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.***

THIRD 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.”
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> 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.

The instant filing, the “Third Quarterly Report,” is intended to satisfy the requirements of the quarterly reports and 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 fallen since the Commission imposed price mitigation effective May 29, 2001. This fortunate result stems from many factors, a number of which are subject to change. With the expiration of this price mitigation just six months distant, on September 30, 2002, the fundamental factors underlying the unjust and unreasonable prices experienced in 2000 and early 2001 *have not* improved sufficiently to provide a reasonable assurance that California’s electricity markets will produce the just and reasonable prices that a truly robust and competitive market would produce. Specifically:

- The unprecedented conservation California enjoyed in summer 2001 cannot be guaranteed to continue;
- The amount of imported energy (on which California depends to serve its Load) has fallen dramatically, reaching zero in recent weeks, as a

result, in large part, of the requirement that marketers bid $0/MWh into the ISO Real Time Market;

- Given that documented anti-competitive bidding practices persist, although somewhat abated, under the present price mitigation provisions, it is not reasonable to expect these practices to stop if price mitigation expires, though it is reasonable to think that without continued, and even enhanced, price mitigation these practices will recreate the unjust and unreasonable prices of not too long ago;
- When first ordered, the Commission's intent for the must-offer obligation was not well understood and the varying interpretations led to varying degrees of compliance among Market Participants. As the Commission has clarified the intent and implementation of the must-offer obligation, Market Participants' compliance has improved. Some form of a must-offer obligation is essential to any successful market design and, because there is no adequate substitute available for implementation on October 1, 2002, the current must-offer obligation should be extended until a substitute is available. Even though the must-offer obligation has been imposed on the entire West, since neither the ISO nor the Commission have any information to ensure compliance outside of California, the ISO is concerned that capacity is not being offered to California or other markets;
- While some new generation has been added in California, many planned projects have been or now are being cancelled, some older

generating units are being retired, and some units either are operating at diminished capacity or not operating at all due to environmental constraints;

- Efforts to eliminate the transmission bottleneck between Northern and Southern California, though underway, will not be competed for several years;
- While the ISO's Participating Load Program already meets many of the principles outlined by the Commission, additional retail demand programs will depend on decisions and leadership of the state regulators; and
- While the California Department of Water Resources has entered into a portfolio of long term power supply contracts to reduce the amount of load that must be served by real-time purchases, not all hours are completely hedged.

This report details the state of these and other elements of the California wholesale electricity markets. Taken together, the ISO strongly believes that current and projected conditions require that the Commission reconsider its current plan to terminate the existing price mitigation on September 30, 2002 and leave the existing price mitigation in place until such a time as a factual record demonstrates that the California electricity market is robust and competitive.

CONTENTS

GENERAL MARKET CONDITIONS

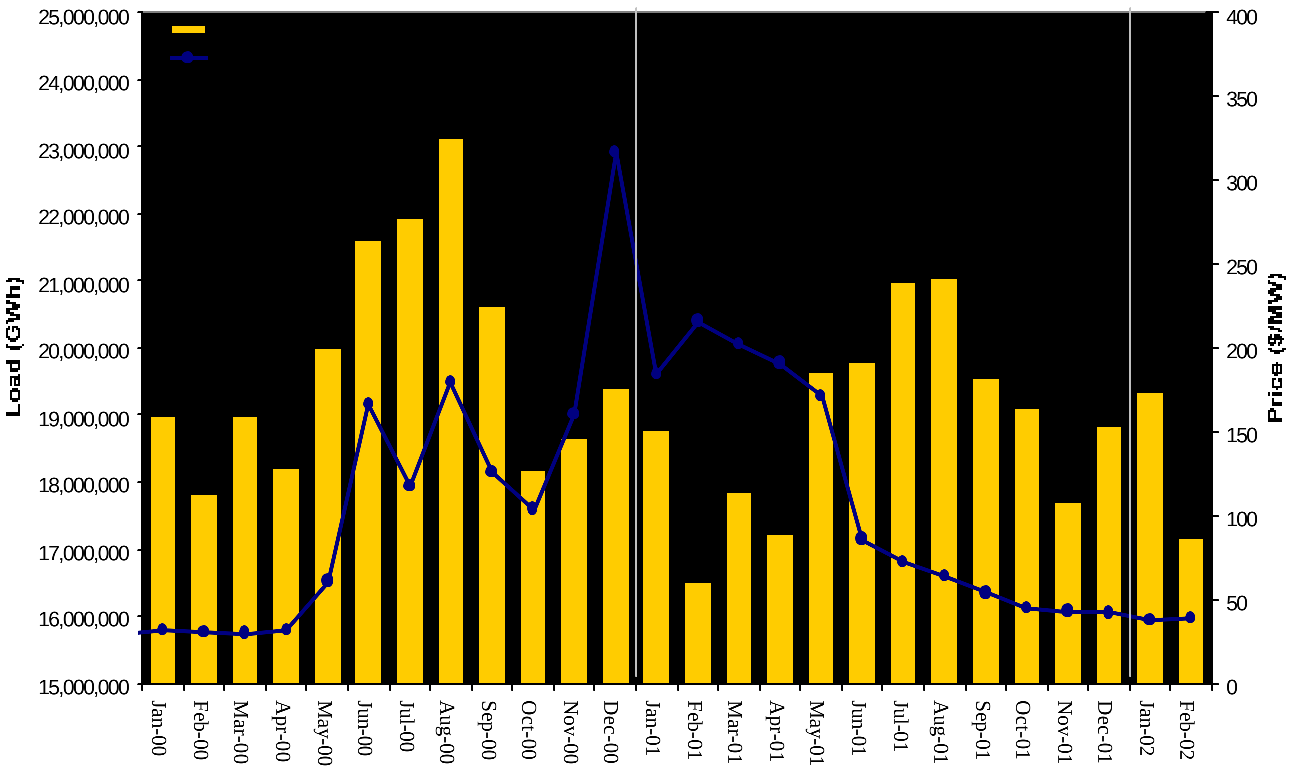
Summary: A temporary confluence of certain market influences, including increased hydroelectric generation, low natural gas prices, and reduced Demand have contributed to lower prices for now.

Soon after the Commission issued the June 19 Order, Energy prices decreased significantly as conservation produced more favorable Demand to Supply ratios. This, combined with significantly lower natural gas prices and forward contracting by the California Department of Water Resources/California Energy Resource Scheduler ("CERS") for the investor-owned utilities' net short[4] Load requirements, significantly reduced Energy prices in the summer and fall of 2001 and has continued to maintain stability in western Energy markets and keep prices in check through the winter. However, as documented throughout the instant report, the continuing Demand to Supply imbalance in California electricity markets could easily lead to a recurrence of sustained price spikes, and is especially likely to, if any of the current underlying market conditions materially change, including the removal of comprehensive regional market power mitigation measures.

[4] The net short is equal to the total load of PG&E, SCE, and SDG&E less their own generation resources.

The average cost of Load per MWh and actual monthly Loads for the period of June 1999 through February 2002 is provided in Figure 1. The average cost of Load includes estimates of utility-owned generation costs, estimated bilateral contract costs, and actual real-time and Ancillary Services costs.

Figure 1. California Loads and Costs



Supply and Demand Conditions: Strong Supply Relative to Demand

As detailed below, since the large run-up in wholesale electric prices from May 2000 through June 2001, Supply and Demand conditions in California have improved. New generation, near-normal hydro conditions, and reduced natural gas costs have improved Supply conditions since the imposition of the June 19

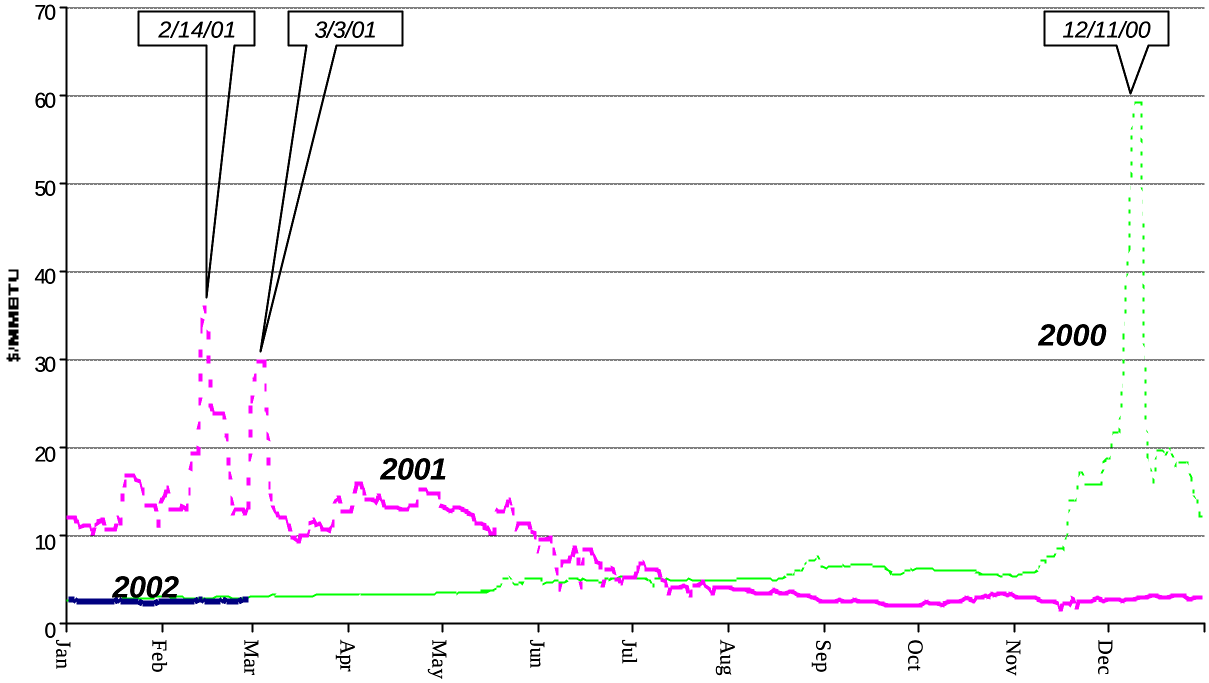
Order. Moreover, Demand in California has been reduced by a relatively weak economy and significant conservation efforts by end-use customers.

Strong Supply Conditions

Low Gas prices

Natural gas prices, the key input to thermal generation prices in California, reached an all-time high of $58.76 per million British Thermal Units ("MMBtu") on December 11, 2000 at the Southern California Border. Natural gas prices continued to be high and volatile through the winter and spring of 2001 until low Demand in the summer of 2001 reduced prices. The price reached a low of $1.74/MMbtu on November 16, 2001, and stabilized in the $2 to $3/MMbtu range, its lowest levels in two years, by late fall and through the winter months, as shown in the Figure 2. While gas prices have fallen, however, wholesale electric prices have not fully tracked the reduction in generator operating costs. Suppliers continue to submit bids that are, at times, significantly in excess of their marginal operating costs. Supplier bidding behavior and the level of price mark-up above cost is discussed in detail in Section 2. It is noteworthy that, despite recent declines, natural gas prices may start to rise later this year because the current low gas prices have led to a reduction in total drilling rig counts in recent months.

Figure 2. Southern California Border Natural Gas Spot Price – 2000, 2001 and 2002



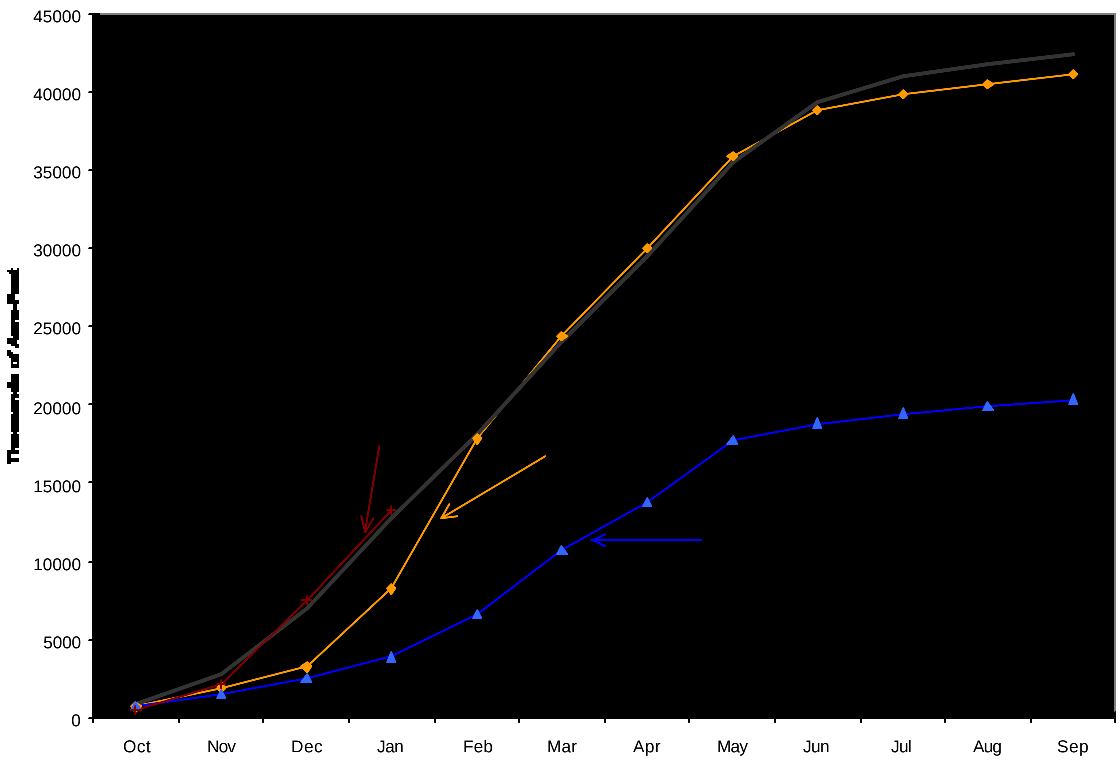
Hydro conditions

Hydroelectric supply conditions have improved significantly from the 2000-2001 hydro season. The 2000-2001 hydro season, October 2000 through September 2001, produced runoffs in the Pacific Northwest and California that were only 50 percent of normal. These conditions severely limited the Energy production from hydroelectric facilities during the spring and early summer of 2001. The shortage of hydroelectric supplies contributed to the high wholesale electric prices throughout the west during the first half of 2001. In contrast, near-normal hydro conditions are forecasted for the 2001-2002 hydro season, which should continue to contribute to the stability of the western electric markets through the spring of 2002. However, another poor hydro year like the 2000-

2001 season easily could contribute to the return of high wholesale electric prices in the west markets are left unchecked by a program of comprehensive fallback mitigation measures.

Figure 3 shows the cumulative California unimpaired runoff for hydro years 2000-2001 and 2001-2002. Figure 4 shows the historical runoff statistics as reported by the Bonneville Power Administration for the years 1992 through 2002 (projected). As shown in Figure 4, the 2001 hydro season was the weakest experienced in over a decade.

Figure 3. Cumulative California Statewide Unimpaired Runoff, Water Year 2000 to Water Year 2002[5]



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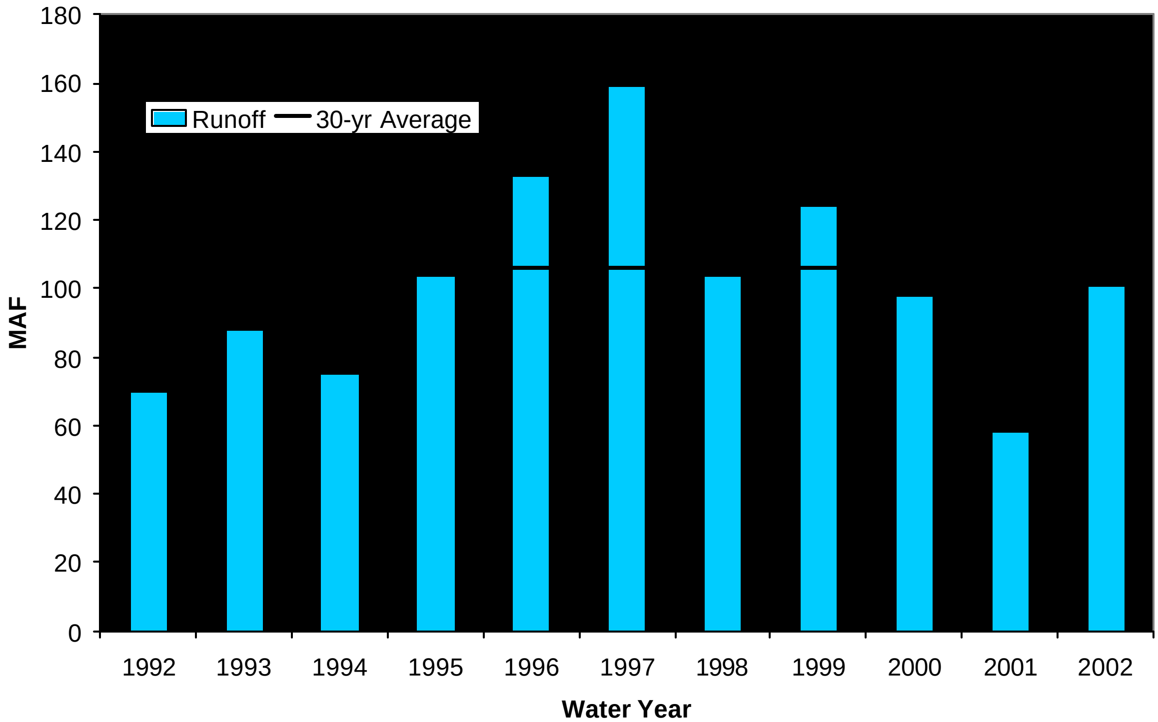
[5] Department of Water Resources, CALIFORNIA DATA EXCHANGE CENTER. Runoff Data for Water Year 2000, 2001, 2002. http://cdec.water.ca.gov

Figure 4. BPA Historical Runoff (January to July at The Dalles) with Projected 2002 Runoff



Expected El Nino Weather Conditions

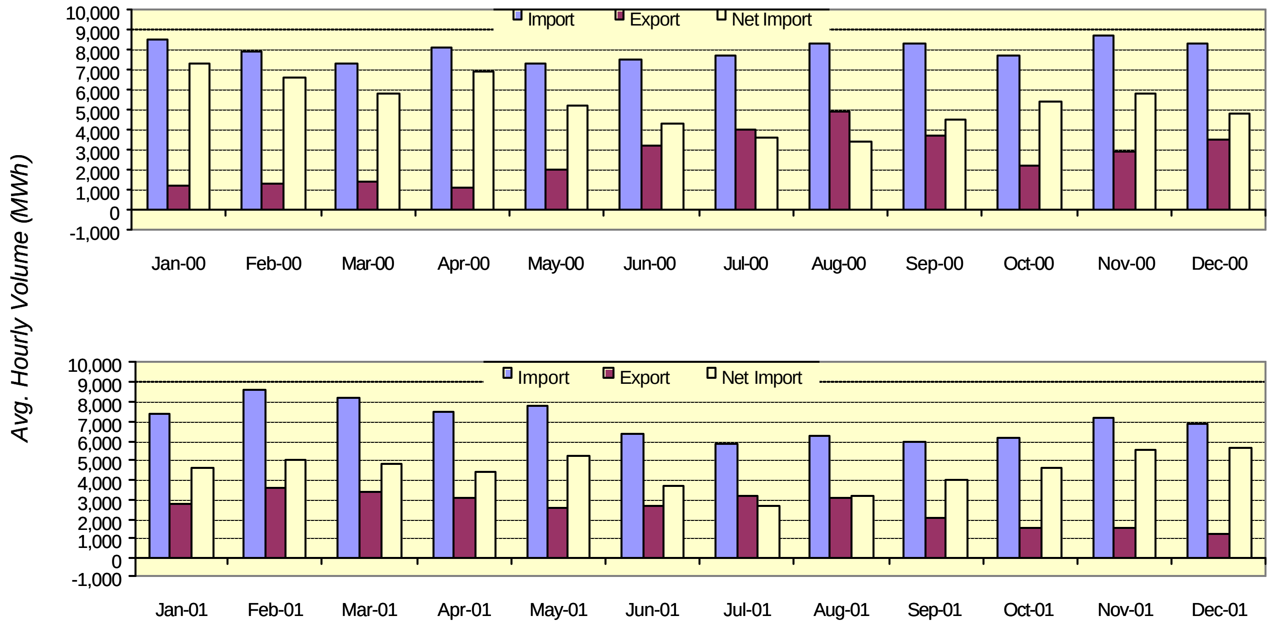
El Nino weather conditions currently are developing in the Pacific Ocean and are expected to affect weather patterns through 2003. Recently some scientists projected that El Nino could "whipsaw" Western electricity prices by creating the conditions for a mild summer and low electricity prices in Summer 2002, then cause an extremely hot summer and shortages and high prices in 2003.[6]

[6] See *El Nino May Whipsaw Western Electricity In Summers*, Jason Leopold and Jessica Berthold, Dow Jones Newswires, March 19, 2002.

Increased Net Imports

Because California relies heavily on imports, west-wide market mitigation measures have been essential to stabilize wholesale prices. While pre- and post-June 19 Order levels of net imports are relatively similar, the absolute levels of imports and exports have decreased significantly since the June 19 Order. One possible explanation for the sharp reduction in the overall flows of power into and out of the state is that the regional nature of the June 19 Order eliminated many of the incentives for "megawatt laundering." With the regional mitigation in place, suppliers no longer have the ability or incentive to ship Energy out of the state and then import the same Energy in a scheme to bypass California-specific price controls. Figure 5 illustrates this phenomenon by comparing net imports for the twelve months ending February 2001 and 2002.

Figure 5. Day-Ahead Imports, Exports, and Net Imports (MW)
Twelve Months Ending February 2001 and 2002



Weak Demand Conditions

Weak Economy and Conservation

Soft Demand has been instrumental in returning western Energy markets to health. The weak economy has reduced consumption, particularly during peak summer hours. California's aggressive conservation campaign also has reduced Demand significantly by encouraging consumers to purchase more efficient appliances and operate air conditioning systems less frequently. The California Energy Commission ("CEC") estimates the changes in monthly peak Demand and Energy use, accounting for growth and weather differences and has indicated that monthly peak Demand and Energy use decreased 8.9 and 6.6 percent, respectively, between 2000 and 2001. There are signs, however, that the economy is beginning to strengthen and that the level of conservation may abate in the next several months. At the last Federal Reserve Open Market Committee meeting on March 19, 2002, for example, the Committee stated “the information that has become available since the last meeting of the Committee indicates that the economy, bolstered by a marked swing in inventory investment, is expanding at a significant pace.”[7] If this trend continues, the State’s electricity demand quickly could rise to levels that put pressure on the tenuous balance between Supply and Demand.

Moderate Weather

The relatively moderate summer of 2001 during the traditionally hottest months in California helped limit cooling-related Demand to near normal levels. Figure 6 compares the summer of 2001 cooling degree-days to the summer of 2000. As shown in the figure, during August 2000, the time of the summer peak, the number of cooling-degree days was much above normal, whereas in 2001, the number of cooling-degree days summer peak was considerably below normal. These conditions helped moderate Demand during the summer 2001 peak periods and helped promote price stability in the California wholesale electric markets, unlike the summer of 2000. Similarly, Figure 7 shows that the fall and winter of 2000 had periods that were colder than normal, leading to an increase in Demand related to heating, whereas the fall and winter of 2000 was on average slightly warmer than normal, leading to reduced Demand for heating and continued price stability through the later half of 2001 and early 2002.

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[7] See Federal Open Market Committee Statement of March 19, 2002 at www.federalreserve.gov/FOMC/.

Figure 6. 2000-2001 and 2001-2002 Cooling Degree Day Difference from Norm[8]

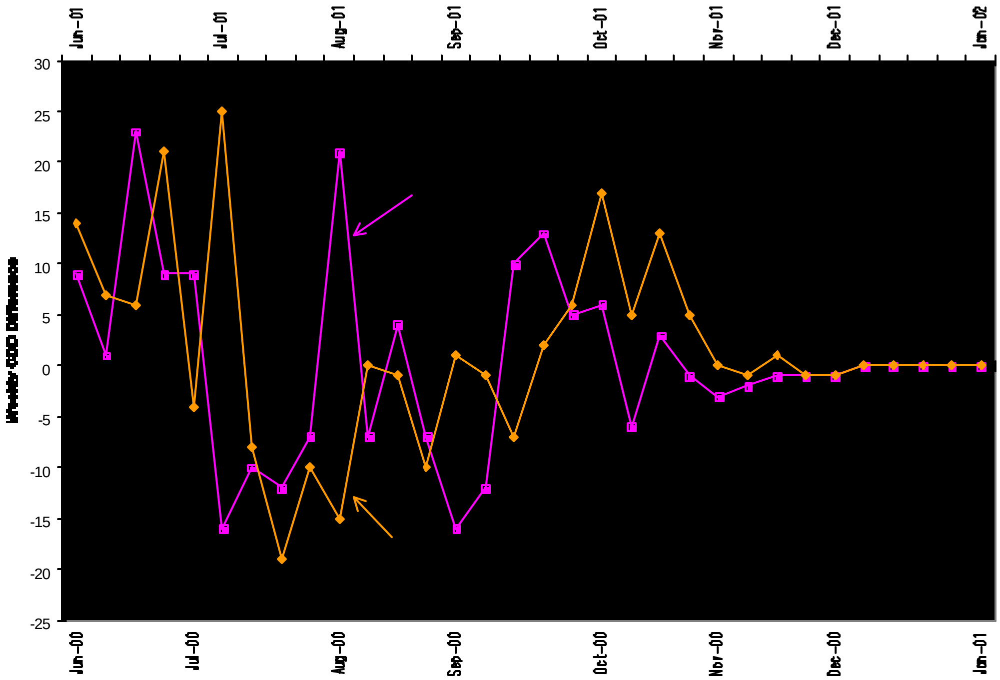
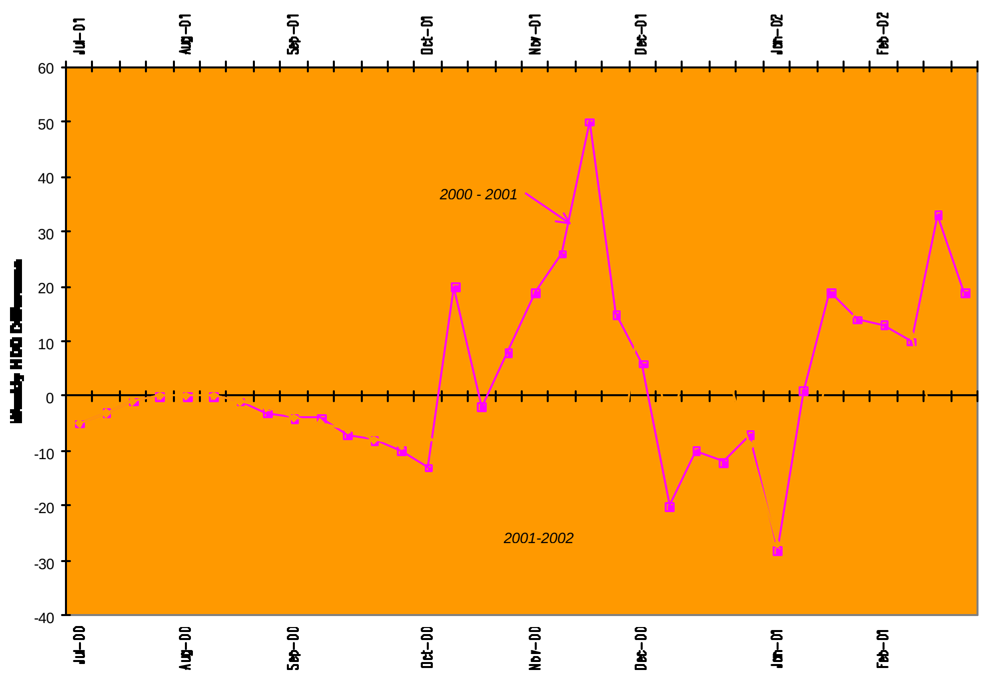


Figure 7. 2000-2001 and 2001-2002 Heating Degree Day Difference from Norm



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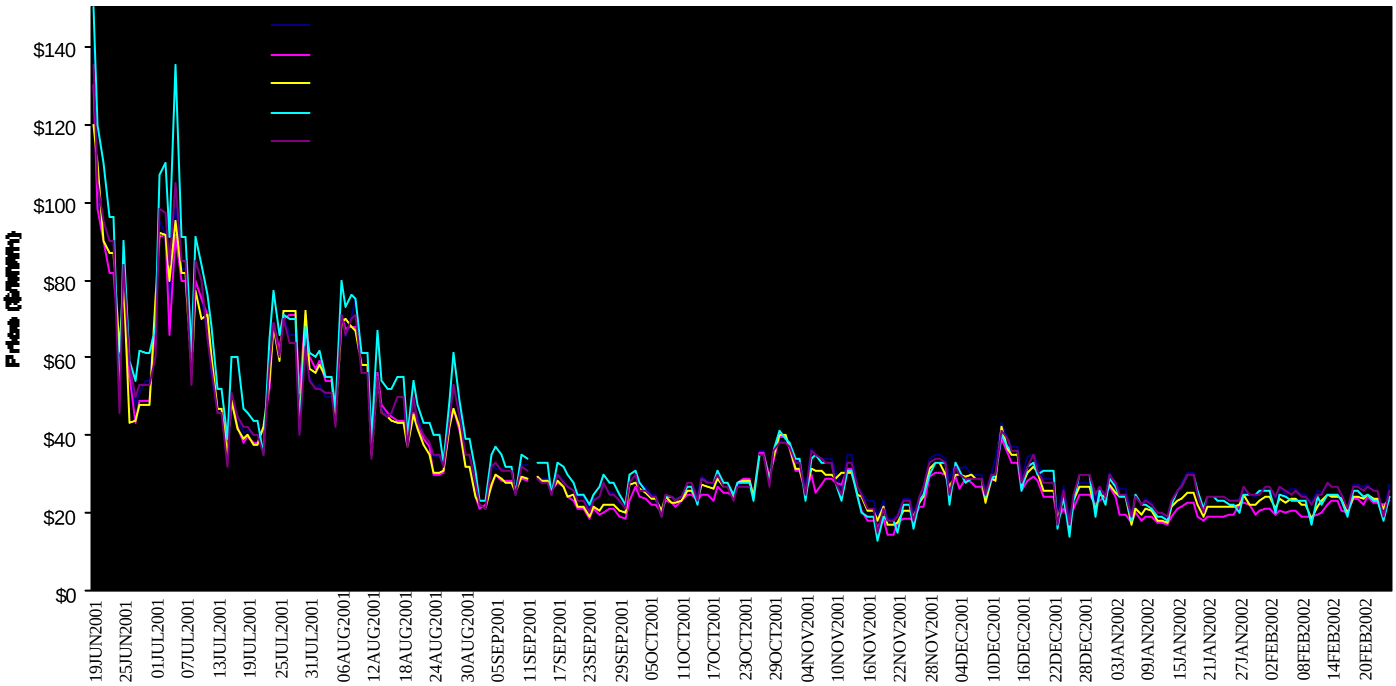
8 Climate Prediction Center, National Centers for Environmental Prediction, NOAA/National

Regional Market Prices vs. California prices

The various western regional prices continue to track one another closely together. As shown in Figure 8, western regional spot electric prices reacted quickly to the June 19 Order, dropping from over $120/MWh to under $60/MWh in two days. While prices increased for a brief period in late June and early July 2001 due to a heat wave in the Southwest, overall, prices remained below the soft cap level of $91.87/MWh, except at Palo Verde, where Load-serving entities purchased supplies above the cap to ensure that they could meet peak Demand conditions. Following this brief excursion of prices above cap, prices continued downward and stabilized between $20/MWh and $30/MWh. Thus, western spot market prices show that the mitigation order had a significant effect on the prices and stability in the western spot markets. These observed results confirm what the Commission long has recognized: the West is truly a regional marketplace and therefore, for mitigation measures to be effective, *such measures must be implemented on a regional basis*. Limited mitigation measures applied to only a portion of the western market, such as California-only price caps, have been proven to be ineffective because suppliers can engage in megawatt laundering by making sales into unrestricted markets, and then re-selling the power back to the restricted market at an unrestricted price.

Weather Service. Degree Days Data. http://www.cpc.ncep.noaa.gov/

Figure 8. Western Regional Firm Peak Spot Prices
June 2001 through February 2002



Three views of market power

Suppliers to California's electricity market possessed and exercised significant market power during the first half of 2001. Appendix E discusses three views of market power as measured by the price/cost markup. The first view looks at long-term market costs compared to competitive baseline costs. The long-term view includes long-term contract purchases (see Appendix C), monthly purchases, balance of month, day-ahead, hour-ahead, and real-time purchases. The second view looks at short-term purchases including day-ahead, hour-ahead, and real-time purchases. The third view looks at only real-time purchases.

The long-term view shows that significant markup which began in May 2000 continues today due in large part to the high cost embedded in long-term contracts. The two shorter-term measures are used to separate the effects of long term contract from the current spot market performance. The short-term measure considers day-ahead, hour-ahead, and real-time Incremental Energy purchases (including BEEP and Out-Of-Market). A significant improvement in price/cost markup occurred in July through December 2001. This reflects the benefit of significant Demand covered by utility-owned generation resources and long-term contracts. It appears the benefit of the long-term contracts has been to promote a more competitive short-term bilateral market. The performance of the short-term bilateral market is contingent upon continued long-term forward purchases, a high level of imports, and the level of Demand growth relative to supply. The third view represents real-time market performance. The mark-up index remains significant after June 2001. This supports the conclusion of continued market power in the Real Time Energy Market. As discussed in the bidding behavior section of the report, suppliers continue to bid significantly in excess of their operating costs. Therefore, when the ISO needs to call on significant amounts of Incremental Energy, real-time prices can rise quickly. In addition, real-time prices may reflect operating constraints and declined bids which may be a reflection of physical withholding.

Requirement that Marketers Bid $0/MWh in the ISO Markets

In accordance with the December 19 Orders[9], the ISO now requires out-of-state generators that wish to sell energy into the ISO Real Time market to offer their energy at a price of zero. As a result, little Energy from these suppliers outside the ISO Control Area is being bid into the ISO's Real Time Market. Specifically, the Commission, in its June 19 Order, required all marketers, which includes generating resources bidding into the ISO markets across interties, to be price-takers and ineligible to set the MCP. In the December 19 Orders the Commission reaffirmed that marketers must be price-takers but added that the ISO must require those marketers that choose to participate in the ISO real time spot markets and do not resell in other bilateral markets to bid $0/MWh to sell their Energy. The Commission reaffirmed that marketers will be paid the MCP (or mitigated MCP in the event of a stage emergency). The $0/MWh bid requirement effectively removed marketers' ability to specify minimum prices they are willing to accept to provide energy to the ISO Control Area.

The ISO complied with the Commission's Order in its Compliance filing of January 25, 2002, and implemented the restriction on February 22, 2002. The ISO expressed serious concern about this zero-bid requirement and informed the Commission in the ISO's January 18, 2002 Request for Clarification and Rehearing that the zero-bid requirement would likely diminish the volume of import bids into the BEEP Stack. This, in turn, reduces a significant source of

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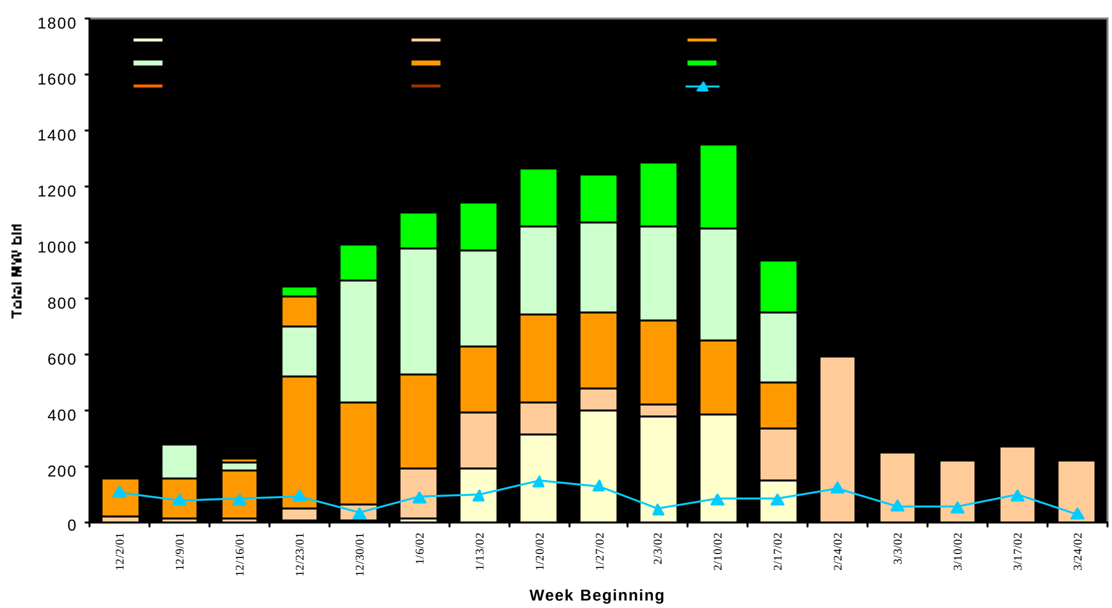
[9] On December 19, 2001, in the above-referenced dockets, the Commission issued an order, 97 FERC ¶ 61,275 (2001) addressing several requests for rehearing of the April 26, May 25 and June 19 Orders ("December 19 Rehearing Order") and an order, 97 FERC ¶ 61,293 (2001) on

competition to in-state generators that otherwise would possess substantially more market power. Moreover, as Load increases in the late spring and summer, the lack of imports may result in shortages, posing serious reliability concerns.

The problem the ISO identified with the zero-bid requirement was realized shortly after its implementation. Since the implementation of the requirement, the average hourly volume of Energy bid from out-of-state resources has dropped dramatically, from approximately 800 to 1200 megawatt-hours (MWh) to fewer than 200 MWh, with no imports bidding in some hours. The attached charts illustrate the decline in imports into the BEEP Stack. Figure 9 shows the level of bids before and after implementation of the requirement.

Figure 9. Average Hourly Supplemental Import Energy Bid into BEEP Stack by Price Bin - Weekly



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several compliance filings the ISO made (“December 19 Compliance Order”).

Beginning in December 2001 California markets saw an increase in the amount of imported Energy, due in part to payments by CERS of ISO invoices for transactions conducted on behalf of the investor-owned utilities ("IOUs"). Both out-of-state and in-state suppliers were paid for past due amounts for transactions that occurred after January 16, 2001, when CERS assumed financial responsibility for the IOUs net short transactions. The volume of Energy bid into ISO markets decreased dramatically following the implementation of the zero-bid requirement on February 22, 2002.

Ultimately, the ISO will confront critical operational challenges should the Commission fail to remove the requirement that out-of-Control Area suppliers must bid at $0/MWh into the ISO Real Time Market. To prevent megawatt laundering, it is appropriate that such entities be price-takers under the Commission's market power mitigation program but bids should be in positive values and inserted into the ISO Beep stack accordingly to permit out-of-Control Area suppliers a means to assure their bids will be accepted and paid at an MCP that is related to their actual bids. Absent this modest degree of control over the price paid for Energy delivered into the ISO Control Area, the out-of-Control Area suppliers simply will not participate in ISO markets, to the extreme detriment of the State.

Creditworthiness Issues

The lack of creditworthiness of PG&E and SCE continues to hamper development of a competitive Energy market in California. The ISO has no control over the PG&E and SCE financial situations and so can only note for the

Commission that until such a time as these two IOUs resume procurement and payment for their total Energy requirements to serve their retail Loads, the State's role in procurement for these utilities will remain essential and less than fully competitive conditions will persist in ISO markets.

The ISO complied with the Commission's November 7, 2001 order[10] directing the ISO to invoice CERS as the Scheduling Coordinator responsible for outstanding payments due ISO Market Participants as a result of transactions beginning on January 17, 2001 on behalf of the IOUs net short position. Moreover, as of February 7, 2002, CERS has remitted to the ISO payment in full for all such overdue amounts.

As set forth in a public Market Notice on Certification of Market Settlement, dated March 13, 2002, several Scheduling Coordinators continue to owe the ISO and thereby other Scheduling Coordinators for transactions conducted in the period of November 2000 through November 2001. Thus, unless and until such debtors honor their debts there will continue to be unpaid creditors for past months.

Since CERS paid overdue amounts owed for transactions on behalf of the IOUs' net short for the period for which CERS assumed responsibility, the ISO markets have enjoyed some increase in participation and Market Participants have indicated a heightened sense of trust that they will be paid for transactions in ISO markets. On the other hand, until such a time that the IOUs resume normal load serving entity responsibilities for procurement and payment of

[10] 97 FERC ¶ 61,151 (2001).

Supply, ISO markets are likely to remain distorted and in need of enhanced market power mitigation provisions. Moreover, CERS is scheduled to halt its role as purchaser of the IOUs' net short position at the end of 2002. It is not certain if the IOUs will be fully capable at that time of resuming their former roles and so the markets may confront even additional confusion and distortion.

In addition, there remain a number of unpaid creditors of the California Power Exchange ("Cal PX"), who collectively are owed millions of dollars for transactions through the Cal PX in November and December 2000 and the first part of January 2001. The ISO understands that the unpaid debts have either reduced or stopped ISO market participation by some generators, including some out-of-state, even though current ISO markets are clearing on an ongoing basis.

Until the Cal PX bankruptcy plan is approved and such unpaid creditors paid, it appears that some generators will be unwilling to re-enter ISO markets. Moreover, PG&E's bankruptcy impacts payments by the Cal PX because PG&E owes significant sums to the Cal PX. Thus, it may be that both the Cal PX and PG&E bankruptcies may need to be fully resolved and all creditors paid before the ISO will see a full return of former participants into ISO markets.

BIDDING BEHAVIOR

Summary: Analysis of bidding in the ISO's real time market indicates that anti-competitive bidding behavior persists following the imposition of price mitigation under the June 19 Order. Excess capacity from steam units that are on-line and scheduled to operate is consistently bid at prices far in excess of marginal costs by numerous suppliers. In addition, most capacity from gas-fired combustion turbines is consistently bid at or near price caps that have been in effect.

Anti-Competitive Bidding Practices

This section summarizes anti-competitive bidding practices in the ISO's Real Time Market since implementation of the June 19 Order. The focus of this section is 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).

The key findings presented in this section of the report have previously been submitted to the Commission through confidential weekly market monitoring reports prepared pursuant to the April 26 Order. However, this report includes additional analysis and discussion of bidding behavior, including a summary of how the bidding behavior of different suppliers has fluctuated over time since the June 19 Order was implemented. In addition, the report includes additional analysis and discussion designed to address some specific issues and questions identified by Commission staff in discussions initiated by the ISO for the purpose of obtaining feedback and suggestions on the types of analysis and information that would be most useful for the ISO to provide as part of ongoing reporting to the Commission. Additional analysis of bidding by individual suppliers will continue to be submitted to the Commission on a confidential basis, and the ISO looks forward to providing additional analysis in response further feedback and suggestions from the Commission and staff.

In summary, key trends and findings of the ISO's analysis of bidding behavior include the following:

- 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, presented in confidential Appendix B of this report, shows that there has been only a weak relationship, at best, 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 are already on-line and scheduled to operate pursuant to a bilateral sale – which has accounted for 67% of the total gas-fired capacity bid into the ISO's Real Time Market during peak hours since implementation of the June 19 Order -- is consistently bid at prices far in excess of marginal costs by numerous suppliers. Thus, the overall trend of bidding in excess of costs cannot be attributed 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.
- While the regional price cap established in the June 19 Order and later modified in the December 19 Winter Price Order[11] provides a limit on extreme exercise of market power, a troubling trend has emerged wherein multiple suppliers continue to bid large portions of their generating capacity at or near the price cap. 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.

- Examination of bid curves indicates that one form of "hockey stick" bidding that can be observed in the ISO's Real Time Market is the tendency of some suppliers to bid 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. Such "hockey stick" bidding of a suppliers portfolio is one form of anti-competitive bidding specifically mentioned in the April 26 Order.[12]

- Despite the systematic bidding significantly in excess of costs by owners of gas-fired generation, prices in the ISO's Real Time Market have remained relatively low since the June 19 Order (compared to the price spikes of the previous 18 months), due to relatively low demand for incremental energy in the ISO's Real Time Market.[13] Demand for Energy in real time has been relatively low due to a combination of (1) relatively low Load levels, and (2) the significant amount of Energy procured by CERS through forward contracts.

- Prices for Incremental Energy dispatched in the Real Time Market have significantly exceeded levels that would result if prices did not exceed the

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[11] "Order Temporarily Modifying the West-Wide Price Mitigation Methodology" ("December 19 Price Mitigation Order") 97 FERC ¶ 61,294 (2001).

[12] One form of "hockey stick" bid that can be observed is to bid all CT capacity at a price at or near the price cap, while bidding excess capacity from on-line steam units at prices that are somewhat lower, but still significantly in excess of marginal costs.

[13] Incremental energy procured in the ISO's Real Time Market (or BEEP system) from July 2001 to March 2002 has accounted for only about 3.5% of the total "net short" position of the state's utilities during this period.

marginal cost of the highest cost gas-fired unit dispatched by the ISO.[14] From July 2001 through February 2002, the price paid for Incremental Energy dispatched in the ISO's Real Time Imbalance Energy Market averaged about $61/MWh, compared to a benchmark price of only about $48/MWh based on the marginal cost of the highest-cost gas-fired unit dispatched by the ISO.

- The total direct impact of bidding in excess of costs on the cost of Incremental Energy dispatched in the ISO's Real Time Market since July 2001 is estimated at about $20 million, or about 29% above the costs that would have been incurred if prices did not exceed the marginal cost of the highest cost gas-fired unit dispatched by the ISO.
- Since prices that are observed or anticipated in the ISO's Real Time Market are likely to have a strong impact on prices in the bilateral spot and long-term markets, the relatively high markup on the Incremental Energy transacted in the Real Time Market may have significant indirect impacts on prices in these other markets.
- 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, which are expected to play a key role in market redesign efforts currently underway

[14] The benchmark price used in this section of the report to assess costs in the real time market is based on the same basic approach adopted by the Commission in refund proceedings under the July 25 and December 19 Orders, which called for calculation of a competitive price based on the "marginal cost" of "the last unit dispatched to meet load in the real time market." Thus, unlike the approach used by the ISO in other reports to assess overall system costs, this benchmark in this report is based on the actual historical dispatch of units in the Real Time Market.

Monitoring of Anti-Competitive Bidding Behavior

In the April 26 Order, the Commission conditioned the market-based rate authority of sellers "to ensure that they do not engage in certain anti-competitive bidding behavior," and indicated that "suppliers violating these conditions would have their rates subject to refund as well as [be subject to] the imposition of other conditions on their market-based rate authority."[15] The April 26 Order also established monitoring requirements "to enable [the Commission] to better track the developments in the California markets." Id. Specifically, the April 26 Order requires the ISO to submit weekly reports to the Commission which include schedule, outage and bid data from the ISO markets, and to identify "any possibly inappropriate bidding behavior" in these weekly reports to FERC.[16] The ISO has submitted such reports on a weekly basis over the last eight months.

The April 26 and June 19 Orders are based on the principle that under competitive market conditions, spot market prices will reflect the marginal cost of the last generating units needed to meet demand. These orders also establish marginal generation cost as the benchmark upon which the competitiveness of bidding behavior and market outcomes should be based. As explained in the April 26 Order:

> The Commission finds that using marginal costs is the appropriate method for calculating bids during price mitigation. During a period when a supplier has available capacity, it should be willing to sell that capacity on a daily basis as long as it covers the marginal cost of producing it. Since marginal cost pricing best

[15] April 26 Order slip op. at 17.
[16] Id.

> approximates competitive pricing, there is no need to include fixed or other costs in the bids." (April 26 Order, slip op. at 17). [17]

In its April 26 Order the Commission noted two specific forms of anti-competitive bidding that are prohibited and would serve as grounds for potential refunds and further conditioning of market-based rate authority:

1. Bids into the ISO markets "that vary with unit output in a way that is unrelated to the known performance characteristics of the unit." An example of this type of bidding cited in the Order includes "hockey stick" bids. (April 26 Order, slip op. at 17).
2. Bids into the CAISO markets "that vary over time in a manner that appears unrelated to change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis." *Id.*

In its December 19 Rehearing Order, the Commission reaffirmed that "behavior such as 'hockey stick bidding' and related [anti-competitive] bidding is prohibited," and that "sellers violating these conditions would have their rates subject to increased scrutiny by the Commission and potential refunds." December 19 Rehearing Order, slip op. at 157. The ISO's compliance filing submitted pursuant to the June 19 Order included tariff revisions that would require sellers bidding in excess of the mitigated Market Clearing Price to submit

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[17] Similarly, in its December 19 Order the Commission rejected to requests for inclusion of other costs in the marginal cost formula, reiterating that "as discussed in our prior orders, our mitigation plan is intended to replicate the price that would be paid in a competitive market, in which sellers have the incentive to bid their marginal costs." December 19 Rehearing Order, slip op. at 84.

cost justification for these bids, even if they are not dispatched, on the grounds that such information would be necessary to enable the Commission and the ISO to monitor the prohibition on anti-competitive bidding. In its December 19 Compliance Order, the Commission denied the tariff provisions proposed by the ISO's, and directed the ISO identify and explain any inappropriate bidding that it has identified in its weekly reports to the Commission.[18]

This section examines 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.

In addition, the report provides an analysis of the impact that bidding in excess of marginal costs has had the Market Clearing Price ("MCP") for Incremental Imbalance Energy based on the same standard adopted by the Commission in recent refund proceedings, i.e., the marginal cost of the highest cost thermal unit dispatched to meet demand in the ISO's Real Time Market.

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

[18] December 19 Compliance Order, slip op at 11.

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 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. [19] 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 Order may be attributed to market power. However, the following section of this report addresses the basic market design features and explanations discussed in several critiques of previous studies of market power in California's wholesale market in order to 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

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[19] 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 prior to implementation of the June 19 Order. Nonetheless, the Harvey and Hogan are frequently cited

commitment decisions for thermal generating units with significant start-up costs, minimum load costs, and minimum operating times.[20] In this report, the ISO addresses 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.[21]

- **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

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[20] 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)

[21] 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).

from the sequential, segmented nature of the original California market design, which 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.[22] 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 Order. As the Commission noted in the December 19 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 this report focuses 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 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

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

gas shortage."[23] Again, while these special circumstances may have played a role in the price spikes prior to the June 19 Order, none of these special conditions could be reasonably expected to affect bidding of the specific generating resources (e.g. gas-fired steam units) and time period covered in this report.[24] 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 Order expressly provided for the recovery of emissions costs associated with complying 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

[23] Hogan and Harvey (2000), p.10.
[24] 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.

in a shortage situation."[25] Again, while this rationale may be offered as a factor that played a role in the price spikes prior to the June 19 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 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% credit adder that is already added to the MCP for Incremental Energy in the ISO's Real Time Market. This issue is addressed 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 assumptions about unit outages, the degree of physical withholding that occurred, and the extent to which physical withholding affected market prices. Thus, it should be noted that analysis of bidding behavior in this study is

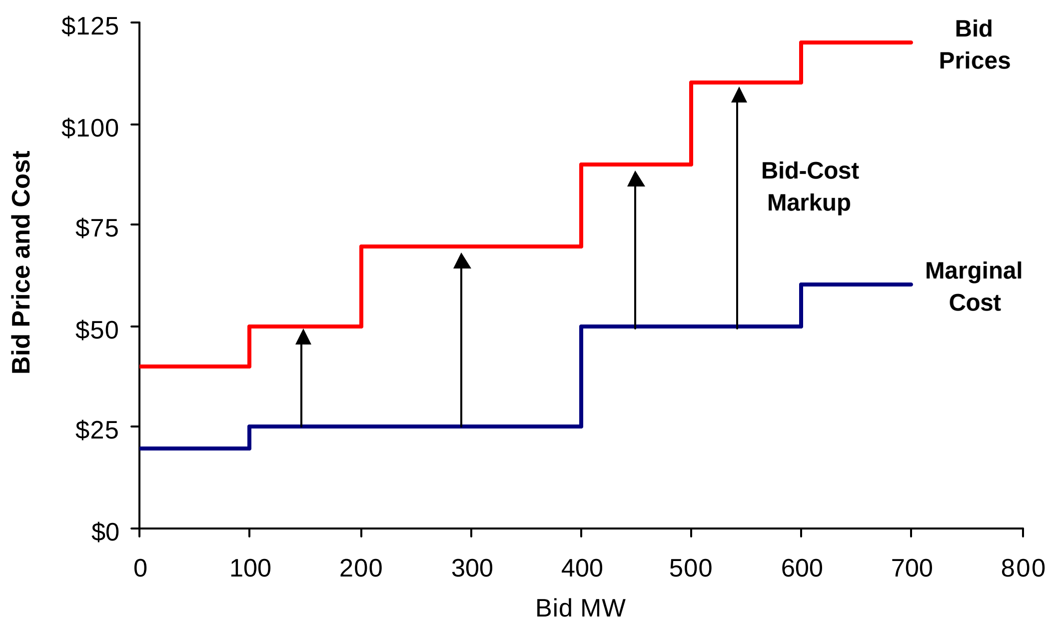
[25] Hogan and Harvey (2000), p.21.

based only on actual bids submitted by generators for capacity bid into the ISO's Real Time Market. No assumptions are made – or are required – about the actual amount of capacity available or any physical withholding that may have occurred.[26]

Analysis of Bidding Behavior based on Bid-Cost Markup Methodology

Figure 10 describes the basic methodology used in this report to analyze bidding of individual suppliers based on the degree to which bid prices exceed marginal operating costs of capacity that was bid into the ISO's Real Time Market, or the *bid-cost markup*. In addition to summarizing the bid-markup in terms of the overall average bid-cost markup of all bids submitted, Appendix B of this report provides analysis based on the bid-cost markup at different points of the suppliers bid curve. Results of this analysis demonstrate that the basic trends can be observed at whichever point the bid-cost markup is measured.

Figure 10. Bid-Cost Markup Methodology



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

The figure above illustrates the bid-cost methodology used to assess and summarize anti-competitive bidding by owners of gas-fired generation in the ISO system. First, 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) is calculated. A marginal cost curve is then developed by sorting bids in ascending order of marginal cost. The bid-cost markup is then calculated for each bid based on the degree to which the bid prices exceed the marginal cost of the corresponding capacity.

For this report, marginal costs are calculated based on heat rates submitted by generators pursuant to the April 26 Order, daily spot market gas prices, and $6/MWh for operations and maintenance costs. Although the June 19 Order uses monthly gas contract prices to determine proxy bids, this report uses 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 <u>percentage</u> of estimated marginal costs. However, one of the key trends that has been noted since implementation of the June 19 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 in this report, results are presented primarily in terms of the absolute bid-cost markup (i.e. $/MWh), calculated based on the degree to which bid prices exceed marginal cost.

economic waiver.

Analysis of the bidding of individual suppliers, provided to the Commission in Appendix B, shows that at least four of the five major owners of gas-fired generation generators have consistently bid significant amounts of capacity well in excess of variable operating costs. Moreover, 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 11, 12, and 13.

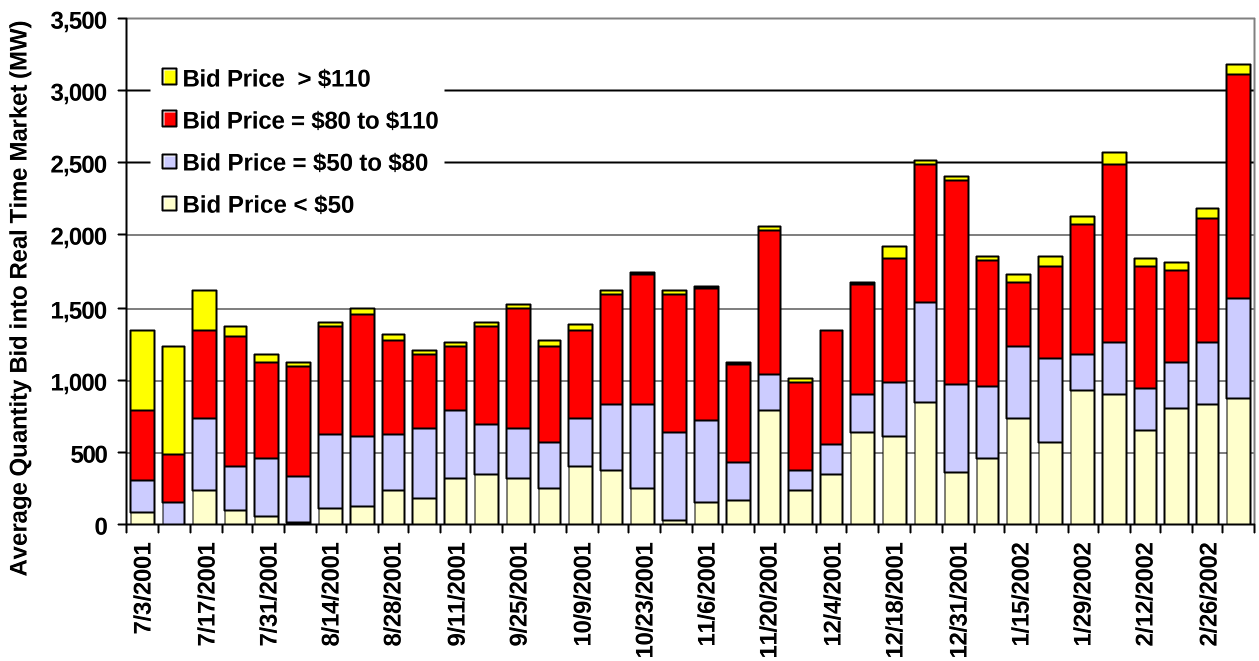
As shown in Figure 11, the portion of capacity bid at prices significantly excess of marginal costs has remained high throughout the entire period since implementation of the June 19 Order, with a high portion of bids being submitted at prices at or near the price caps that have been in effect during this period (represented by the price category ranging from $80/MWh to $110/MWh). Most capacity from combustion turbines (70-80%), 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.

A second key finding of the analysis presented in this report is that that excess capacity from steam units that are on-line and scheduled to operate (as a result of a bi-lateral transaction) has been routinely bid into the Real Time Market at prices far in excess of marginal costs by numerous suppliers. Figure 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 since October is approximately $65/MWh, compared with average marginal costs of about $37/MWh, representing a bid-cost markup of about 75%. Capacity from steam units committed prior to the Real Time Market represents about 67% of the total gas-fired capacity bid into the ISO's Real Time Market during super peak hours.

A third key finding of analysis presented in this report 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 somewhat lower (but often still significantly in excess of marginal costs). Illustrative examples of such "hockey stick" bidding are provided to the Commission in Appendix B of this report.

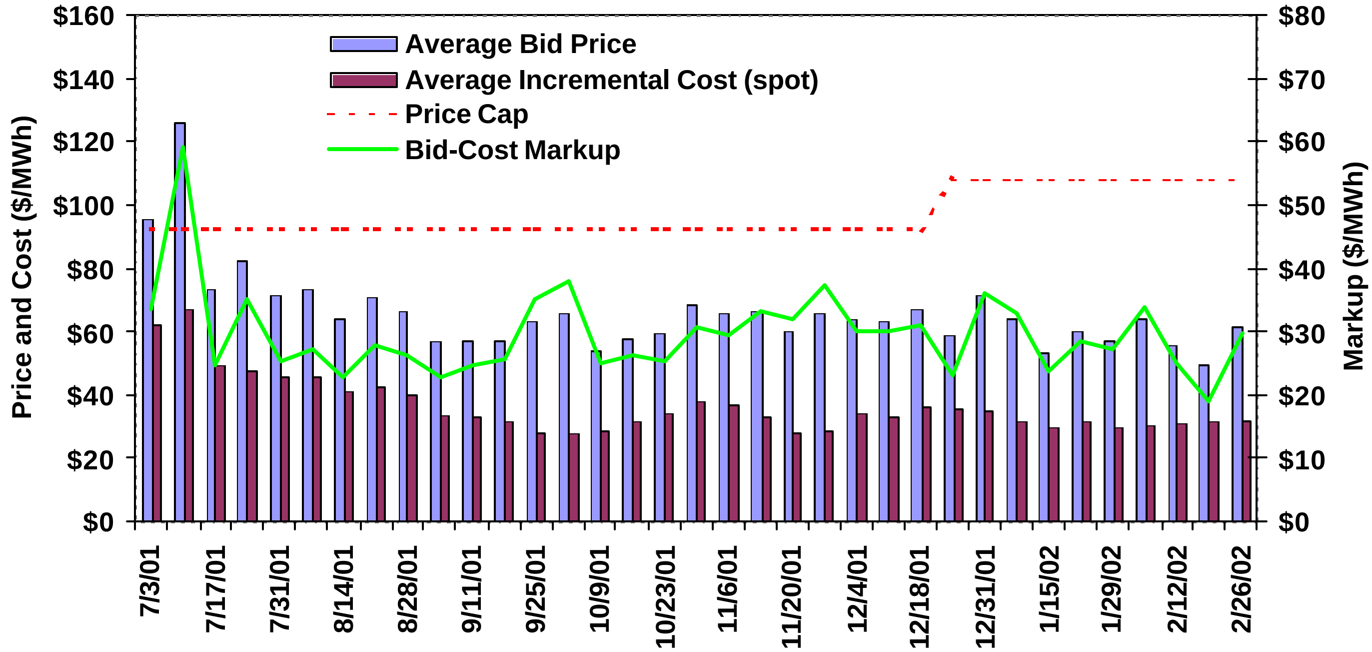
As noted above, additional analysis of bidding by individual suppliers will continue to be submitted to the Commission on a confidential basis, and the ISO looks forward to providing additional analysis in response further feedback and suggestions from the Commission and staff.

Figure 11. Gas-fired Capacity Bid into the ISO Real-time Energy Market In Super Peak Hours



This chart 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, 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 in effect until December 2001, as well as the $108/MWh price cap in effect hereafter. Virtually all bids at this level are significantly in excess of costs, as spot market gas prices averaged less than $2.75/MMBtu and remained below $3.50/MMBtu from September 2001 through March 2002. Appendix B provides more detailed results of bidding by each supplier, including a comparison of each suppliers bid prices to estimated marginal costs based on the heat rates of each generating unit and daily spot market gas prices. 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 12: Weekly Average Bid Price, Cost, and Markup For Steam Units On-line and/or Scheduled to Operate Prior to Real Time (Super Peak Hours)

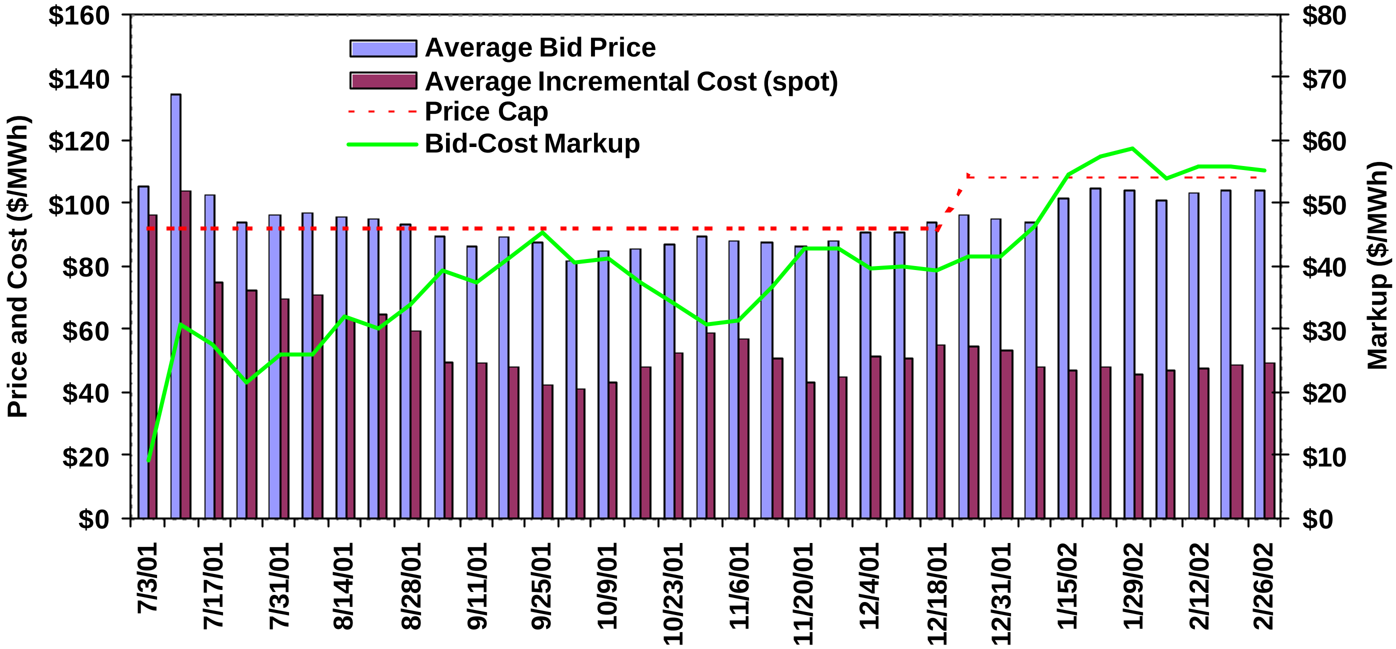


This chart shows average bid price, marginal cost, and price-cost markup (in $/MWh) for gas-fired steam units that were on-line and/or scheduled to operate (as a result of a bilateral market transaction) prior to the real-time market. For these units, startup costs and minimum load costs are already 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 has largely remained in the range of $25/MWh to $35/MWh, or roughly 75% on average. Capacity from steam units committed prior to the real time market represents about 67% of the total gas-fired capacity bid into the ISO's real time market during the time period included in the figure above.

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 13. 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. Capacity from CTs has represented an average of only about 31% of gas-fired capacity bid into the real time market during the super-peak hours depicted in the time period depicted in the figure above. 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).

Analysis of Real Time Market Prices

This section provides an assessment of the impact that bidding in excess of marginal costs has had on market clearing prices in the ISO's Real Time Market. For this analysis, actual costs incurred for Energy dispatched in the ISO's Real Time Market are compared to costs that would be incurred if prices were limited by the standard adopted by the Commission in recent refund proceedings: i.e., the marginal cost of the highest cost gas-fired unit dispatched to meet demand in the Real Time Market. Figures 14 and 15 describe the methodology used to calculate costs in excess of this benchmark level, using an illustrative example from an actual 10-minute interval when prices hit the $91.87 price limit in effect at that time.

Figures 16 and 17 summarize the overall impact of anti-competitive bidding on costs for incremental energy in the ISO's Real Time Market based on the methodology described in Figures 14 and 15. As shown in Figure 16, from July 2001 through February 2002, the price paid for Incremental Energy dispatched in the ISO's Real Time Market averaged about $61/MWh, compared to a benchmark price of only about $48/MWh.

Figure 14. Bid Prices and Marginal Costs of Gas-Fired Capacity Dispatched in ISO Real-Time Market

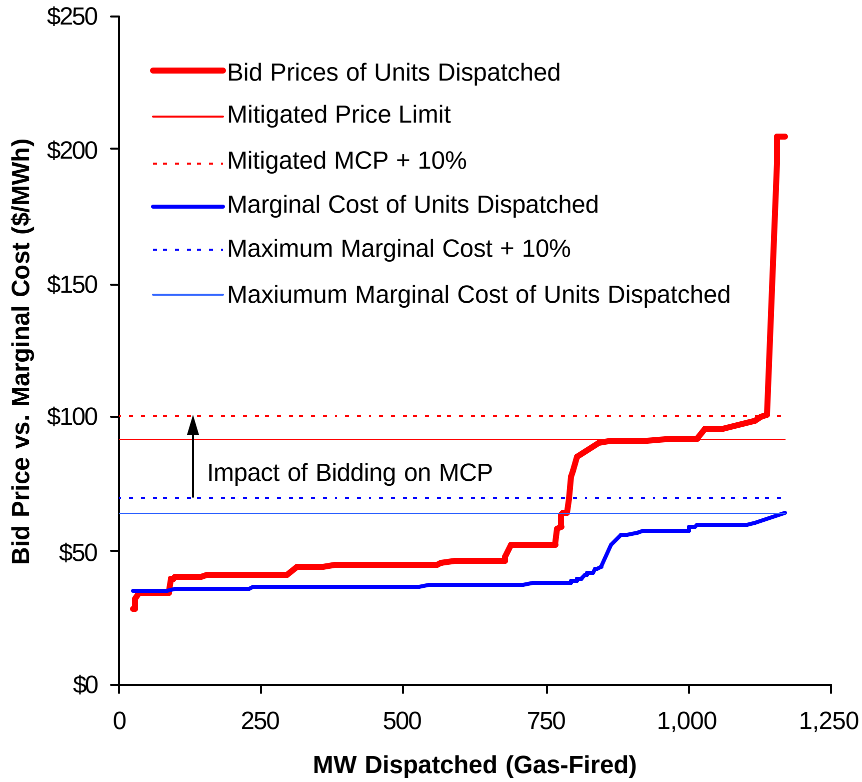


Figure 14 compares the bid prices and marginal costs of gas-fired capacity dispatched in the ISO's real time market during a recent 10-minute interval when prices hit the current price limit in place from the June 19 Order. As shown in Figure 14, bid prices of units dispatched during this hour significantly exceeded marginal costs, with a high portion of bids being submitted at or near the region-wide cap in effect during this time period ($91.87/MWh). These bidding trends, by themselves, illustrate a lack of competition in the real time market. The impact of anti-competitive bidding during this period is further illustrated in Figure 14 terms of the increase in the market clearing price (plus the 10% adder) from less than $71/MWh to $101/MWh, representing an price increase of about 43% above the highest cost unit dispatched (plus 10%).

The analysis in this report calculates a benchmark price for incremental energy for each interval based on the lower of the assumed marginal cost of the highest cost gas unit dispatched (as shown in Figure 14), or the actual MCP in the ISO's real time market. For intervals when the congestion occurred, a separate price is calculated for each of the ISO's two major zones (NP15 and SP15).

Figure 15. Impact of Anti-Competitive Bidding on Total Costs for Incremental Energy

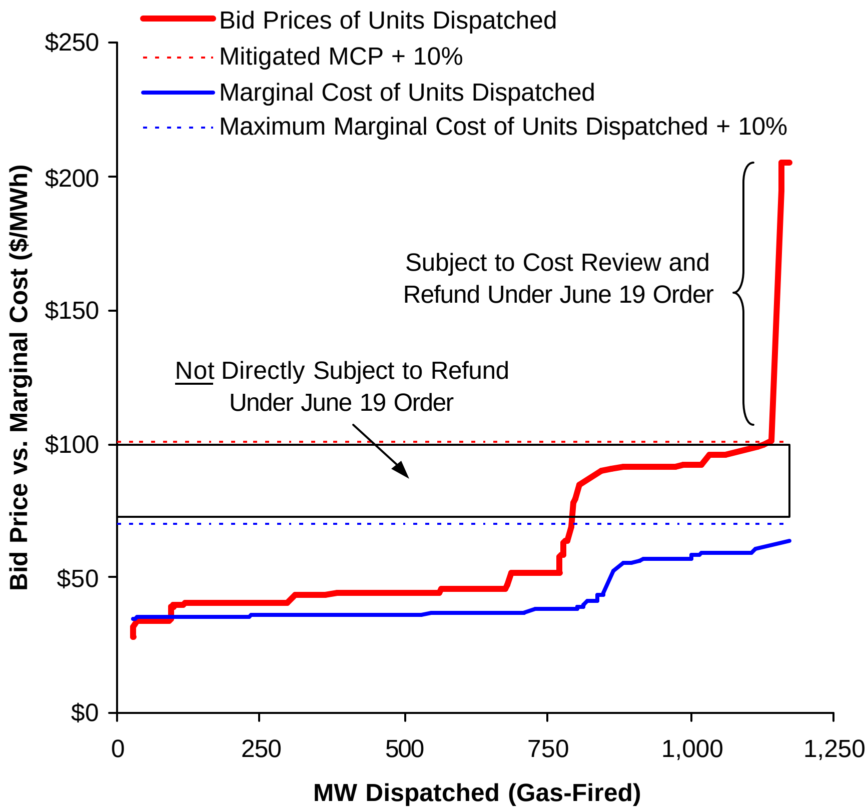


Figure 15 illustrates the affect of anti-competitive bidding on the overall costs for Real Time Energy as calculated in this report. Under the June 19 Order, bids dispatched over the mitigated price limit (formerly $91/MWh plus 10%) are subject to automatic cost justification requirements and refund authority. The shaded (yellow) portion of Figure 15 shows the increase in total real time energy costs for energy from gas-fired units resulting from an increase in the market clearing price (plus the 10% adder) from less than $71/MWh to $101/MWh that are not subject to similar cost justification and refund provisions during non-reserve deficiency hours. The June 19 Order provides for limited mitigation of the cost impacts of market power in the type of situation represented in Figure 15.

This report, quantifies the impacts of market power (or bidding above marginal costs) as depicted in Figure 15. The shaded (yellow) portion of Figure 15 represents additional costs incurred for gas-fired generation dispatched in the real time market due to bidding above marginal costs. Since imports and non-thermal resources dispatched by the ISO also receive the market clearing price, the increase in these costs is also included in this analysis.

As shown in Tables 1 and 2, the total direct impact on costs for Incremental Energy due to anti-competitive bidding since July 2001 is estimated at nearly $20 million, or about 29% of total costs of Incremental Energy dispatched through the ISO's Real Time Market. Thus, while the total cost of incremental energy procured in the ISO's Real Time Market has been relatively low[27] when compared to prior periods, the cost of Incremental Energy has exceeded the marginal cost of the highest cost gas-fired unit dispatched by a significant amount level (29%).

Figure 18 summarizes the average hourly quantities of incremental energy dispatched in the ISO's Real Time Market since July 2001, and shows that the share of incremental energy provided by imports dispatched in the ISO's Real Time Market increased significantly following modifications in procurement practices in December 2001 which eliminated CERS' procurement of imports through out-of-market ("OOM") transactions. Well over half of the generation dispatched for incremental energy in the ISO's market, however, continued to be supplied by gas-fired resources within the ISO system even after the increase in imports in December 2001.

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[27] The primary reason for the relatively low totals costs incurred in the ISO's Real Time Market is the fact that Incremental Energy procured in this market from July 2001 to March 2002 accounted for only about 3.5% of the total "net short" position of the state's utilities during this period.

Figure 16. Average Price of Incremental Energy

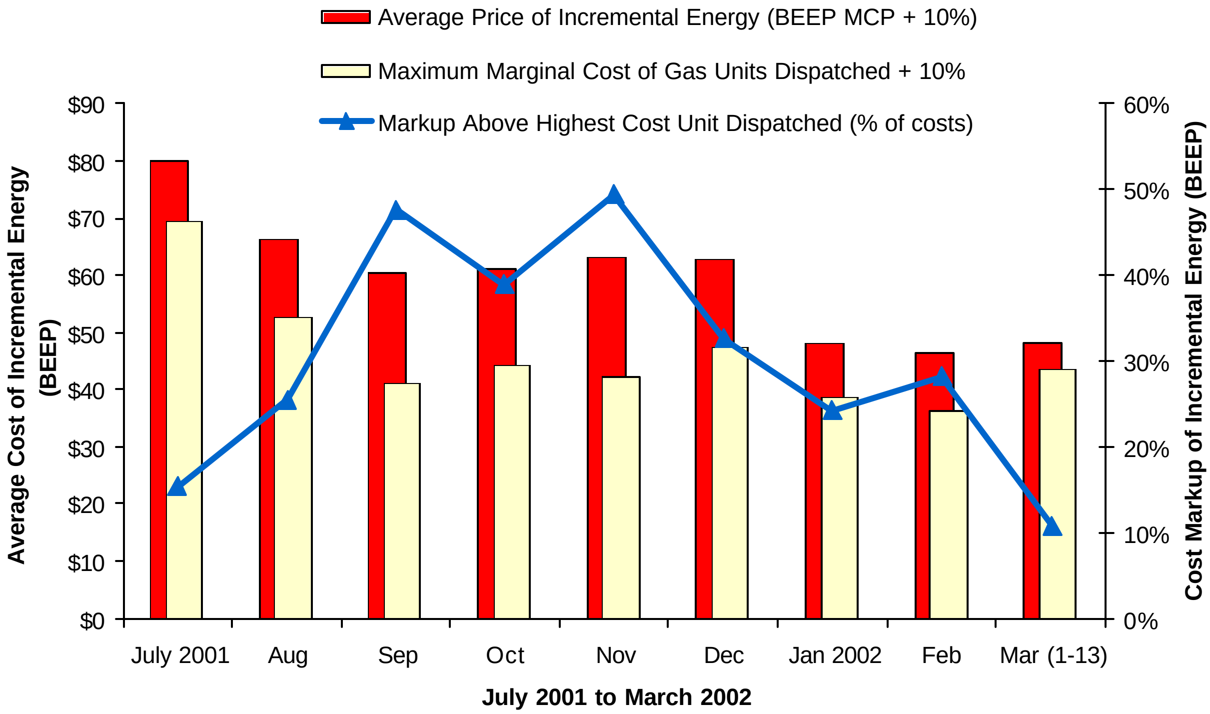


Table 1. Average Price of Incremental Energy

Month	Average Cost of Incremental Energy*	Average Cost at Benchmark Price**	Excess Costs (%)
July 2001	$80	$69	15%
Aug	$66	$53	26%
Sept	$60	$41	48%
Oct	$61	$44	39%
Nov	$63	$42	49%
Dec	$63	$47	33%
Jan 2002	$48	$39	24%
Feb	$47	$36	28%
Mar (1-13)	$48	$44	11%
Total	$61	$48	29%

* Based on incremental energy dispatched through BEEP at MCP + 10%

** Based on incremental energy dispatched through BEEP valued at highest marginal cost of units dispatched + 10%

Figure 17. Costs of Incremental Energy Dispatched Through the Balancing Energy Ex Post Price Market (BEEP)

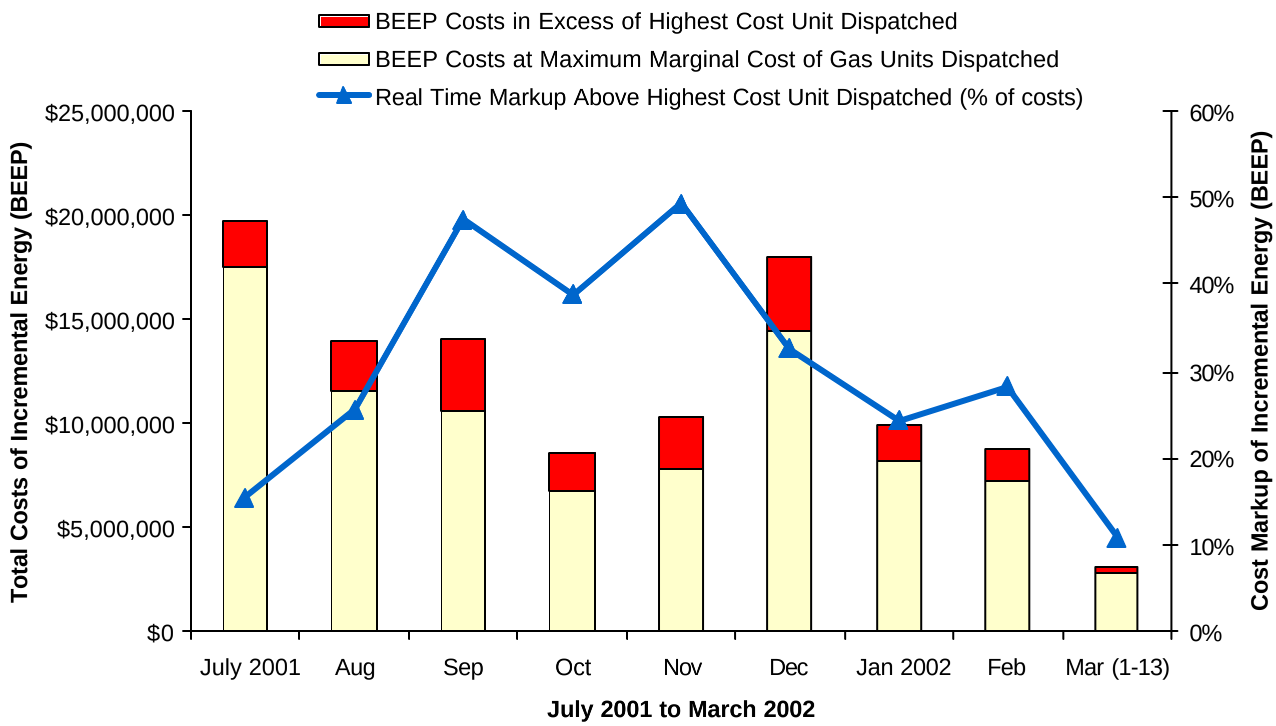


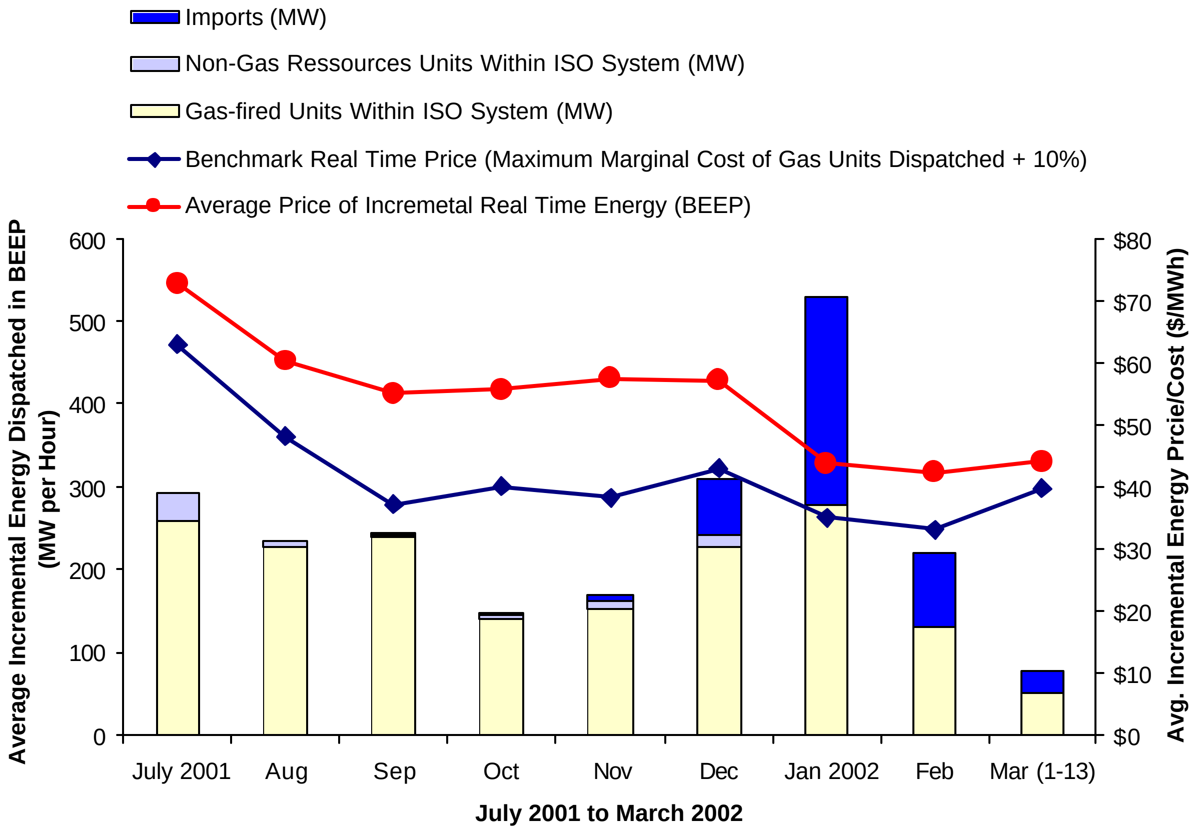
Table 2. Costs of Incremental Energy Dispatched Through BEEP

Month	Approximate BEEP Payments*	BEEP Costs If Mitigated at Highest Unit Dispatched**	Costs In Excess of Highest Unit Dispatched	Excess Costs (%)
July 2001	$17,431,665	$15,102,388	$ 2,329,277	15%
Aug	$11,538,151	$ 9,188,547	$ 2,349,604	26%
Sept	$10,563,455	$ 7,155,275	$ 3,408,180	48%
Oct	$ 6,718,622	$ 4,838,813	$ 1,879,809	39%
Nov	$ 7,740,425	$ 5,178,933	$ 2,561,491	49%
Dec	$14,444,331	$10,892,675	$ 3,551,655	33%
Jan 2002	$ 8,219,493	$ 6,616,770	$ 1,602,723	24%
Feb	$ 7,196,905	$ 5,614,880	$ 1,582,025	28%
Mar (1-13)	$ 2,800,103	$ 2,527,055	$ 273,048	11%
Total	$86,658,212	$67,119,494	$19,538,718	29%

* Based on incremental energy dispatched through BEEP x MCP + 10%

** Based on incremental energy dispatched through BEEP x highest marginal cost of units dispatched + 10%

Figure 18. Average Hourly Quantities Incremental Energy Dispatched Through BEEP by Source



COMPLIANCE WITH THE MUST-OFFER OBLIGATION

Summary: When first ordered, the Commission's intent for the must-offer obligation was not well understood and the varying interpretations led to varying degrees of compliance among Market Participants. As the Commission has clarified the intent and the implementation of the must-offer obligation, Market Participants' compliance has improved. Some form of a must-offer obligation is essential to any successful market design and, because there is no adequate substitute available for implementation on October 1, 2002, the current must-offer obligation should be extended until a substitute is available.

The must-offer obligation applies to all sellers in California (including non-public utilities) that own or control one or more generating units, System Units or System Resources that are not hydroelectric generating units. In addition, the Energy or capacity from these units must either be (i) sold through a market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. The must-offer obligation requires that generators offer the ISO all available generating capacity except (I) to the extent that generation or capacity is required to serve native load, or (ii) if running the unit would violate a certificate, result in criminal violations or penalties or result in qualifying facilities violating their contracts or losing their qualifying facility status.

The must-offer obligation was established in the April 26 Order and expanded in the June 19 Order. The objective of the must-offer obligation is to prevent physical withholding of available generation. The ISO has identified four means by which generators may fail to comply with the must-offer obligation:

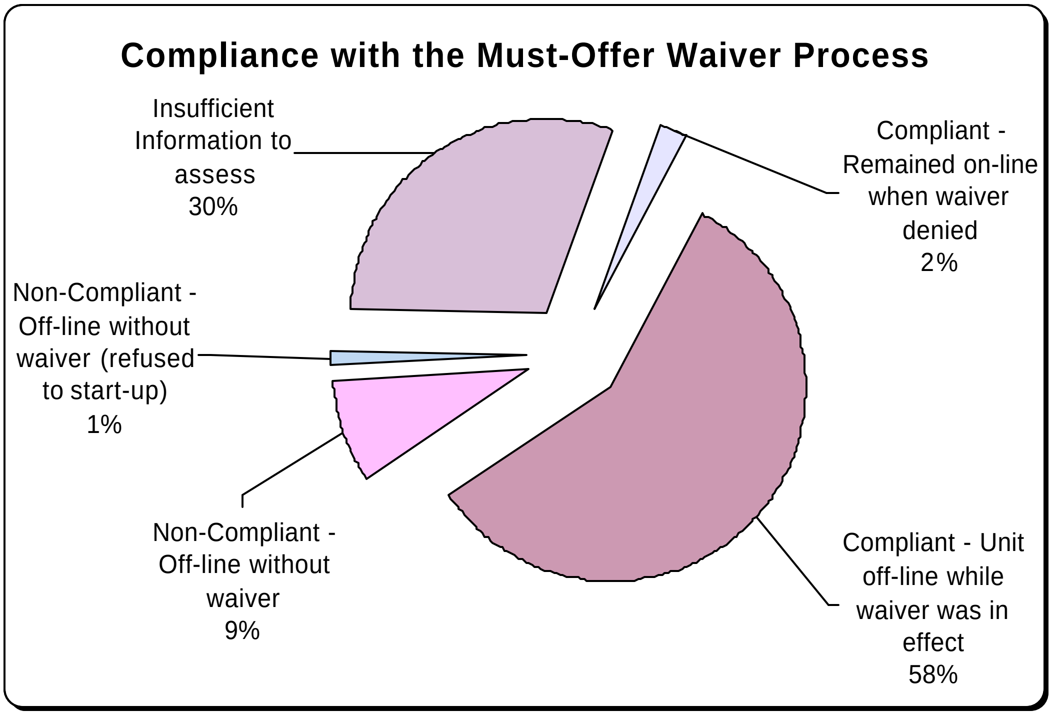
- Failure to make generation available
- Failure to submit bids

- Rejection or Decline of Dispatch instructions
- Failure to respond to accepted Dispatch instructions

Failure to Make Generation Available

The must-offer requirement demands that available generation must be on-line or otherwise available to accept and comply with ISO Dispatch instructions. The ISO has established a process for issuing waivers from the must-offer obligation at such times that all available generating capacity is not expected to be needed to meet the reliability requirements of the ISO Control Area. In the waiver process, generators request a waiver from the must-offer obligation from the ISO. When generators may be taken off-line without compromising reliability, the ISO issues a waiver from the must-offer obligation to those generators that have requested them. The ISO Dispatchers record issued and rescinded waivers and various other related incidents into the ISO Dispatch log. Of the 523 must-offer waiver events logged between September 1, 2001 and December 31, 2001, 60% indicate compliance with the must-offer obligation, 10% indicate non-compliance, and, in 30% of the cases, there was insufficient information to assess compliance. The following figure summarizes instances in which generators complied with the must-offer obligation by either receiving waivers allowing them to shut down or remaining on-line when waivers were denied or failed to comply with the must-offer obligation by shutting down without having been issued a waiver or refusing to start-up to become available to respond to dispatch instructions.

Figure 19. Compliance with the Must-Offer Waiver Process



Failure to Submit Bids

Following the June 19 Order, when the must-offer obligation was extended to all hours, the ISO implemented a system to Dispatch available capacity based upon actual bids submitted by generators or upon proxy bids calculated by the ISO and inserted on behalf of the generator when the generator failed to submit bids for any available generating capacity as required by the must-offer obligation.

The implementation of the software to calculate and insert bids has had one of the most direct impacts on Market Participants of any of the components of the must-offer obligation. Because bids, whether actual or proxy, are inserted into the BEEP stack once and then used throughout the operating hour, there are unavoidable instances in which: (1) bids are Dispatched for generating capacity that is no longer available due to an intervening Outage or (2) no bids are submitted or inserted for generating capacity that has just been restored from an Outage. Furthermore, there were instances in which communication failures within the ISO resulted in bids being inserted for generating capacity that had been properly reported as unavailable. Initially, the ISO only inserted bids on generators that were not scheduled to provide regulation.[28] However, there were instances in which Market Participants appeared to have evaded the ISO proxy-bid software by scheduling very small quantities of regulation. On December 12, 2001, the ISO began inserting bids for generation units that failed to submit bids for their certified regulation range.

Declined Dispatch Instructions

Generators receive Dispatch instructions from the ISO through the Automated Dispatch System ("ADS"). Generators receiving an ADS instruction have two minutes in which to respond and failure to so respond results in an automatic decline of a new instruction or automatic acceptance when the instruction is to rescind a previously accepted instruction. If a generator declines a Dispatch instruction, it must select from one of fourteen reasons[29] for doing so. Generators that decline instructions because capacity was not available to

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[28] When a Generating Unit provides Regulation service to the ISO, there is often a portion of its available capacity that cannot be dispatched as Energy without interfering with the Generating Unit's ability to provide Regulation. In the initial implementation of the software to calculate bids on behalf of resources that had not submitted pursuant to the must-offer obligation, it was necessary to exclude Generating Units scheduled to provide Regulation to protect against the loss of the Regulation service that is essential to reliable operation of the Control Area.

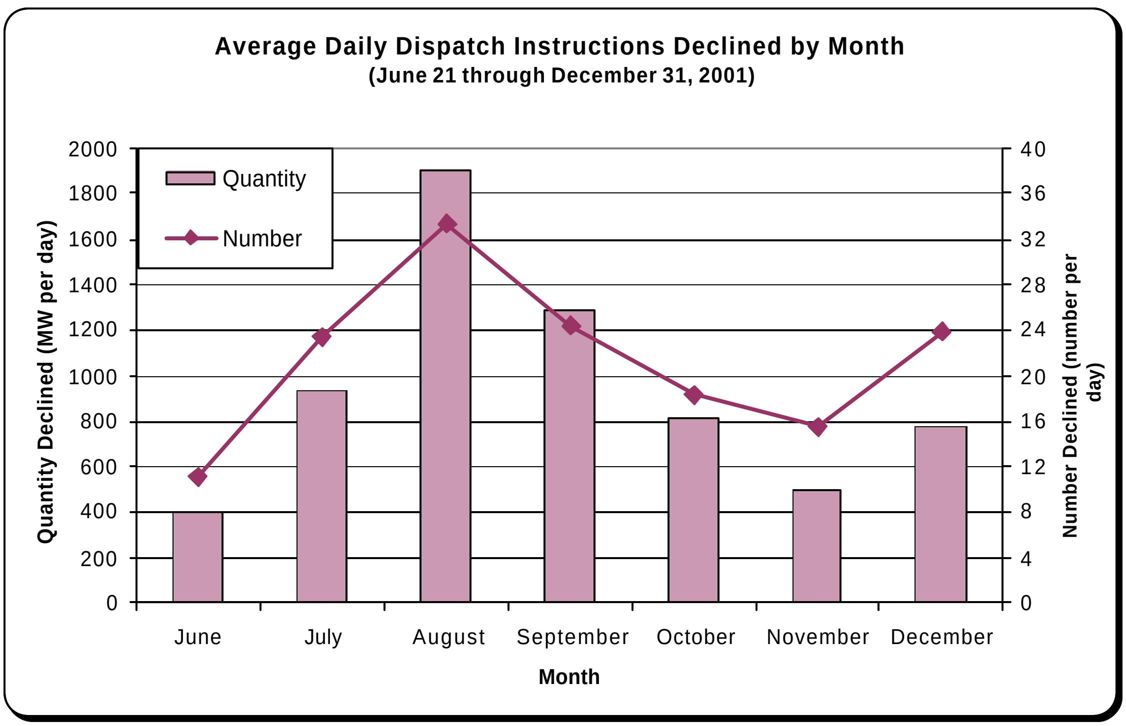
[29] The fourteen reasons that may be selected in ADS are: Water Management, Equipment Failure, Unit Forced Out, Safety, Fuel Constraint, Emission Constraint, Environment Constraint, Intertie Reasons, Line derate, Line down, Economic Considerations, Bad Bid Submitted, Unit Derate, and No Available Transmission.

respond to the instruction are required to report their de-rated capacity to the ISO through the normal Outage Coordination process.

The ISO's 60-Day Comments noted that the rate of declined Dispatch instructions for incremental Imbalance Energy for July 2001 was approximately 25%. The ISO has issued reports on declined Dispatch instructions to the Commission's Office of Market Oversight and Enforcement on July 26, August 15, September 7 and October 31, 2001 and February 8, 2002. During the period from early July through December 2001, rates of declined Dispatch Instructions have ranged from 17% to 30%. The ISO has found that many of the Dispatch instructions issued through ADS, however, were issued to unavailable generating capacity. In some of these cases, the unavailable capacity had been reported to the ISO, but the manually intensive process of updating the available generating capacity had not been completed and the ISO inadvertently used incorrect data on generator availability to calculate and insert bids on behalf of such generators. In other cases, the unavailable capacity had not been reported to the ISO and the ISO therefore believed that the capacity was available at the time Dispatch instructions were issued. The ISO is modifying its Outage reporting software to allow Scheduling Coordinators to directly manage their generator availability data through an internet interface. However, to the extent that a Scheduling Coordinator fails to notify the ISO that its available generating capacity has been reduced, the ISO has no option but to assume that the full capacity is available.

The following figure summarizes average daily Dispatch instructions declined from June 21 through December 31, 2001. The ISO has assessed declined Dispatch instructions for both incremental and decremental Imbalance Energy. The following chart summarizes the average daily rate of declined Dispatch instructions, excluding instances in which Dispatch instructions were issued for generating capacity that was unavailable,[30] and also excluding a number of Dispatch instructions issued for very small amounts of MW, based upon inconsistencies between data on record for units' maximum generation capacities and the actual operational capacity at any given time. These Dispatch instructions for small amounts of MW constitute only a very limited portion of the total quantity of Dispatch instructions issued.

Figure 20. Average Daily Dispatch Instructions Declined By Month



[30] For the purpose of this chart, the unavailable capacity includes that properly reported to the ISO and that which is suspected to have been unavailable based on the response provided through ADS.

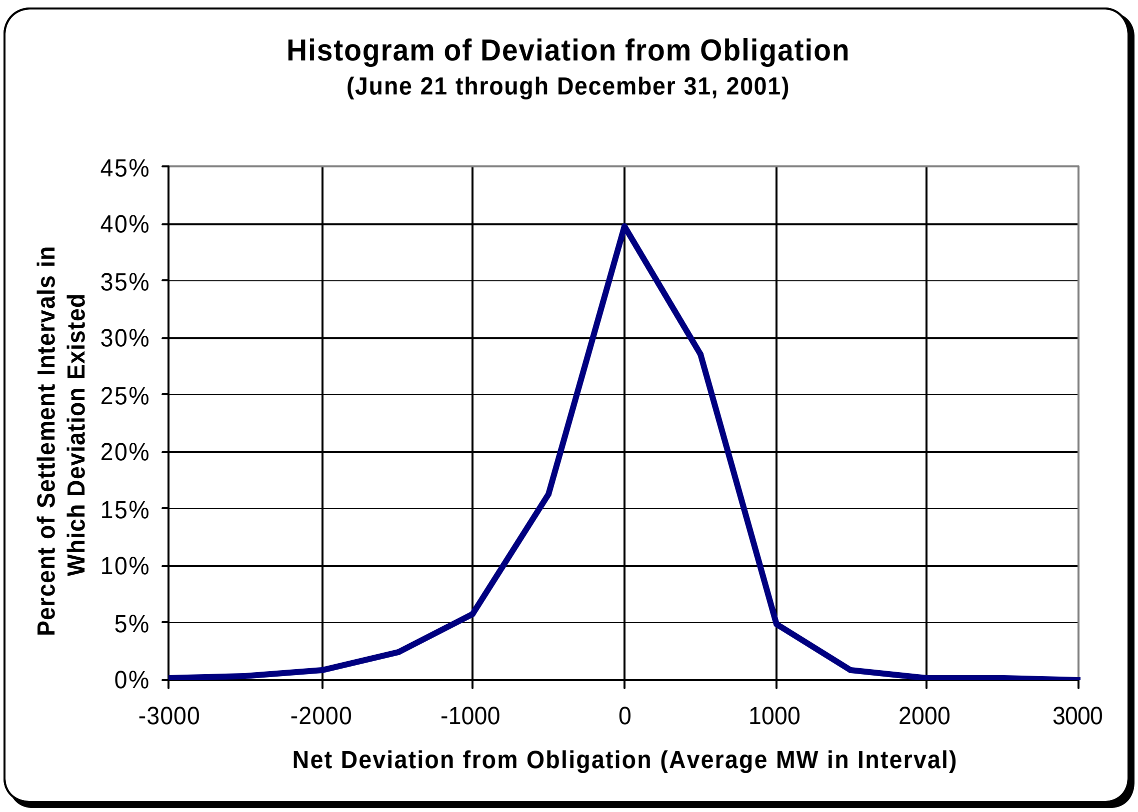
Failure to Respond to Accepted Dispatch Instructions

While the ISO is obligated to provide reasonable and consistent Dispatch instructions to generators, generators also must provide consistent and predictable responses to ISO Dispatch instructions. Generators that do not fully respond to Dispatch instructions or that do not fulfill their total scheduled plus instructed Energy obligations force the ISO to incur additional costs in Dispatching additional resources to meet the unfulfilled obligations.

The ISO monitors generators by comparing the Energy delivered with the Energy expected based on Schedules and accepted Dispatch instructions. Individual generators may produce Energy in quantities that deviate from their respective obligations. Such obligation deviations may cause or exacerbate Inter- and Intra-zonal congestion, or, when taken in aggregate across the Control Area, may require the ISO to procure additional incremental or decremental Imbalance Energy.

The following histogram nets deviations from individual resources against one another to produce a net obligation deviation that represents the effect of deviations from the expected performance of all of the generators in the ISO Control Area from June 21 through December 31, 2001. As expected, the aggregate performance is predominantly within a relatively small range (*i.e.,* hundreds of MW) around the expected operating point. It is not necessarily the case, however, that every generator is performing near to its expected operating point; rather, it may be that deviations in one direction for some generators may be offset against deviations in the other direction for other generators. In some cases, extreme under-performance has caused the ISO to issue Dispatch instructions for thousands of MW for the sole purpose of supplying Energy that other generators have neglected to deliver. Figure 21 indicates that in nearly 10% of the BEEP intervals between June 21 and December 31, 2001, the ISO was forced to Dispatch at least 1000 MW of Energy solely because generators were under-delivering on their obligations.

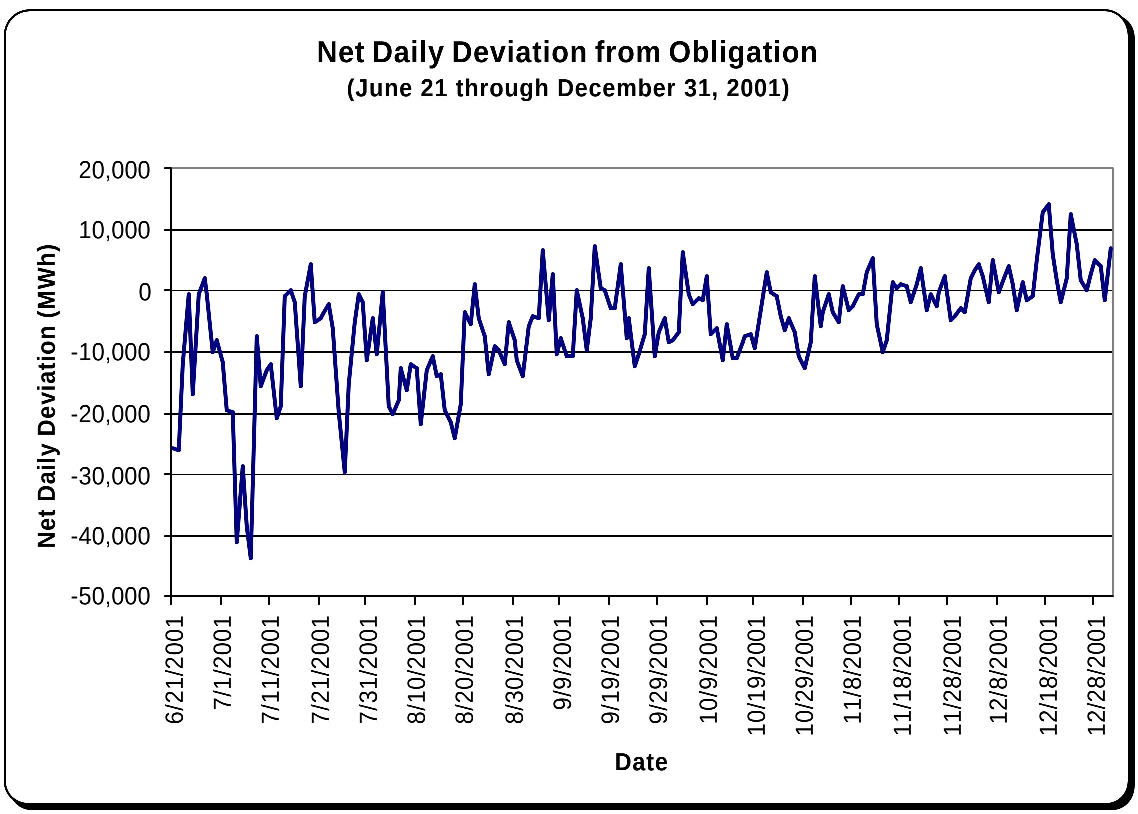
Figure 21. Histogram of Deviation from Obligation



The following figure aggregates all of the deviations observed over each day into a daily net deviation and plots the results for the period from June 21through December 31, 2001. The chart clearly demonstrates systematic under-performance with respect to the Energy that would be expected based on

Schedules and accepted Dispatch instructions. The under-performance is most pronounced from June through August 2001, but continues through November 2001. Performance in late November and early December 2001 is much more balanced, but in the latter part of December 2001, there appears to be a tendency towards over-delivery. It should be noted that this chart nets deviations in the 144 Dispatch and Settlement Intervals in each day into a single value and so there may be some offsetting of over-delivery in one interval against under-delivery in another.

Figure 22. Daily Net Deviations



STATUS REPORT ON NEW GENERATION PROJECTS

Summary: While California has added some new generation in 2001, and expects to add more in 2002, the pace of generation development has slowed, and hurdles remain.

The June 19 Order required the ISO's March 26, 2002 report to include a discussion of all new generating resources that the State of California had announced in 2001 would be on-line by summer 2002 and identify which of those facilities actually are on line.[31] The April 26 Order quoted Governor Gray Davis' press release of April 4, 2001 stating that the CEC projected that new generation totaling 4,168 MW would be on-line by August 2001 and that there could be as much as 6,879 MW on-line for the summer of 2002.[32]

The ISO has been tracking the status of new generation projects since mid-2000 and has extensive data on proposed and "realized" new generation from January 1, 2001 forward. Based on data from the ISO's database, the ISO Control Area has realized 1,937 MW of new generation capacity actually on-line by August 1, 2001, with potentially as much as 7,646 MW of new capacity on-line for the summer of 2002. Table 3 below shows the estimated amounts of new capacity. Note that 4,350 MW of capacity is actually on-line as of February 28, 2002, with a possible 3,296 MW of capacity that may be completed after February 28, 2002 for the summer of 2002.

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[31] June 19 Order, slip op. at 40.
[32] April 26 Order, slip op. at 7.

Table 3. Estimated New Generation to be On-Line by Summer 2002
January 1, 2001 through July 31, 2002

	Projects	MW
Realized January 1, 2001 to July 31, 2001	19	1,937
Realized August 1, 2001, to December 31, 2001	13	607
Total 2001	32	2,544
Realized January 1, 2002 to February 28, 2002	19	**1,806
Total through February 28, 2002	51	4,350
Projects not complete with expected COD* before July 31, 2002	29	3,296
Total New Generation Estimated On-line by August 2002	80	7,646

* Commercial Operations Date.
** includes plant capacity that paralleled with the grid during this time but may not yet be available to serve load.

The following describes the assumptions and characteristics of the data used in this section of the report.

- The starting period for the ISO's detailed data is January 1, 2001.
- The data shown in this section of the report is through February 28, 2002.
- For completed (i.e., "realized") projects, the capacity listed is the amount of generation actually available to the ISO Controlled Grid. For proposed projects not yet completed, the capacity listed is the "nameplate capacity," which is the estimate of the maximum continuous output of the completed unit.
- "Summer of 2002" is assumed to be the period ending July 31, 2002.
- The data for projects not yet completed is very dynamic (and has been so for the last few years). Commercial Operation Dates, and in some cases capacity values, frequently change.

Table 4 shows the status of the 3,296 MW of projects that are not yet completed whose capacity may be available for the summer of 2002. The list includes projects will be completed and operational by August 1, 2002, based on information provided by developers as of February 28, 2002. Some 1,540 MW of capacity is currently in the install/test/certification stage, with the remaining capacity less far along in the development process.

Table 4. Status of Additional New Generation With CODs Between January 1, 2002 and July 31, 2002 (Data as of February 28, 2002)

	Projects	MW
New generators currently being installed, tested or certified	4	1,540
New generators with major equipment on-site	9	681
New generators under construction	6	263
New generators in the permitting or study phase	10	812
TOTAL new generators	29	3,296

In reviewing the data in Table 4, the following points are relevant:

- The probability of completing projects currently undergoing installation, testing, or certification in 2002 is very high;
- The probability of completing projects for which major equipment already is on-site in 2002 is rather high;
- The probability of completing projects for which construction has already begun in 2002 is medium to high; and
- The probability of completing projects currently in the permitting or study phase in 2002 is uncertain.

Looking beyond the summer of 2002, developers initially had planned over 2,500 MW of additional capacity that would be on-line in the second half of 2002.

Developers already have cancelled approximately half of these projects. Nevertheless, an additional 1,589 MW of capacity is scheduled to become operational during the second half of 2002. Tables 5 and 6 show this additional capacity and its current stage of development.

Table 5. Additional New Generation Proposed to be On-Line between August 1, 2002 and December 31, 2002

	Projects	MW
New generators originally planned	12	2,578
New generators cancelled	6	989
Additional new generators proposed for 2002 (after cancellations)	6	1,589

Table 6. Status of Additional New Generation With Expected CODs Between August 1, 2002 and December 31, 2002

	Projects	MW
New generators currently being installed, tested or certified	1	255
New generators with major equipment on-site	0	0
New generators under construction	2	1,152
New generators in the permitting or study phase	3	182
TOTAL new generators	6	1,589

Appendix A of this report provides detailed information on the capacity additions for calendar years 2001 and 2002, as well as projects cancelled by developers in 2001 and 2002.

Factors to Consider in Setting Expectations for New Generation

The decision to construct new generation and subsequent decisions to continue with or halt construction are driven by numerous factors, many of which fall outside the ISO's control. While it is not the intent of the ISO to provide statistical and probabilistic analysis from which accurate conclusions can be drawn, the macroeconomic environment in which development decisions are made should be considered when drawing conclusions from the data presented in the previous section.

- **Energy prices.** Energy prices are an integral part of the decision to continue with or halt a generation project, and while the uncertainty of Energy prices would likely be the single greatest macroeconomic factor to contribute to the initial new generation investment decision by developers, there are other factors that might play roles in determining the outcome of the investment decision.

- **The Enron case.** The bankruptcy and subsequent investigation of Enron is likely to have significant industry-wide effects on how power generation facilities and their associated debt are treated on balance sheets. There now is greater scrutiny of the accounting treatment for long-lived assets and long-term debt by investors, creditors, and credit rating firms, particularly in conjunction with the use of special-purpose entities to move debt and assets off balance sheets. To prevent adverse impacts to equity share values, many companies recently have chosen to either delay, place on hold, or withdraw projects to try to strengthen balance sheets and reduce debt loads. The number of withdrawn generation projects within California anecdotally supports this concern.

- **Credit ratings.** The generation development industry has suffered credit downgrades, partly in response to the Enron bankruptcy, and partly in response to weakening Energy prices and poor economic conditions. Credit downgrades will result in higher costs of capital demanded by creditors, negatively impacting the project's net present value calculation. It is important to note that credit rating changes will have greater effect at particular points in time during the construction process. For example, credit costs play potentially decisive roles when initially acquiring financing for the project and also later should the developer choose to acquire additional financing or to refinance the project.

- **Higher California costs.** New generation development is more costly in California compared to the rest of the western United States, owing in part to more stringent environmental regulations. These additional costs must be factored into the investment decision analysis and also will negatively impact project net present value calculations. The Executive Orders issued by Governor Gray Davis in 2001 relaxing some of these environmental restrictions expired on December 31, 2001 and have not been renewed. Further, people living close to planned generation project sites have lobbied vigorously against initiating a project or continuing development. This increases political costs for local air quality districts, which are subsequently unwilling to grant permits for projects, causing many projects to be withdrawn even before construction begins.

Table 7 lists the generation projects that have been cancelled by developers since January 1, 2001. For example, developers cancelled five projects totaling 179 MW expected to come on line in June 2001. The data is quite variable and it is hard to draw specific conclusions from it. The ISO has observed that a large number of projects (and their associated capacity) have been cancelled in the last six months. The number of cancelled generation projects by calendar year is as follows: 29 projects totaling 1,773 MW in 2001, and 33 projects totaling 2,888 MW so far in 2002.

Table 7. Cancelled Generation
(January 1, 2001 through December 31, 2002)

Month-Year	# of Projects	Total MW
Jan-01	0	0
Feb-01	0	0
Mar-01	0	0
Apr-01	0	0
May-01	0	0
Jun-01	5	179
Jul-01	0	0
Aug-01	5	67.5
Sep-01	10	1113.9
Oct-01	5	245.3
Nov-01	1	49.9
Dec-01	3	117.9
Jan-02	3	150.9
Feb-02	0	0
Mar-02	1	180
Apr-02	3	125.4
May-02	0	0
Jun-02	20	1441.8
Jul-02	0	0
Aug-02	2	196
Sep-02	4	793.5
Oct-02	0	0
Nov-02	0	0
Dec-02	0	0
Total	**62**	**4661**

Appendix A provides additional detail on these cancelled generation projects.

Differences Between ISO and CEC New Generation Data

The data presented in this report are taken from the ISO's New Resource Interconnection ("NRI") database. The ISO tracks new generation projects both to assess supply adequacy and to facilitate essential new interconnection activities such as complying with the ISO's metering and telemetry requirements. The ISO and CEC data may differ for the following reasons:

- CEC data contain new generation throughout the state where the ISO NRI data generally contain only data associated with generation projects in the ISO Control Area.
- CEC data are available from multiple sources. These sources are not always internally consistent, and thus some discrepancies, at least, can be attributed to differing criteria for data sorting.
- Sources of information concerning project schedules and ratings are not always the same between the CEC and the ISO, leading to differences in MW ratings and generation availability dates.
- The ISO often is aware of projects that are not yet part of the CEC approval process.
- CEC data may or may not include projects below 50 MW.
- The ISO is not able to identify all generation projects that are interconnecting at the distribution level and with municipalities.
- Criteria for determining what or which projects are entered into NRI vs. CEC are not identical.

- Project names or identification are, at times, different, and thus projects may be double-counted.

Ongoing Activities to Facilitate New Generation Additions

This section lists some ongoing ISO activities specifically targeted at facilitating addition of new generation in California.

ISO Market Redesign

The ISO is considering an Available Capacity ("ACAP") obligation in its market redesign. The ACAP obligation, which would require Load serving entities to arrange for sufficient generating capacity to serve their peak Load, is intended to provide both operational reliability and an incentive for generation investment. The ISO has retained an expert consultant to design proposed details of an ACAP program that considers the specific nature of the California Energy system and markets, while building upon the experience with capacity obligations and markets in the United States and other industrial countries.

Activities of the ISO regarding New Generation Interconnections

Over the past two years, the ISO has worked with Market Participants to develop comprehensive procedures governing the interconnection of new generating facilities to the ISO Controlled Grid. Establishment of ISO Controlled Grid interconnection procedures will ensure that there are clear and uniform procedures for the interconnection of new capacity. These interconnection procedures are a necessary first step towards ensuring that California can attract critical new generating capacity. In addition, standardized interconnection procedures will help guarantee that each new facility is treated in a transparently non-discriminatory manner. Moreover, by clearly establishing the cost-responsibilities of new generators interconnecting to the grid, the ISO and Participating Transmission Owners, who are filing compatible changes to their Transmission Owner Tariffs, can reduce the financial uncertainty and risk of developers and thereby facilitate development of new capacity in California.

To foster these objectives, and in accordance with the Commission's direction, the ISO filed Amendment No. 39 to the ISO Tariff in April 2001. Before Amendment No. 39, the details of the interconnection application process were contained only in the individual tariffs of the Participating Transmission Owners. In order to promote consistency throughout the ISO Controlled Grid, Amendment No. 39 defined these requirements in the ISO Tariff. Unfortunately, the Commission has not yet acted on this submission.

The ISO's proposed interconnection procedures are but one part of a larger initiative to re-energize the California electricity market. While reducing barriers to entry for new generating capacity is an obviously essential element of any plan to revive competitive markets in California, the ISO must also provide assurances that such new capacity reliably can be delivered to Load. Therefore, as part of its ongoing process to enhance its grid planning and expansion process, the ISO and Market Participants continually are examining policies to ensure that the ISO Controlled Grid is expanded in a manner that supports competitive markets. The ISO is exploring policies to expand the transmission system not only to satisfy reliability criteria, but also to ensure access to critical new supplies and markets and to, if necessary, mitigate the exercise of locational market power in certain constrained areas of the ISO Controlled Grid.

The ISO did not propose in Amendment No. 39 to require that new facility operators pay for the costs of delivery upgrades. These costs include the costs of facilities necessary to deliver Energy from the point of interconnection of the new facility to Load and would include such costs as the cost of upgrading a line to eliminate Congestion.

In late 2001, the Commission began its advance notice of proposed rulemaking ("ANOPR") proceeding regarding new generation interconnections. The ISO filed its reply comments in this ANOPR on February 1, 2002. The ISO supports the creation of region-appropriate *pro forma* interconnection procedures, agreements, and services that ensure that all parties can interconnect to the transmission system on a non-discriminatory basis. The ISO believes that the Commission must specify and create a foundation for further development of region-appropriate *pro forma* procedures. Such a foundation must be based on sound operational and economic principles, and should provide for innovation and regional variation based on the specific requirements of each region. In providing its comments, the ISO addressed many of the topics included in the ANOPR, including comparable treatment, exemptions, queuing, generator siting, and project time lines.

Intermittent Resources

The State of California encourages new investment in wind, solar and other environmentally-benign generation resources. Renewable "intermittent resources" are expected to provide important economic and environmental benefits to California both now and in the future.

The California Consumer Power and Conservation Financing Authority ("CCPCFA") has received proposals for over 2,500 MW of new wind generation. At the time of this report, the CCPCFA has expressed its intentions to award contracts for construction of new wind facilities that will add over 1,000 MW of capacity.

In addition, the ISO has been working with representatives from the American Wind Energy Association, California Wind Energy Association, California Energy Resources Scheduler, Governor's Office, CEC, IOUs and wind power marketers to develop a proposal that allows intermittent resources to more fully participate in ISO markets. The ISO filed this proposal as part of Tariff Amendment No. 42 on January 31, 2002. The changes proposed in Amendment No. 42 will facilitate the development of intermittent resources by reducing risk without providing a systematic subsidy or imposing significant costs on other market participants. The proposal:

- Minimizes ISO market costs that arise from the difficulty of scheduling intermittent resources;
- Incorporates safeguards and incentives to minimize potential cost-shifting to other market participants;
- Provides a transmission- and market-access framework though which intermittent resources can secure project financing; and

- Accommodates intermittent resources without degrading system reliability.

Energy from intermittent resources is already price-competitive and can displace Energy generated by non-renewable resources such as thermal generation. The requirement of an unbiased forecast for scheduling will benefit ISO operations with more accurate information about Supply from such resources.

Generation Retirements

The ISO has received informal notice that at least one generator intends to retire two large combustion turbine units before January 1, 2004. Additional retirements from California's aging generator fleet of which the ISO is not yet aware are likely over the next few years.

Environmental Restrictions

Generators owning older units increasingly face a difficult decision: whether to add expensive new emissions control equipment to comply with stricter environmental standards or to shut down. In 2002, a generator shut down four older units totaling 600 MW because those units could no longer operate within stricter emissions standards imposed by the local air quality management district and because the generator determined it was not cost-effective to retrofit these units with complying control equipment. Other plant owners have elected to retrofit certain facilities: the decisions are unit- and owner- specific and the ISO can not accurately predict such decisions.

Summary

The ISO is doing all that it can to ensure Supply adequacy. It is clear that coordinated Commission and State policies are needed to complement ISO's attempts. While California has added some new generation, recent events have slowed the pace of new generation development in California, and substantial barriers to developing new generation in California remain. Until significant additional generation comes on-line in California and throughout the West, the region will remain exposed to supply shortages and price spikes.

STATUS REPORT ON NEW TRANSMISSION PROJECTS

Summary: While the ISO has approved over 200 transmission projects, certain key projects that will help ensure a competitive market will not be in service for several years.

The ISO aggressively has pursued a number of transmission system improvements and build-outs that that will improve system reliability and enhance the functioning of competitive power markets. To date, the ISO has approved over 200 transmission projects, with a total cost of approximately $1.5 billion. The majority of these approved projects will enhance local reliability. Two major projects, discussed below, will resolve certain persistent problems of market power and help bring about competitive markets.

Valley-Rainbow Transmission Project

The Valley-Rainbow Transmission Project is a proposed interconnection between San Diego Gas & Electric Company's ("SDG&E") existing 230 kilovolt (kV) transmission system and SCE's existing 500 kV transmission system. The project would be located in northern San Diego County and southwestern Riverside County. The proposed project consists of:

1. Construction of a new 500/230/69 kV substation located in Rainbow in northern San Diego County;
2. Construction of approximately 31 miles of 500 kV single-circuit overhead transmission line from SCE's existing Valley Substation to the proposed Rainbow substation; and
3. Modification of the existing Valley Substation to accommodate the new 500 kV transmission line.

In addition, the Valley-Rainbow Transmission Project would add a second 230 kV circuit to the existing Talega-Escondido 230 kV transmission line, rebuild 7.7 miles of 69 kV transmission between the existing Pala and Lilac Substations, and add voltage support systems to the existing Mission, Miguel, and Sycamore Canyon Substations.

If no new generation is added in the San Diego area, the Valley-Rainbow Transmission Project is needed in 2005 to meet ISO Grid Planning Standards in the San Diego area. As new generation comes on line in the San Diego area, assuming no significant retirements of existing generation, the need for the line to meet ISO Grid Planning Standards diminishes and the Valley-Rainbow Transmission Project might be deferred. The Valley-Rainbow Transmission Project still offers important reliability benefits even if not required to meet ISO Grid Planning Standards.

Moreover, the Valley-Rainbow Transmission Project will likely have important economic value. With the addition of significant new generation in the San Diego area and Mexico, the Valley-Rainbow Transmission Project becomes important to make this generation available to Central and Northern California. The economic value of the Valley-Rainbow Transmission Project requires additional assessment. Such assessment should consider the competitive and regional nature of the wholesale electricity market. It should examine in particular, the likely impact of the project on the development of new generation in the San Diego area, and on how generation development in San Diego will affect market power. Finally, the Valley-Rainbow Transmission Project is an important piece in an overall strategy to improve the critical 500 kV backbone transmission system that California and the West depend on to move power among regions.

SDG&E has applied to the California Public Utilities Commission ("CPUC") for a Certificate of Public Convenience and Necessity ("CPCN") for the project. The ISO Governing Board determined that a 500 kV Project, such as the Valley-Rainbow Transmission Project, is needed (without selecting a preferred near-term alternative, and without regard to routing) to address the identified reliability concerns of the San Diego and southern Orange county portion of the ISO Controlled Grid beginning in 2004 and directed SDG&E to proceed with design and licensing activities for the proposed project.

Path 15 – Los Banos-Gates 500 kV Transmission Project

To further strengthen the backbone transmission system in California and enhance power markets, the California ISO is proposing to add a new 500 kV transmission line and related facilities in the middle of the California ISO Control Area. The reinforcements proposed for Path 15 would become part of the Pacific Alternating Current Intertie, which was built to facilitate seasonal exchanges between California and the Pacific Northwest as well as to reinforce the ability to transmit energy between Northern and Southern California.

The majority of the flow of power from Southern California to Northern California and to the Pacific Northwest flows over Path 15; the remaining small percentage (unscheduled flow) goes through Arizona, Nevada, Utah and Idaho. Historically, Path 15 has played a major role in the seasonal energy exchanges that take place between Northern and Southern California, and California and the Pacific Northwest. Much thermal generation is located in Southern California and the desert Southwest, whereas much hydroelectric generation is located in Northern California and the Pacific Northwest. Driven by this geographic dispersion of thermal and hydroelectric generation, power typically flows from the south to north over Path 15 during winter off-peak hours, in part to enable northern hydroelectric resources to restock and conserve their water supplies, thus making those critical resources available during critical summer peak periods. This historical use of resources (and Path 15) has held constant even after the implementation of restructuring in California. These historical seasonal exchanges and resultant power flows over Path 15, however, have often been limited by the operating capacity of Path 15. Thus, since the ISO began operations, Path 15 has been defined as an Inter-Zonal Interface connecting the Congestion Zone north of Path 15 (NP15) with the Congestion Zones south of Path 15 (SP 15) and ZP26 in the ISO's congestion management process. As a result of this designation, transmission customers (Scheduling Coordinators) that submit schedules that use Path 15 must pay a Usage Charge for the right to use the constrained or "scarce" transmission capacity available on Path 15 when Path 15 is Congested.

Path 15 currently consists of the following lines:

Los Banos-Gates 500 kV	Gates-Panoche #2 230 kV
Los Banos-Midway 500 kV	Gates-Gregg 230 kV
Gates-Panoche #1 230 kV	Gates-McCall 230 kV

The maximum south-to-north limit for this path is 3950 MW, based on the simultaneous loss of the two 500 kV lines south of Los Banos listed in the above table.

An upgrade of this path is being considered to provide Northern California with increased access to existing and proposed resources in Southern California and the Desert Southwest. Such access could reduce the possibility of load interruptions in Northern California[34] and reduce supply costs to consumers in Northern California.

The preliminary plan for increasing the path rating is as follows:

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[34] Congestion on Path 15, which prevented power from being moved from Southern California to Northern California, was one of the primary causes of the firm load shedding that took place in Northern California on January 17 and 18, 2001.

- Construct a series-compensated, single-circuit 500 kV transmission line between Los Banos and Gates substations.
- Convert the Gates 500 kV bus from a ring bus arrangement to a breaker-and-a-half arrangement and loop the existing Los Banos-Midway line into the Gates 500 kV bus.
- Establish a second 230 kV transmission circuit between Gates and Midway substations.
- Install voltage support facilities at Los Banos and Gates substations.

This upgrade is expected to provide approximately 1500 MW of additional Path 15 capability. Every effort is being made to have this proposed upgrade operational by October 2004.

On April 13, 2001, PG&E filed a conditional application for a CPCN for this project with the CPUC. The application included a Proponents Environmental Assessment and a discussion on justification or need for the project. The project need was based on the ISO analyses of supply adequacy in Northern California and the economic impacts of Path 15 congestion through the end of 2000.

The ISO considers that a $300 million project to add 1500 MW of transfer capability at Path 15 is economically justified to reduce the risk of high prices associated primarily with the exercise of market power by strategically located generation and the existence of drought hydro conditions but also associated with other factors such as the risk of a low level of new generation development in Northern California. An examination of historical Congestion costs and studies undertaken by the ISO show that 1) between September 1, 1999 and December

31, 2000, Congestion on Path 15 cost California electricity consumers up to $221.7 million; and 2) using reasonable assumptions, the $300 million cost of upgrading Path 15 could potentially be recovered in within one drought year, plus three normal years. Further, upgrading Path 15 is consistent with a broader strategy to put into place a robust high-voltage transmission system that supports cost-effective and reliable electric service in California and a broader and deeper regional electricity market.

STATUS REPORT ON DEMAND PROGRAMS

Summary: The ISO fully supports the demand response principles outlined in the Commission's Standard Market Design on March 15, 2002. The ISO's Participating Load Program already meets many of the principles outlined by the Commission, and further demand program enhancements will be made in the ISO's Market Design 2002 filing. Additional retail demand programs will depend on decisions and leadership of the state regulators.

The Commission stated that "[d]emand response is essential in competitive markets to assure the efficient interaction of supply and demand". Commission *news release on Standard Market Design, March 13, 2002.* The ISO agrees with the Commission's position on Demand response and has taken an active role to develop Demand response programs. While several new Demand programs were introduced in California in 2001, the summer of 2002 is unlikely to see a substantial expansion in demand programs in California. This section on Demand programs will outline a) the ISO programs' status, including enhancements contemplated in the current Market Design 2002 process; b) the status of the CPUC interruptible rulemaking, c) the Commission - Department of

Energy ("DOE") Demand Conference on February 14, 2002, and d) a new Demand response program at the CCPCFA.

ISO Program Status

The ISO will maintain and enhance its Participating Load Program. This program allows Loads to bid similar to generating resources into the Non-Spin and Replacement Reserve Market and into the real-time Supplemental Energy market. While the Participating Load Program attracted bids of 700-800 MW during the summer of 2000, mostly from large water project pumps, creditworthiness concerns and a water shortage reduced participation to less than 100 MW during the summer of 2001. The ISO anticipates the Summer 2002 participation to be somewhere in-between. To further increase participation, the ISO is reviewing further refinements to the program, such as multi-hour dispatch, that can make it more attractive to a more diverse load population.

As noted in the two preceding ISO quarterly reports, the ISO aggressively developed two new programs – the Demand Relief Program and the Discretionary Load Curtailment Program – in 2001. These programs, unfortunately, have been suspended for the summer of 2002. Creditworthiness issues that scarred 2001 program performance are not expected to be resolved by the summer of 2002. Also, as noted in the Second Quarterly report, the ISO programs, which interact significantly with retail Loads, depend on IOU support. These programs cannot be effective without full state regulatory support for the IOUs to market, aggregate, and provide meter data for the ISO programs. IOU support, however, depends on the support of the CPUC. Without CPUC support for IOU load aggregation and metering, the ISO's DRP and DCLP cannot function effectively. The CPUC has not provided support for the ISO's demand response programs in its interruptible rate rulemaking.

CPUC Interruptible Rulemaking

An interim CPUC ruling on interruptible and Demand programs was issued on March 14, 2002, with a final ruling expected in April 2002. The CPUC is proposing only minor changes for Summer 2002. The ISO continues to monitor the CPUC rulemaking process and will help implement demand response programs where possible.

The ISO participated in a workshop sponsored by the CEC and the CPUC on March 15, 2002, which addressed, among other topics, remaining barriers to and key decisions that will affect the deployment of advanced meter systems, Demand response programs, and real time tariffs in California.

Commission Initiatives and Commission- DOE Demand Conference

The ISO attended the Commission -DOE sponsored conference in Washington DC on February 14, 2002. This was a valuable exchange of ideas and the ISO encourages the Commission to pursue future meetings on a regional basis including state regulators as well. Several speakers encouraged closer coordination between federal and state regulators, and a regional meeting could promote this.

California Consumer Power and Conservation Financing Authority ("CCPCFA")

The CCPCFA is working with a Market Participant in California to implement a new Demand response program that uses additional technology and also takes advantage of the 2001 initiatives that increased real-time meter installations. The ISO met with representatives of the CCPCFA and the program manager on March 13, 2002 and believes the program can provide diverse additional demand response resources to the ISO. Part of the program could bid in the Participating Load program and part of the program could serve to offset Capacity obligations that are contemplated for Load serving entities as part of the ISO Market Design 2002 (MD02). The ISO anticipates that this program will be funded by the State, and, like the ISO programs, will require state regulatory support for the IOUs to market and aggregate for the program for maximum effectiveness. The ISO is working to facilitate this program's participation in the ISO markets.

Demand Programs as Part of the MD02 Process

The Commission has provided clear direction that Demand response programs will be vital in the new Standard Market Design. The ISO fully supports this role for Demand programs. The ISO also urges the Commission to respect the necessary role of state regulators in any Demand program that affects retail load. As part of its MD02 process the ISO will include Demand programs as a vital ingredient that may satisfy the contemplated Available Capacity ("ACAP") obligation for Load Serving Entities. Two contemplated new features of MD02 - the Day-Ahead Energy market and the Day Ahead Residual Unit Commitment process - will both include provisions for loads or aggregated loads to participate. When viewed in the context of a capacity obligation, the new market design being developed will place additional financial incentives on load-serving entities to develop these programs to reduce their costs. The ISO looks forward to working with the Commission on Demand programs as part of the long-term market design project.

Demand response programs are still evolving in California. As a critical element of an efficient market, they have not matured to the extent that they can sufficiently temper demand and thereby contribute to market power mitigation in 2002. This is another reason supporting the ISO requests that the Commission continue the market power measures beyond September 30, 2002.

LONG-TERM CONTRACT EXECUTION

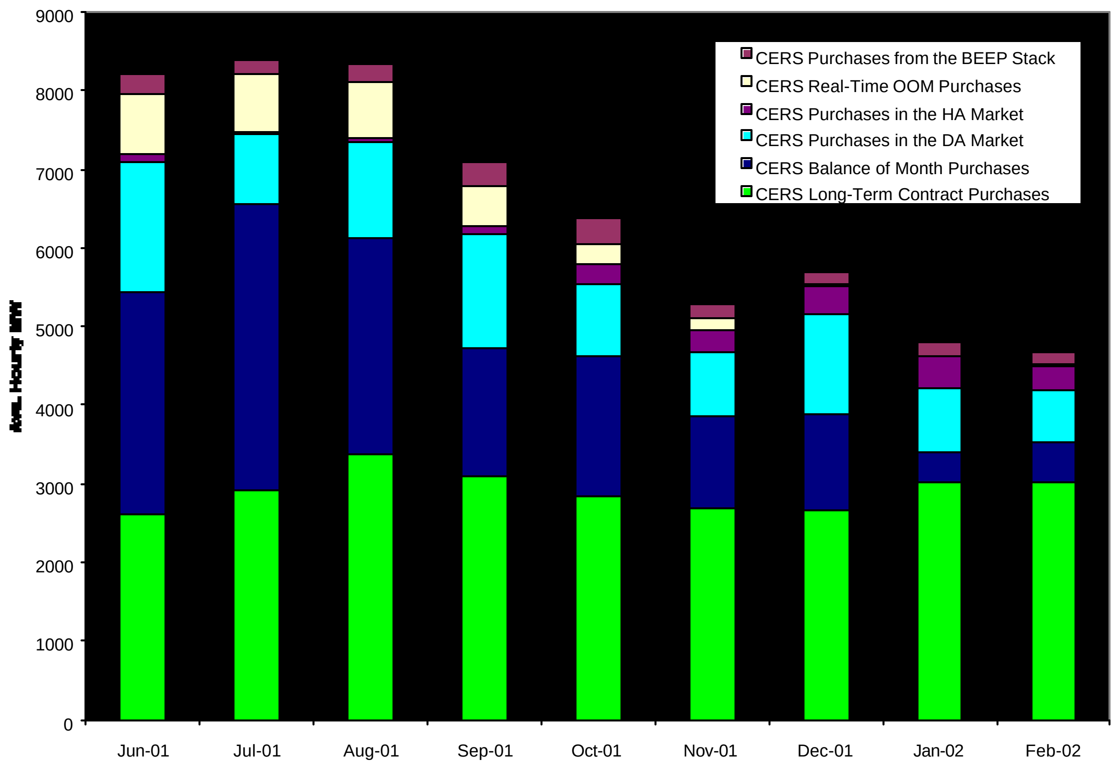
Summary: California's long-term contracts are not yet sufficient to effectively hedge Load from short-term price volatility.

The June 19 Order requires the ISO to report on the State's progress in executing long-term contracts to reduce the reliance on the spot market.[35] The June 19 Order stated that the reduction of the size of the ISO's spot market to levels more reflective of appropriate risk management was, and remains, the cornerstone of its price mitigation.[36] The ISO considers the spot markets to

35 June 19 Order, slip op. at 40.
36 June 19 Order, slip op. at 3.

include all short-term purchases including balance of the month, day-ahead, and hour-ahead purchases. The ISO has provided comments to the Commission on several occasions stating its view that significant forward contracting reduces the incentives for suppliers to exercise market power and protects Load Serving Entities from spot market volatility. Based on the ISO's understanding of the CERS' contracts, although the State has been working diligently to get long term contracts in place, Loads in California remain exposed to significant spot market risk, especially during peak periods. As shown in Figure 23 below, during the peak summer period of 2001, CERS' long term contracts covered less than 40 percent of the capacity needed to meet the three California IOU's net short requirement. Moreover, as described in more detail below, the actual long-term contract coverage provided by *firm* contracts is considerably less than the total portfolio, leaving significant Load exposed to volatile spot and real-time markets and potential high prices from the exercise of market power.

Figure 23. CERS Net Short Purchases by Month



While the State of California has made significant progress towards limiting California Load's exposure to the short-term and real time markets, more time, more contracts and more coordination between the IOUs and CERS are necessary to achieve sufficient coverage to protect load from volatile spot and real-time prices. The CPUC has been working to help SCE and PG&E regain financial solvency and meet the ISO's creditworthy requirements for Market Participants. Once SCE and PG&E can plan for and purchase long-term supplies to meet their forecasted needs, more effective long-term contracting should take place. Until that time, CERS is limited to bridging the gap between the IOUs' own generation and their Load through long-term contracts supplemented with short-term purchases. CERS has difficulty contracting for long-term supplies to meet the shape of the net short load because the market prefers to provide long-term block products that are ill-suited for serving peak loads. Purchasing peaking power through long-term contracts is both difficult and expensive.

Moreover, given that CERS entered into the majority of its long-term contracts under emergency conditions, the current portfolio of contacts contains several contracts with unfavorable terms that limit protection from price volatility and the exercise of market power.

To date, CERS has entered into significant quantities of long-term contracts to meet its role as the creditworthy supplier to purchase Energy to meet the net short supply needs of the State's three IOUs.[37] CERS entered into these well-publicized long-term power purchase agreements with various suppliers beginning in February 2001 and continuing through December 2001. To date, CERS has procured roughly 57 contracts from 27 separate suppliers at an estimated 10-year cost of $42.6 billion. A list of these contracts is set forth Appendix C to the instant report.

For the purposes of this report, a single energy flow from a supplier with a specified quantity, term and pricing structure is considered to be a contract, despite the fact that many of these contracts from a single supplier were bundled into the same document, and that many of the provisions within a single contract change over the term of the contract. Below are some summary statistics describing these contracts.

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[37] SDG&E may elect to have CERS provide for its net short requirements, however, it is the ISO's understanding that this is rarely done.

Table 8. Summary Statistics for Long-Term Power Purchase Agreements

Number of Contracts	57
Number of Suppliers	27
Maximum Contract Term	20 years
Minimum Contract Term	Five months
Maximum Monthly Quantity	13,369 MW
Price range for fixed price contracts	$45 - $249 / MWh

The problems encountered during the negotiating process and troubling provisions within the contracts have been discussed at length elsewhere.[38] The discussion herein is restricted to the impact of these contracts on price behavior and, in particular, a showing that the existence of these agreements does not eliminate the need for continued price mitigation past September 30, 2002. Due to the difficulties detailed above, the firm quantities of power provided under the contracts each hour do not match the fluctuating net short load, and as a result, in some hours there potentially is an excess of power provided under contract while in other hours, particularly peak hours, there is a deficit of power provided under contracts. The end result is that CERS must procure power through short-term agreements and spot purchases. Further, details within many of the contracts provide for decreases in the amount of power provided under the contracts potentially increasing the un-hedged portion of CERS' net short responsibility.

To argue that price mitigation is no longer needed as a result of sufficient long-term contracting requires a showing that the long-term contracts provide a long term hedge against a sufficiently large portion of the net short, such that the impact of short-term purchases is small compared to the overall cost of procuring power to cover the net short. If an insufficient amount of the net short is hedged, then suppliers will have incentives to exercise market power and price fluctuations in the un-hedged portion of the net short have the potential to sharply inflate costs to California load. Previous studies by the ISO's Market Surveillance Committee have recommended coverage levels of 70% or greater to control the impact of spot market and real-time price fluctuations on costs in covering the net short,[39] thus limiting the un-hedged portion of the net short to 30% or less of the total net short.

Contract Provisions are Complex and May Negatively Impact the Amount of Power Provided

The power purchase agreements may be classified against three axes for comparison. A first axis for comparison is whether a contract is effective during peak hours, off-peak hours, or both. A second axis is a contract's firmness, which is a description of the strictness of the supplier's obligation to supply power under the contract.[40] The third axis addresses whether the power is dispatchable, with CERS having the ability to alter the amount of power to be provided through a dispatchable contract and lacking the ability to do so under a nondispatchable contract.

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[38] See California State Auditor, Bureau of State Audits, California Energy Markets: Pressures Have Eased, but Cost Risks Remain, 2001-009, December 2001.

[39] See Market Surveillance Committee, CA Independent System Operator, Proposed Market Monitoring and Mitigation Plan for California Electricity Market, February 6, 2001.

[40] Firm contracts obligate suppliers to provide power or pay damages in the amounts specified in the contract. System or unit-contingent contracts obligate suppliers to provide power under the contract, but with an option to decrease power provided due to system or unit conditions, respectively, up to a per-year maximum. As-available contracts obligate suppliers to provide

It may be useful to envision these contracts as long-term forward contracts with potentially embedded call or put options, with firm, nondispatchable contracts as the “vanilla” forward purchase contract. Non-firm contracts (e.g. the unit contingent, system contingent, and as-available contracts) embed a put option in the contract, allowing suppliers to decide how much to supply beyond a certain level, subject to contractual constraints. Dispatchable contracts embed a call option in the contract, allowing CERS to make the decision to purchase at contract price or to decline and purchase spot market energy.

Figure 24 below shows the composition of the long-term contract portfolio over a ten-year period, separated by category along the three axes detailed above:

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power only up to the amounts available from the units from which power originates.

Figure 24. CERS Long-Term Contracted Quantities, by Month and Type

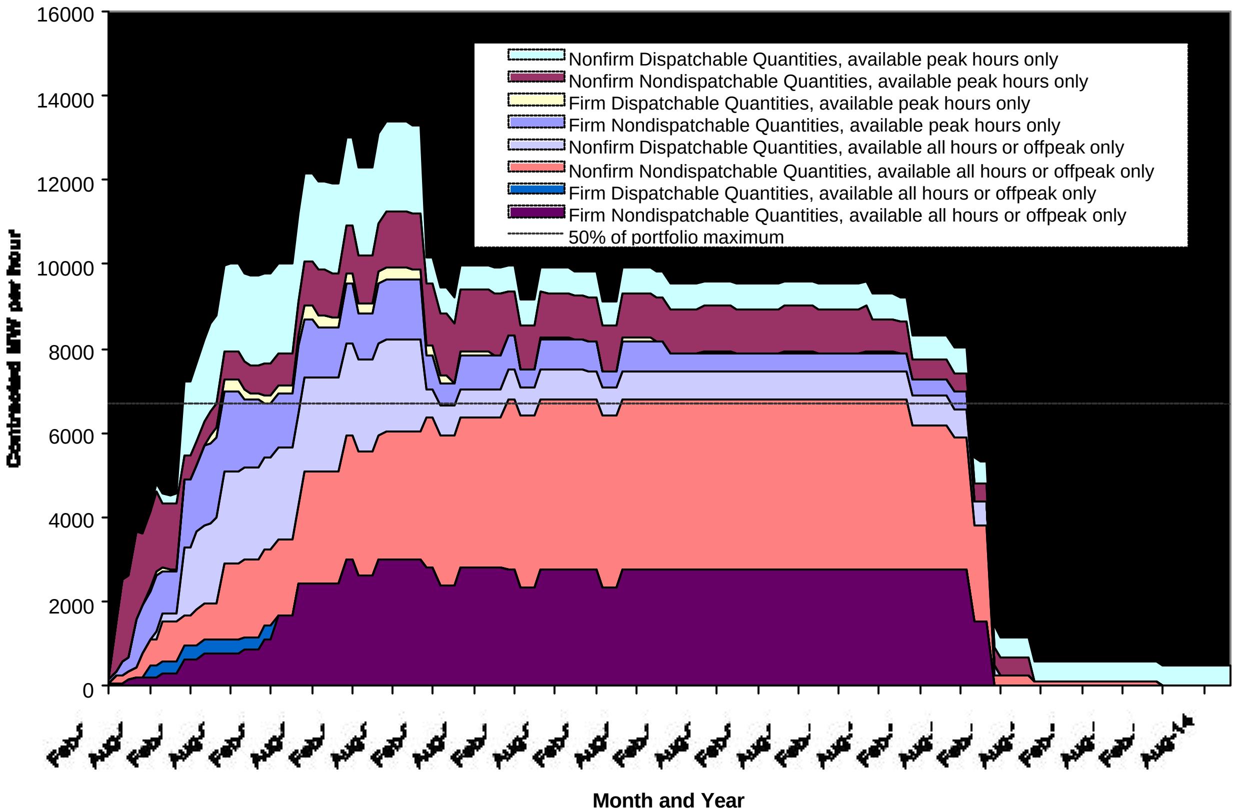


Figure 24 demonstrates that first, after ten years, the size of the portfolio drops sharply, *i.e.,* while there are 20-year contracts, the effective life of the portfolio is 10 years. Second, a substantial majority of the portfolio consists of non-firm contracts, in which there are embedded options to decrease the amount of power supplied, without penalty, up to a specified amount. Third, between 2002 and 2005, roughly half of the portfolio consists of contracts that only provide power during peak hours.

Similar observations can be made based upon examination of the data at a single point in time. Table 9 decomposes the contract types and quantities maximally available on February 1, 2002. In all instances, non-firm contracts outweigh firm contracts; during off-peak hours, that amount increases to a 7:3 ratio. During peak hours, contracts without dispatchability provisions markedly outweigh contracts with dispatchability provisions.

Table 9. Contract Quantities and Percentages on February 1, 2002

During Peak Hours:

	In MWh	Contract: No	Contract: Yes	Subtotal
Contract Firmness	Firm	2250	325	**2575**
	Non-Firm	1279.6	1858.5	**3138.1**
	Subtotal	**3529.6**	**2183.5**	**5713.1**

	% of Total	Contract: No	Contract: Yes	Subtotal
Contract Firmness	Firm	39.4%	5.7%	**45.1%**
	Non-Firm	22.4%	32.5%	**54.9%**
	Subtotal	**61.8%**	**38.2%**	**100.0%**

During Off-Peak Hours:

	In MWh	Contract: No	Contract: Yes	Subtotal
Contract Firmness	Firm	650	325	**975**
	Non-Firm	719.6	1611	**2330.6**
	Subtotal	**1369.6**	**1936**	**3305.6**

	% of Total	Contract: No	Contract: Yes	Subtotal
Contract Firmness	Firm	19.7%	9.8%	**29.5%**
	Non-Firm	21.8%	48.7%	**70.5%**
	Subtotal	**41.4%**	**58.6%**	**100.0%**

The Long-Term Contract Portfolio Does Not Provide a Sufficient Hedge Against Price Volatility

In the near term, the long-term contract portfolio's ability to cover in excess of 70% of the net short load is uncertain, as the portfolio quantities imperfectly match the net short load profile. By taking the mean of the net short less the total quantities that can be provided under contract in January of 2002, conditioned on day of the week and hour of the day, off-peak hours are shown to be more adequately hedged than peak-hours.

Figure 25. Expected Contracted MW in Excess of Expected Net Short Percentage, by Weekday and Operating Hour

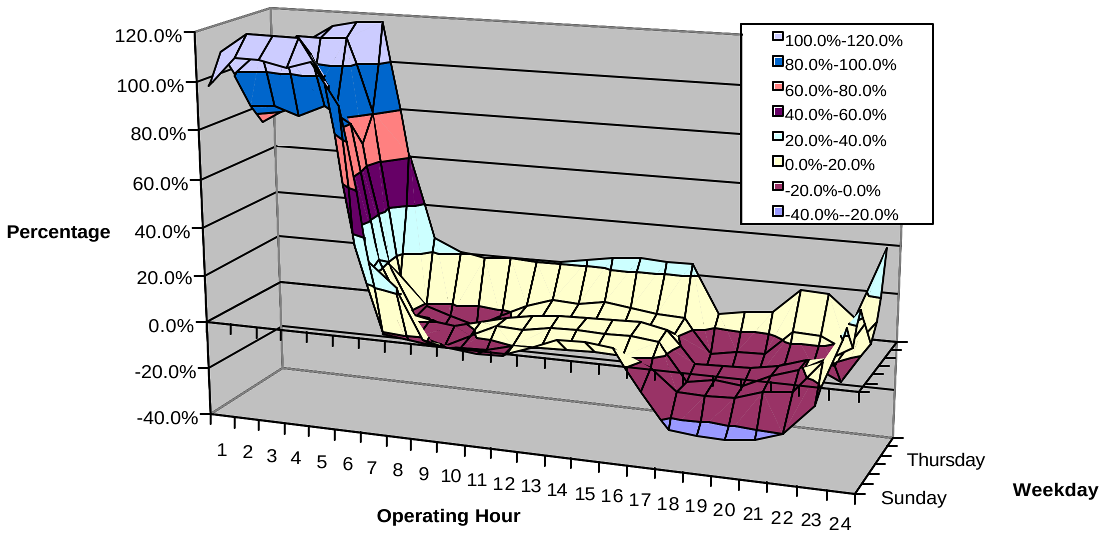
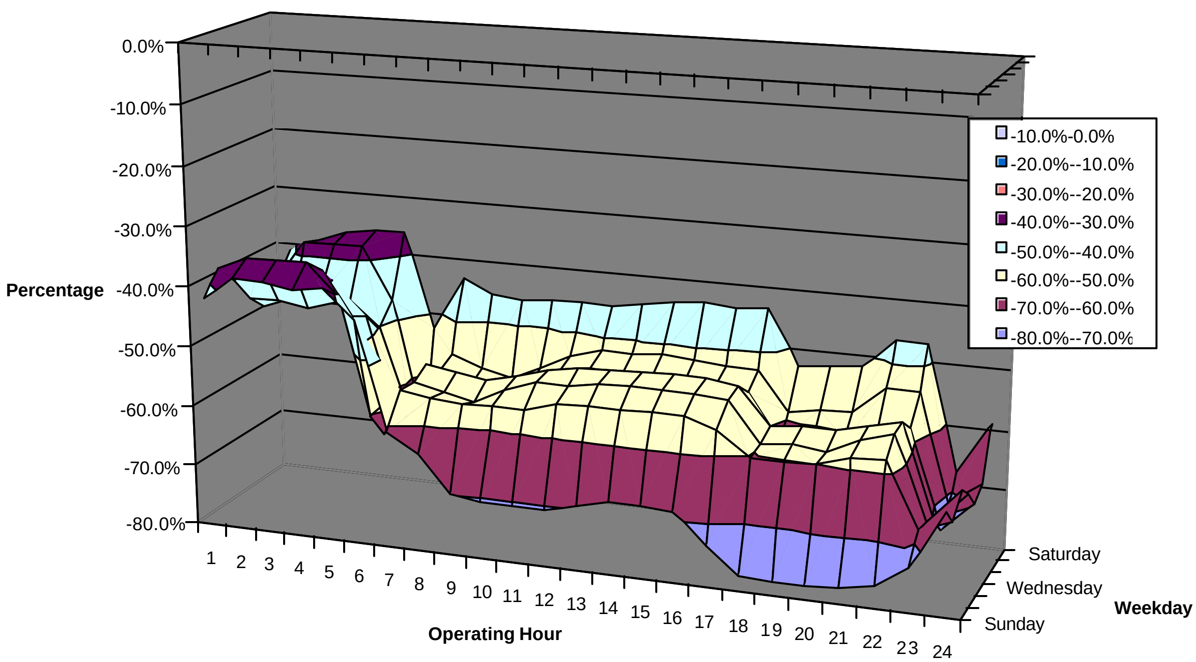


Figure 25 shows that the contracts provide some hedge against price volatility. Between hours 1 through 7 over all weekdays, there is sufficient portfolio capacity in total to cover the net short. Between hours 7 and 17, there is theoretically sufficient capacity to cover almost the entire net short. Somewhat more problematic are hours 17 through 22, where long-term contract capacity falls short by in excess of 20% across all days except for Saturday. Hours 23 and 24 show sufficient portfolio capacity to cover the net short. Under perfect conditions with no outages and 100% dispatch by CERS, the net short appears to be significantly hedged, although there is still a five-hour period each weekday where a significant portion of the net short remains un-hedged, and thus subject to price volatility risk.

However, Figure 25 does not take into account the numerous contingency and "as-available" provisions embedded in over half of the power purchase agreements. A closer examination of these contracts shows that the firm contracts are the *only* contracts that *guarantee* supply of power under contract in the maximum quantities under contract. The difference between the expected firm amount of power provided and the expected net short is significantly greater. Figure 26 shows a marked deficit over all hours and all days far greater than the recommended 30% or less un-hedged portion of the net short.

Figure 26. Expected Firm Contracted MW in Excess or Deficit of Expected Net Short Percentage, by Weekday and Operating Hour



Even during early morning off-peak hours there is a deficit in excess of 30%; during the peak hours with the heaviest load (hours 17 through 22) the deficit exceeds 70% across all days except Saturday. Assuming that the non-firm put options are exercised to a 70% level (e.g. of a 500 MW contract 350 MW are provided), during hours 17 through 22 the coverage would fall significantly below 70%.

Thus, despite CERS' long-term contracting activities and the fact that during off-peak hours there appears to be sufficient contracting to cover the net short, there are substantial blocks of time where much of the net short remains un-hedged.

The insufficiency of CERS' long-term power contracts to provide a long hedge is another strong argument for the continuation of market power mitigation provisions until such time as Load Serving Entities are effectively hedged from short-term price volatility. Consequently, continued comprehensive regional price mitigation past September 30, 2002 remains necessary, in spite of CERS' long-term contracting efforts, because of the necessary continued reliance on short-term market energy purchases to cover the investor-owned utilities' net short requirements. Moreover, given that at the end of 2002 CERS will terminate its role as purchaser of power for the IOUs' net short requirements, it will be critical that market power mitigation measures remain in place to help smooth the transition to a new market without the CERS presence.

NEED FOR CONTINUED MARKET POWER MITIGATION

Summary: The fundamental conditions that would ensure competitive markets are not yet in place. While the ISO is preparing to propose market power mitigation to take effect after the expiration of the current price mitigation on September 30, 2002, a California-only mitigation plan cannot be as effective as the current west-wide plan.

Market power mitigation is an indispensable element of electricity markets. Conditions can always arise in a Energy market such that market participants can raise prices considerably above competitive levels even in the absence of Energy scarcity, a condition in which prices legitimately may rise. Structural deficiencies in California Energy markets increased the frequency of such occurrences starting in May 2000, and help to bring about several Commission orders imposing various measures for market power mitigation. The west-wide market power mitigation plan adopted by the Commission in its June 19 Order is set to expire on September 30, 2002. The ISO has protested the application of a hard, or automatic, sunset date for ending the west-wide market power mitigation plan and requested that the expiration should be tied to an affirmative determination that the fundamental structural elements for a workably competitive market are in place as opposed to termination on an arbitrary date. In its December 19 Rehearing Order, the Commission unfortunately denied this request and reaffirmed the September 30, 2002 sunset date. While the ISO is working to develop market mitigation proposals and to meet the Commission's clear goal to remove itself from the role of requiring certain price limits and other temporary market restraints, the ISO remains concerned that the structural elements necessary to ensure a workably competitive market will not be fully in place on October 1, 2002 and so, the ISO, of necessity, must continue, through all available means, to advocate extending the west-wide mitigation plan beyond September 30, 2002.

The ISO understands that the most effective approach to mitigating market power is to correct the structural deficiencies that enable suppliers to exercise significant market power. Correcting these deficiencies takes time, however, particularly when California is still trying to recover from the devastating financial effects the California Energy crisis caused in the previous two years. Until the creditworthiness of California's IOUs is restored and further progress is made in adding new generation capacity and Demand response, California will be exposed to significant market power abuse unless the Commission extends the west-wide mitigation plan.

The ISO also is actively engaged in developing alternative market power mitigation plans to replace the west-wide mitigation plan. Critically and fundamentally, however, a California-only program for market power mitigation cannot provide the same level of market power protection as a west-wide mitigation approach, unless there is a mechanism for ensuring through long-term contracting that adequate capacity is committed to serving California load. Absent such an obligation, suppliers in California can simply circumvent market power mitigation in California's spot markets by exporting out of California and reselling back as an import, *i.e.,* megawatt laundering. Megawatt laundering was one of the most devastating forms of market power abuses that generators performed in the period leading to PG&E's bankruptcy, SCE's financial insolvency, and the curtailment of Load and disruptions in delivery of power in California in late 2000 and early 2001. Megawatt laundering became such a significant problem that the Commission ordered west-wide implementation of the must-offer obligation in all hours to combat the problem.

Unfortunately, California's IOUs still are not returned to a financial position from which they can procure adequate long-term contracts for ensuring sufficient capacity is obligated to serving California load in October 2002 and beyond. Given these circumstances, the ISO believes it is unreasonable to expect that California can effectively minimize, through forward contracting in the extraordinary situation in which California now finds itself, its exposure to the spot market beginning in October 2002. Thus California will remain susceptible to market power abuse absent the continuation of the west-wide mitigation plan.

The ISO, however, does believe that it is developing a long-term approach to market power mitigation that can, when fully implemented, foster competition while providing proper safeguards against significant market power abuse. The proposed approach includes a four-step process to achieve these objectives:

I. Market design changes embodied in the ISO's proposed MD02 and other initiatives;[41]

II. A damage control bid cap;

III. Resource specific bid screens and mitigation; and

IV. An explicit standard for just and reasonable rates, which, if violated, would trigger the automatic implementation of a more stringent market power mitigation plan (*e.g.,* re-impose the price mitigation imposed in the June

[41] Specifically, the ISO's recent filing of Tariff Amendment No. 42 seeking additional authority to mitigate local market power and seeking penalties for excessive uninstructed deviations.

19 Order, or, alternatively, impose cost-based bid caps on only those suppliers found to have exercised market power).

The first three steps of this proposal are consistent with the market power mitigation approaches the Commission has authorized for other ISOs. For instance, two other independent system operators, PJM and the New York ISO, have many of the same market design elements being proposed in Step 1 as well as the Step 2 Damage-Control Bid Cap. Additionally, the New York ISO has the Step 3 protection of resource specific bid screens and mitigation. What is fundamentally missing in the market power mitigation plans for all ISOs is an explicit prospective standard for measuring whether wholesale electricity rates are, over time, just and reasonable, as proposed in Step 4. In the event the standard is violated, a pre-authorized market power mitigation plan would be implemented. Such a standard would allow occasional price spikes but on a cumulative basis would not allow or cause irreparable damage to the market. A well-designed standard would inform all parties when mitigation would be implemented. Thus suppliers could take self-correcting steps to avoid provoking mitigation.

Consumers also have assurances that once the threshold is exceeded, rates would be deemed unjust and unreasonable, and a refund obligation would be in place on a prospective basis. The ISO believes that the fourth step of the proposal addresses this fundamental deficiency. Attached as Appendix D hereto is an ISO white paper that was publicly released on February 28, 2002 describing this alternative market power mitigation proposal.

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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APPENDICES