UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange	)))))	Docket Nos. EL00-95-000, *et al.*

FOURTH QUARTERLY REPORT OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

On April 26, 2001, the Commission issued its "Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets" in the above-captioned dockets ("April 26 Order").[1] In the April 26 Order, the Commission required the California Independent System Operator Corporation ("ISO")[2] to:

> "On September 14, 2001, and quarterly thereafter . . .[to] file with the Commission a report analyzing how the mitigation plan is operating as well as the progress that has been made in developing new generation and demand response."

April 26 Order at ¶ 61,364.

On June 19, 2001, the Commission issued its "Order On Rehearing Of Monitoring and Mitigation Plan For The California Wholesale Electric Markets, Establishing West-Wide Mitigation, And Establishing Settlement Conference"

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 95 FERC ¶61,115 (2001).

[2] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

("June 19 Order").[3] In the June 19 Order, the Commission continued the requirement that the ISO submit quarterly reports that addressed, among other things, the status of new generation and the development of Demand response programs in California. In addition, the June 19 Order directed that the ISO:

> "[F]ile on or before March 26, 2002, a report on market conditions that addresses, among other things: (1) a list of all new generating resources (including the nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of those facilities are actually are on line...and (2) the continued progress in executing long-term contracts and reducing the reliance on the spot market."
>
> June 19 Order at ¶ 62,567.

On August 20, 2001, the ISO filed "Comments of the California Independent System Operator Corporation Concerning the Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference" ("60-Day Comments") in the above-captioned dockets. In its 60-Day Comments, the ISO included its summary of comments and status report on the Commission's mitigation plan. The information and data included in those comments analyzed market conditions through July 31, 2001.

On September 14, 2001, the ISO filed the "First Quarterly Update of the California Independent System Operator Corporation" ("First Quarterly Report") in the above-captioned dockets.

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[3] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al., 95 FERC ¶61, 418 (2001).

On December 14, 2001, the ISO filed the "Second Quarterly Update of the California Independent System Operator Corporation" ("Second Quarterly Report") in the above-captioned dockets.

On March 26, 2002, the ISO filed the "Third Quarterly Update of the California Independent System Operator Corporation" ("Third Quarterly Report") in the above-captioned dockets.

The instant filing, the "Fourth Quarterly Report," is intended to satisfy the requirements of the quarterly reports and provide an update of the specific report directed by the June 19 Order by providing an update on the development of new generation, the status of Demand response programs, forward contracting efforts, and other actions the ISO has taken with regards to the Commission's price mitigation orders.

EXECUTIVE SUMMARY

Wholesale electricity prices in California have remained relatively stable since the ISO filed its Third Quarterly Report with the Commission. The price stability has resulted from a continued strong supply position due to near-normal hydro conditions in the Pacific Northwest and California and to relatively stable natural gas prices. The market also has benefited from the positive impacts of the Commission's June 19, 2001 west-wide mitigation measures.

The California market structure has undergone significant changes since the Third Quarterly Report. For example, the California Department of Water Resources California Energy Resources Scheduler ("CERS"), the credit worthy buyer of the net short energy requirements of the investor-owned utilities ("IOUs"), has renegotiated a large portion of its supply portfolio. While the new contracts allow CERS to more effectively schedule its portfolio supplies to meet load, the contracts still leave a significant portion of the California load exposed to short-term price volatility. Another significant change since the last report has been the dramatic decline in the amount of new generation resources that previously were expected to come on-line in the past two months. Between April 15, 2002 and June 1, 2002, only 100.5 megawatts out of an expected 1,988 MW of viable new generation has been brought on-line. This alarming trend largely is due to financial difficulties facing new generation developers. Although new generation capacity is planned for the remainder of 2002, much of it is due to projects having been delayed past June 1, 2002. In addition, the ISO has received indications that an additional 1,400 MW of generation in Southern

California may be retired by the end of 2002, beyond the 653 MW previously forecasted for retirement. This additional amount of generation projected to be retired will be taken down purportedly because the facility owners consider that the environmental regulations in the region render the plants non-economically viable.

Anti-competitive bidding behavior persists in the ISO real-time energy market. "Hockey-stick" type bidding exists in the real-time market and numerous suppliers consistently bid at prices far in excess of marginal costs for excess capacity from on-line steam units. In addition, most capacity from gas-fired combustion turbines consistently is bid at or near the applicable price caps.

Given the tight supply and demand balance in California and the persistent anti-competitive bidding behavior in the ISO's markets, the ISO believes that west-wide price mitigation must remain in place past September 30, 2002 to provide a backstop against suppliers' ability to exercise significant market power during tight supply conditions. While market conditions have improved over the past year, more structural remedies, including additional generation and transmission resources, credit worthy utilities that are empowered to procure a portfolio of long, mid, and short-term supply contracts, and a price responsive demand are needed before price mitigation measures can be responsibly removed from the California wholesale electric markets.

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Effectiveness of Price Mitigation

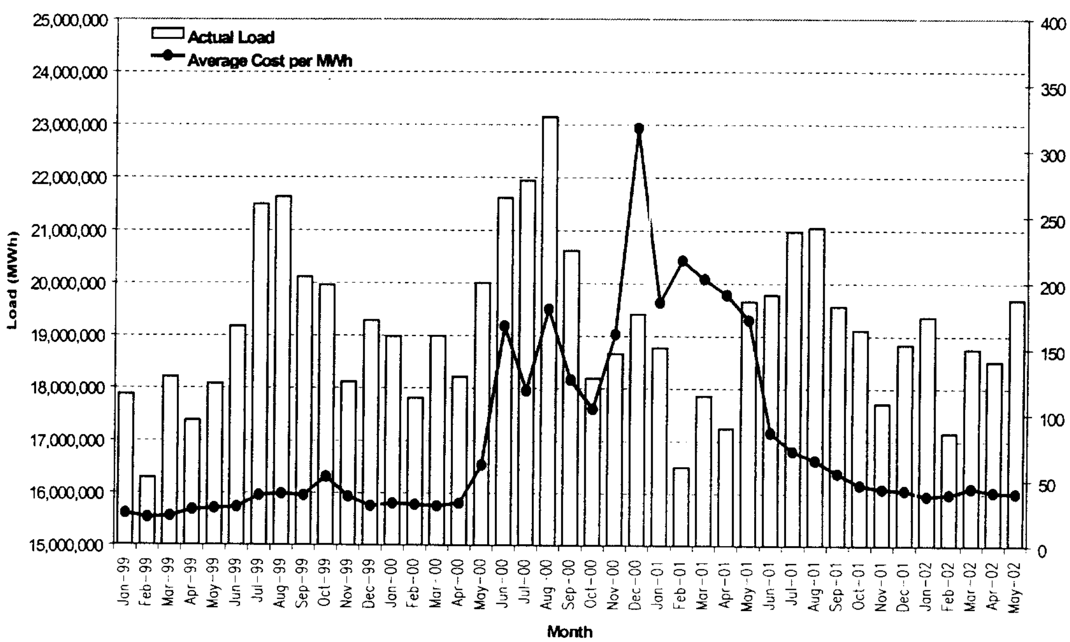
The outlook for the California wholesale energy market has improved since summer 2001. As a result of the Commission's June 19, 2001 order, west-wide price mitigation has limited California's exposure to extraordinary price spikes. On the other hand, California's good fortune largely can be attributed to merely transitory supply and demand conditions. Mild weather, a weak economy, and conservation have all been instrumental in keeping loads manageable. Additionally, brisk hydroelectric production in the Pacific Northwest and low gas prices has contributed to strong supply in California and throughout the West. As the Commission is well aware, California's considerably worse luck in late 2000 and early 2001 ultimately led to an energy crisis.

Energy Costs and Loads

The average total cost to serve load of energy and ancillary services ("AS") consistently has remained in the range of $39 to $46 per megawatt-hour ("MWh") since October 2001. This includes estimated costs of utility-owned generation and bilateral contracts to meet net-short load, plus actual costs of real-time energy and AS. While these costs are well below those incurred during the crisis period from mid-2000 through early June 2001, when costs ranged from $100 to $350/MWh, these more recent costs still are above those incurred before the crisis, when costs stayed relatively constant at $33/MWh. The bulk of the approximately 30 percent upward shift in costs from pre-crisis to post-crisis levels can be attributed to costs embedded in long-term bilateral contracts entered into by the California Department of Water Resources' California Energy Resources Scheduling Division ("CERS").

Loads in spring 2001 largely were below levels seen in 2000, due to mild weather, a weak economy, conservation, and involuntary curtailment during the crisis period of summer 2000 through spring 2001. The ISO has observed that loads in 2002 have increased since 2001, albeit to levels below those experienced during the crisis. This recent load increase largely is due to the lower volume of retail customers subject to curtailment programs. Warmer weather, modest economic rebound, and conservation fatigue also are significant factors. The California Energy Commission reports that peak demand, when adjusted for growth and weather conditions, increased 5.8 percent from April 2001 to April 2002. However, this is still 3.8 percent below the level seen in April 2000. Figure 1 shows monthly ISO loads and costs since January 1999.

Figure 1. California ISO Loads and Costs

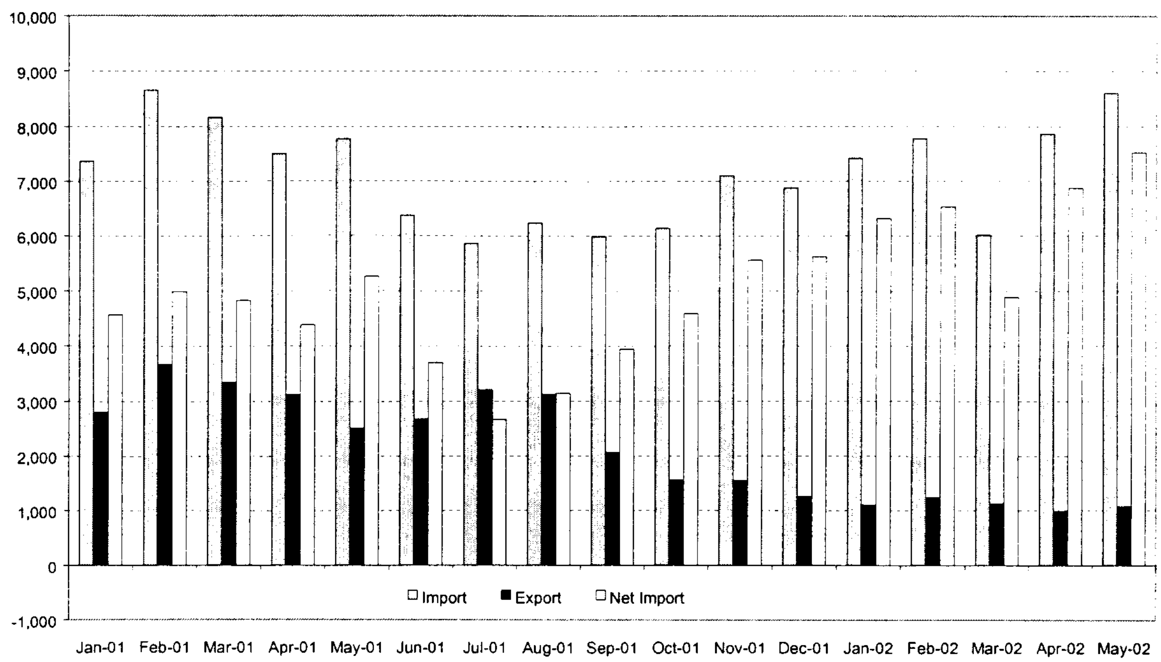


Supply Conditions Are More Favorable Today

California has better supply and demand conditions since those detailed in the Third Quarterly Report. The Northwest has enjoyed plentiful runoff, and so has offered low-cost hydroelectric power to California throughout the spring of 2002.

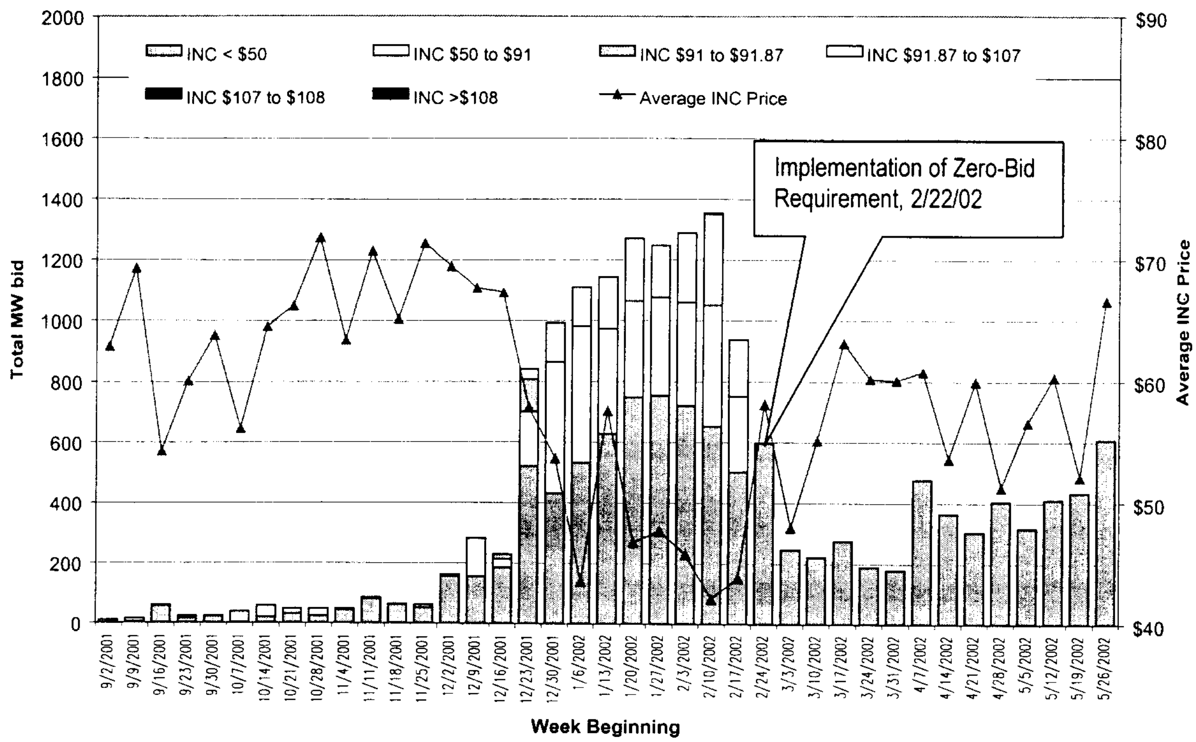
Favorable hydro conditions, in conjunction with the substantial elimination of "megawatt laundering" by West-wide mitigation in the June 19 Order, have contributed to a significant increase in the net volume of generation imported into California over 2001 levels. During the crisis month of April 2001, import volume averaged 7,502 MW, of which 3,120 MW (41.6%) was offset by exports. In contrast, California had an average of 7,861 MW of imports in April 2002, of which only 987 MW (12.6%) was offset by exports. While the total import volume did not change significantly between April 2001 and April 2002, west-wide price mitigation has been effective in preventing the phenomenon of export followed by re-import of energy through which generators successfully evaded the then California-specific market power mitigation in 2001. Figure 2 shows monthly average imports, exports, and net imports, for January 2001 through May 2002.

Figure 2. Imports, Exports, and Net Imports through April 2002



While marketers have offered a significant amount of import energy to California in bilateral forward contracts, they have almost completely refused to bid imports into the ISO BEEP Stack since the Commission on December 19, 2001 ordered such bids be set at $0/MWh. Continuing this trend, the majority of the imports that have been provided to the ISO Control Area during spring 2002 have been sold in bilateral forward contracts. The ISO expects that the already low volume of import energy offered into the BEEP Stack will further diminish as the Northwestern runoff slows. Figure 3 shows that import volumes bid into in the ISO BEEP Stack have stayed relatively low since the implementation of the zero-bid requirement on February 22, 2002. Moreover, average BEEP prices have increased following the zero-bid requirement, largely due to lower volumes being bid into the ISO's real-time market.

Figure 3. Weekly Average Import Bid Volume into BEEP Stack by Price Bin

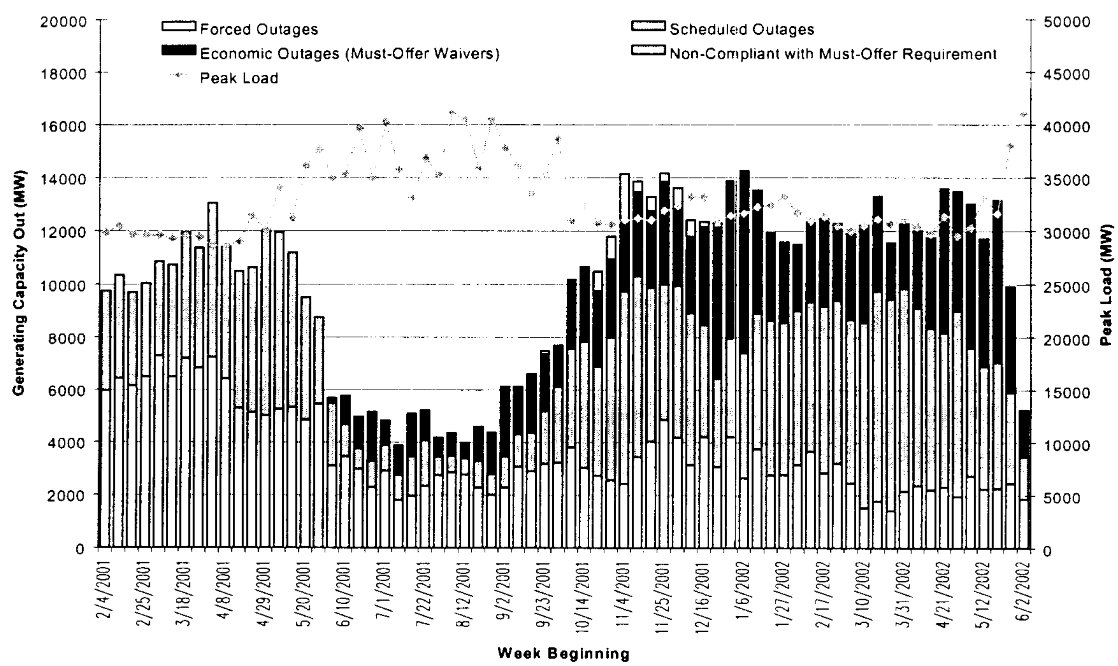


Generation Outages, Economic Waivers, and Peak Loads

The volume of forced outages has been significantly lower in spring 2002 compared to spring 2001. Forced outages averaged approximately 2000 MW from March through May 2002, compared with approximately 6000 MW for the same months in 2001. This decrease in forced outages was somewhat offset by an increase in planned outages. Planned outages increased to approximately 6000 MW in spring 2002, from approximately 4000 MW in 2001. Thus, the sum total of forced and planned outages increased approximately 2000 MW between spring 2001 and spring 2002.

The ISO has implemented a waiver process as part of its compliance with the Must-Offer obligation. Generators that do not wish to offer their total available capacity to the market may apply for a waiver from the Must-Offer Requirement, with the understanding that they may be called back to service when needed. For example, the average generating capacity subject to waiver fell from 5870 MW to 4148 MW in the last week of May 2002, as the ISO called several units back to service, in anticipation of an increase in load due to a heat wave in California. Figure 4 shows weekly outages by type and weekly peak load since the late winter of 2001.

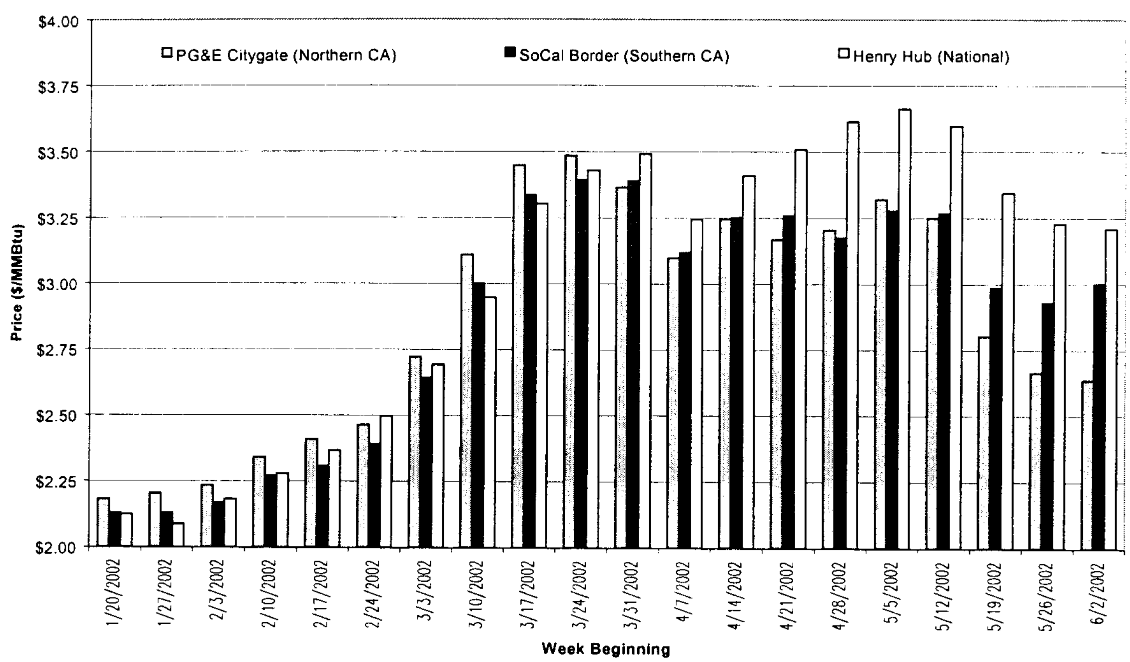
Figure 4. Outages by Type and Weekly Peak Load



Moderate Input Prices Persist

The price of natural gas in 2002 has closely followed the path it took in the early part of 2001. Prices have stayed in the range of $2.41 to $4.00 per million British Thermal Units ("MMBtu") in spring 2002. In April, California gas prices had the unusual characteristic of being lower than national Henry Hub prices, due in part to unseasonably hot and cold weather in the Northeast and Midwest, respectively. Figure 5 shows weekly average gas prices at California delivery points and Henry Hub through early June 2002.

Figure 5. Weekly Avg. Gas Prices: CA Delivery Points and Henry Hub



Bidding Behavior

Anti-competitive bidding behavior persists in the ISO real-time energy market. "Hockey-stick" type bidding continues in the real-time market and numerous suppliers consistently are bidding far above their marginal costs for excess capacity from on-line steam units. In addition, most capacity from gas-fired combustion turbines consistently is bid at or near the price caps.

Anti-Competitive Bidding Practices

This section summarizes anti-competitive bidding practices in the ISO's Real Time Market following the June 19 Order. This section focuses 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 (i.e., economic withholding).

The key findings presented here previously have been submitted to the Commission through confidential weekly market monitoring reports prepared pursuant to the April 26 Order. Extensive discussion of the methodology employed in this analysis in addition to analysis of specific generator's bidding behavior was included in the Third Quarterly Report and will not be repeated here. This section of this Fourthly Quarterly Report should be considered a supplement to the analysis of bidding behavior detailed in the Third Quarterly Report as filed on March 26, 2002. Key trends and findings of the ISO's analysis of bidding behavior through May 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. Analysis of bidding patterns of individual suppliers shows that there has been only a weak relationship between bid price and variable costs for several suppliers for most of the time since the June 19 Order.

- Excess capacity from steam units that already are on-line and scheduled to operate pursuant to a bilateral sale – which has accounted for about 70% of the total gas-fired capacity bid into the ISO's Real Time Market during peak hours since implementation of the June 19 Order - consistently is bid at prices far in excess of marginal costs by numerous suppliers. The bid price - cost markup over variable costs for these units has ranged from 40% to 70% for the period of March 2002 through May 2002. Thus, the overall trend of previously committed steam units bidding in excess of costs clearly cannot be attributed to these suppliers' need to recover start-up and minimum load costs.
- Situations wherein multiple suppliers bid large portions of their generating capacity at or near the price cap have continued through May 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 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.

- Prices in the ISO's Real Time Market have remained moderate through May 2002, despite the systematic bidding significantly in excess of costs by owners of gas-fired generation. However, this result is due to a relatively low and stable demand for incremental energy in the ISO's Real Time Market throughout the past three months.

These observations provide further indication that continued market power mitigation is warranted to protect against market power in both the Real Time Market and forward Energy markets until such time as the market power provisions in the ISO's current market redesign proposal are approved and implemented.

Analysis of Bidding Behavior based on Bid-Cost Markup Methodology

Suppliers consistently have bid significant amounts of capacity well in excess of variable operating costs. This is illustrated in Figures 6 through 8. Since the Third Quarterly Report, the proportion of energy from gas-fired units bid at prices greater than $50/MWh has increased substantially. The portion of capacity bid at prices significantly excess of marginal costs has remained high throughout the entire period since implementation of the June 19 Order, with a high portion of bids being submitted at prices at or near the price caps (represented by the price category ranging from $80/MWh to $110/MWh). Furthermore, the proportion of energy bid at prices greater than $80/MWh has been increasing in recent weeks compared with the past two months (Figure 6).

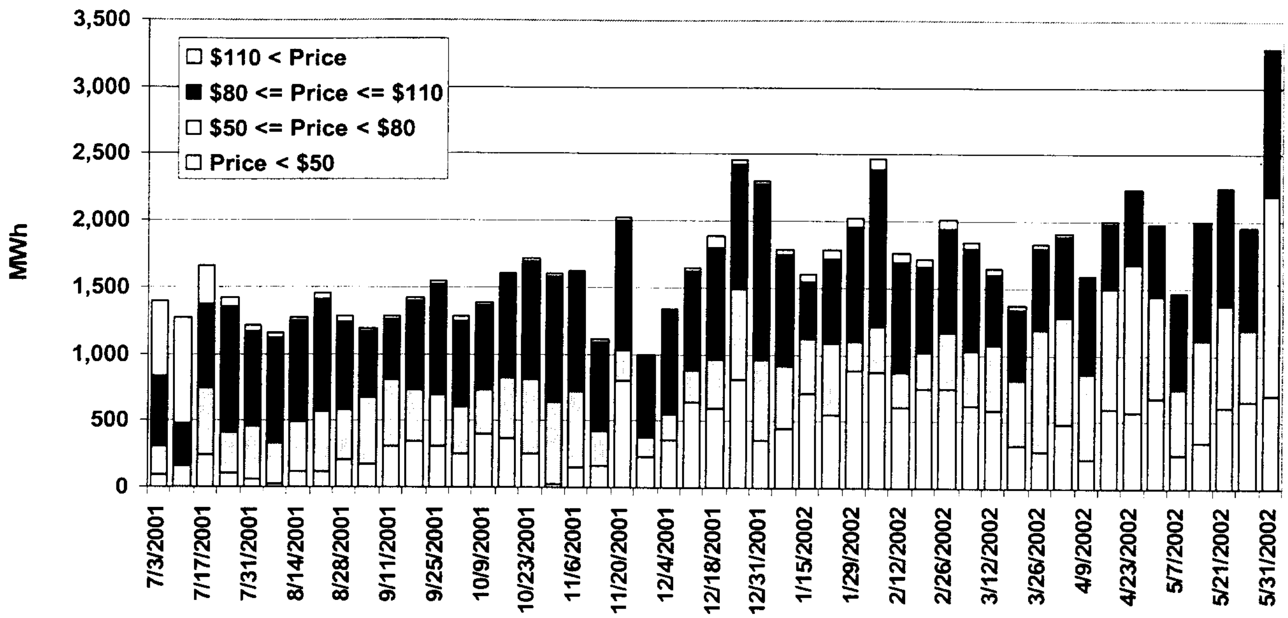
A second key finding of the analysis is that many suppliers are bidding into the Real Time Market at prices greatly exceeding marginal costs for excess capacity from steam units that are on-line and scheduled to operate (as a result of bilateral transactions). This trend has persisted through the spring months. Figure 7 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 since October is approximately $60/MWh, compared with average marginal costs of about $39/MWh, representing a bid-cost markup of about 54%. Average bid price does not appear to be positively correlated with estimated variable cost (based on spot price of natural gas and the heat rate of the unit). In recent weeks, variable costs have declined as natural gas prices come down, yet the average bid price shows an increasing trend (Figure 7). Capacity from steam units committed prior to the Real Time Market represents about 70% of the total gas-fired capacity bid into the ISO's Real Time Market during super peak hours.

Energy from CT units consistently has been bid at or near the price cap. This is shown in Figure 8, where average bid prices for these units has remained just below the $91.87/MWh or $108/MWh price cap. Figure 8 also shows that bid prices are not correlated with estimated variable costs for these units.

Additional analysis of bidding by individual suppliers will continue to be submitted to the Commission on a confidential basis, and the ISO is prepared to provide additional analysis in response to any further comments and suggestions from the Commission and staff.

Figure 6. Gas-fired Capacity Bid into the ISO Real Time Energy Market

(*Super Peak Hours)



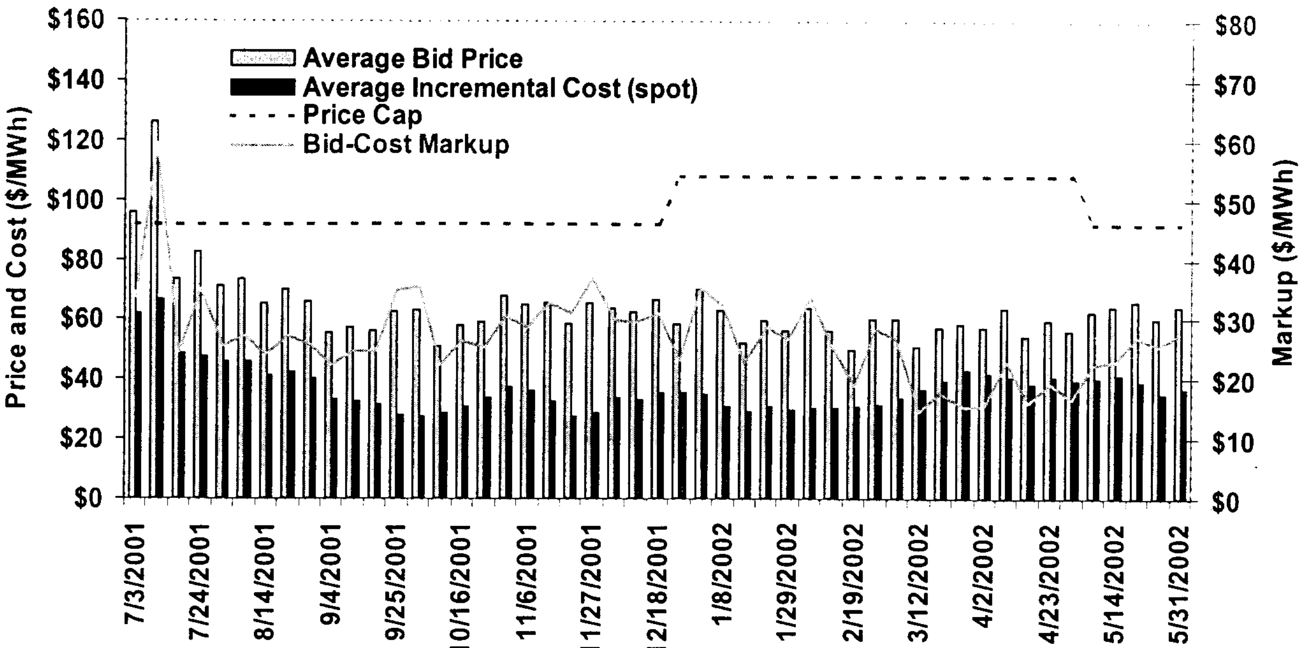
This chart shows average hourly amount of capacity bid into the ISO real-time market by gas-fired units at different price levels during super peak hours. Since mid-July, the prevalent trend has been a significant amount of capacity bid at prices between $80/MWh and $110/MWh. This price range includes bids at the $91.87/MWh price cap and the $108/MWh price cap**. Virtually all bids at this level are significantly in excess of costs, as spot market gas prices averaged less than $3.15/MMBtu in the south from March 2002 through May 2002 and remained below $3.60/MMBtu from September 2001 through May 2002.

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

** 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.

Figure 7: Weekly Average Bid Price, Cost, and Markup For Steam Units On-line and/or Scheduled to Operate Prior to Real Time

(*Super Peak Hours)



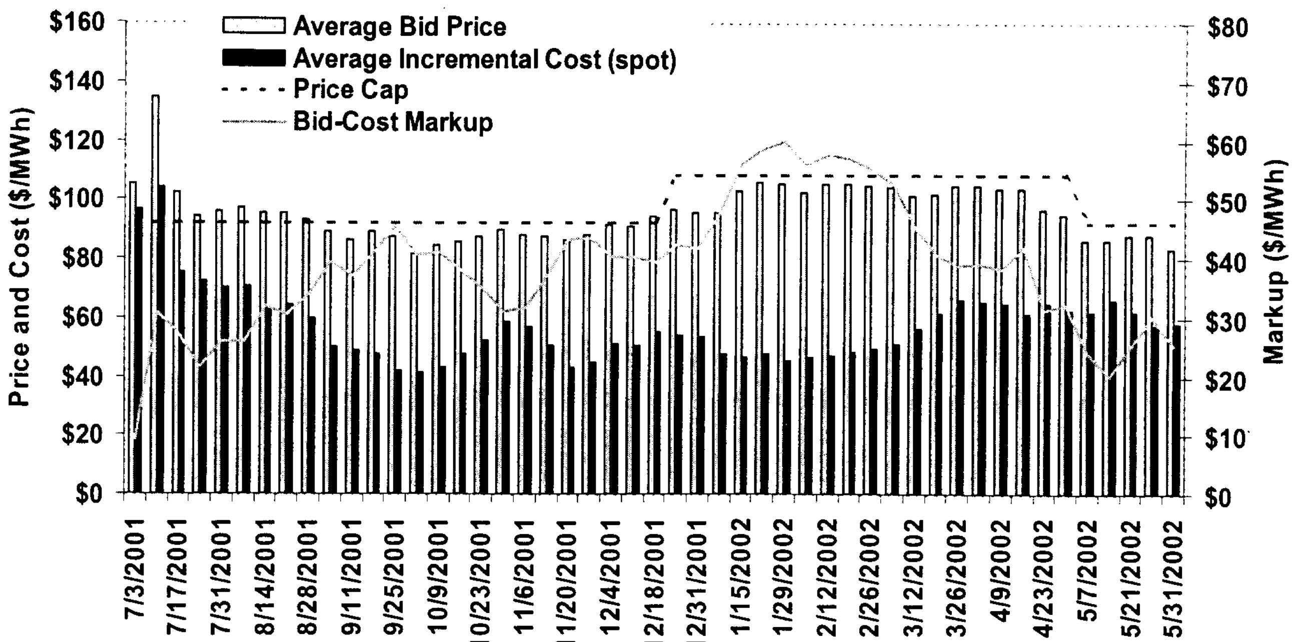
This chart shows average bid price, marginal cost, and price-cost markup (in $/MWh) for gas-fired steam units that were on-line and/or scheduled to operate (as a result of a bilateral market transaction) prior to the real-time market. For these units, startup costs and minimum load costs are already 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 largely has remained in the range of $15/MWh to $28/MWh, or 40% to 70% over variable costs on average.

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

Figure 8. Weekly Average Bid Price, Cost, and Markup For Combustion Turbine Units

(*Super Peak Hours)



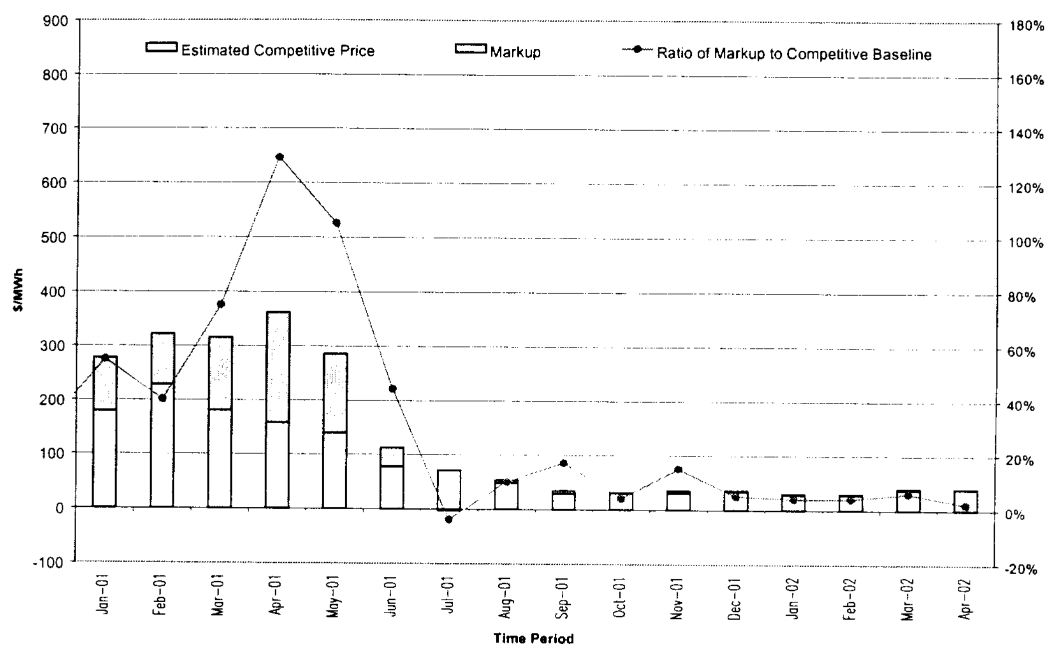
This chart shows average bid price, estimated marginal cost, and price-cost markup (in terms of $/MWh) for combustion turbine units owned by the five major owners of gas-fired generation in the ISO system during super peak hours. The average bid prices in this chart reflect the fact that the bulk of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

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

Market Power Remains Modest in 2002

The ISO monitors several price-to-cost markup indices, all of which compare the price paid for energy to an estimate of the price that likely would be paid in a competitive market, which is a price close to the system marginal cost. One such index is the markup in short-term energy, which includes energy procured by CERS in short-term bilateral forward contracts (balance of month, day-ahead, hour-ahead), as well as real-time energy procured by the ISO on behalf of load-serving entities. Figure 9 demonstrates that short-term markup has remained under control, at levels below ten percent since January 2002.

Figure 9. Price-to-Cost Markup in Short-Term Energy



Summary—Effectiveness of Price Mitigation

The Commission's west-wide price mitigation plan, especially the west-wide mitigated market clearing price and the must offer obligation, continues to provide stability to the western wholesale electric markets. However, it is the current supply to demand ratio in California that has, for the most part, kept prices below the mitigated market clearing price in the western markets. That is, it is the supply to demand ratio, and not price mitigation that is influencing prices. However, without new supply and continued favorable hydro conditions, tight supply margins could once again enable suppliers to significantly influence western wholesale electric prices through the use of the anti-competitive bidding behavior. Significant structural remedies including additional new generation and transmission resources, credit worthy utilities that are empowered to purchase a portfolio of supplies to meet their load requirements, and price responsive demand are necessary before price mitigation measures safely can be removed from the California electric markets.

New Generation Update

Since the filing of the ISO's Third Quarterly Report, projections of the amount of new generation to be developed in California have been reduced significantly. Between April 15, 2002 and June 1, 2002, only 100.5 megawatts of viable new generation has been brought on-line. The following table is a synopsis of generation status changes within California since the Third Quarterly Report.

Table 1. Generation Status Changes within the ISO Control Area.

	MW
Viable New Generation brought on-line between April 15 and June 1, 2002	100.5
Generation projects cancelled, withdrawn, or placed on indefinite hold after April 15, 2002	1,770.9
Retired or environmentally constrained generation expected to be offline after April 15, 2002	653.0
Planned generation expected to be brought on-line after June 1, 2002	4,796.7

These numbers are in sharp contrast to the Third Quarterly Report, which projected 1,988 MW of new capacity to be on-line by May 31, 2002. More new generation capacity is planned for the remainder of 2002, but much of that is due to projects having been delayed past June 1, 2002.

The ISO also has received indications that an additional 1,400 MW of generation in Southern California may be retired by the end of 2002, such amount being in addition to the previously forecasted 653 MW expected to be lost from retirement or environmental constraints. Pursuant to Rule 2009 of the South Coast Air Quality Management District ("SCAQMD") Regulations, the owners of these power plants submitted a compliance plan detailing a methodology for determining the most appropriate Best Available Retrofit Control Technology ("BARCT") to install for continued NOx reductions. The owners of these units contend that under conditions where these plants run at less than 100% load, retrofit of these facilities is not economical. SCAQMD staff has, in the alternative, based their economic analysis on these facilities operating at 100% load during all hours, which results in BARCT installation potentially being an acceptable investment. In light of the SCAQMD analysis, owners of these facilities have elected to retire these facilities by the end of the year. As this is a matter between SCAQMD and the respective owners of these facilities, the ISO has declined to take a position. Nonetheless, the ISO continues to be concerned about the impact these retirements will have on overall generation capacity available in the ISO control area.

As detailed in the Third Quarterly Report, lower energy prices, the fallout from the Enron bankruptcy, and regulatory hurdles continue to present barriers to the development of new generation. Accounting difficulties, credit downgrades, and the heightened regulatory scrutiny generation owners have received of late has made new generation development even more difficult, as evidenced by the volume of cancelled capacity between April and June 2002.

CERS Long-Term Power Purchase Agreements Update

Contract Renegotiations

On April 22, 2002 and May 2, 2002, CERS successfully renegotiated 15 long-term power purchase agreements with Calpine Energy Services, Constellation Power Source, Whitewater Energy Corporation, Capitol Power, and Calpeak Power. Additionally, CERS terminated one contract with Calpeak Power. Contingent on these agreements were settlements terminating the California Attorney General's lawsuits and the California Public Utilities Commission's and the California Electricity Oversight Board's complaints before the Commission against these suppliers. The current status of the contracts after the latest renegotiation efforts and other related events is as follows:

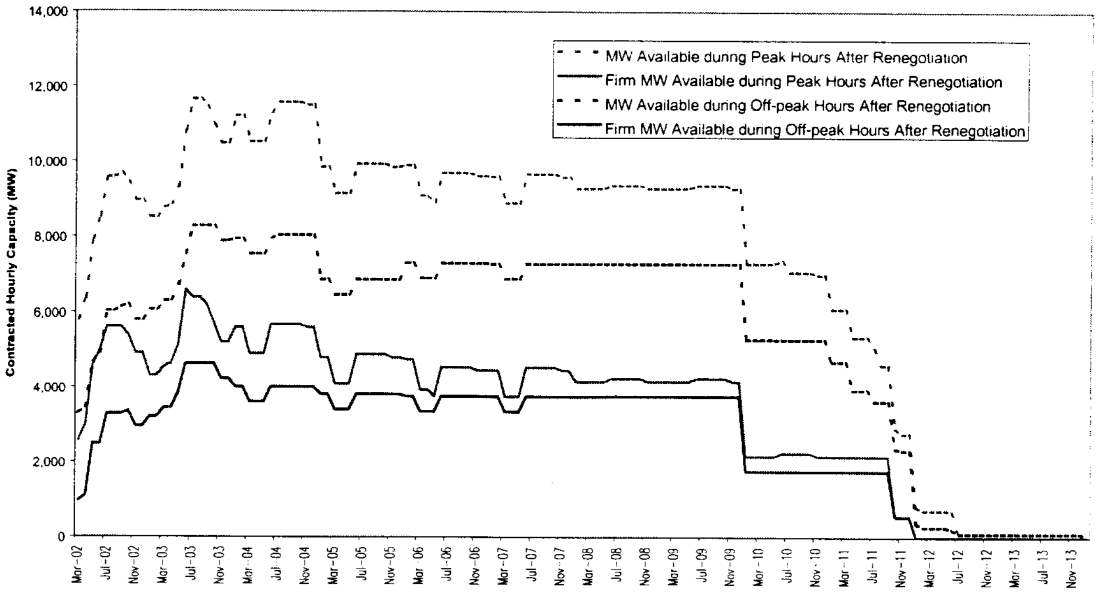
Number of Long-term Power Purchase Agreements	55
Number of Suppliers	26
Maximum term of Agreements	11 years

	Peak Hours	*Off-peak Hours*
Maximum hourly available capacity before renegotiation	11856.1 MW	8223.6 MW
Maximum hourly available firm capacity before renegotiation	4715.0	3010.0
Maximum hourly available capacity after renegotiation	11667.1	8279.6
Maximum hourly available firm capacity	6586.0	4626.0
Maximum hourly capacity increase between May 2002 and December 2003	1298.0	1104.0
Minimum hourly capacity increase between May 2002 and December 2003	120.0	610.0

Figure 10 is a graph of the monthly maximum hourly capacity provided under long-term contract.

Figure 10. Contracted Peak and Off-peak Hourly Capacities After Renegotiation

(by Month)

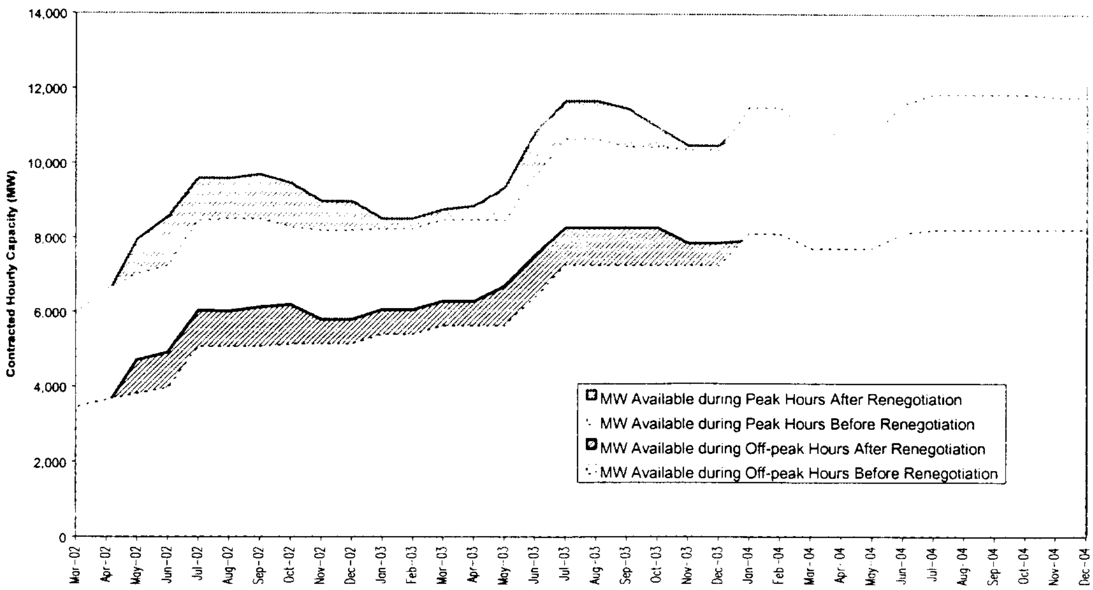


Renegotiation of these power purchase agreements has changed the structure of the long-term contract portfolio in the following ways:

- While the peak amount of capacity available has changed only slightly, significant amounts of capacity were added, both firm and non-firm, for May 2002 to December 2003. Figure 11 shows the capacity additions (shaded) during this time period.

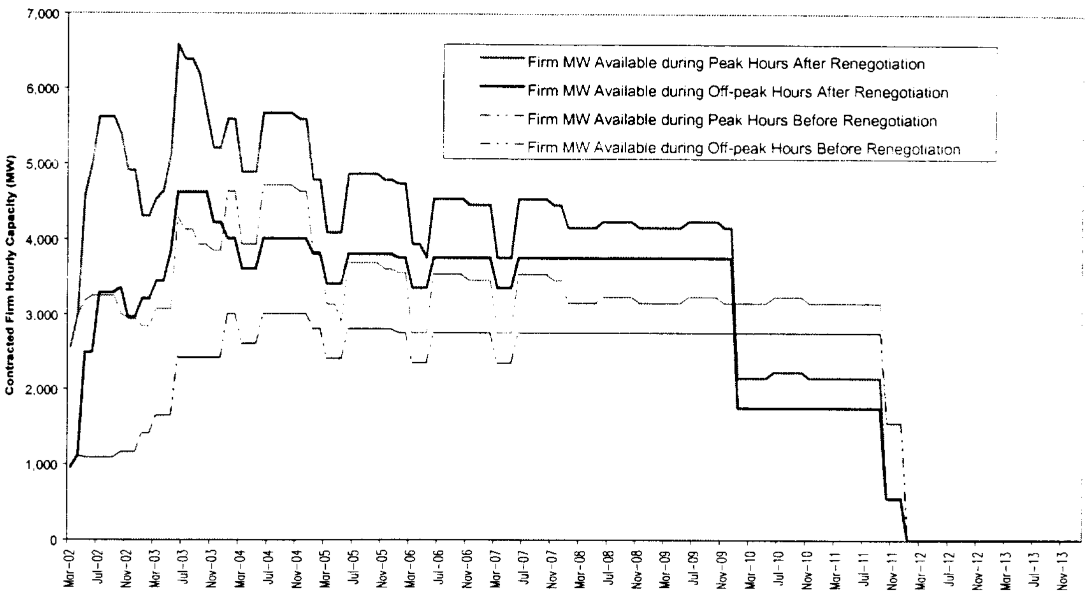
Figure 11. Peak and Off-peak Hourly Capacity Additions

(from May 2002 to December 2004)



- Figure 12 shows that from May 2002 to December 2011, the amount of firm capacity increased by between 35% and 200%, with the largest increases in firm capacity occurring between May 2002 and December 2003.

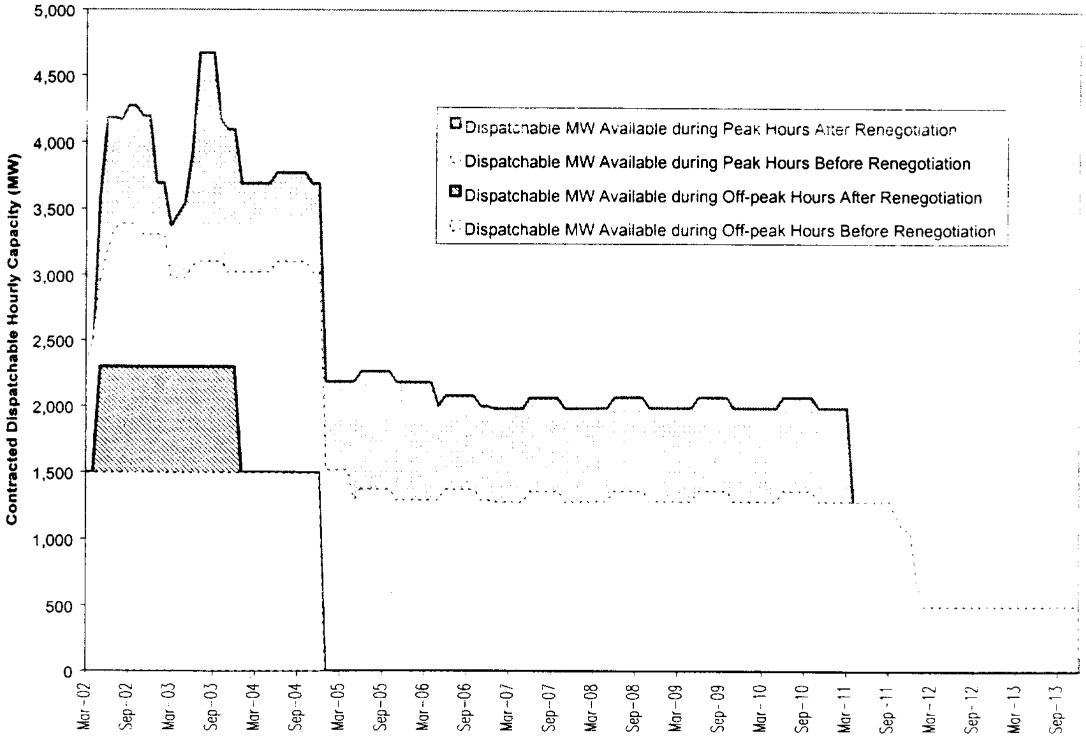
Figure 12. Peak and Off-peak Hourly Firm Capacity from 2002 to 2013



- Figure 13 shows that dispatchable capacity available during peak hours increased by between 500 and 1500 MW for each hour May 2002 to December 2011, and dispatchable capacity available during off-peak hours increased by roughly 750 MW for each hour from May 2002 to December 2003.

Figure 13. Peak and Off-peak Hourly Dispatchable Capacity Additions

(from May 2002 to December 2011)



- A few contracts now have substantially reduced terms. In particular, one Calpine contract has been reduced from 19 years in length to nine years.

- A number of contracts have been adjusted so that instead of a fixed pricing structure for energy, the payment rate for energy now varies in relation to the price of natural gas.

Other Recent Developments

Events apart from the renegotiation of the contracts have slightly changed the structure of CERS' contract portfolio. On March 27, 2002, CERS terminated a 13.5 MW contract with Soledad Energy, which drew power from a biomass plant in Northern California. Subsequent to this termination, Soledad Energy closed the plant after April 4, 2002.

There also is a dispute between the State of California and Sempra Energy regarding a long-term power purchase agreement. The State argues that Sempra Energy's failure to construct the Elk Hills generation plant near Bakersfield, California by April 1, 2002 is a violation of the contract, and has threatened cancellation of the contract if unspecified Sempra Energy does not provide assurances. In turn, Sempra Energy has countered that it intends to have a more efficient facility operating at the Elk Hills site, and has filed a lawsuit for a declaration that it is not in breach of contract.

The recent CERS contract renegotiations have increased CERS' ability to schedule in accordance with forecasted system loads. The renegotiated terms also have increased the amount of firm capacity available to CERS to hedge against volatile spot prices. While these contract revisions significantly have improved CERS' ability to hedge against and schedule to peak load forecasts, the revisions are not sufficiently significant to alter the conclusions reached in the detailed analysis set out in the Third Quarterly Report. In short, significant amounts of load remain subject to spot market risk during periods of peak demand.

Demand Response Programs Update

Demand Program development in California is proceeding on two fronts. The ISO is expanding its Participating Load Program ("PLP") through the Market Design 2002 ("MD02") project and demand participation has been incorporated throughout the MD02 design proposal. Other California entities also have accelerated activity in several areas to encourage further demand participation in new or revitalized retail programs.

ISO Program Status

Previous quarterly reports have outlined the history of demand program development at the ISO. Because of the various obstacles faced in 2001, the ISO shifted its policy on demand programs, to concentrate on increased flexibility for wholesale participation through the Participating Load Program. Further retail demand program design and implementation will be undertaken by state agencies and the IOUs.

The ISO's PLP allows Loads to bid in a manner similar to generating resources into both the Non-Spin and Replacement Reserve Market and the real-time Supplemental Energy market. The PLP attracted bids of 700-800 MW during peak periods in the summer of 2000, mostly from large water project pumps. Adverse hydro conditions and creditworthiness concerns reduced participation to less than 100 MW during the summer of 2001. The ISO anticipates the summer 2002 participation to be somewhere in-between. The ISO has initiated a round of discussions with all PLP participants to increase their 2002 participation. The ISO will launch a broad awareness campaign on new market opportunities targeted at potential load participants following the Commission's approval of the MD02 design.

Significant enhancements to the PLP are proposed in the MD02 design. The ISO seeks to give loads more flexibility through multi-hour commitments and advance notice of curtailments. In the fall of 2002, loads will be able to compete in the Residual Unit Commitment market. Further, when the ISO markets shift to Day Ahead energy trading in 2003, loads will be able to bid in the Day Ahead and Hour Ahead Energy markets, showing their willingness to curtail at different price levels.

CPUC Interruptible Rulemaking

The CPUC rulemaking process recently proposed reopening the state Demand Bidding Program, which would allow loads to bid from $100 to $750 to be curtailed during periods of emergencies. The IOUs have reported that just over 200 MW is signed up for the program. The program will be operated by the IOUs and will be triggered by information from the ISO about operating reserves. On June 6, 2002, the CPUC reinstated California's 20/20 program, a program that was very successful in 2001. However, this year's program is limited to residential customers and compares 2002 energy use with the same monthly use in 2000. The 20/20 message is simple: If a residential load reduces consumption by 20%, it saves 20% on its bill, and it receives an additional rebate of another 20%. The three large IOUs recently reported enrollments on the interruptible tariffs at slightly over 1000 MW. This is less than the 1500-1600 MW that has participated in earlier years, but higher than participation during the summer 2001. The ISO can curtail the interruptible loads during a Stage II emergency.

The ISO continues to monitor this rulemaking process and will assist in implementation of programs wherever possible.

California Consumer Power and Conservation Financing Authority

The Third Quarterly Report discussed the California Consumer Power and Conservation Financing Authority's ("CCPCFA") demand exchange program. The CCPCFA is promoting a program applicable to all loads, including bundled loads that are aggregated by a single entity and bid into the ISO markets. The CCPCFA intends to initiate this program for energy bidding by July 1, 2002 and expects to have participation of some 250 MW of Non-Spinning Reserve by October 1, 2002. The ISO has met with the program manager and other representatives of the CCPCFA on several occasions to facilitate implementation. If successful, the program could add significant demand participation to the ISO markets.

In the Third Quarterly Report, the ISO noted that demand response programs are still evolving in California. As a critical element of an efficient market, such programs are not mature and do not make their full potential contribution to market power mitigation. This is yet another consideration in support of the ISO's request that the Commission continue market power measures beyond September 30, 2002. Even with the progress noted above, demand programs still do not provide the level of market power mitigation needed for competitive markets.

CONCLUSION

The ISO thanks the Commission for the opportunity to comment and report on the progress being made to stabilize the California electricity markets. The ISO also urges the Commission to reconsider its order for an automatic termination of the current price mitigation provisions and instead order a termination of those provisions only when a factual record supports that termination.

Respectfully submitted,

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Dated: June 14, 2002