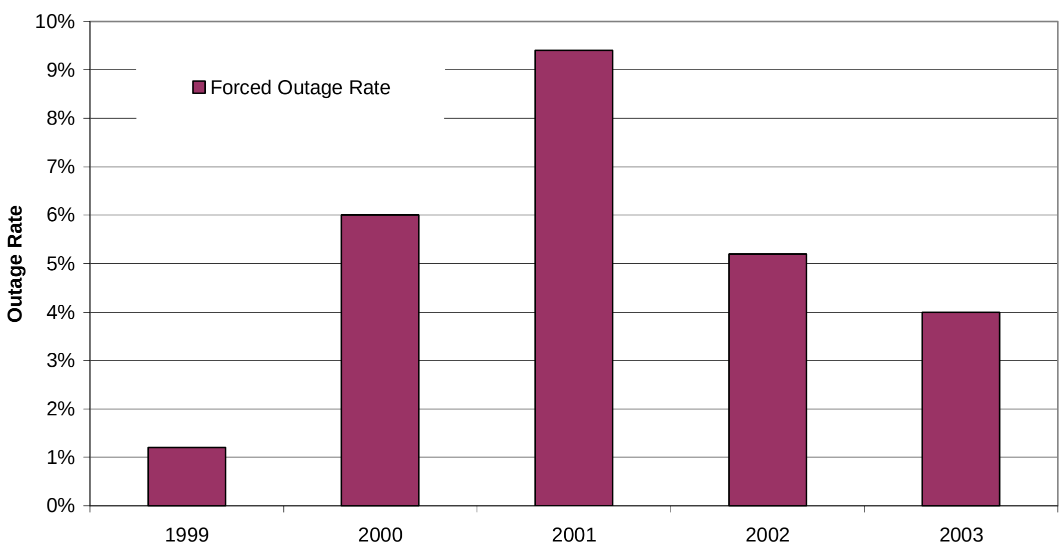



**Figure 2.8 1999-2003 Forced Outage Rate**



## 2.2 Market Cost Indices

### 2.2.1 Total Annual Wholesale Energy Costs[5]

Since 1999, the CAISO has reported a wholesale energy cost index. The index provides an estimate of total wholesale costs to load served that can be compared across years, and includes estimates of utility retained generation costs, forward bilateral contract costs, real-time incremental energy costs, and ancillary service reserve costs. In 2003, the estimated total cost was $12.1 billion, compared to $10.1 billion in 2002. Most of this increase can be attributed to the higher cost production costs of natural gas fired generation units. The 2003 annual average price of natural gas in California has risen 64 percent over 2002 levels. The following tables show the Wholesale Energy Cost Index by month for 2003, and annual summaries from 1998 through 2003. A chart of annual totals for the index is shown in the Executive Summary, in figure E1.

[5] Since January 2003, the CAISO has not received information from LSEs regarding actual costs of forward-scheduled energy. To calculate both the Wholesale Energy Cost Index and the All-In Price discussed in the next section, the Department of Market Analysis estimated forward energy costs. In both the Wholesale Energy Cost Index and the All-In Price Index, forward-scheduled energy includes:

(i) Utility-retained generation, priced at estimated costs of production;

(ii) Long-term contracted energy, estimated using 2002 delivery volumes (which were available to the CAISO by CERS); and

(iii) Short-term procured energy, priced at hour-ahead bilateral transaction prices reported by Powerdex, an independent energy information company offering the first hourly wholesale power indexes in the Western Interconnection.

## Table 2.3 Monthly Wholesale Energy Costs, 2003

| | ISO Load (GWh)* | Forward Energy (GWh)* | Est Forward Energy Costs (MM$)* | RT Energy Costs (MM$)* | A/S Costs (MM$)* | Total Energy Costs (MM$) | Total Costs of Energy and A/S (MM$) | Avg Cost of RT INC Energy ($/MWh) | Avg Cost of Energy ($/MWh) | A/S Cost ($/MWh Load) | A/S % of Energy Cost | Avg. Cost of Energy & A/S ($/MWh Load) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jan-03 | 17,992 | 17,035 | $ 917 | $ 8 | $ 14 | $ 925 | $ 939 | $ 61 | $ 51 | $ 0.79 | 1.5% | $ 52 |
| Feb-03 | 16,007 | 15,044 | $ 872 | $ 13 | $ 9 | $ 885 | $ 895 | $ 74 | $ 55 | $ 0.58 | 1.0% | $ 56 |
| Mar-03 | 18,105 | 17,055 | $ 1,016 | $ 17 | $ 13 | $ 1,033 | $ 1,046 | $ 78 | $ 57 | $ 0.73 | 1.3% | $ 58 |
| Apr-03 | 17,301 | 16,271 | $ 833 | $ 14 | $ 15 | $ 847 | $ 862 | $ 66 | $ 49 | $ 0.86 | 1.7% | $ 50 |
| May-03 | 18,742 | 16,667 | $ 886 | $ 14 | $ 25 | $ 900 | $ 925 | $ 88 | $ 48 | $ 1.31 | 2.7% | $ 49 |
| Jun-03 | 19,377 | 17,606 | $ 926 | $ 8 | $ 27 | $ 933 | $ 960 | $ 62 | $ 48 | $ 1.40 | 2.8% | $ 50 |
| Jul-03 | 23,027 | 21,038 | $ 1,192 | $ 20 | $ 24 | $ 1,212 | $ 1,236 | $ 64 | $ 53 | $ 1.05 | 2.0% | $ 54 |
| Aug-03 | 22,767 | 20,663 | $ 1,147 | $ 20 | $ 16 | $ 1,167 | $ 1,183 | $ 67 | $ 51 | $ 0.70 | 1.3% | $ 52 |
| Sep-03 | 20,948 | 19,208 | $ 1,041 | $ 14 | $ 14 | $ 1,055 | $ 1,069 | $ 68 | $ 50 | $ 0.68 | 1.3% | $ 51 |
| Oct-03 | 19,681 | 18,103 | $ 1,021 | $ 15 | $ 15 | $ 1,036 | $ 1,051 | $ 75 | $ 53 | $ 0.76 | 1.4% | $ 53 |
| Nov-03 | 17,687 | 16,345 | $ 909 | $ 6 | $ 12 | $ 915 | $ 927 | $ 55 | $ 52 | $ 0.65 | 1.2% | $ 52 |
| Dec-03 | 19,034 | 17,427 | $ 1,014 | $ 23 | $ 15 | $ 1,037 | $ 1,052 | $ 69 | $ 55 | $ 0.79 | 1.4% | $ 55 |
| **Total 2003** | 230,668 | 212,462 | $ 11,773 | $ 173 | $ 199 | $ 11,946 | $ 12,145 | | | | | |
| **Avg 2003** | 19,222 | 17,705 | $ 981 | $ 14 | $ 17 | $ 995 | $ 1,012 | $ 70 | $ 52 | $ 0.86 | 1.6% | $ 53 |

* Notes:

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

Forward energy costs 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 Powerdex hour-ahead prices.

Real-time energy costs include OOM, dispatched real-time paid at market clearing price, and dispatched real-time paid as bid.

A/S costs include ISO A/S market costs, plus self-provided A/S estimated at ISO market prices, less replacement reserve refund.

## Table 2.4 Annual Wholesale Energy Costs, 1998-2003

| | ISO Load (GWh) | Est Forward Energy Costs (MM$) | RT Energy Costs (MM$) | A/S Costs (MM$) | Total Energy Costs (MM$) | Total Costs of Energy and A/S (MM$) | Avg Cost of Energy ($/MWh) | A/S Cost ($/MWh Load) | A/S % of Energy Cost | Avg. Cost of Energy & A/S ($/MWh Load) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Total 2003** | 230,668 | $ 11,773 | $ 173 | $ 199 | $ 11,946 | $ 12,145 | | | | |
| Avg 2003 | 19,222 | $ 981 | $ 14 | $ 17 | $ 995 | $ 1,012 | $ 52 | $ 0.86 | 1.6% | $ 53 |
| **Total 2002** | 232,011 | $ 9,802 | $ 99 | $ 165 | $ 9,900 | $ 10,065 | | | | |
| Avg 2002 | 19,334 | $ 817 | $ 8 | $ 14 | $ 825 | $ 839 | $ 43 | $ 0.70 | 1.7% | $ 43 |
| **Total 2001** | 227,024 | $ 21,248 | $ 4,162 | $ 1,346 | $ 25,410 | $ 26,756 | | | | |
| Avg 2001 | 18,919 | $ 1,771 | $ 347 | $ 112 | $ 2,117 | $ 2,230 | $ 115 | $ 6.07 | 5.3% | $ 118 |
| **Total 2000** | 237,543 | $ 22,890 | $ 2,877 | $ 1,720 | $ 25,373 | $ 27,083 | | | | |
| Avg 2000 | 19,795 | $ 1,907 | $ 240 | $ 143 | $ 2,114 | $ 2,257 | $ 107 | $ 7.24 | 6.8% | $ 114 |
| **Total 1999** | 227,533 | $ 6,848 | $ 180 | $ 404 | $ 7,028 | $ 7,432 | | | | |
| Avg 1999 | 18,961 | $ 571 | $ 15 | $ 34 | $ 586 | $ 619 | $ 31 | $ 1.78 | 5.7% | $ 33 |
| **1998 (9mo)** | 169,239 | $ 4,704 | $ 209 | $ 638 | $ 4,913 | $ 5,551 | | | | |
| Avg 1998 | 18,804 | $ 523 | $ 23 | $ 71 | $ 546 | $ 617 | $ 29 | $ 3.77 | 13.0% | $ 33 |

**Notes:**

**1998-2000:**

Forward costs include estimated 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, ISO Real Time Energy Costs include OOM Costs.

**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 OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

**2003:**

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

Forward energy costs 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 Powerdex hour-ahead prices.

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

**All years:**

A/S costs Include ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

### 2.2.2 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 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. Thus, the All-In Price Index is **not** equivalent to the Wholesale Energy Cost Index discussed in section 2.2.1. The All-In Price index is not an estimate of total wholesale market costs; rather it is a simplified index that shows the relative cost contribution of various market services. Extreme care should be taken when comparing the All-In Price Index to other indices published by the Department of Market Analysis or by other entities. 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[6] to units held on pursuant to the "Must-Offer" waiver denial process, plus
- Out-of-sequence energy costs, plus
- RMR costs, plus
- Market costs of ancillary services (with self-provided services estimated at market costs), plus
- Grid management charges for all services.

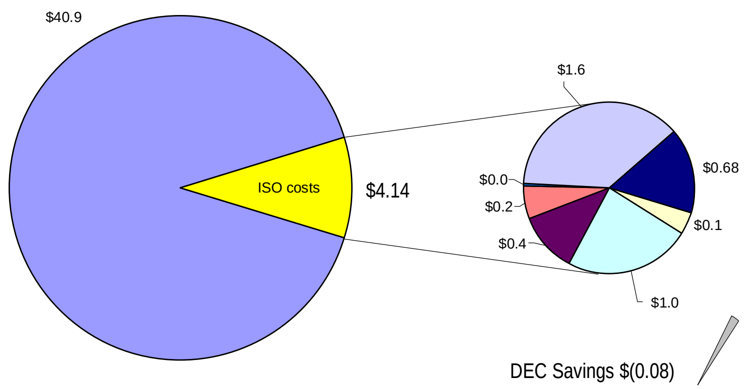
The All-In Price Index was $54.92/MWh in 2003 compared to $45.06/MWh in 2002 using an equivalent methodology. The increase of approximately 22 percent can be largely attributed to the 64 percent increase in natural gas costs during the same time period. The increase in gas costs was cushioned substantially by near-normal hydroelectric production in the Pacific Northwest and fixed energy prices set by long-term contracts.

This methodology differs from that used to calculate the Total Wholesale Cost Index in that real-time prices are itemized into incremental and decremental components and an out-of-sequence component (comprising redispatch premium costs in excess of market costs) is also included.

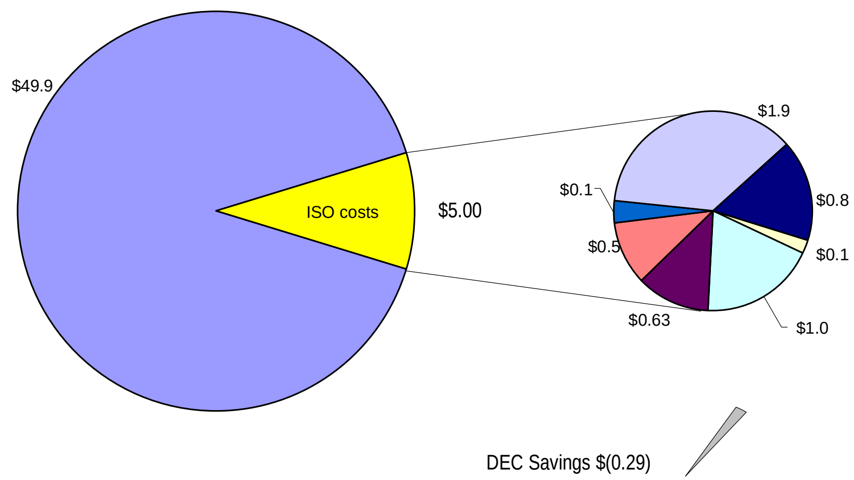
The following figures and tables provide several views of all-in costs and prices. Figures 2.9 and 2.10 respectively show the All-In Price Index for 2002 and 2003 by contributing factor. Figure 2.11 shows a side-by-side comparison of the All-In Prices for 2002 and 2003. Table 2.5 provides contributing factors by value. Figure 2.12 provides a monthly profile of the All-In Price Index for 2002 and 2003.

[6] Minimum Load Compensation Costs (MLCC) include startup and no-load costs paid to generation units that are denied must-offer waivers.

## Figure 2.9 2002 All-In Price: $45.06 per MWh of load served

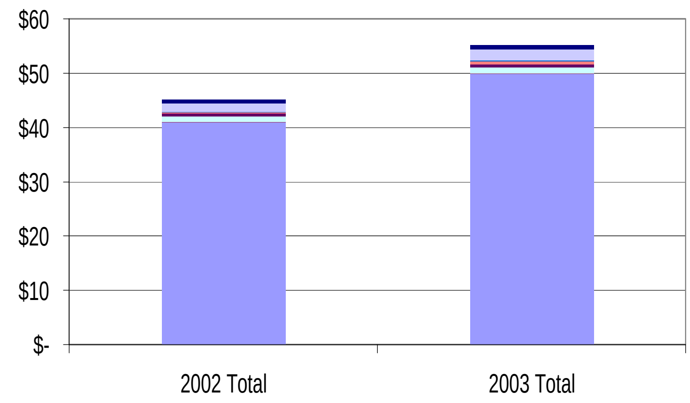



## Figure 2.10 2003 All-In Price: $54.92 per MWh of load served




Notes: Values are $/MWh of load served.
Category colors correspond to Table 3.3.
Forward energy costs 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 Powerdex hour-ahead prices.

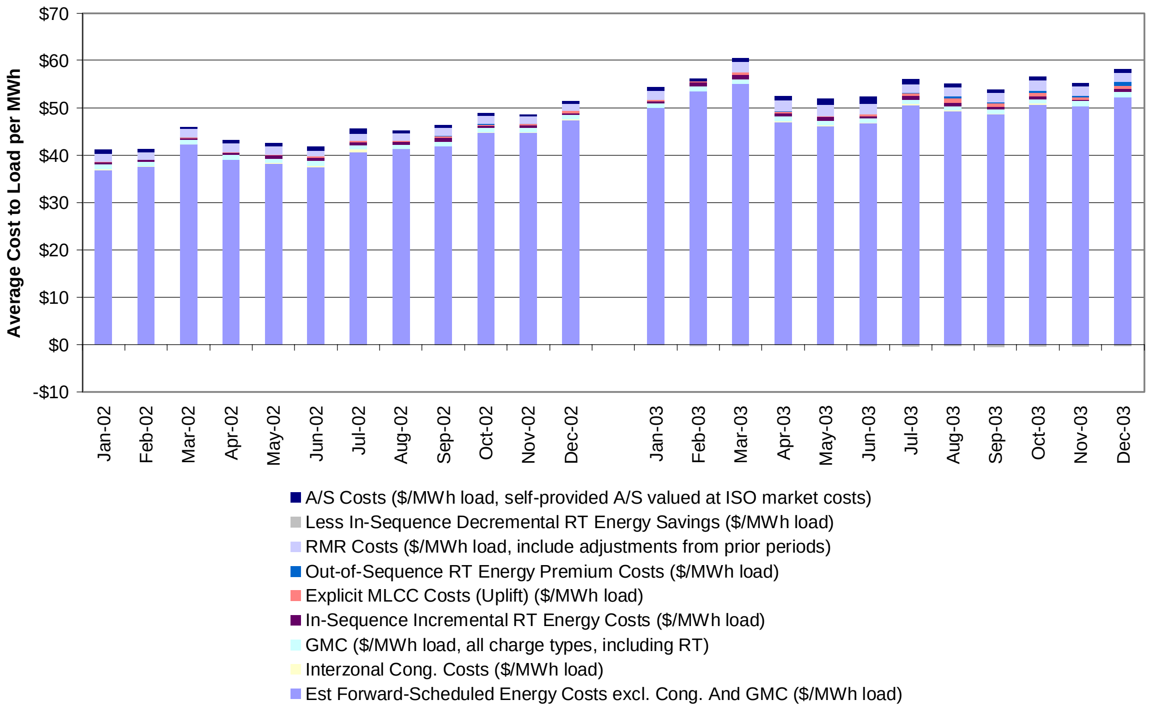
## Figure 2.11 Annual All-In Prices: 2002 vs. 2003




## Table 2.5 All-In Price by Cost Contributor: 2002 and 2003

| | | 2002 Total | | 2003 Total | Growth Rate |
|---|---|---|---|---|---|
| Est Forward-Scheduled Energy Costs excl. Cong. And GMC ($/MWh load) | $ | 40.92 | $ | 49.92 | 22% |
| Interzonal Cong. Costs ($/MWh load) | $ | 0.18 | $ | 0.12 | -37% |
| GMC ($/MWh load, all charge types, including RT) | $ | 1.00 | $ | 1.00 | 0% |
| In-Sequence Incremental RT Energy Costs ($/MWh load) | $ | 0.49 | $ | 0.63 | 29% |
| Explicit MLCC Costs (Uplift) ($/MWh load) | $ | 0.26 | $ | 0.54 | 108% |
| Out-of-Sequence RT Energy Premium Costs ($/MWh load) | $ | 0.02 | $ | 0.19 | 931% |
| RMR Costs ($/MWh load, include adjustments from prior periods) | $ | 1.60 | $ | 1.95 | 22% |
| Less In-Sequence Decremental RT Energy Savings ($/MWh load) | $ | (0.08) | $ | (0.29) | 246% |
| **Total Energy Costs ($/MWh load)** | **$** | **44.39** | **$** | **54.06** | 22% |
| A/S Costs ($/MWh load, self-provided A/S valued at ISO market costs) | $ | 0.68 | $ | 0.86 | 28% |
| **Total Costs of Energy and A/S ($/MWh load)** | **$** | **45.06** | **$** | **54.92** | 22% |
| **A/S % of All-In Price** | | 1.5% | | 1.6% | |

**Figure 2.12 Monthly Average All-In Prices, 2002-2003**




## 2.3 Market Competitiveness

### 2.3.1 *Market Performance Indices*

***Price-to-Cost Markup as a Measure of Market Performance***

Market power is the ability of one or more sellers to sustain prices significantly above levels that would emerge in a competitive environment; or the ability of one or more buyers to sustain prices below such levels. One index used to measure market performance in the California wholesale electricity markets is the price-to-cost markup. 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 markup to marginal cost is a metric that can be used to identify market performance trends over time.

#### 2.3.1.1 Real-time Imbalance Energy Market Performance

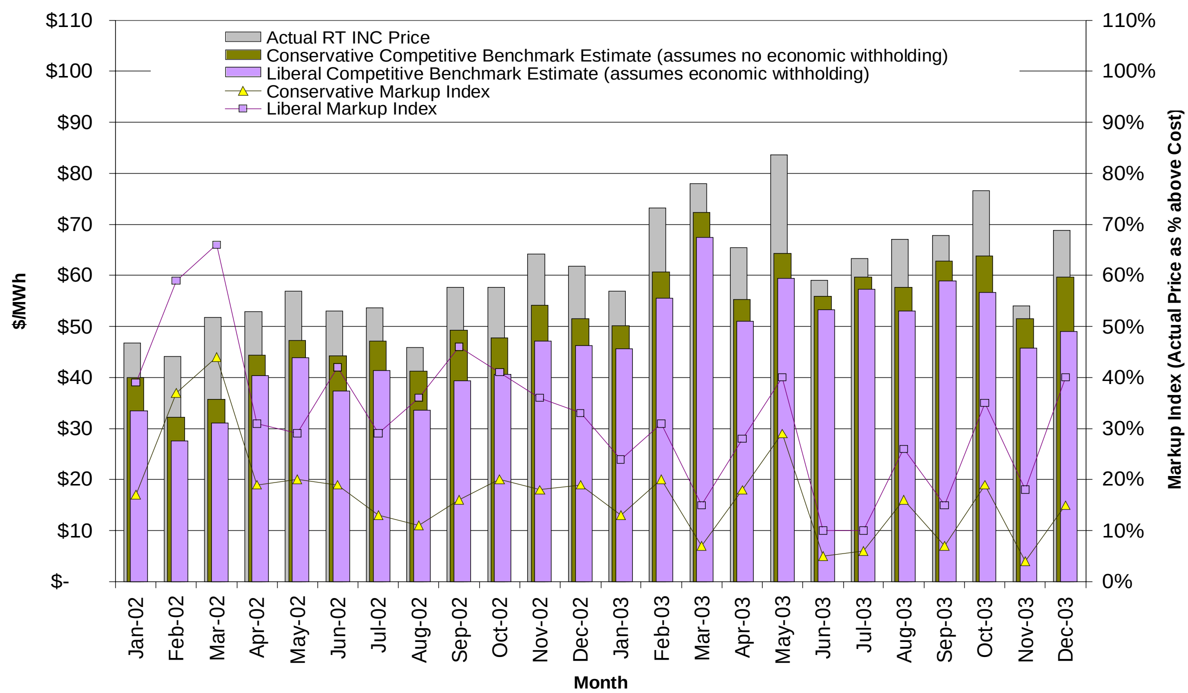
DMA has developed two indices designed to measure market performance in the real-time market. These indices compare real-time market prices to estimates of real-time system marginal costs. They both exclude resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[7] While an index based upon the small volume of transactions in the real-time market is not the preferred method of calculating markup, it provides a profile of general market trends. These two indices differ in their assumptions of bidding behavior. As any calculated index of market performance is only an estimate, the two indices could be considered together to provide lower and upper bounds of price-to-cost markup in each month.

The first of these two real-time indices is a conservative measure of a competitive baseline price. 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. This methodology assumes that high-priced bids correspond to high costs, and produces a higher estimated competitive baseline price. The second measure is a more liberal measure. It not only includes units that were dispatched, but also includes units whose estimated marginal costs are less than the market-clearing price yet submitted bids in excess of the market-clearing price and consequently were not awarded dispatch instructions. Therefore, this second index includes an estimate of the impact of potential economic withholding on the competitive baseline price. This has the effect of increasing the realized real-time markup. This methodology adjusts for economic withholding by reoffering those bids at their estimated marginal cost and dispatching units in the resultant merit order. Please see the *Market Analysis Report for September 2003* for more information regarding the markup index for real-time energy. The two indices taken together represent a range of possible competitive baseline prices in the CAISO's real-time incremental imbalance energy market.

[7] The original real-time price-cost markup index used system marginal cost based on all resources available for day-ahead scheduling. That competitive benchmark is more applicable to measure competitiveness of day-ahead and short-term energy markets. Only a subset of those resources is used in the calculation of the real-time mark-up.

Actual electricity prices were considerably higher in 2003 than in 2002 due to the precipitous rise in the cost of natural gas. Because natural gas cost is a factor in the estimate of the competitive price, and the CAISO's market for real-time incremental balancing energy was more competitive in 2003 than 2002, both markup estimates decreased form 2002 to 2003 as we would expect under abundant supply conditions. The index that assumes no withholding fell to 13.8 percent markup for the year 2003, compared to 20.0 percent markup in 2002. The index that incorporates estimated economic withholding fell to 23.3 percent markup for the year 2003, compared to 39.6 percent markup in 2002. The fairly high average monthly mark-ups in the real-time market are largely due to the fact that the most of the incremental real-time energy is dispatched during periods of rapidly increasing load, or rapidly decreasing generation schedules that exceed load drop-offs in late evening periods. During these periods, CAISO dispatchers must dispatch deep into the bid stack and often skip units that are operationally constrained (i.e., units with minimum run times) leading to short periods of less competitive real-time market conditions. Most of the real-time markup occurs during these periods. Due to the very small volumes transacted and operational constraints present in the real-time market, the short-term markup index discussed in the next section provides a more comprehensive view of the competitiveness of the California short-term energy market. Figure 2.13 compares the volume-weighted average actual real-time CAISO incremental market-clearing price for each month in 2002 and 2003 to both estimates of the competitive price. It presents the resultant markup indices in each month as well.

**Figure 2.13 Market-Clearing Price vs. Two Estimates of Competitive Baseline Price: 2002-2003**



#### 2.3.1.2 Short-term Energy Market Performance

In 2002, the Department of Market Analysis used a market power index that considered "short-term energy". This included real-time incremental balancing energy procured in the CAISO's market and forward bilaterally contracted (non-CAISO) energy not procured through long-term contracts. DMA used this index as a basis for the Twelve-Month Competitiveness Index (12MCI), which the Federal Energy Regulatory Commission requested in its Order of October 11, 2002. This index used prices for energy procured by the Department of Water Resources' California Energy Resources Scheduler (CERS), which managed energy procurement on behalf of the load-serving utilities due to credit problems through 2002. When this responsibility was returned to the utilities in 2003, the CAISO no longer had access to actual forward procurement information. As a substitute, CAISO has purchased an hourly short-term forward price index from Powerdex[8], an independent energy information company. Powerdex computes hourly Western hub prices by compiling information from buyers and sellers.

The methodology for computing a competitive baseline for hour-ahead market prices treats resources in the CAISO control area as a single resource portfolio. Every element of this resource portfolio is assumed to bid competitively – all bids are at marginal cost. The contract position against which this resource portfolio is optimized is defined to the sum of the hour-ahead generation schedules for the target period. The result of this optimization is a competitive market-clearing price (CMCP) for the hour-ahead bilateral market.

Several assumptions were required to reasonably approximate competitive market outcomes for the hour-ahead bilateral market. The commitment of all CAISO resources is fixed to reflect the anticipated commitment status per the hour-ahead schedule. Resources for which variable cost information is known are allowed to dispatch within their operational limits subject to their ramp rates. Hydroelectric resources are given weekly energy budgets calculated by totaling the metered output of each hydro resource over each week of history. Pumped storage resources are allowed to generate and pump subject to their cycle efficiency and reservoir constraints. Other units for which variable costs are not known (e.g. cogeneration) or for which there are no variable costs (e.g. solar) are fixed to operate exactly to their forward schedules. Imports are priced at the hub prices for the California-Oregon Border (COB) and Palo Verde (PV) regions and are restricted to the hourly availability of the California-Oregon Intertie (COI) and Palo Verde (PV) paths, respectively. Hour-ahead ancillary services requirements are applied to reserve spare capacity for the regulation up, regulation down, spin and non-spin markets. For each ancillary service type, only spare capacity on resources certified for the service are able to provide capacity to that market. These assumptions allow the considered resources to compete with each other to be dispatched in the optimization.

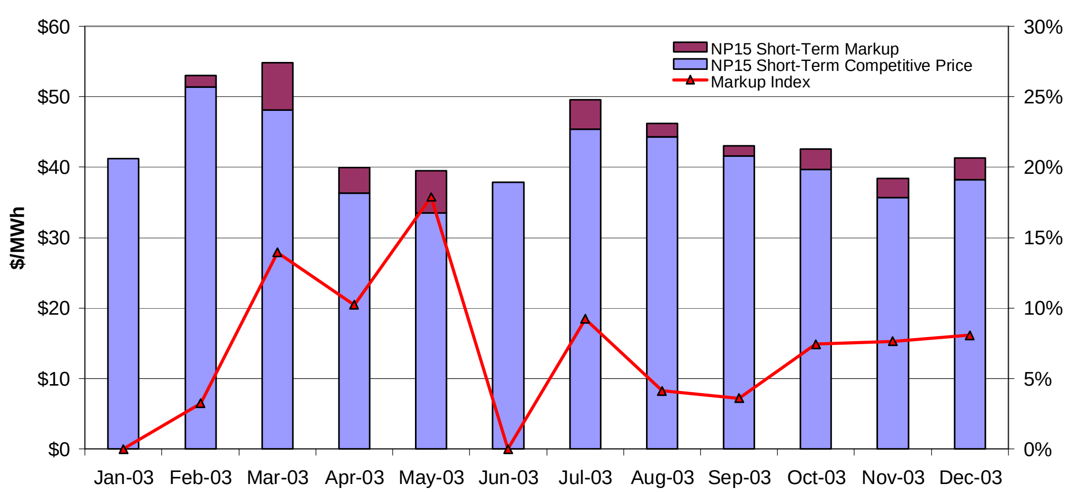
[8] http://www.hourlyindexes.com - P.O. Box 710886, Houston, TX, 77071

The data for this model comes from three sources. Resource owners or scheduling coordinators provide hour-ahead schedules, hydro output, generating resource variable cost information, reserve requirements and hourly path limits for each resource to the CAISO. Variable cost information not available through from data provided to the CAISO is obtained – when possible – from data purchased from Henwood Energy Services, Inc.[9] developed for WECC market price forecasting. Henwood Energy Services, Inc. also provides data for pumped storage reservoir volumes and cycle efficiencies. Powerdex provides hub prices for PV and COB.

PLEXOS for Power Systems™ is the market simulation tool used for this study. It 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[10].

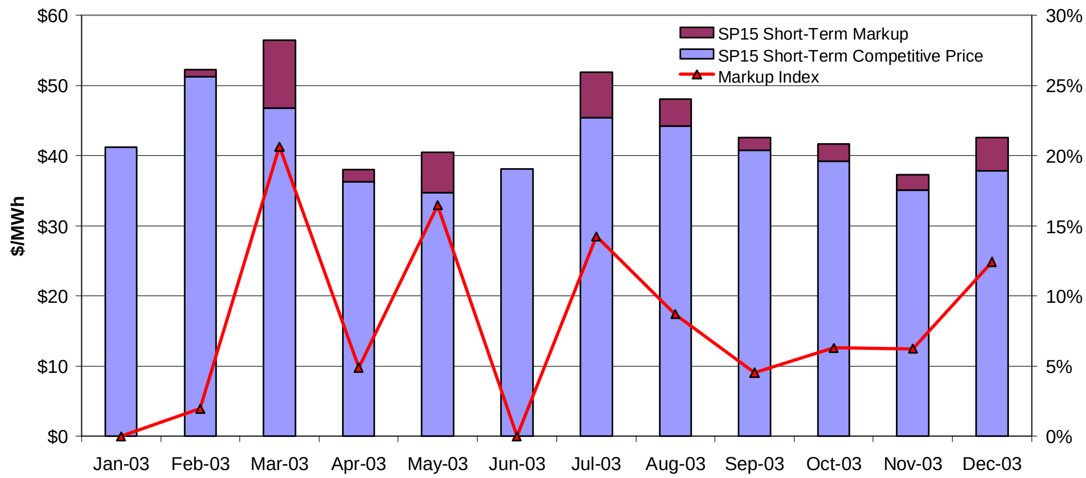
As shown in figures 2.14 and 2.15, short-term markups for NP15 and SP15 ranged between zero and 20 percent, indicating competitive market conditions in the short-term wholesale energy markets in California. The highest monthly average markups occurred in March, May and July. Higher March markups are likely a result of the natural gas price spike that occurred in late February that led electric energy suppliers to raise prices in anticipation of prolonged gas shortages. Unexpectedly high loads at the end of May and summer peaking loads in July likely led to the slightly higher markups calculated for those months. Overall, the index corroborates both the real-time markup residual supplier index discussed below to indicate that short-term wholesale energy markets produced very competitive outcomes in 2003.

**Figure 2.14 2003 Short-term Forward Market Index – NP15**




[9] http://www.henwoodenergy.com - 2379 Gateway Oaks Dr., Suite 200, Sacramento, CA, 95833
[10] http://www.draytonanalytics.com - PO Box 696, Prospect East, SA 5082, Adelaide, Australia

**Figure 2.15 2003 Short-term Forward Market Index – SP15**

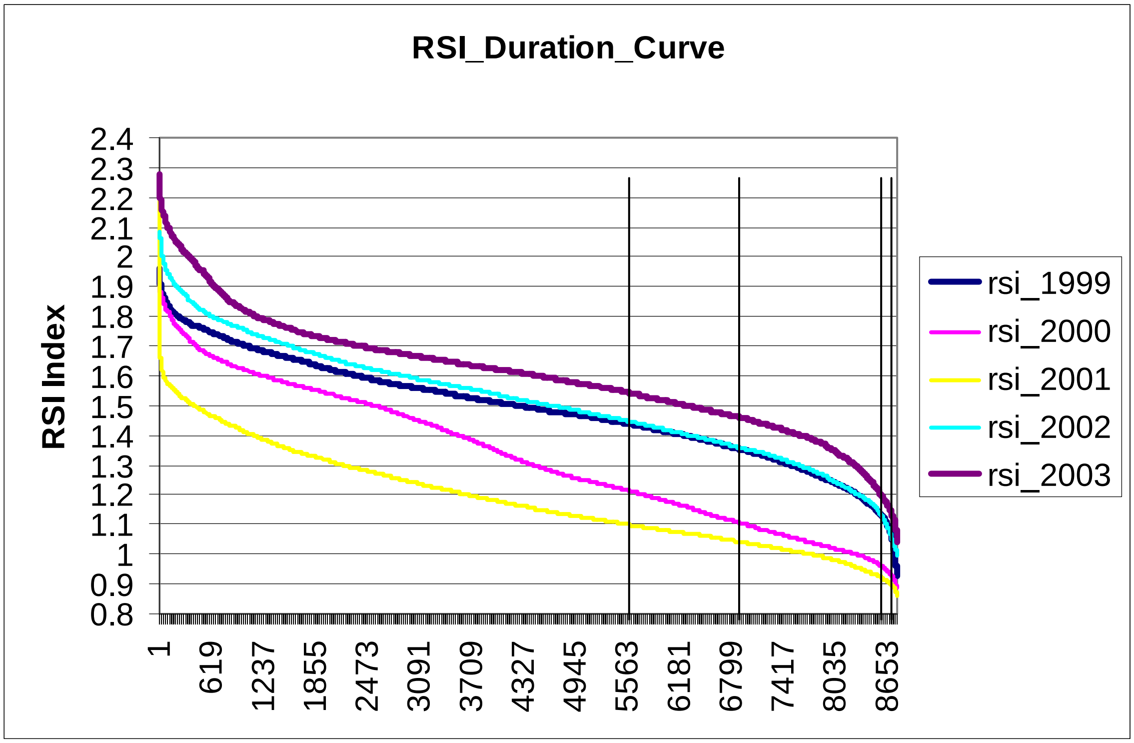



### 2.3.1.3 RSI Duration Curve

The CAISO has also defined a measure of the degree to which suppliers are pivotal in setting market prices called the residual supplier index (RSI). 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 translate to 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. An RSI value of 1.1 provides for some degree of tacit collusion, which may exist in the market.

Figure 2.16 compares the RSI duration curves from 1999 to 2003. The RSI indices in 2003 were the highest of the past five years. In 2003, the RSI indexes were less than 1.1 in less than 0.2 percent of the hours (only 21 hours out of 8760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2003 were significantly more competitive than in 2001 and 2000. The RSI indices are consistent with the market outcomes and price-cost markups we observed in 2003. As mentioned before, the improvements in market competitiveness in 2003 can be associated with many factors including a significant volume of forward contracts, additional capacity added into the system, moderate demand, as well as mitigation procedures implemented by the FERC.

**Figure 2.16 Residual Supplier Index 1999-2003**




### *2.3.2 Net Revenue Analysis and Revenue Adequacy of New Generation*

Another benchmark that has been proposed for assessing the competitiveness of markets is the degree to which prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. This analysis examines the economics of investment in new supply capacity given observed prices in the CAISO's imbalance energy and ancillary service markets over the last two years.

The majority of projects proposed in California and the WECC during the last three years have been gas-fired combined cycle plants of approximately 500 MW. This analysis is based on a typical 500 MW combined cycle unit and a typical 100 MW combustion turbine unit as defined in a 2003 California Energy Commission (CEC) study.[11] Tables 2.6 and 2.7 summarize the key generation unit assumptions for a typical new combined cycle unit and a typical new combustion turbine unit used in this analysis derived from the CEC study.

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

**Table 2.6 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 2.7 Analysis Assumptions: Typical New Combustion Turbine Unit**

| | |
|---|---|
| Maximum Capacity | 100 MW |
| Minimum Operating Level | 40 MW |
| Ramp Rate | 6 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 |

In practice, new investment would typically be supported, at least in part, by a long-term contract, rather than entirely by real-time energy and ancillary service capacity sales in the CAISO's markets. However, we calculated revenues from a hypothetical unit selling solely in the CAISO real-time imbalance energy and ancillary service markets to provide a benchmark for prices in the CAISO's markets.[12]

As shown in Figure 2.6, the CEC estimates that over a 20 year period, a new combined cycle unit would need to recover on average $90/kW-year or $90,000/MW-year in fixed costs to be profitable. Similarly, the CEC estimates the fixed cost recovery requirement for a new combustion turbine unit to be $78/kW-year or $78,000/MW-year as shown in Figure 2.7. The net revenue analysis was run for both the 2002 and 2003 calendar years. The results show that in 2002, a combined cycle unit selling solely into the CAISO imbalance energy and ancillary service spinning reserve markets would have received a net revenue in the range of approximately $74 to $78/kW-year for NP15 and SP15 respectively. In 2003, the largely decremental imbalance energy market resulted in significantly lower net revenues of $47 to $58/kW-year for NP15 and SP15, significantly less than the $90/kW-year net revenue requirement that would be required to signal new investment. Similarly, a new combined cycle unit selling solely into the CAISO imbalance energy and non-spinning reserve markets in 2002 would have received a net revenue in the range of approximately $32 to $34/kW-year for NP15 and SP15 respectively. In 2003, the net revenue for the combustion turbine unit was similar to 2002 levels in a range of $32 to $36/kW-year for NP15 and

[12] The operational and scheduling assumptions used for each unit are summarized below:

1. An initial operating schedule is first determined based on real time energy prices and the unit's marginal operating costs. The unit is scheduled up to full output when hourly prices exceed variable operating costs.

2. The initial schedule is 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 compares operating losses during these hours to the cost of shutting down and restarting the unit: if operating losses exceed these shutdown/startup costs, the unit is scheduled to go off-line over this period. Otherwise, the unit is ramped down to its minimum operating level during hours when its variable costs exceed real time energy prices.

3. A series of simplified ramping constraints are 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 costs associated with the simulated operating of the units are included in operating costs.

5. Ancillary service revenues are calculated by assuming the unit could provide 50 MW of spinning reserve each hour it was available for service. Revenues from the ancillary service were based on Day Ahead market prices.

Other assumptions:

- A combined forced and planned outage rate of 8% is represented by decreasing total annual net operating revenues by this amount.
- Gas prices used in the analysis are the daily spot market gas prices for southern and northern California

SP15, again primarily as a result of the small volumes transacted in the real-time imbalance energy market. The net revenue results for both a new combined cycle unit and a new combustion turbine are well below the estimated range of revenue that would be needed to stimulate investment in new supply relying only on spot market revenues. These results serve to highlight the key role that forward contracts must play in stimulating investment in new supply with the current structure of California's wholesale market and the importance of effective resource adequacy rules to facilitate new generation infrastructure. The next section discusses the recent developments in the establishment of resource adequacy standards for the California electric markets. These results also point to the historical boom/bust investment in generation infrastructure as 2003 was characterized by three consecutive years of significant new generation additions that led to wide reserve margins throughout the year. Therefore, short-term price signals for new investment would not be expected during this period. Tables 2.8 and 2.9 show the 2002 and 2003 expected capacity factors, energy revenue, ancillary service capacity revenue, operating costs, and net revenue of the combined cycle and combustion turbine units used in this analysis.

### Table 2.8 2002 and 2003 Financial Analysis of New Combined Cycle Unit

| | 2002 | | 2003 | |
|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 69.7% | 70.2% | 57.6% | 60.1% |
| Energy Revenue ($/kW-yr) | $ 238.0 | $ 245.0 | $ 263.9 | $ 280.3 |
| Ancillary Service Capacity Revenue ($/kW-yr) | $ 1.2 | $ 1.1 | $ 3.2 | $ 2.8 |
| Operating Cost ($/kW-yr) | $ 165.4 | $ 168.3 | $ 220.6 | $ 225.6 |
| Net Revenue ($/kW-yr) | $ 73.8 | $ 77.8 | $ 46.5 | $ 57.5 |

### Table 2.9 2002 and 2003 Financial Analysis of New Combustion Turbine Unit

| | 2002 | | 2003 | |
|---|---|---|---|---|
| | NP15 | SP15 | NP15 | SP15 |
| Capacity Factor | 36.2% | 36.8% | 16.0% | 20.2% |
| Energy Revenue ($/kW-yr) | $ 158.7 | $ 164.7 | $ 103.7 | $ 130.8 |
| Ancillary Service Capacity Revenue ($/kW-yr) | $ 6.1 | $ 5.9 | $20.6 | $19.2 |
| Operating Cost ($/kW-yr) | $ 132.5 | $ 136.2 | $ 91.9 | $ 113.6 |
| Net Revenue ($/kW-yr) | $ 32.3 | $ 34.4 | $ 32.4 | $ 36.4 |

#### 2.3.2.1 Resource Adequacy Requirement

Regardless of how well an energy market is designed, it cannot function effectively, i.e., efficiently and in line with reliable system operation in the absence of adequate infrastructure. Prominent infrastructure components advocated by the CAISO are supply resource adequacy requirement and clear and transparent rules for transmission expansion.

As part of its MD02 market redesign effort the CAISO developed a resource adequacy obligation it named the available capacity obligation (ACAP). This would require the load serving entities (LSEs) to line up supply capacity commensurate with their load plus a reserve margin, in a demonstrable manner, well in advance of the CAISO's spot markets. The ACAP obligation did not necessarily require advance purchase or procurement of energy by the LSEs. It could be partially satisfied by a contract between the LSE and a supplier requiring the supplier to self schedule or bid into the ISO's spot markets a pre-specified quantity of supply, possibly at one or more pre-specified delivery points (zones, scheduling points, or trading hubs) at a pre-specified bid price, or even a bid price at seller's choice, subject to prevailing market power mitigation measures prevalent in the CAISO's markets. The ACAP design was to ensure that adequate resources would be available to: 1) support reliable operation of the transmission system (short term reliability), 2) lead to competitive spot markets thus substantially mitigating the ability of the suppliers to exercise market power, and 3) promote supply investment (long-term reliability).

Notwithstanding the clear benefits of such an integrated design, the CAISO did acknowledge that a resource or capacity obligation would have to go hand in hand with resource procurement rules that are under the purview of the state and local authorities, and would best be addressed in those forums. Accordingly, in November 2002 the CAISO Board directed the CAISO management to defer implementation of the ACAP element of MD02, and instead dedicate CAISO staff's efforts towards active participation in the CPUC Procurement Proceeding.

During 2003, the CAISO actively participated in the CPUC Procurement Proceeding. The ISO filed written testimony, and later testifies and submitted briefs. The main recommendations made by the CAISO is a state-sponsored resource adequacy program that includes a set of comprehensive, consistent, and mandatory requirements to be put in place as soon as possible with the following six essential elements:

1. Required planning reserve of 17%
2. Established and standardized load forecast (as a basis for defining the capacity obligation)
3. Specific deliverability criteria
4. Unambiguous and comprehensive rules for counting of resources towards meeting a LSE's obligation
5. Restricted reliance on spot markets to satisfy capacity requirements
6. Availability of LSE's procured resources for possible use by the CAISO, along with adequate provisions for the LSE's to manage their own use-limited resources under normal conditions.

In addition the CAISO espoused the following four overarching characteristics that would complete an effective resource adequacy framework:

(1) Ex-ante procurement and cost recovery rules that allow the LSEs to enter into long-term contracts, which in turn would commit available resources to California load and stimulate needed investment in electricity infrastructure.

(2) A reporting mechanism with consistent formats and information to update each LSE's plan on an ongoing basis.

(3) Well-defined consequences for LSEs that fail to line up sufficient capacity, commensurate with their obligation in a timely manner.

(4) Adoption of clear rules and procedures for transparent real-time use of the supply capacity by the ISO under emergency (or supply shortage) conditions.

On November 18, 2003, the ALJ at the CPUC assigned to the procurement proceeding issued a "Preliminary Decision" concurrently with an Alternative Ruling by President Peevey of the Commission, the assigned commissioner. At the time the ISO supported the Peevey Alternative, which included many of the desirable elements and characteristics that the ISO had recommended.

Subsequently, on January 22, 2004, the CPUC issued its decision in the Procurement Proceedings. The decision deviated markedly from the Peevey Alternate and failed to adopt a number of the important recommendations supported by the CAISO and adopted in the Peevey Alternate. In particular, and of critical importance to the CAISO, the CPUC decision:

- Deferred full implementation of the adopted procurement rules until 2008,
- Did not include, in any material respect, how compliance with the long-term rules would be monitored and enforced, and
- Deferred resolution of a number of key issues including the following:
    a. Deliverability
    b. Coordination with MD02
    c. Penalties for non-compliance
    d. Reporting
    e. Load forecasting methodology
    f. Counting of resources, and
    g. The phase-in period.

The issues are to be resolved in a series of workshops and through another rulemaking process. The CAISO is engaged in discussions in different forums, participating in CPUC's Procurement Proceeding with a view to synergy between resource adequacy and the MD02 project.

## 2.4 Effectiveness of Market Power Mitigation Measures

The significant number of long-term contracts entered into by the State of California in 2001 and significant amounts of new generation have provided effective market power mitigation in 2002 and 2003 at the system level.[13] When load serving entities are adequately supplied though longer-term arrangements, precise market power mitigation rules become less crucial because the residual exposure of consumers to spot price volatility will not subject them to large cost impacts. Adequate supply also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures need to be in place to prevent market manipulation and opportunistic exploitation of contingencies and extreme circumstances. However, they must not excessively dampen spot market volatility that encourages load-serving entities to reduce their forward contract cover and rely more on the spot markets. The following section discusses the effectiveness of the current market power mitigation measures that were implemented in October 2002.

### *2.4.1 Price Cap*

As discussed in Chapter 1, FERC ordered a $250/MWh soft price cap be implemented on October 31, 2002. In 2003, the $250/MWh soft price cap almost never restricted real-time incremental energy prices. This was due to the competitive market conditions and operating costs in all hours below $250/MWh for nearly all-thermal units within the CAISO system. Only on one instance during the year, July 2, did the market-clearing price reach $250/MWh. It did so only within NP15 due to a fire that resulted in derates of Path 15 and the California-Oregon Intertie (COI). In only seven hours during the year, energy was procured as bid above $250/MWh. In each of these cases, the selling units were subject to severe emissions constraints and under order by a state agency to bid into the CAISO markets at the highest price permitted. In each of these cases, all other resources submitted bids at or below the price cap, and the market-clearing price (set by the highest-priced awarded bid at or below the price cap) was below $250/MWh. In fact, these emission-constrained resources were the only resources ever to bid above $250/MWh in 2003.

Similarly, the DEC price cap of -$30/MWh also appeared to be unrestrictive. In 101 hours, scheduling coordinators submitted bids below -$30/MWh; only a single such bid was awarded, at -$45/MWh, on May 20, between 10:00 and 11:00 p.m., when the MCP was set by the next lowest DEC bid at $0/MWh. Negative decremental bids were awarded in 60 distinct hours in 2003.

### *2.4.2 Incremental Market-Clearing Price Automatic Mitigation Procedure*

As discussed in Chapter 1, the Automatic Mitigation Procedure (AMP) was implemented on October 30, 2002 as part of Phase 1B of the CAISO's Market Design 2002 (MD02) process directed by FERC in its Order of July 17, 2002. AMP is a procedure designed to prevent the exercise of market power and is applied to all bids submitted to the CAISO's real-time market. AMP is applied to address local market power to both INC and DEC bids awarded out of sequence, as discussed in Chapter 6 (Intrazonal Congestion). The following discusses the performance of AMP applied to INC bids paid at the MCP.

[13] This section is directed at system level market power mitigation measures. The need for Local Market Power Mitigation measures are addressed in Chapter 6.

In 2003, the AMP thresholds to activate bid mitigation were never breached and no bids were mitigated. The Department of Market Analysis has focused its evaluation of AMP effectiveness on 193 "market power-susceptible" hours in 2003 during which the incremental MCP exceeded $100/MWh and the price-to-cost markup exceeded 40 percent of estimated system wide marginal cost using the liberal real-time markup index (discussed above in § II.b).[14] Of these market power-susceptible hours, units failed the AMP conduct test in only 13 hours (6.7 percent). In none of these hours in which units failed the conduct test did any unit fail the impact test.

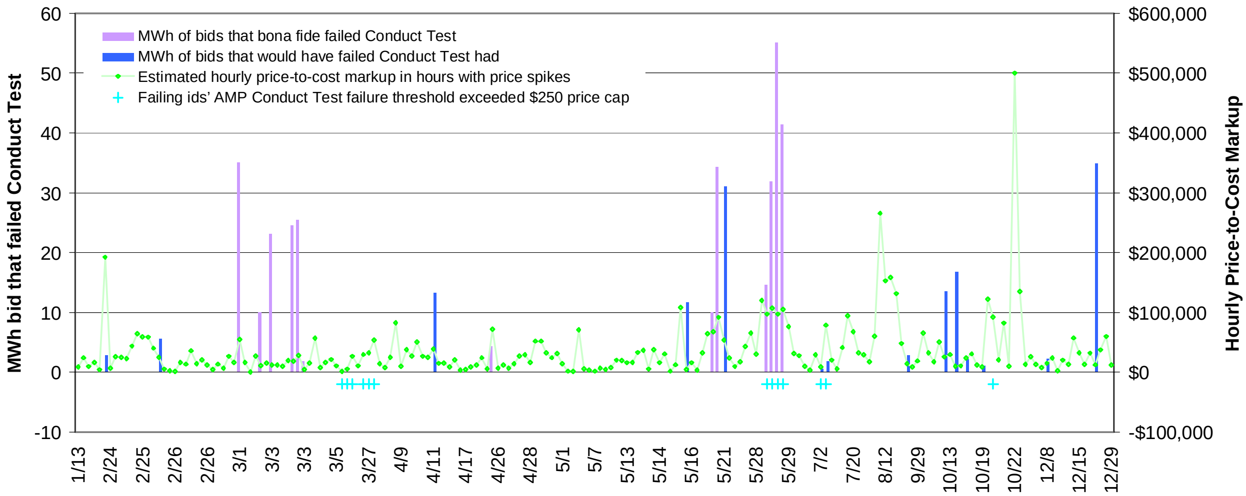
In some cases, the predicted price screen prevented AMP from being applied. As noted in Section I, the hour-ahead predicted MCP must exceed $91.87/MWh for AMP to apply. Of the 193 market power-susceptible hours during which the incremental MCP exceeded $100/MWh and the real-time markup exceeded at least 40 percent of estimated operating cost, a predicted MCP below $91.87/MWh allowed units that would have failed the conduct test to evade it in 14 hours (7.3 percent).

Occasionally the $250/MWh price cap itself renders AMP ineffective. If a unit's AMP reference level is at least $150/MWh, it can only fail the conduct test by bidding above $250/MWh. In 13 of the 193 market power-susceptible hours (6.7 percent), it would have taken a bid in excess of the price cap for a unit to fail the conduct test. Of these 13 hours, five included conduct test failures, and another two included hours in which units would have failed the conduct test had the predicted price screen not been below $91.87/MWh.

In the remaining 159 of 193 market power-susceptible hours (82.4 percent), bidders set high prices without failing the conduct test or bidding in excess of the price cap. Figure 2.17 shows all market power-susceptible hours in 2003 and identifies by hour the volumes of bids that *bona fide* failed the conduct test (shown in purple), and those that would have failed the conduct test in the event that the predicted price screen had not prevented application of AMP (shown in blue). The 159 hours without vertical bars are those in which no dispatched unit bid in a manner that violated its conduct test thresholds. The chart also identifies hours in which at least one unit could only have failed the conduct test by bidding in excess of the price cap, and shows the estimated maximum price-to-cost markup in those hours.

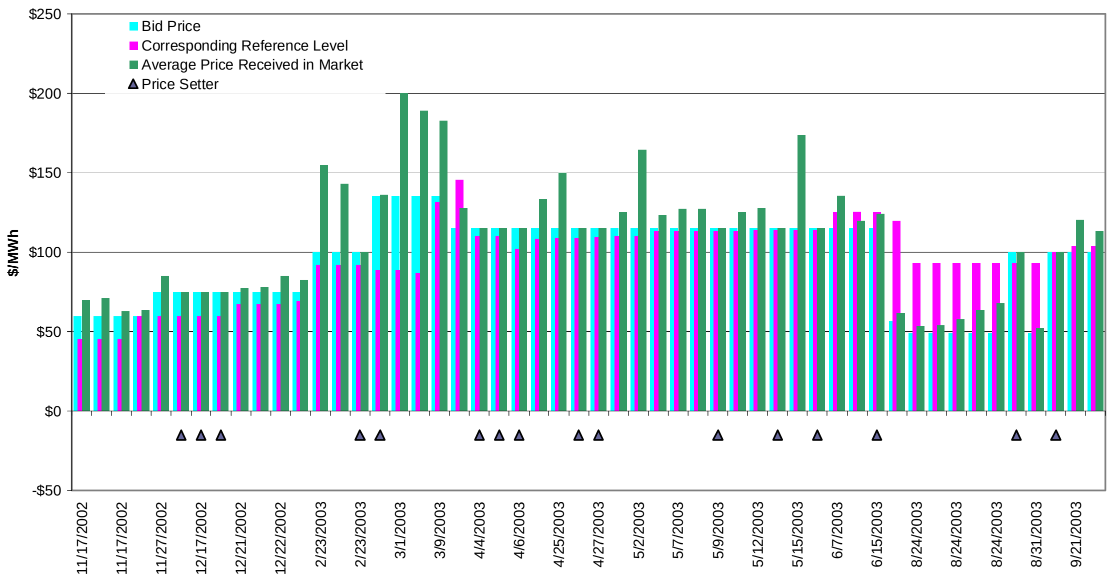
[14] We do not discuss conduct test failures in other hours because we do not consider them relevant in measuring AMP's efficacy in mitigating the exercise of market power. For example, we ignore hours in which (a) there were no incremental dispatches, or (b) the cost impact of markup was small.

### Figure 2.17 AMP Conduct Test Effectiveness in 193 Market Power-Susceptible Hours




The most significant problem with AMP evidently is that units are able to bid prices significantly in excess of their estimated marginal costs without violating their AMP thresholds. This is due in large part to the fact that some bidders have been able to raise their AMP reference levels by bidding higher prices over time. Certain units that repeatedly have been able to set the MCP have also succeeded in maintaining high reference levels. Figure 2.18 shows off-peak bids and corresponding reference levels between October 2002 and September 2003 for a particular unit that successfully set prices above $100/MWh and raised its reference levels as a consequence. Reference levels have been normalized to adjust for changes in natural gas prices. The chart also identifies whether the unit set the market-clearing price in at least one of the six dispatch intervals within the hour.

**Figure 2.18 Bids and AMP Reference Levels for a Unit that Set Prices above $100, Normalized for Gas Price Changes[15]**

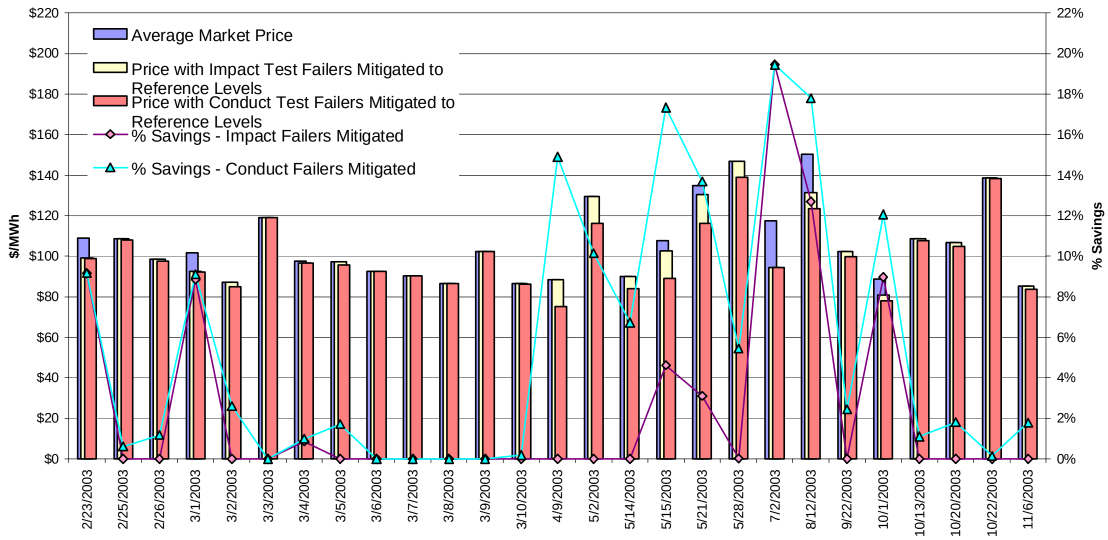



### *Estimates of Market Savings due to Mitigation*

To review the effects of the price screen and impact test thresholds on the overall market impact of AMP, the CAISO's Department of Market Analysis has developed estimates of the real-time market prices under the scenarios in which units that failed the conduct test are mitigated to their reference levels and then redispatched. When these units' bids are mitigated, the set of awarded bids changes, since high and out of merit bids, which were in excess of their corresponding conduct test thresholds, may become in-merit when reference levels are substituted for the original bids. Figure 2.19 compares daily average actual prices (denoted in blue) on days in which the daily average price exceeded $85/MWh to average prices that would have occurred had the price screen not been required (denoted in yellow), and to prices that would have occurred had the price screen and impact test not been required for mitigation -- that is, if all bids from units that failed the conduct test had been mitigated (denoted in orange).

15 Maximum average reference levels corresponding to awarded bids less $6 O&M adder, divided by monthly gas index used in deflating reference levels, multiplied by October 2002 gas index of $3.34/MMBtu, plus $6 O&M adder. Gas index ranges from $3.34 to $7.27/MMBtu (high in March 2003). Peak-hour reference levels are computed independently of off-peak-hour reference levels.

**Figure 2.19 Daily Average Price Compared to Estimated Prices When Bids are Mitigated to Reference Levels, when Daily Average Price exceeds $85/MWh**




The real-time incremental balancing market was relatively competitive in 2003 in comparison to recent years. It was not subject to the stress that it endured during the crisis period of 2000-2001. Even in a competitive market, some generators frequently bid significantly in excess of competitive levels, often resulting in significant price-to-cost markup. The soft price cap may have had some effect on bidding behavior, given the small number of resources that bid above $250/MWh and the few times that energy was procured from those resources. AMP appears to have limited effectiveness, as bidders have systematically been able to raise their reference levels by bidding high prices, and approximately 50 percent of the time, the price screen has prevented conduct test threshold-violating bids from being identified. Finally, even if bidding behavior had resulted in failure of the impact test and bids had been mitigated to reference levels in these instances, prices would not have been significantly lower in most high-markup situations.