3. Summary of 2002 Market Performance

This section reviews the overall performance of California's electricity and ancillary service markets in 2002. The health of the markets improved substantially in 2002 compared to the preceding years of crisis. This was due primarily to market demand and supply fundamentals. While load was considerably higher in 2002 than in 2001, near-normal hydroelectric conditions in California and in the Pacific Northwest and long-term energy contracts procured by the State of California helped to reduce real-time market volumes. Meanwhile, a series of regulatory changes to California's market mitigation structure relaxed the real-time market's price cap by raising it from $91.87 to $250 per megawatt-hour (MWh).

The following are highlights of market conditions in 2002:

- **Dramatically lower costs in all wholesale market segments.** Overall wholesale market costs fell to $10.1 billion in 2002, or 62.2 percent less than the 2001 level of $26.7 billion. Improved forward scheduling has resulted in less reliance on the real-time market to meet load. Consequently, wholesale real-time electricity costs fell to $99 million in 2002, compared to $4.16 billion in 2001, and $180 million in 1999, previously the year with the lowest real-time costs. The low real-time costs are due in part to the high frequency in 2002 of scheduling in excess of load. When scheduled power exceeds load, suppliers repurchase decremental (DEC) energy; that is, they pay the ISO for the privilege of reducing output. Ancillary services costs fell to $165 million in 2002 from $1.35 billion in 2001. The costs of bilaterally contracted forward-scheduled wholesale electricity also decreased significantly to $9.8 billion in 2002 from $21.2 billion in 2001.[1]
- **Significant improvements in forward scheduling.** During the energy crisis in 2000 and 2001, there were wide disparities between forward-scheduled energy and forecasted load. The situation has improved steadily since December 2000, when underscheduling reached its most extreme level of 14 percent below actual load. In 2002, underscheduling was 1 percent of actual load on average.
- **Improved hydro conditions.** Flows in the Pacific Northwest were near normal in 2002, leading to plentiful supplies of inexpensive hydroelectric power during most periods of peaking demand. This helped to maintain adequate margins of generation available to meet load throughout the year.
- **Rising gas prices.** The price of natural gas was remarkably low in the first quarter of 2002, averaging below $2.25/MMBtu at California delivery points in January and February 2002. Prices rose steadily during the course of the year, and particularly in the fourth quarter, closing the year in the neighborhood of $5/MMBtu, a 120 percent increase since the first quarter.

[1] Year-to-year comparisons do not adjust for inflation or gas costs.

- **Management of market mitigation structure.** Following a series of system deficiencies during a heat wave beginning July 9, 2002, the price ceiling in the ISO's real-time Balancing Energy Ex-Post Price (the BEEP Stack) and ancillary services auction markets was lowered from $91.87/MWh to $57.14/MWh, and again below that the following day, in accordance with the Federal Energy Regulatory Commission's (FERC) Order of June 19, 2001. Because the lower ceiling likely would have constrained supply, FERC quickly ordered that the previous ceiling of $91.87/MWh be reinstated immediately. This ceiling held until Phase 1a of the ISO's 2002 Market Redesign (MD02) was implemented on October 30, 2002.

3.1 Supply and Demand Conditions

3.1.1 Loads and Scheduling

Loads were considerably greater in 2002 than in 2001as the levels of conservation seen during the energy crisis diminished. Weather conditions were near normal in 2002, providing for adequate hydroelectric supplies in both the Pacific Northwest and in California, with mild temperatures for most of the year.

The California Energy Commission (CEC) publishes an index of monthly peak demand, adjusted for growth and weather conditions, in the ISO Control Area. While adjusted demand was considerably higher in all months in 2002 than in 2001, it was still lower than levels seen in 2000.

Table 3.1 shows percentage growth in average monthly loads for 2002 compared to 2001. It also shows changes in average daily and monthly peak loads and the CEC peak demand indices for those months. [2]

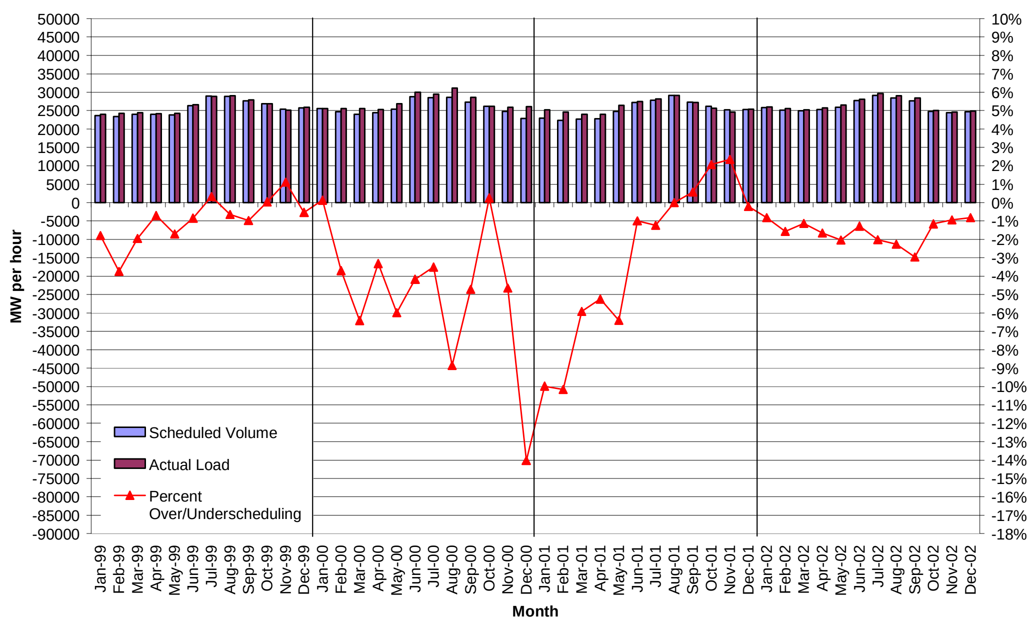
[2] All loads are actual top-of-hour loads. In order to make appropriate comparisons, 2001 loads are adjusted beginning 6/19/2001 for the departure of the Sacramento Municipal Utility District (SMUD) from the ISO Control Area on 6/19/2002. The CEC conservation indices for December 2002 had not yet been released at the time of writing.

Table 3.1. Changes in Monthly Demand in 2002

	Change in Avg. Hourly. Load 2002-2001	Change in Avg. Daily Peak 2002-2001	Change in Monthly Peak 2002-2001	CEC Conservation Index 2002-2001	CEC Conservation Index 2002-2000
January-02	-1.5 %	-1.6 %	-2.1 %	0.7 %	-5.5 %
February-02	-0.4 %	-0.5 %	-0.4 %	3.8 %	-4.5 %
March-02	0.7 %	-0.5 %	0.6 %	4.1 %	-5.5 %
April-02	3.0 %	2.1 %	-4.5 %	5.8 %	-3.7 %
May-02	-3.9 %	-6.1 %	-5.0 %	3.9 %	-6.9 %
June-02	1.5 %	0.4 %	3.7 %	3.3 %	-11.2 %
July-02	10.1 %	12.7 %	11.5 %	8.8 %	-2.8 %
August-02	4.2 %	2.6 %	4.6 %	4.8 %	-4.5 %
September-02	9.3 %	10.5 %	15.3 %	6.9 %	-1.7 %
October-02	1.9 %	0.6 %	-4.2 %	1.3 %	-7.6 %
November-02	4.4 %	2.6 %	3.7 %	1.7 %	-3.3 %
December-02	2.6 %	1.9 %	1.4 %	n/a	n/a

Since the crisis period ended in mid-2001, scheduling accuracy has improved dramatically. In each month in 2002, forward schedules were within 3 percent of actual load on average. Figure 3.1 shows monthly average loads and scheduling deviations through 2002.

Figure 3.1. Loads and Scheduling Deviations through 2002



3.1.2 Demand Response

Demand response, or the ability of load to withhold consumption in response to high prices, is essential in competitive markets to ensure that the interaction of supply and demand result in efficient outcomes. The ISO has taken an active role to develop demand response programs; however, there still is not sufficient demand response in place to significantly impact market competitiveness. While several new demand programs were introduced in California in 2001, there was not a substantial expansion in programs in California during 2002. The following summarizes the current demand response activities in the ISO Control Area.

In addition to a variety of programs operated by the California Energy Commission and California Public Utilities Commission (CPUC), the ISO operates its own Participating Load Program (PLP), which includes the Consumer Power and Conservation Financing Authority (CPA) as one of several participants.

The PLP was developed to provide a means by which electricity consumers could participate in the ISO markets by competing with generation to provide operating reserve ancillary services. At the present time, participation consists largely of the California Department of Water Resources' (CDWR) pumps that move water through California's primary aqueducts. At its highest level in the summer of 2000, CDWR bid volume peaked above 700 MW. This participation fell in the summer of 2001 due to hydro conditions and concerns surrounding the energy crisis.

In the summer of 2001, the ISO also created the Demand Relief and the Discretionary Load Curtailment Programs under which loads can collect a fixed price of $350/MWh plus market revenues for curtailing consumption. The ISO used these programs only once, on July 3, 2001, curtailing a combined 185 MW from both programs. This despite heightened concern at the time for credit repayment issues and the CPUC's lack of support for the programs. In particular, the CPUC declined to permit the utilities from recovering the costs incurred by these programs or to participate in them as load aggregators. It also directed the utilities to create a similar competing program.

In response, the ISO suspended the two programs in order to focus on the PLP and to integrate it with existing state-sponsored programs. The CPA's Demand Reserve Partnership enables load to sign up to be curtailed on peak days during the year in exchange for a monthly reservation fee. The load then is bid into the day-ahead and hour-ahead non-spinning reserves markets and is paid as procured. The recruitment and administration of load occurs through organizations known as load aggregators, and the load is bid through the Automated Power Exchange (APX), a scheduling coordinator authorized to bid in the ISO markets.

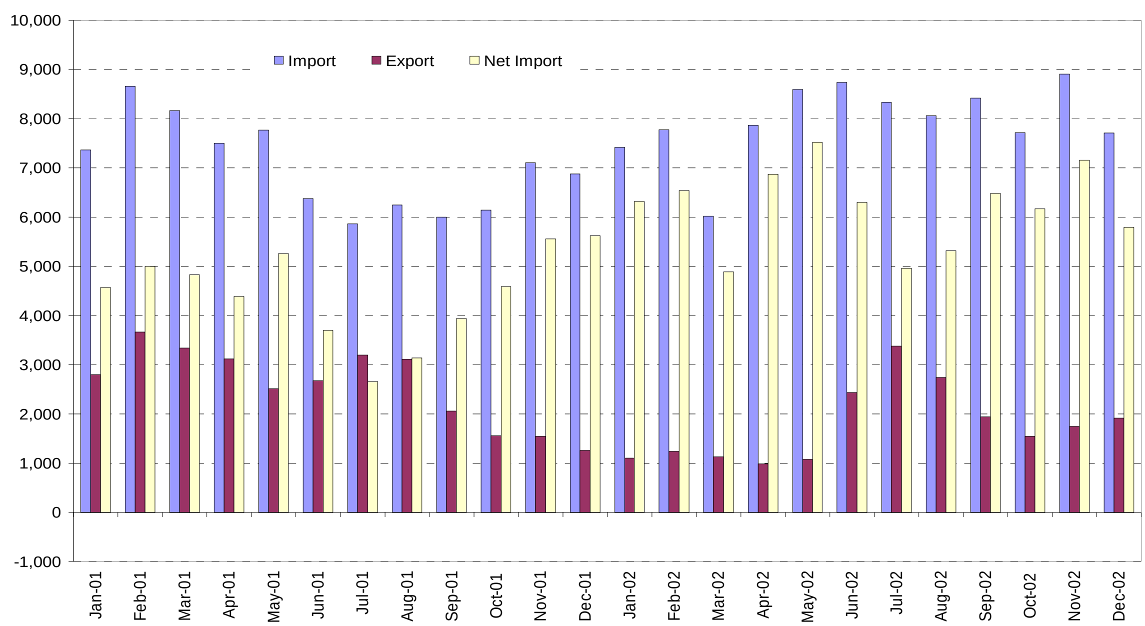
In March 2003, the CPUC issued an order to begin the development of three pilot programs to test demand response in retail residential consumer users. While the implementation details of these programs – such as how they will feed into wholesale markets—have yet to be resolved, their concepts are:

1. Two-tiered time-of-use (peak and off-peak) pricing;
2. Fixed critical peak pricing, with higher peak pricing on ten to fifteen predetermined peak days in the year and day-ahead notification of peak pricing; and
3. Variable critical peak pricing, with an unlimited number of peak days and same-day notification of peak pricing.

3.1.3 Supply Conditions

Average net imports increased approximately 1750 MW, or 40 percent from 2001 to 2002, not adjusted for SMUD's withdrawal from the ISO Control Area. On average, there was an increase in imports of 962 MW and a decrease in exports of 789 MW. Almost all of the import growth was from the Pacific Northwest where a normal or better snow pack[3] enabled suppliers to export a portion of the plentiful hydroelectric resources to California. The decrease in exports was most pronounced in flows to the northwest and flows to the Los Angeles and Arizona control areas also decreased. One possible reason for the decrease in exports was the cessation of "Ricochet"-style scheduling tactics. Flows between the ISO and SMUD in the months that it has been a separate control area have been almost exclusively in the export direction, averaging approximately 800 MW between June 19 and December 31, 2002. Figure 3.2 shows average imports, exports, and net imports between the ISO and neighboring control areas for each month in 2001 and 2002.

Figure 3.2. Average Hourly Import and Export Volume in 2001 and 2002[4]



[3] Natural Resources Conservation Service, "April 1, 2002 Western Snow Pack Conditions and Water Supply Forecasts," ftp://ftp.wcc.nrcs.usda.gov/downloads/wsf/2002/apr02wsfwww.pdf

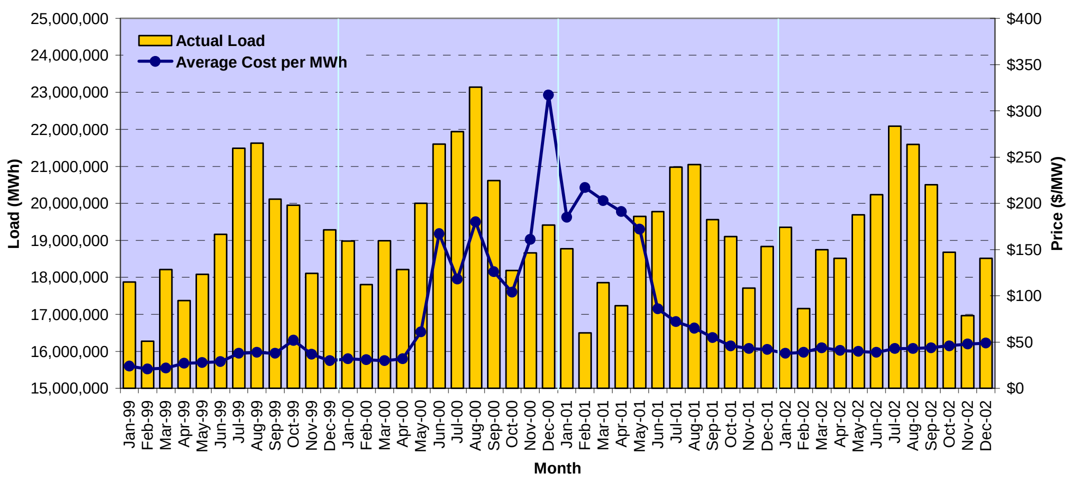
[4] Imports and exports after June 19, 2002, include SMUD traffic.

As utilities were able to rely on imported and local hydroelectric power in 2002, they depended less on thermal generation. Thus, overall expenditures on forward energy declined despite the precipitous rise in the price of natural gas over the course of the year. Average thermal generation volume (shown in purple in Figure 3.2) fell by approximately 40 percent to the range of 5,500 MW between August 2001 and 2002.

3.2 Energy and Ancillary Service Costs

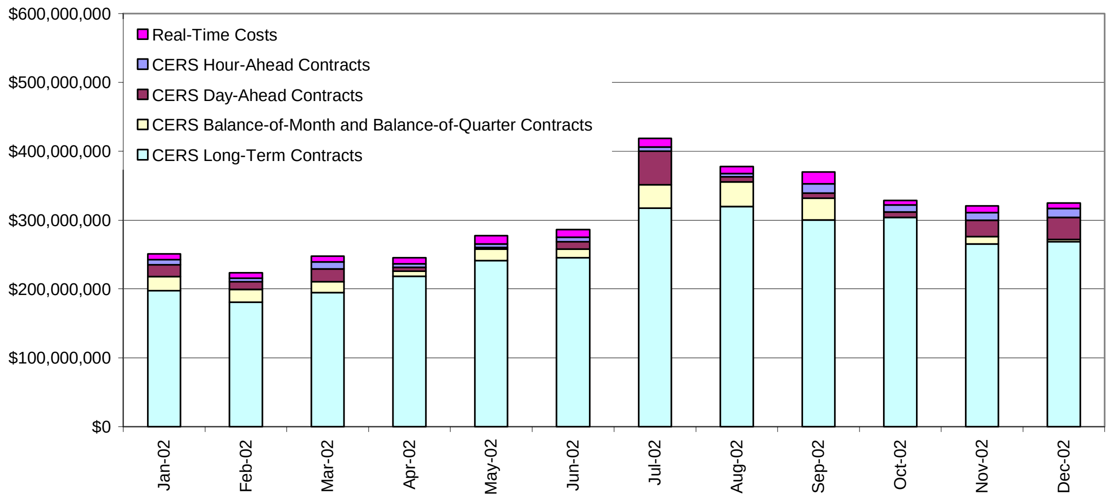
Energy costs reached record lows in 2002, besting even the first year of ISO operation in some market segments. Average wholesale electricity costs were $43/MWh in 2002, compared to $118/MWh in 2001. Total wholesale costs amounted to $10.1 billion, compared to $26.7 billion in 2001. Figure 3.3 shows average wholesale electricity costs and total load from January 1999 through December 2002.

Figure 3.3. Average Costs and Actual Load January 1999-December 2002



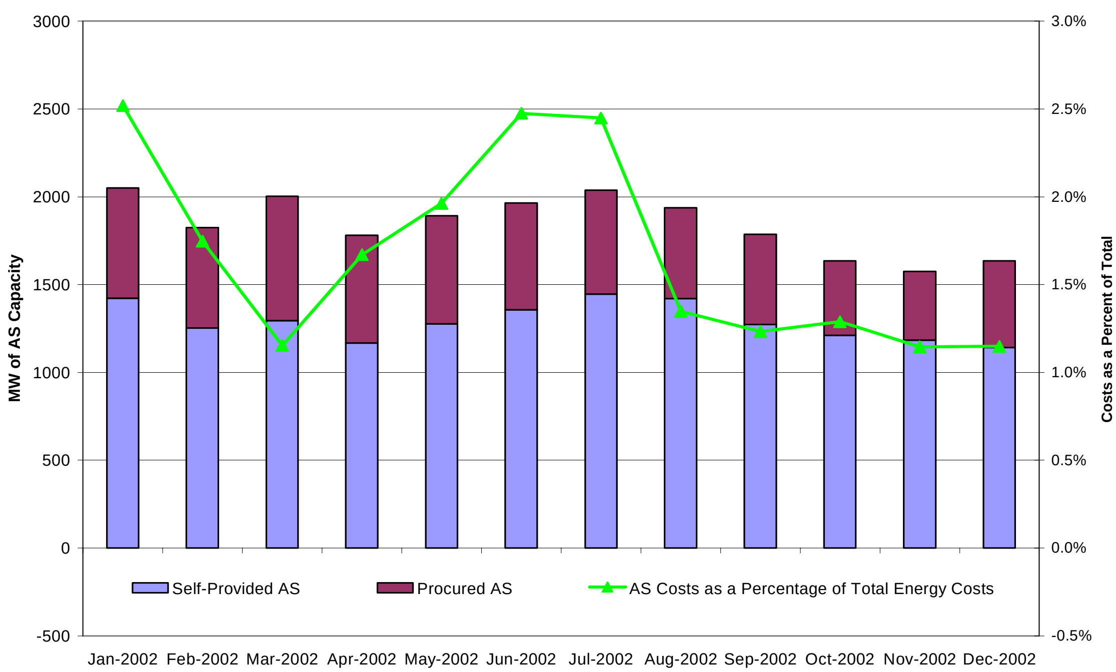
Approximately 83 percent of 2002 "Net-short" energy costs, costs of energy not supplied by the utilities' own generation, resulted from long-term contracts entered into by the State of California in January 2001. The remainder of the forecasted net-short was provided by balance-of-quarter and balance-of-month bilateral contracts (combined 6 percent of costs); day-ahead and hour-ahead bilaterals (5 and 3 percent, respectively); and real-time procurement (3 percent). Figure 3.4 presents the monthly detail.

Figure 3.4. Composition of Net-Short Energy Costs in 2002



Ancillary services (AS) costs, including the cost of self-provided AS estimated at market prices, totaled $264 million in 2002, compared to $1.346 billion in 2001. Hydro resources had been stored for later use and utilities were able to self-provide capacity without going to the market, putting downward pressure on prices by alleviating demand. Figure 3.5 shows the proportions of AS that were self-provided and procured. It also shows AS costs as a percentage of total energy costs.

Figure 3.5. Self-Provision of AS, and AS as a Percentage of Total Energy Costs



Real-time energy costs were $99 million in 2002, compared to $4.162 billion in 2001. With overscheduling in many hours due in part to the large long-term contracts, ISO operators balanced generation with load by decrementing generation. When a resource is decremented, it pays for the privilege of decreasing output. Thus, except in unusual circumstances, decrementing tends to result in lower costs to load.

Ancillary services and real-time energy costs were both lower in 2002 than in any other year since the ISO's inception in 1998. Figure 3.6 shows total wholesale costs by market for each year since inception. Tables 3.2 and 3.3 on the following pages show monthly wholesale energy costs by component and annual costs since inception.

Figure 3.6. Total Annual Wholesale Energy Costs, 1998-2002

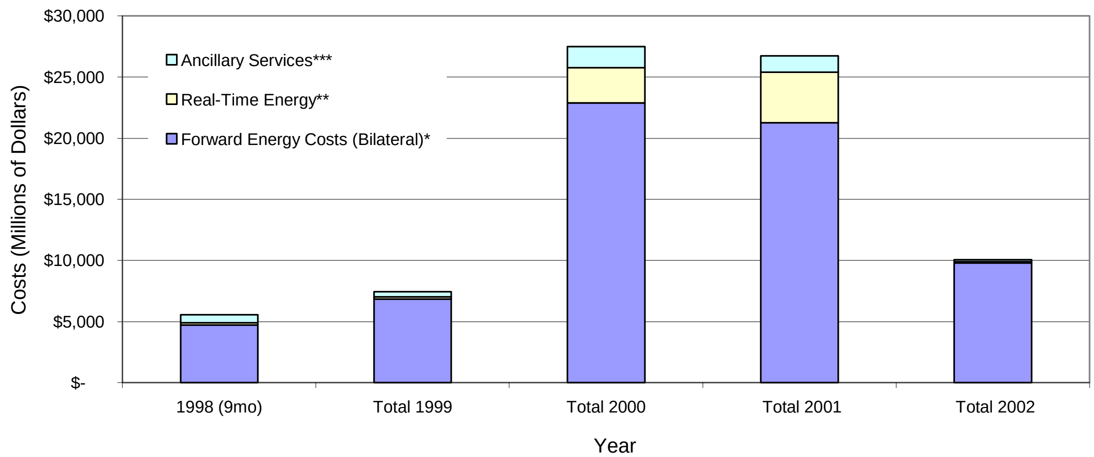


Table 3.2. Monthly Wholesale Energy Costs for 2002

	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-02	19,356	18,940	$ 737	$ 7	$ 19	$ 744	$ 763	$ 45	$ 38	$ 0.97	2.5%	$ 39
Feb-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 45	$ 39	$ 0.68	1.7%	$ 40
Mar-02	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 52	$ 44	$ 0.50	1.2%	$ 44
Apr-02	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 53	$ 41	$ 0.68	1.7%	$ 41
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 54	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 52	$ 39	$ 0.97	2.5%	$ 40
Jul-02	22,079	21,319	$ 931	$ 11	$ 23	$ 942	$ 965	$ 51	$ 43	$ 1.04	2.4%	$ 44
Aug-02	21,588	20,798	$ 914	$ 8	$ 12	$ 923	$ 935	$ 47	$ 43	$ 0.58	1.3%	$ 43
Sep-02	20,498	19,089	$ 878	$ 15	$ 11	$ 893	$ 904	$ 58	$ 44	$ 0.54	1.2%	$ 44
Oct-02	18,677	17,682	$ 856	$ 4	$ 11	$ 860	$ 871	$ 60	$ 46	$ 0.59	1.3%	$ 47
Nov-02	16,967	16,839	$ 812	$ 7	$ 9	$ 819	$ 828	$ 66	$ 48	$ 0.55	1.1%	$ 49
Dec-02	18,510	17,608	$ 897	$ 4	$ 10	$ 901	$ 911	$ 62	$ 49	$ 0.56	1.1%	$ 49
Total 2002	232,011	223,870	$ 9,802	$ 99	$ 165	$9,900	$10,065					
Avg 2002	19,334	18,656	$ 817	$ 8	$ 14	$ 825	$ 839	$ 53	$ 43	$ 0.70	1.7%	$ 43

***** Sum of hour-ahead scheduled quantities

****** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

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

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

November and December forward costs (and resulting totals) are estimated. Values in March report will include true-up and may differ from values shown here.

Table 3.3. Annual Wholesale Energy Costs, 1998 through 2002

	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 2002	232,011	$ 9,802	$ 99	$ 164.81	$ 9,900.39	$ 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	$ 1,346.09	$25,409.97	$ 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

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

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

All years:

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

3.3 Out-of-Market Purchases

3.3.1 2002

The process of balancing the grid occurs in the real-time imbalance energy market where generators submit bids to either increment generation (sell energy to the grid) or decrement generation (buy over-supplied energy from the grid). The bid-based balancing of the grid is generally problem-free unless there are local reliability problems or bid-sufficiency problems. Since the implementation of the Must-Offer-Obligation where all in-control-area generators have to offer their capacity to the grid, the problem of bid sufficiency, while occasionally present, has not been common. When bid sufficiency is an issue, the volume of OOM calls can spike quite quickly. As a rule OOM[5] calls result from emergency conditions, such as transmission lines going down or plants tripping unexpectedly. Generally, they are infrequent as all the energy required to balance the grid should be available from market-based systems such as the BEEP stack, which includes bids both by in-state generators and bids by out-of-state generators via tie-bids. We view the presence of occasional OOM calls as anomalous, whereas the persistence of OOM calls requires further investigation due to the possibility of market under-performance or market failure.

In 2002, Out-Of-Market (OOM) purchases of energy by the ISO were infrequent compared to 2001. In 2002, there were a total of 5,973 MWh of OOM calls at an average price of $60 for a total cost of $355,478. This is shown in Figure 3.7 on the next page. The pattern of the OOM calls is reassuring as it indicates that OOM calls are most likely in the summer months of June, July, August, and in September, when resources are most stretched and occasional anomalies are most likely to surface. For example, Table 3.4 shows a great deal of volume of OOM calls in July. During the heat wave of July 8 to 11, supply conditions reached near-critical levels. The ISO declared a Stage I emergency on July 9 and the BEEP stack was exhausted. The price cap was also reset twice to levels (mid $50 dollar range) regarded as insufficient to provide incentive for generators to offer enough capacity for the evening ramp. It was returned to $91.87 by FERC. This single incident accounted for a great deal of all the OOM calls made during the year. The raising of the price cap to higher levels subsequently has resulted in an absence of bid-insufficiency inspired OOM calls.

[5] This write up will only analyze purchases of incremental energy from out-of-state entities to alleviate system conditions.

Figure 3.7. 2002 OOM Calls

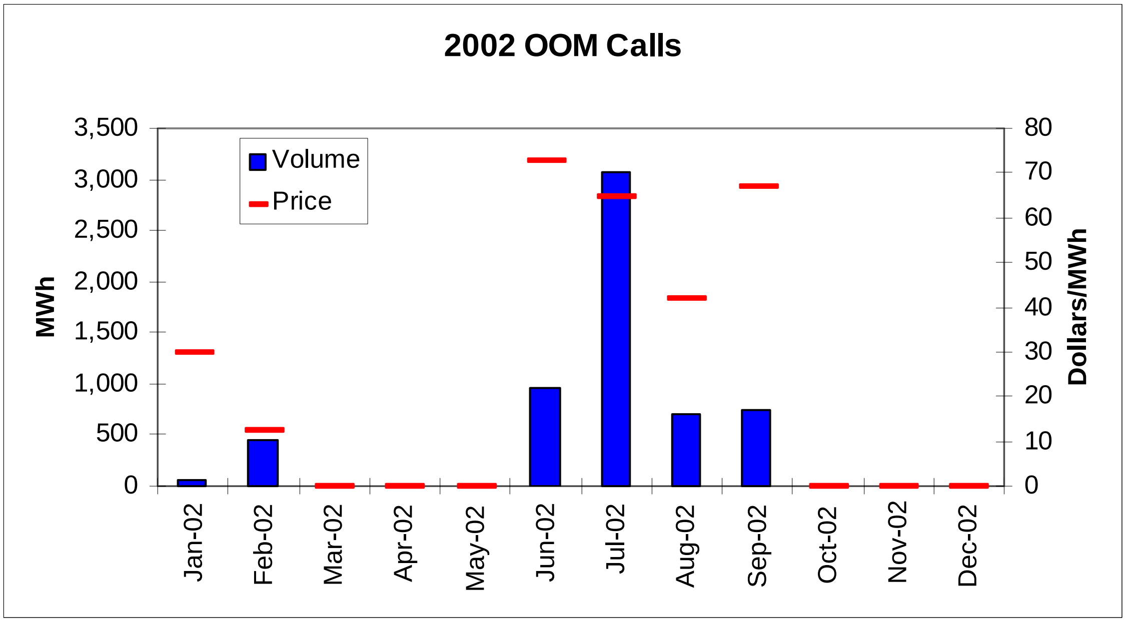


Table 3.4. OOM Calls for 2002

OOM Calls for 2002			
	MWh	Weighted Avg. Price	Cost
Jan-02	50	30	1,500
Feb-02	453	13	5,764
Mar-02	0	0	0
Apr-02	0	0	0
May-02	0	0	0
Jun-02	967	73	70,430
Jul-02	3,061	65	198,766
Aug-02	700	42	29,400
Sep-02	742	67	49,618
Oct-02	0	0	0
Nov-02	0	0	0
Dec-02	0	0	0
Total	5,973	60	355,478

3.3.2 Comparison to Previous Years

Comparing OOM calls in 2002 to previous years is difficult due to the substantial structural changes the market has undergone as a result of the energy crisis. There was a period in 2000 and 2001 when massive underscheduling by load resulted in the ISO exhausting the bids in the BEEP stack. In volume, there were more OOM calls in August of 2001 that there were in the whole of 2002. Figures for the weighted average price and the total cost show similar dislocations from the 2001 data (Table 3.5). A number of market and institutional factors were responsible for these changes. These include:

1. The presence of substantial under-scheduling in the summer of 2001. This resulted in the exhaustion of the BEEP stack and reliance on OOM calls to balance the grid;
2. The implementation of a soft cap of $250 MWh on December 8, 2001 to try and push more energy into BEEP and overcome the reliance on OOM calls;
3. The role of CERS personnel in making bilateral deals to service load in January after the credit ratings of a number of companies were downgraded to junk status. Many of these transactions were misclassified as OOM calls.

By 2002 though, the real-time markets had largely returned to health, and OOM calls became much less common.

Table 3.5. OOM Calls for 2000 and 2001

	MWh	Weighted Avg Price	Cost $
Jan-00	0	0	0
Feb-00	0	0	0
Mar-00	250	30	7,375
Apr-00	0	0	0
May-00	5,780	626	3,615,869
Jun-00	18,934	668	12,645,055
Jul-00	28,403	478	13,586,927
Aug-00	118,599	411	48,693,276
Sep-00	60,549	248	15,036,127
Oct-00	372	239	88,872
Nov-00	328,124	251	82,286,452
Dec-00	1,316,092	459	603,489,706
Jan-01	1,029,161	285	292,829,653
Feb-01	337,146	137	46,250,421
Mar-01	61,885	35	2,194,105
Apr-01	27,894	0	1,246
May-01	14,599	1	7,571
Jun-01	7,436	0	385
Jul-01	1,459	2	3,101
Aug-01	6,600	0	66
Sep-01	0	0	0
Oct-01	0	0	0
Nov-01	0	0	0
Dec-01	0	0	0

3.4 Market Power and Competitiveness

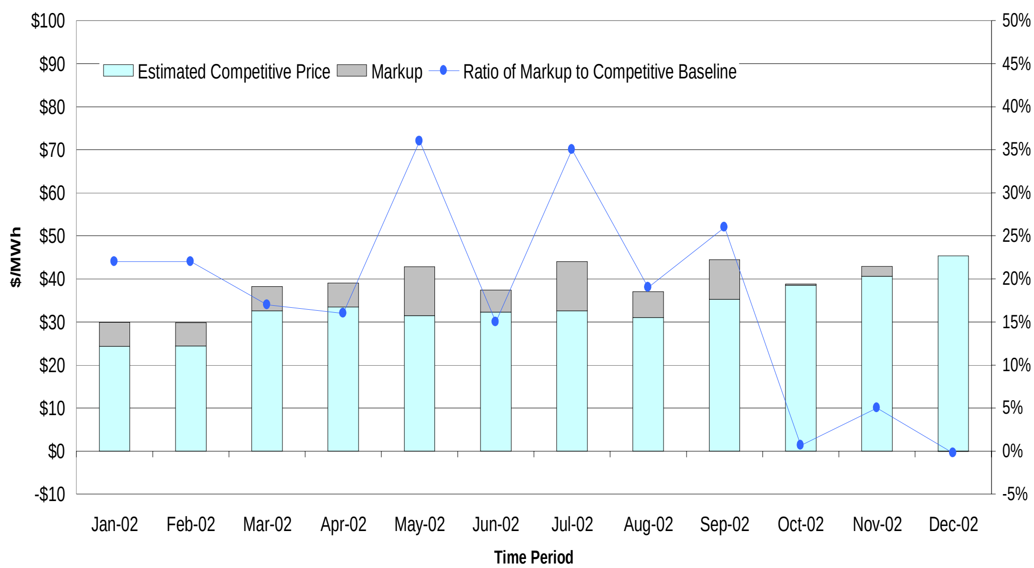
3.4.1 Markup Indices and 12-Month Competitiveness Index

Market power is the ability of suppliers to set prices above competitive levels for sustained periods of time. The DMA estimates the degree of market power by comparing the price actually paid to suppliers for energy to an estimate of the price that would exist under competitive conditions.[6] A perfectly competitive market in a risk-free business would be indicated by the index equal to zero (no markup).

An index that the DMA introduced in early 2002 is the price-to-cost markup for short-term energy. This index includes costs for real-time energy procured through the BEEP Stack and day-ahead and hour-ahead bilateral procurement by CERS to cover utilities' net-short loads. By excluding the cost of long-term contracts, this index provides a measure of the market power included among costs that utilities and CERS were able to control on a going-forward basis.

In 2002, the overall price paid for short-term electricity was $39.46/MWh, with an average cost of $33.76/MWh. Thus, the average markup was $5.69/MWh, or 17 percent above cost. Markups approaching 35 percent in the summer months were offset in the fall, as the rising price of natural gas put upward pressure on production costs, while actual market prices increased to a much lesser degree. Figure 3.8 shows monthly markups in 2002.

Figure 3.8. Price-to-Cost Markup in Short-Term Energy in 2002



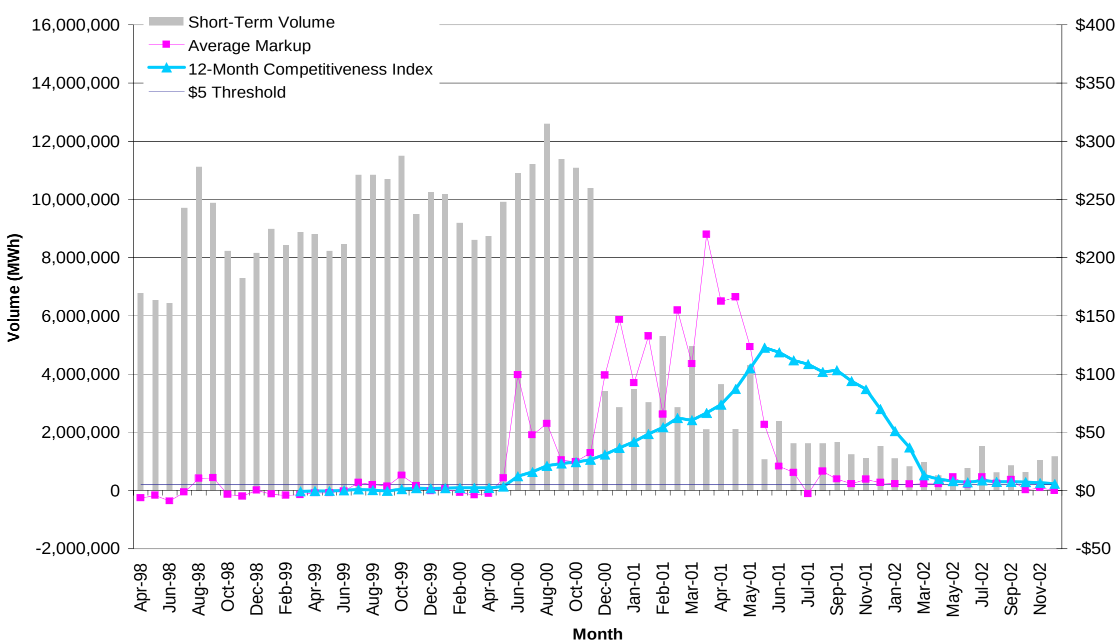
While the ISO's 2002 Market Redesign (MD02) stresses structural and design changes to promote competitive markets, the DMA has proposed the Twelve-Month Competitiveness Index (12MCI) as a standard to measure the competitiveness of the

[6] In a competitive market, suppliers compete away profits, so that the competitive price just covers all costs. This includes economic costs, such as a market rate of return sufficient to attract investment in a business of similar risk.

market. This index effectively is a volume-weighted twelve-month rolling average of the short-term markup. It provides a benchmark to measure the degree of market power in the market during its transition to the new structure, as adequate supply infrastructure and demand response capability are developed. It will also be useful following the deployment of the various phases of MD02 to monitor the markets for unexpected problems or bottlenecks.

We assume the market is workably competitive provided the 12MCI is below $5/MWh. Since the 12MCI has remained above $5 in each month in 2002, ranging from $5.69 to $50.91/MWh, it appears as though some market power persists in the short-term market Figure 3.9 shows the 12MCI through December 2002.

Figure 3.9. Twelve-Month Competitiveness Index through December 2002



3.4.2 Changes to CMCP Methodology

The competitive market-clearing price (CMCP), which the DMA has been using, is an estimate of the market-clearing price in a perfectly competitive market for California's energy.

The calculation of CMCP involves a single supply curve crossing with an inelastic demand. The demand consists of the sum of all metered reading values from in-state generators, the sum of netted metered reading values from imports and the hour-ahead regulation-up requirement. The components used in the supply curve are more detailed. We discuss them below according their level of complexity.

First, we assign a zero price to the sum of metered reading values from non-thermal in-state generators as well as the sum of net metered reading values from imports, that is, we net them out. Next, we assume, for in-state thermal generators participating in California energy market, the quantities of their bids are their maximum capacities less than their scheduled outage plus an unit dependent forced outage factor times the maximum capacities, the last item used to capture the amount of forced outages. The average value of forced factor is around 0.06. We calculate the prices of their bids as the average heat rates at their corresponding maximum capacities times zonal specific daily gas price with distribution charges plus variable operation and maintenance cost. Last, to account for the elasticity and opportunity cost from imports, we use the import day-ahead adjustment bids anchored at the weighted energy price.

3.4.3 Measuring Competitive Behavior through Bidding Practices: The Bid-Cost Markup for Real-time Energy

This section summarizes anti-competitive bidding practices in the ISO's real time market since implementation of the June 19 Order. We focus this section on the most direct and identifiable form of anti-competitive behavior within the ISO system: bidding of thermal capacity into the real time market at prices in excess of operating costs (economic withholding).

We examine the competitiveness of bidding practices by comparing the degree to which bid prices exceed marginal costs, or the bid-cost markup, based on the basic performance characteristics (heat rates) and input costs (daily spot market gas cost). Bidding significantly in excess of costs represents the most direct and identifiable form of anti-competitive bidding by thermal generators. The bid-cost markup provides a standard measure that can be used to compare bidding by different generating units and portfolios of resources over time. Prior to discussing methodology and results we first address several issues that are central to obtaining a meaningful measure of bid-cost markup.

3.4.3.1 Market Design or Market Power?

The degree to which bids and prices exceed marginal production costs is one of the most basic and widely recognized measures or indicators of the exercise of market power in single-price auction markets. However, in the context of analyzing the cause of price spikes in California's wholesale market prior to implementation of the June 19, 2001, Order, some observers have argued that "the California market design and conditions include many features and circumstances where rational competitive suppliers would bid more than their direct marginal costs yet not be withholding, and therefore, not exercising market power," and that previous studies of market power have not accurately differentiated between behavior or outcomes attributable to these market design features rather than the exercise of market power.[7] The primary focus of the debate on previous studies of California's wholesale energy markets centers on the degree to which price spikes prior to implementation of the June 19, 2001, Order may be attributed to market power. However, we can address the basic market design features and explanations discussed in several critiques of previous studies of market

[7] Scott Harvey and William Hogan, "Further Analysis of the Exercise of Market Power in the California Electricity Market," November 21, 2001. p.4 (Harvey and Hogan, 2001a). Also see "Issues in the Analysis of Market Power in California," October 27, 2000 (Harvey and Hogan, 2000) and "Identifying the Exercise of Market Power in California," December 28, 2001 (Harvey and Hogan, 2001b). It should be noted that the primary focus of papers by Harvey and Hogan papers is on refuting the basic conclusions of previous studies of overall system prices and physical withholding in the period <u>prior</u> to implementation of the June 19 Order. Nonetheless, Harvey and Hogan are frequently cited.

power in California's wholesale market and demonstrate how these arguments either do not apply or have been factored into the ISO's analysis presented in this report.

- ***Unit Commitment:*** One explanation frequently offered for why generators may bid in excess of marginal costs in California's hourly markets—even under perfectly competitive conditions—involves the need to make unit commitment decisions for thermal generating units with significant start-up costs, minimum load costs, and minimum operating times.[8] In this report, we address the issue of unit commitment and minimum run times by performing a separate analysis of bidding by gas-fired steam units (excluding combustion turbines) that are already committed to operate prior to the Real Time Market (e.g. by being scheduled on a day-ahead or hour-ahead basis to meet a bilateral sale or a requirement to run pursuant to a Reliability Must-Run contract at a pre-agreed price). Since these units are already committed to operate, all start-up and minimum load costs associated with being committed to operate are sunk, making irrelevant any reasons for bidding above marginal costs relating to the unit commitment decision. Under these conditions, a supplier facing competitive market conditions would have no reason to bid to supply energy from any excess capacity at a price above the unit's marginal operating cost.[9]
- ***Opportunity Costs Stemming from Inter-temporal Arbitrage and the Ancillary Service Markets:*** Another rationale offered for why generators may bid in excess of marginal costs in the day-ahead energy market stems from the sequential, segmented nature of the original California market design. This may lead a generator to offer its capacity on a day-ahead basis at a price reflecting expected margins in the ancillary service capacity and/or real time energy markets, rather than its incremental production costs.[10] While this aspect of California's market design may have played a role in the price spikes in the California Power Exchange day-ahead market during 2000, this market design feature simply does not apply to bidding of any excess capacity in the ISO's real time market subsequent to the June 19, 2001, Order. As the Commission noted in the December 19, 2001, Rehearing Order, "the real-time market is the last opportunity to resell energy and the only alternative is to allow the resource to be unused with no revenue recovery." Since we focus only on bidding in the ISO's real time market, this potential explanation for bidding and prices observed in other energy or capacity markets is not applicable to results of this analysis.
- ***Energy-limited Generators:*** A third reason why energy-limited generators may bid in excess of marginal production costs in the real time market, even under perfectly competitive conditions, involves the potential opportunity

[8] As explained by Harvey and Hogan, "in energy and ancillary service markets that clear hour by hour on one-part bids, competitive suppliers that do not expect to be able to profitably operate at anticipated prices would, to the extent that they submit offer prices at all, submit offer prices that exceed their incremental production costs." (Harvey and Hogan, p.5).

[9] Harvey and Hogan acknowledge that once a non-energy limited unit is committed to operation on a day-ahead basis, the unit would have an incentive to bid incremental costs in the real time energy market: "These generators would find it rational to bid their energy into the market at incremental production costs (aside of course from considerations discussed above relating to inter-temporal arbitrage and the multiple and separate energy and ancillary service markets." (Harvey and Hogan, 2000, p.14).

[10] See Harvey and Hogan (2000), p.9.

costs of forgone sales during future time periods. However, as noted by Harvey and Hogan, "units of this type could include pondage hydro units with relatively little remaining flexibility to reduce water level, thermal units that are constrained by emissions limits, or gas-fired units that are constrained by a gas shortage."[11] Again, while these special circumstances may have played a role in the price spikes prior to the June 19, 2001, Order, we cannot reasonably expect any of these special conditions to affect bidding of the specific generating resources (e.g. gas-fired steam units) and time period covered in this report.[12] Emissions constraints that may have played a role in price spikes of late 2000 and early 2001, for instance, have been dramatically eased through a combination of lower loads and thermal generation levels, installation of emission equipment at many plants during the first half of 2001, and, in some cases, modification of local emissions restrictions. Moreover, the June 19, 2001, Order expressly provided for the recovery of emissions costs associated with complying with the must-offer obligation by bidding into the real time market.

- ***Price Caps During Shortages:*** A fourth reason offered to explain why generators may, even under perfectly competitive conditions, bid in excess of marginal production costs in the real time market involves how market prices are determined when an absolute shortage of capacity or energy occurs. As Harvey and Hogan explain, "in a shortage, the market-clearing price will rise to the price cap. Because sellers are not automatically paid the price cap in a shortage, at least one supplier must bid that price in each product category to set the market clearing price at the price cap level, even in a shortage situation."[13] Again, while this rationale may be offered as a factor that played a role in the price spikes prior to the June 19, 2001, Order, during virtually the entire period covered in this report, no shortages occurred or were even anticipated on a day-ahead basis based on load and supply conditions routinely posted by the ISO. Moreover, as Harvey and Hogan note, this aspect of market design only requires each supplier bid a small portion of capacity at the price cap in order to ensure recovery of some "scarcity rents", so that this aspect of California's market design cannot be offered as a valid reason for the significant amounts of capacity routinely bid into the ISO's real time market at or above the regional price cap in place since the June 19, 2001, Order.

- ***Credit Risk:*** Another factor that may be cited by some generators as an explanation for bidding in excess of marginal costs is that the risk of not receiving payment may exceed the 10 percent credit adder that is already added to the MCP for Incremental Energy in the ISO's real time market. We addressed this issue by examining bidding before and after payment for Energy provided in the ISO's real time market resumed on December 14, 2001.

- ***Physical Withholding***: Finally, previous studies of market power have also been criticized as being based on inadequate data or questionable

[11] Hogan and Harvey (2000), p.10.

[12] In future reports, we look forward to providing a more detailed review and analysis of any environmental constraints that could affect bidding of specific units under current conditions.

[13] Hogan and Harvey (2000), p.21.

assumptions about unit outages, the degree of physical withholding that occurred, and the extent to which physical withholding affected market prices. Our analysis of bidding behavior in this study is based only on actual bids submitted by generators for capacity bid into the ISO's Real Time Market. We made no assumptions – nor were required to – about the actual amount of capacity available or any physical withholding that may have occurred.[14]

Figure 3.10. Bid-Cost Markup Methodology

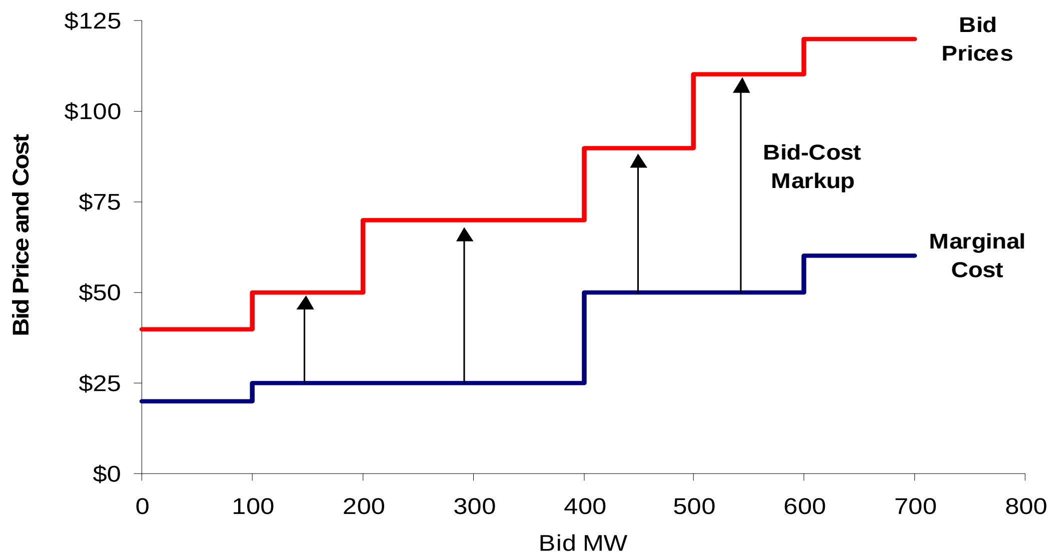


Figure 3.10 illustrates the bid-cost methodology used to assess and summarize anti-competitive bidding by owners of gas-fired generation in the ISO system. First, we calculate the marginal cost of capacity bid into the real time market (including capacity providing spinning, non-spinning and replacement reserve, plus any additional capacity bid as supplemental energy). We then develop a marginal cost curve by sorting bids in ascending order of marginal cost. We can then calculate the bid-cost markup for each bid based on the degree to which the bid prices exceed the marginal cost of the corresponding capacity.

For this report, we calculated marginal costs based on heat rates submitted by generators pursuant to the April 26, 2001, Order, daily spot market gas prices, and $6/MWh for operations and maintenance costs. Although the June 19, 2001, Order uses monthly gas contract prices to determine proxy bids, we used daily spot market gas prices in this report since several generators have indicated that their actual bidding is based on gas prices in the daily spot markets, rather than the monthly markets.

The bid-cost markup is most commonly expressed as a percentage of estimated marginal costs. However, one of the key trends we noted since implementation of the

[14] Similarly, this study does not include any capacity not bid into the ISO's market due to an economic waiver.

June 19, 2001, Order is that actual bid prices have tended to remain at relatively constant levels over time or have varied in ways which cannot be explained by changes in gas prices. Consequently, to provide a better indication of the degree to which bid prices exceed costs over time, we present the report results primarily in terms of the absolute bid-cost markup (i.e. $/MWh), calculated based on the degree to which bid prices exceed marginal cost.

Two themes are prevalent throughout the time period studied: In aggregate the five major owners of gas-fired generation generators have consistently bid significant amounts of capacity well in excess of variable operating costs and bid prices appear to remain relatively constant, rather than reflecting significant variations in spot market gas prices over time, the heat rates of different units, or other factors that would be expected to effect bid prices under competitive conditions. These basic findings are illustrated in aggregated results provided in Figures 3.10, 3.11, and 3.12.

As shown in Figure 3.10, the portion of capacity bid at prices that were significantly in excess of marginal costs has remained high throughout the entire period since implementation of the June 19, 2001, Order, with a high portion of bids being submitted at prices at or near the price caps that have been in effect during this period (represented by the price category ranging from $80/MWh to $110/MWh up to October 29, 2002, when the price cap became $250/MWh). Much of the capacity from combustion turbines, as well as significant quantities of excess capacity from on-line steam units, have been bid into the real time market at prices at or near the price caps that have been in effect, up to the implementation of the $250/MWh price cap on October 29, 2002.

Figure 3.11. Gas-fired Capacity Bid into the ISO Real-time Energy Market

(Super Peak Hours)

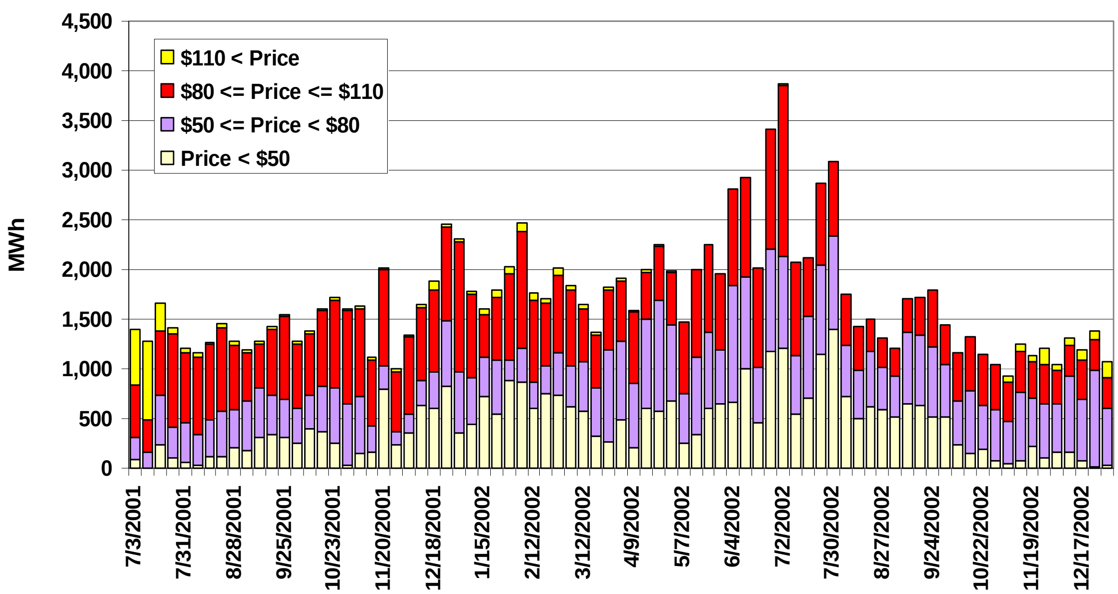


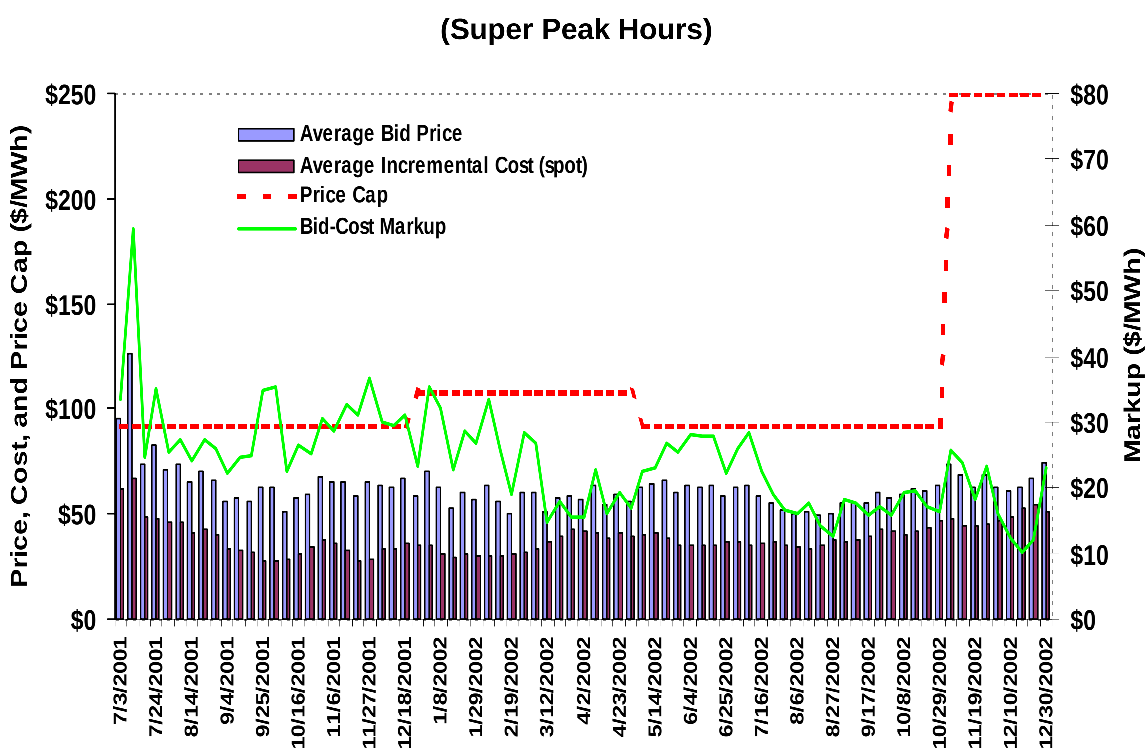
Figure 3.11 shows average hourly amount of capacity bid into the ISO real time market by gas-fired units within the ISO system at different price levels during super peak hours. Since mid July 2001, the prevalent trend has been a significant amount

of capacity bid at prices between $80/MWh and $110/MWh. This price range includes bids at the $91.87/MWh price cap and the $108/MWh price cap.[15] Virtually all bids at this level are significantly in excess of costs, as spot market gas prices averaged around $3.00/MMBtu in the south from March 2002 through September 2002.

For purposes of this analysis, we defined super peak hours as the 8-hour block of hours with the highest average system load each month (excluding weekends and holidays).

Our second key finding is that that excess capacity from steam units that are on-line and scheduled to operate (as a result of a bi-lateral transaction) have been routinely bid into the real time market at prices far in excess of marginal costs by numerous suppliers. Figure 3.12 compares the bid prices of excess capacity from on-line steam units to the estimated marginal costs of this capacity. The average bid price for on-line steam capacity for 2002 is approximately $60/MWh, compared with average marginal costs of about $37/MWh, representing a bid-cost markup of about 60 percent. Capacity from steam units committed prior to the real time market represents about 65 percent of the total gas-fired capacity bid into the ISO's Real Time Market during super peak hours.

Figure 3.12. Weekly Average Bid Price, Cost, and Markup For Steam Units On-line and/or Scheduled to Operate Prior to Real Time



This chart shows average bid price, marginal cost, and price-cost markup (in $/MWh) for gas-fired steam units that were on-line and/or scheduled to operate (as a result of

[15] The $91.87 price cap was in effect through mid-December, 2001 and again after May 1, 2002. The $108/MWh price cap was in effect in the interim, and a $250/MWh price cap has been in place since October 29, 2002.

a bilateral market transaction) prior to the real-time market. For these units, startup costs and minimum load costs are already sunk and bid prices for capacity bid into the real-time energy market should reflect incremental costs of any additional output.

The average price-cost markup for bid prices for steam units committed prior to the real time market has largely remained in the range of $15/MWh to $30/MWh, or 40 to 75 percent more than variable costs on average.

Our third key finding is that one form of "hockey stick" bid that can be observed is the practice of some suppliers to bid all peaking capacity (CTs) at a price at or near the price cap, while bidding excess capacity from on-line steam units at prices that are lower (but often still significantly in excess of marginal costs). The average bid price for combustion turbine capacity for 2002 is approximately $93/MWh, compared with average marginal costs of about $59/MWh, representing a bid-cost markup of about 56 percent.

Figure 3.13. Weekly Average Bid Price, Cost, and Markup For Combustion Turbine Units

(Super Peak Hours)

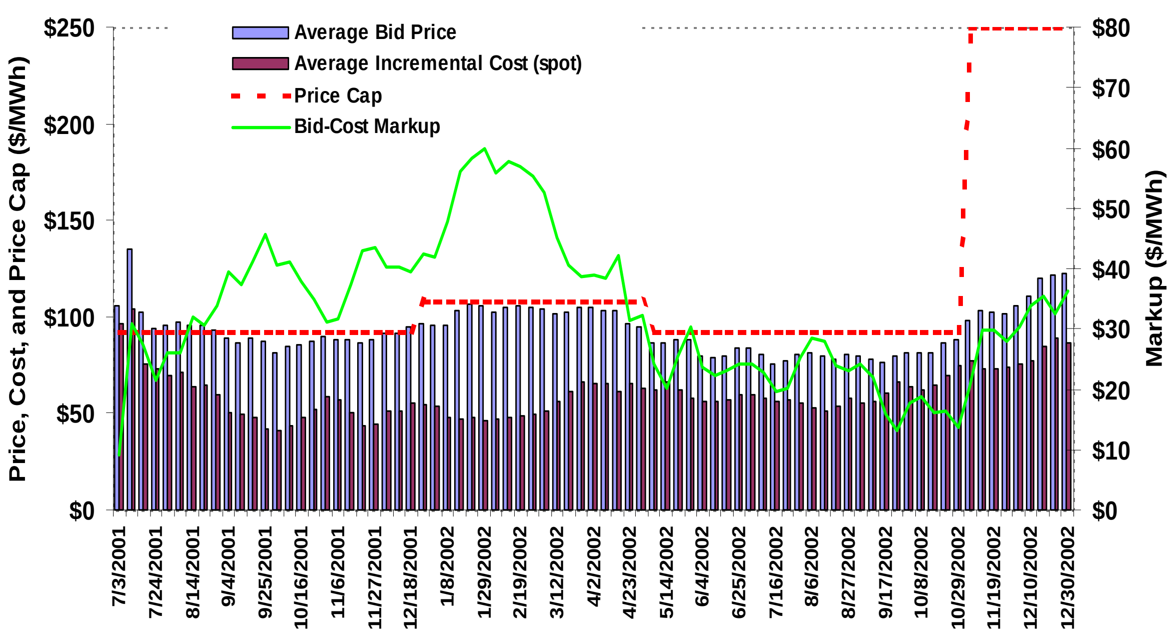


Figure 3.13 shows average bid price, estimated marginal cost, and price-cost markup (in terms of $/MWh) for combustion turbine units owned by the five major owners of gas-fired generation in the ISO system during super peak hours. The average bid prices in this chart reflect the fact that the bulk of capacity from CTs were bid at prices at or near the price caps that have been in effect under the June 19 Order up to the change to $250/MWh in late October 2002.

Our key findings, based upon our analysis of bidding behavior through December 2002 include:

- Several of the five major non-utility owners of gas-fired generation within the ISO system engage in a clear and consistent pattern of bidding significantly in excess of the marginal operating costs of thermal generation. Our analysis of bidding patterns of individual suppliers shows that there has been only a weak relationship between bid price and variable costs for key portions of 2002.
- Excess capacity from steam units that are already on-line and scheduled to operate pursuant to a bilateral sale – which has accounted for about 65 percent of the total gas-fired capacity bid into the ISO's real time market during peak hours in 2002 -- is consistently bid at prices far in excess of marginal costs by numerous suppliers. The bid price - cost markup for these units has ranged from 40 to 75 percent over variable costs from March 2002 through September 2002. Thus, we cannot attribute the overall trend of bidding in excess of costs to "uncommitted capacity" that --- suppliers may argue --- needs to be bid at prices in significantly in excess of marginal operating costs in order to ensure that start-up and minimum load costs are recovered.
- The situation where multiple suppliers bid large portions of their generating capacity at or near the price cap has continued through October 2002. Given that the caps are far in excess of the marginal costs of virtually all gas-fired capacity, this trend suggests that the caps continue to serve as a "target" that facilitates similar patterns of anti-competitive bidding amongst multiple suppliers.
- The anti-competitive "hockey stick" bidding specifically mentioned in the April 26, 2001, Order, where a supplier bids capacity from combustion turbines ("CTs") at a price at or near the price cap, while bidding excess capacity from on-line steam units at somewhat lower prices, continues to be prevalent in the ISO's real time market.
- Energy prices in the ISO's real time market have remained moderate through 2002, despite the systematic bidding significantly in excess of costs by owners of gas-fired generation. This result is due to consistent low demand for incremental energy in the ISO's real time market throughout most of the year. California experienced mild summer weather in 2001 and 2002 compared to the summer of 2000, which tempered peak loads and helped keep the anti-competitive bidding practices from dramatically affecting the realized market price for real time energy. The bidding practices we identify in this section indicate that, should California experience more severe summer weather, there is a risk that imbalance load will be exposed to considerably higher real time prices than have been observed over the past two summers.

3.4.4 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. Therefore, this analysis examines the economics of investment in new supply capacity given observed prices in California's wholesale energy markets over the last three years.

The analysis is based on a typical 500 MW combined cycle unit, since the majority of projects proposed in California and the WECC during the last three years have been gas-fired combined cycle plants of approximately this size. Table 3.6. summarizes the key assumptions used in this analysis.

Table 3.6. Study Assumptions: Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Heat Rates (MBTU/MW)	
Maximum Capacity	7,200
Minimum Operating Level	8,200
Installed Capacity Costs	\$500 - \$600 /kW
Fixed Annual O&M	\$10 /kW
Other Variable O&M	\$2/MWh
Startup Costs	
Gas Consumption	2,000 MMBtu
Other Startup Costs	\$2,000
Fixed Charge Rate [1]	14 –15 %
Fixed Cost Revenue Requirement [2]	\$70 - \$90/kW/year

[1] Range of 14%-15% based on 14.5% fixed revenue requirement and sensitivity analysis of specific financial assumptions outlined in *Market Clearing Prices under Alternative Resource Scenarios: 2000-2010*, Staff Report by the California Energy Commission (February 2000), Section III: New Market Entry, p.2-4.

[2] [\$500/MW installed costs x 14% Fixed Charge Rate] + \$10/kW Fixed O&M = \$70/kW/year.
[\$600/MW installed costs x 15% Fixed Charge Rate] + \$10/kW Fixed O&M = \$90/kW/year.

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 ISO's markets. However, revenues from a hypothetical unit operating solely in the real-time market were nonetheless calculated to provide a benchmark for prices in the ISO's markets.[16]

Results of this analysis show that during 2002, real time energy and ancillary service revenues in California ($72-$77/kw) were within the lower range that may be needed to support new investment in baseload supply ($70-$90/kw). 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.

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

1. An initial operating scheduled is first determined based 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 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 (1) 50 MW of nonspinning reserve each hour it was available for service, and (2) 300 MW of replacement reserve each hour it was either in operation or available for service. Revenues from all Ancillary Services 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

Table 3.7. Financial Analysis of New Combined Cycle Unit

	NP15	SP15
Load Factor	61%	62%
Average Energy Revenue ($/MWh)	$ 40	$ 41
Average Operating Cost ($/MWh)	$ 26	$ 26
Net Energy Revenue ($ /kW)	$ 66	$ 71
A/S Capacity Revenue ($/kW)	$ 6	$ 6
Total Net Revenue ($/kW)	$ 72	$ 77