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.***

SECOND 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]

> 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.[3]

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.

3 April 26 Order at 61,364.

(“June 19 Order”).[4] 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.[5]

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 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.

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. To comply with the June 19 Order, the First Quarterly Report:

- Described the status of the ISO’s Summer Reliability Generation program, undertaken to bring additional peaking generation capacity into California in 2001;

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[4] 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).

[5] June 19 Order at 62,567.

- Included an update on the changes to the ISO's Outage Coordination programs directed by the April 26 Order;
- Discussed the ISO's interconnection policy and asked the Commission to act on the ISO's Tariff Amendment No. 39, filed on April 2, 2001;
- Provided a table on the status of California generation additions using data from the California Energy Commission's ("CEC") 2001 Generation Progress report;
- Described Demand reduction efforts, including the ISO's Participating Load, Demand Response and Demand Load Curtailment Programs, the California Public Utilities Commission's ("CPUC") Interruptible rate rulemaking process, and the California Demand Bidding Program; and
- Discussed other actions the ISO has taken to meet anticipated peak Demand, including the back-up generator programs.

The instant filing, the "Second Quarterly Report," now provides an update on the development of new generation, the status of Demand response programs, creditworthiness issues, and other actions the ISO has taken with regards to the Commission's price mitigation orders. The Second Quarterly Report does not duplicate information contained in First Quarterly Report, but provides updated and additional information only.

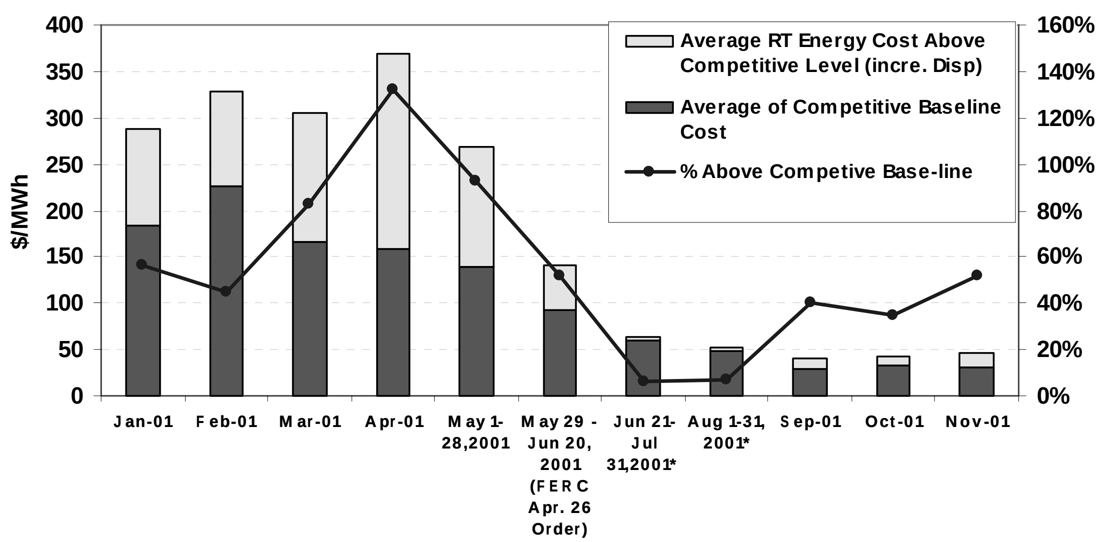
A. EFFECTIVENESS OF PRICE MITIGATION

From September 2001 through November 2001, average market prices have declined from summer levels and have been generally moderate and stable. As discussed in the First Quarterly Report, however, due to the multiplicity of influences and factors, it is difficult to discern how much of the current market stability can be attributed to the price mitigation implemented through the April 26 and June 19 Orders and how much stems from other market conditions. Moderate loads, new generation, and increased forward contracting certainly have contributed to the improvement in market competitiveness.

1. Real Time Energy Costs

Figure 1 provides real time energy prices (in $/MWh) in the ISO Control Area and compares those prices with competitive baseline prices. Real time energy costs are calculated based on incremental dispatches during peak hours and represent the combined costs of purchases from the ISO's Real Time Imbalance Energy Market (the BEEP stack, including as-bid purchases above the Market Clearing Price ("MCP")) and real time Out-Of-Market ("OOM") purchases (i.e., OOM purchases made after the close of the Hour-Ahead Market). The competitive baseline prices are based on a market simulation model developed by the ISO's Department of Market Analysis. That model calculates estimated competitive baseline prices using supply and demand conditions, spot market gas prices, unit incremental heat rates, and other factors expected to affect system marginal costs under competitive market conditions.[6]

Figure 1. Price-Cost Mark-Up in ISO Real-Time Market



Real time energy prices roughly matched calculated system marginal cost from the time the June 19 Order was implemented on June 21, 2001 through August 2001. Average real-time prices climbed somewhat above the competitive baseline from September to November, but the price mark-ups during this time remained relatively moderate compared to price mark-ups calculated during the first half of 2001. The competitive baseline prices for the September-November period decreased mainly due to low natural gas prices.

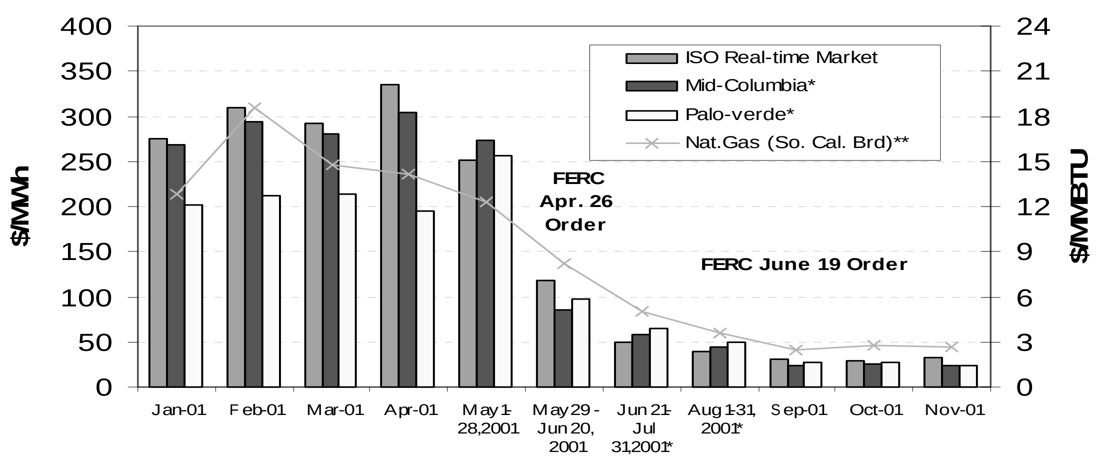
While prices have been generally competitive, the ISO continues to see certain suppliers submitting energy bids well in excess of their proxy bid cost, i.e.

[6] Competitive baseline prices include NOx costs until June 20. Thereafter NOx costs are excluded as provided for in the June 19 Order.

incremental cost.[7] Approximately twenty percent of the total volume bid into the ISO BEEP stack in September and October 2001 had prices above the $91.87/MWh Non-Emergency Clearing Price Limit ("NECPL"). Fortunately, the ISO did not have to call such high bids due to declining Demand and an ample supply of lower-priced bids. The ISO will continue to monitor the level of bids above the competitive base line in the coming winter months.

Figure 2 compares daily average energy costs in the ISO's Real Time Imbalance Energy market during peak hours to average peak-hour energy prices for the Palo Verde and Mid-Columbia trading hubs for the period January to November 2001. The findings indicate that the reductions in and stabilization of Western energy prices observed from June through August continued through November. Figure 2 also shows that Southern California gas spot prices remain stable and moderate as well.

Figure 2. Comparison of CAISO Average Energy Costs to WSCC Spot Prices and Natural Gas Spot Prices

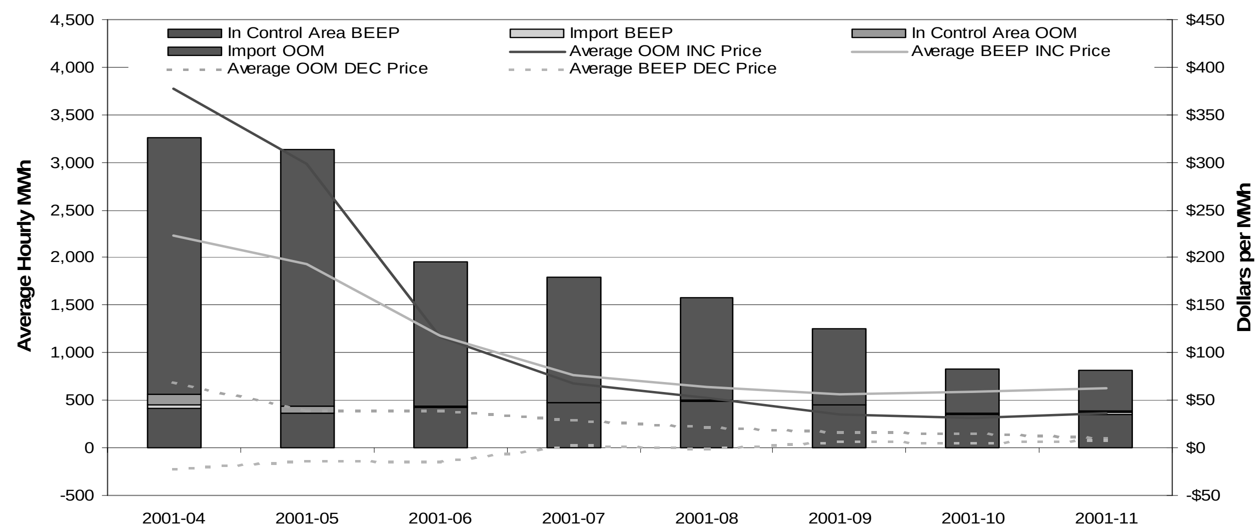


* Mid-range daily energy spot prices as reported in Energy Market Report by Economic Insight, Inc.
**Mid-range daily natural gas prices as reported in Daily Gas Price Indexes by Natural Gas Intelligence .

[7] Evidence of high bid-cost mark-ups can be found in the confidential Market Monitoring Reports submitted weekly to FERC by the Department of Market Analysis for the following weeks: September 27 - October 3, October 18 - October 24, and November 15 - November 21.

Figure 3 illustrates the trend in real time energy volumes and prices (both the ISO's BEEP stack and OOM transactions) from April to November 2001. While the total volume of transactions in the ISO's BEEP stack has been relatively stable and small (about 500 MWh per hour) during the period, the average hourly OOM transaction volume has decreased significantly, from more than 2,500 MWh in April to less than 500 MWh in November.

Figure 3. OOM Volume and Average Price



The participation of imports in the ISO's Real Time Imbalance Energy Market (i.e. the BEEP stack) has been minimal throughout the period. The ISO attributes minimal import participation to:

1) the exposure to uninstructed deviation prices in the ten-minute settlement system (which can occur if the ISO first dispatches the importer's bid, then reverses that instruction later in the hour),
2) credit risks associated with real-time market purchases,

3) the Commission's June 19 Order, which directed importers to be price-takers in the ISO's markets, and

4) importers' preference for enhanced price certainty and greater assurance of payment associated with the OOM purchases made by CERS.[8]

Before July, average BEEP stack incremental prices were lower than average OOM incremental prices. However, this trend has reversed since July. Average OOM decremental prices have been consistently higher than average BEEP stack decremental prices for the entire period shown in Figure 3.

Effective December 13, 2001, the ISO no longer allows CERS to make OOM purchases. At this time it is unclear whether this will cause out-of-state suppliers to shift from OOM to the BEEP stack or Hour-Ahead market or to simply stop offering supply to the ISO Control Area. To ensure continuity of supply into the ISO Control Area, the ISO is evaluating measures to reduce the price risk of imports participating as price takers[9] in the ISO's real-time market. Specifically, in recognition of the inflexibility of imports to follow ten-minute dispatch instructions, the ISO is considering, once ties have been pre-dispatched at the top of the hour, to not issue any subsequent within-hour dispatch instructions. This measure would ensure imports are paid "instructed" ten-minute

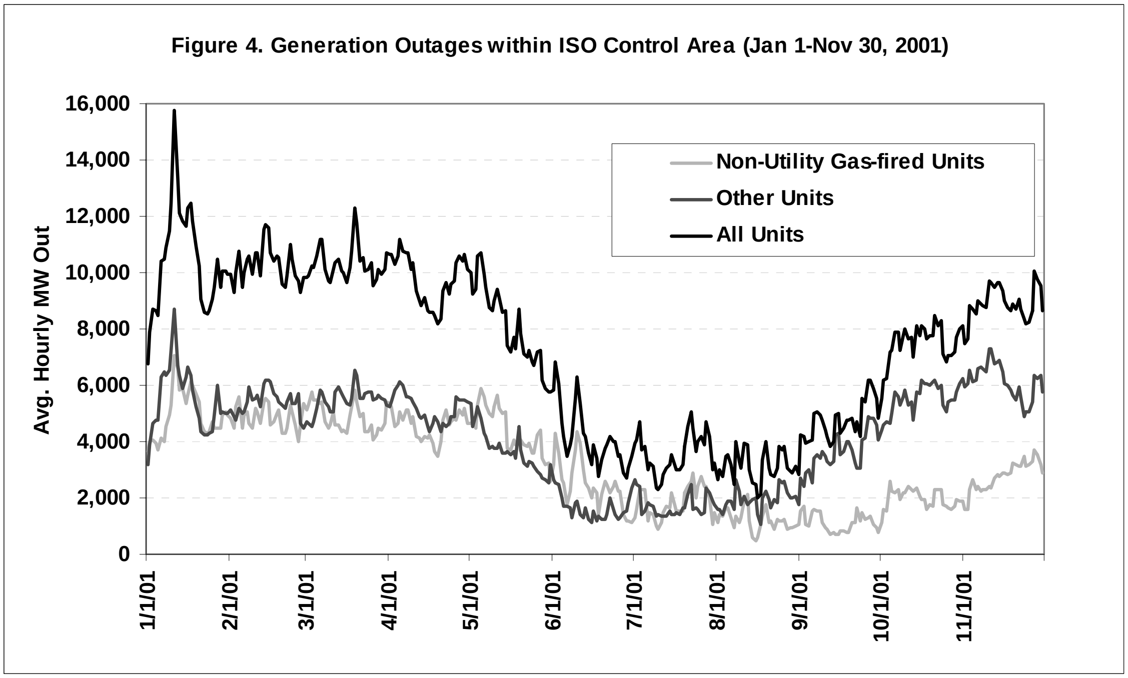
[8] To comply with the Commission's November 20, 2001 Order, the ISO no longer allows CERS to make OOM purchases effective December 13, 2001.

[9] Based on FERC's June 19 Order the imports (other than those that are resource-specific and dynamically scheduled) are price takers in the ISO's real-time market. This measure was adopted primarily to mitigate MW laundering.

prices throughout the hour rather than a mix of “instructed” and “uninstructed” prices.

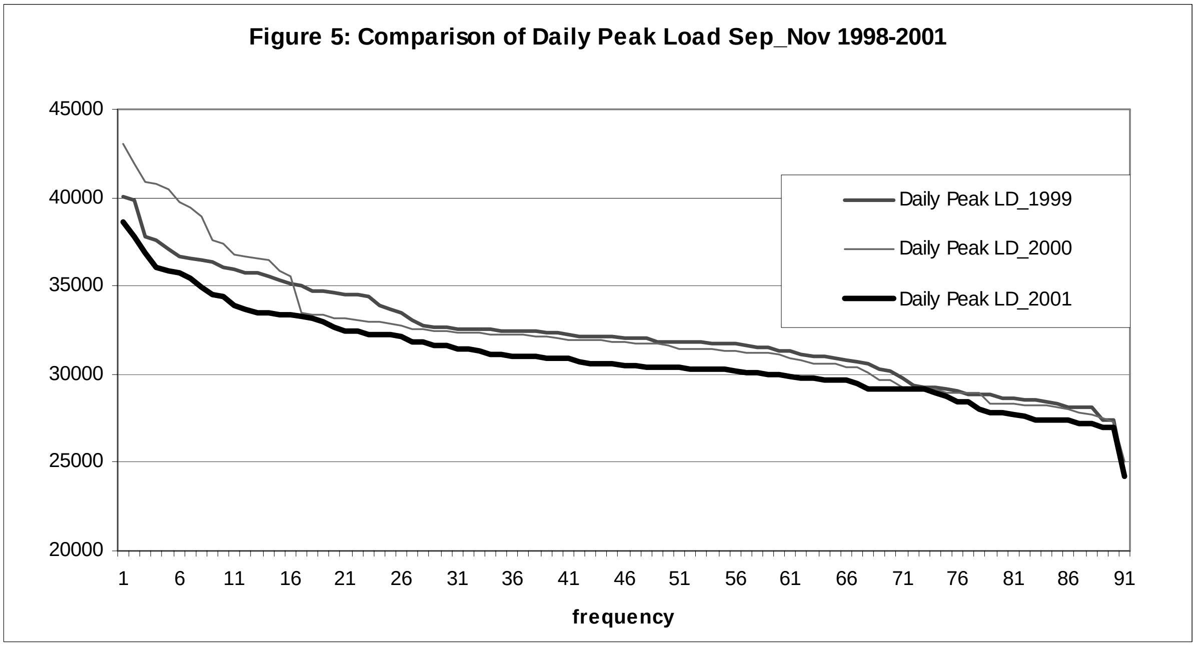
2. Generation Outages

Beginning in October 2001, an increasing number of Generating Units within the ISO Control Area have gone off-line as shown in Figure 4. The amount of generation capacity on outage reached nearly 10,000 MW by the end of November. Some of these generation outages are for economic reasons wherein Generating Unit owners unilaterally elected to shut down their Generating Units, claiming they could not operate the Generating Unit at an acceptable level of profit or cost recovery during certain periods of time under prevailing market prices. To the extent such outages are taken unilaterally, the Generating Unit is in violation of the Commission’s must-offer obligation as set forth in the April 26 Order and expanded in the June 19 Order. On December 4, 2001, the ISO filed with the Commission a revised approach to the must-offer obligation that would provide compensation for minimum load costs for Generating Units the ISO directs to stay on-line pursuant to the must-offer obligation.



3. Load

ISO Load during September and November continues to be low compared with same period in 1999 and 2000, due, at least in part, to effective conservation measures, mild weather, and a softening economy. During this time, the ISO only experienced seven days where ISO system daily peak loads were greater than 35,000 MW (as compared to sixteen days during the same time in both 1999 and 2000). The CEC reports that total energy consumption declined 5.4 percent in September 2001 and 1.5 percent in October 2001 compared to the same months in 2000, after normalizing for growth and weather conditions. Figure 5 shows the 1999, 2000 and 2001 Load duration curves, which clearly indicate the reduced Load observed in 2001.



4. Summary

In summary, market prices for the September through November 2001 period have declined from summer levels and have been generally moderate and stable. However, due to multiple influences and factors, it is difficult to discern how much of the current market stability can be attributed to the price mitigation implemented through the April 26 and June 19 Orders and how much stems from other market conditions. Moderate loads, new generation, and increased forward contracting certainly have improved market competitiveness. Despite these favorable trends, the ISO remains concerned that market conditions could become unstable during the next few months, particularly if northern California and the Pacific Northwest experience a prolonged cold snap. If such an event were to occur, imports to California from the northwest will likely decline significantly and the ISO will be more dependent on in-state thermal resources for supply. Given the high level of in-state generation that is out on maintenance, greater reliance on in-state supplies may make certain suppliers pivotal and significant market power problems may again arise.

B. NEW GENERATION

1. ISO Summer Reliability Generation

The ISO signed Summer Reliability Agreements ("SRAs") for 30 units for a total of 1,324.1 MW. To date, five of those units, for a total of 184.9 MW have reached commercial operations under their ISO SRAs:

SRA Site	Contracted Capability	Commercial Operations Date
Harbor Cogen	17.9 MW	6/15/01
NEO Chowchilla	48.6 MW	6/13/01
NEO Red Bluff	41.5 MW	8/11/01
RAMCO Chula Vista	38.6 MW	8/23/01
RAMCO Escondido	38.3 MW	10/26/01

Seventeen SRAs either were terminated or suspended after the owners of those agreements reached a new agreement with the California Department of Water Resources ("CDWR") to provide energy and capacity. Five of the units with suspended SRAs have reached commercial operation by October 31, 2001, and may re-activate their ISO SRA no later than December 31, 2001, and continue under the SRA with the ISO. These units are:

SRA Site	SRA Contracted Capability	SRA Suspended	Commercial Operations Date
Larkspur 1	46.7	5/21/01	9/13/01
Larkspur 2	47.2	5/21/01	9/19/01
Indigo 1	48.6	5/21/01	9/19/01
Indigo 2	45.0	5/21/01	10/16/01
Indigo 3	48.3	5/21/01	9/18/01

Other units' SRAs were terminated either for failure to reach the SRA's October 31, 2001 Commercial Operations Date requirement or because the units were never built. These facilities are:

SRA Site	SRA Contracted Capability
NRG	43 MW
Panda West (3 units)	147 MW
RAMCO (2 units)	99 MW
Tenaska	49.9 MW
Stockton Sierra Cogen (Wellhead)	22 MW

2. Other Generation

According to ISO information, nearly 10,000 MW of new in-state generation has reached commercial operation status, or is expected to do so by December 2002. Appendix A contains that list of new generation projects.

C. DEMAND RESPONSE

The ISO believes Demand response programs are vital for both grid reliability and for robust, competitive electricity markets. For eighteen months, the ISO led an aggressive Demand response program development project made up both of internal activity and cooperative efforts with Load participants and Load aggregators. This activity and the resulting three ISO Demand response programs are outlined in the ISO's First Quarterly Report.[10] The instant Second Quarterly Report focuses on the status and influence of the CPUC Interruptible Rate Rulemaking Process, the performance of the ISO's Demand response programs during Summer 2001, and the ISO's plans for future Demand programs in the context of other state activities regarding Demand response.

1. CPUC Interruptible Rate Rulemaking Process

The CPUC Rulemaking on Interruptible Rate Programs ("CPUC Interruptible Rate Proceeding") began in October 2000 and the final decision for Phase I of that proceeding was issued on April 4, 2001. Phase I of the CPUC Interruptible Rate Proceeding was discussed at length in the ISO's First Quarterly report.

On September 21, 2001 the CPUC commenced Phase II of the CPUC Interruptible Rate Proceeding. The initial scoping memorandum provided that Phase II would, among other things, focus on necessary or reasonable modifications to, or consolidations of, existing Demand response programs. The

[10] The three ISO Demand response programs are the Demand Response Program ("DRP"), the Discretionary Load Curtailment Program ("DLCP") and the Participating Load Program

scope thus appeared sufficiently broad to address the issues highlighted in the ISO's First Quarterly Report. To date, however, parties have not responded as intensively in Phase II as they had in Phase I. In fact, only a handful of entities filed detailed comments regarding the CPUC's request for comments, including the CEC's proposal for a new Demand response program, based largely on the ISO's Demand Relief Program, to be funded by a retail ratepayer surcharge. The ISO's comments in Phase II of the CPUC Interruptible Rate Proceeding set forth the ISO's intentions regarding its own Demand response programs as described below, and also generally supported the CEC's proposal, provided that certain operational coordination issues were addressed. The CPUC is expected to issue a proposed decision addressing all Phase II issues on February 1, 2002 and a final decision by the end of February 2002.

Based on the filings in the rulemaking thus far, the ISO anticipates that the CPUC's decision will focus primarily on issues of coordination among its own Demand response programs, rather than among those proposed by other state agencies or those operated by the ISO. Accordingly, the ISO continues to participate in Phase II of the CPUC Interruptible Rate Proceeding and to coordinate with the recently created California Power Authority ("CPA"), the CEC, and the Investor Owned Utilities on Demand response program issues.

Last year's CPUC decisions regarding Demand response programs were not consistent with the ISO's Demand response programs. The CPUC refused to allow loads on interruptible rate tariffs to participate in the ISO's Participating

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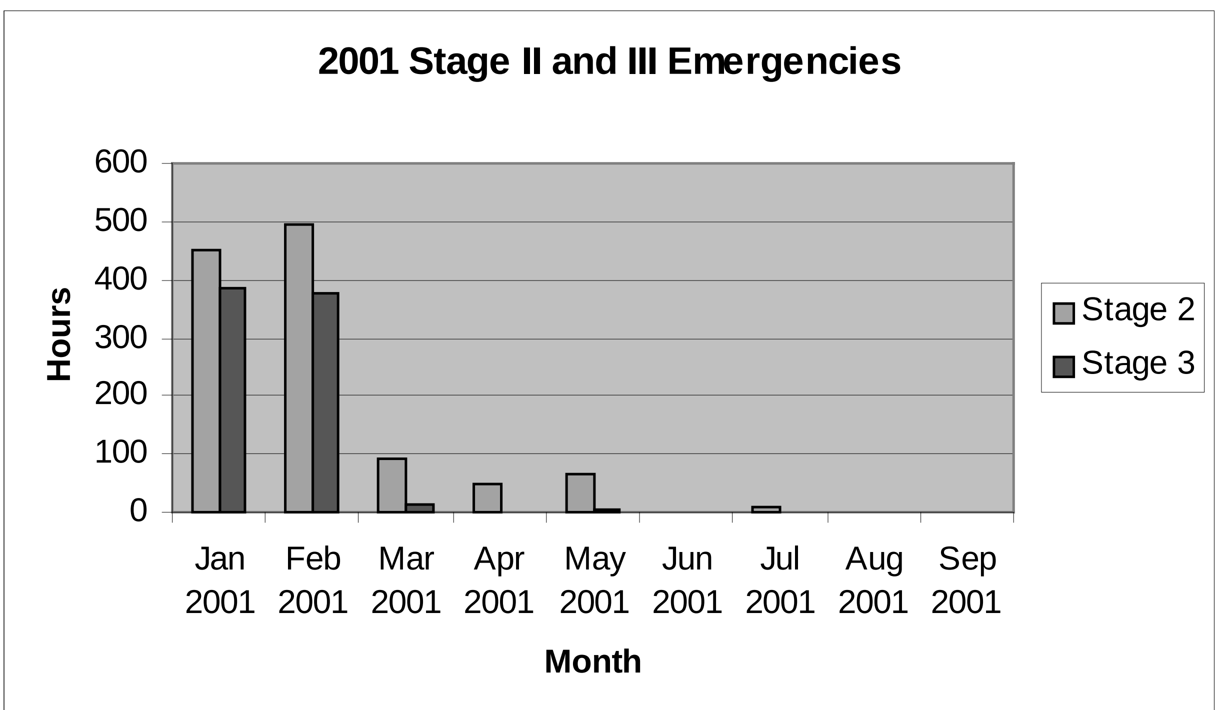
("PLP").

Load Program ("PLP"). PLP Loads would have participated in the ISO markets during System Emergencies and during normal operation. In response to CPUC concerns of "double-dipping" or "double-counting" by PLP Loads, the ISO argued that additional Load participation in the Ancillary Services markets would apply downward price pressure in those markets, to the benefit of California customers. The ISO also proposed to (i) deny PLP Loads the Ancillary Service capacity payment in the hours that the ISO called on them pursuant to an interruptible rate program, and (ii) if necessary, reduce the amount of PLP Load available to the ISO as Ancillary Services should system conditions require that the interruptible rate programs be called. The IOUs and interruptible rate Loads supported the ISO's position. The CPUC rejected the proposed solution on the basis that since the interruptible rate programs had already been paid for through rate reductions, any additional payment for curtailment would necessarily result in double-dipping and double-counting, since there would not be any additional curtailment by the interruptible rate Loads if system conditions ultimately required them to be curtailed through the interruptible rate programs after they had already been curtailed as an Ancillary Service.

Subsequently, the CPUC instituted its Voluntary Demand Relief Program ("VDRP"), which is almost identical to the ISO Discretionary Load Curtailment Program ("DLCP"), in its April 2001 order. This shifted interest for bundled IOU loads from the DLCP to the VDRP. The VDRP, however, was terminated with the implementation of the state-initiated Demand Bidding Program on August 1, 2001. In addition, the CPUC decided not to allow the IOUs to serve as aggregators for the ISO's Demand programs. In a draft decision issued on August 28, 2001, the CPUC stated "…contemplated programs developed in conjunction with the ISO are not within the scope of the modified Rate Agreement." This terminated efforts between the ISO and CDWR to develop the financial backing for the ISO's Demand Relief Program and DLCP as discussed in the First Quarterly Report. The apparent conflict of jurisdiction between the CPUC, ISO and even the CEC is a major factor in the ISO's recommendations for future Demand response program operation set forth at the end of this section.

2. Summer 2001 Demand Programs' Performance

A combination of factors reduced Demand during Summer 2001, resulting in only one ISO-declared Stage 2 System Emergency during the period June through September 2001. The number of ISO declared Stage 2 and Stage 3 System Emergencies for 2001 is shown below.



The ISO has called only one Stage 2 System Emergency since June 1, 2001. On July 3, 2001, the ISO declared a Stage 2 System Emergency that curtailed Demand under the IOU interruptible programs, the DRP and the DLCP. Program performance on July 3, 2001 was as follows:

Program	**MW Curtailed**
Interruptible IOU loads	760 MW
ISO DRP	162 MW
ISO DLCP	22 MW

Considering the pervasive concerns over creditworthiness, and the fact that many businesses had shut down early for the July 4th holiday on July 3, the ISO was pleased with the response of its Demand response programs, especially the response observed under the DRP.

The IOU Interruptible programs produced approximately 760 MW of curtailed Demand when those programs were called on July 3. Most of this response was concentrated in Southern California Edison Company's ("SCE's") service area. This level of participation is consistent with participation observed in May 2001 after the Pacific Gas and Electric Company ("PG&E") interruptible program was exhausted, but is far lower than the 1500 MW of interruptible rate Demand response available in Summer 2000.

Participation in the PLP was greatly reduced during Summer 2001, with average bid levels below 100 MW, compared to participation levels of 600-700 MW during some periods in 2000. The ISO believes a combination of creditworthiness concerns and the adverse hydro conditions in 2001 caused the reduction.

The state's Demand Bidding Program went into operation on July 31, 2001. Little Demand was bid into this program in August and September, with the lowest price Demand tier bid for $100/MWh. Because price levels for generation have been below $100/MWh most of the time, CDWR did not dispatch the program. Despite the experience of Summer 2001, the ISO believes that the platform development for the Demand Bidding Program was very positive and hopes that this program can be revamped and supported by the CPUC to attract load participation in 2002.

3. Future Recommendations

In the short term, Conservation and Demand response programs can help address California's resource shortage. In the long term, they add a level of price elasticity to Demand that should improve the operation of the markets. Unfortunately, the future of Demand response programs both at the ISO and in California is unclear. Many Loads in California have been discouraged from participating in Demand response programs because of payment concerns, extensive curtailment of loads on the interruptible rate tariff, regulatory uncertainty, a large number of different, competing programs, and ongoing revisions to those programs. Demand response programs cannot succeed without better coordination among the various state entities, including the CEC, the CPUC, and the CPA.

At this point, the ISO believes it is prudent to scale back its efforts and defer to the CPUC, the CPA, and the IOUs to develop programs and provide program funding. To this end, the ISO

(1) has suspended its DRP effective October 31, 2001;

(2) will suspend its DLCP effective March 31, 2002; and

(3) will continue to enhance its PLP, which operates completely within the ISO reserve and supplemental energy markets.

The ISO's decision to suspend the DRP and DLCP can be revisited if creditworthiness is fully restored to the California markets, and the state directs the ISO to re-introduce these programs or other programs and provides support from the CPUC.

The ISO is changing its stance due largely to problems encountered when ISO Demand response program jurisdiction and policy conflicted with CPUC jurisdiction and policy. The three IOUs control most of the load in California, so these entities are best situated to lead Demand response programs. The IOUs have direct access to the loads for marketing and coordination. The IOUs can interface directly with the loads to market these programs, take bids, aggregate Demand, dispatch the Demand at the ISO's direction, and meter and validate the performance of the Demand response. The ISO looks to the CPUC to provide leadership for the utility-led programs. If the CPUC does not provide this leadership, but if the CPUC is willing to support the IOUs facilitating, aggregating and settling ISO Demand response programs, the ISO could move forward with Demand response programs for 2002.

D. ISO COMMENTS IN THE COMMISSION'S OCTOBER 29, 2001 TECHNICAL CONFERENCE ON WEST-WIDE PRICE MITIGATION

The ISO participated in the Commission's October 29, 2001 Technical Conference on West-Wide Price Mitigation[11] and filed additional written comments on November 9, 2001. The ISO urged the Commission to:

- leave price mitigation in place at least through September 30, 2002;
- extend the must-offer obligation to decremental Supplemental Energy bids;
- eliminate the 10% creditworthiness adder;
- ensure that any new procedures for setting the west-wide price limit be symmetrical (i.e., ensure that the price limit can go down as well as up).

E. October 23 Outage Coordination Order

The Commission's October 23, 2001 Order "Accepting in Part and Rejecting in Part Portion of Compliance Filing Related to Outage Coordination" directed the ISO to report questionable outages to the Commission within seven days. The ISO filed conforming Tariff changes on November 7, 2001. The ISO will monitor the effectiveness of these changes and report its findings to the Commission in future quarterly reports.

[11] EL01-68-000.

F. Creditworthiness Issues

Creditworthiness issues have affected greatly California's electricity markets since the Commission's April 26 Order was implemented on May 29, 2001. On November 7, 2001, the Commission issued an Order "Granting Motion Concerning Creditworthiness Requirement and Rejecting Amendment No. 40" ("November 7 Order"), which directed the ISO to (1) enforce its Tariff billing and settlement procedures, especially in regards to the CDWR; (2) invoice CDWR for all ISO transactions made on behalf of SCE and PG&E from January 17, 2001 forward; (3) file a report indicating overdue amounts from CDWR and presenting a schedule for repayment by February 7, 2002; and (4) rejected Tariff Amendment No. 40, which proposed returning to a "one-invoice" billing and settlement system to address inequities caused by Market Participants defaulting on their ISO invoices. The November 7 Order also conditioned the must-offer obligation imposed by the April 26 Order with an obligation for the ISO to pay those parties from which the ISO purchases energy.

On November 13, 2001, the ISO ceased providing CERS with the hourly aggregate MW and prices in the ISO's Real Time Imbalance Energy Market BEEP stack.

On November 16, 2001, ISO ceased providing CERS with the PG&E, SCE and San Diego Gas & Electric Company Hour-Ahead Schedules.

On November 20, 2001, the Commission issued an Order "Granting in Part and Denying in Part Complaint" ("November 20 Order"), which (1) found the

ISO in violation of its Tariff by allowing CDWR to engage in OOM transactions; (2) directed the ISO to post information on all OOM activities on the ISO web site; and (3) required CDWR to follow the ISO Scheduling and Billing Protocol when procuring energy on behalf of SCE and PG&E.

The ISO invoiced CDWR for amounts due from January 17, 2001 through July 31, 2001 on November 20, 2001. On November 21, 2001, the ISO filed a report detailing the ISO's compliance with the November 7 Order with the Commission. On November 30, 2001, the ISO ceased providing to CERS information on:

a. Municipal utilities' Hour-Ahead Schedules;

b. Hourly Direct Access Load;

c. ISO forecasted Load for each Investor Owned Utility;

d. Average Hourly BEEP Stack volume and costs, including both incremental and decremental bids and prices;

e. Real Time OOM volume and average OOM prices;

f. Daily Energy purchases (i.e., total cost by Hour and Day);

g. Hour-Ahead and Day-Ahead Congestion volume and clearing prices; and

h. Hour-Ahead and Day-Ahead Ancillary Services volume and clearing prices

The ISO now posts information pertaining to (a), (b), (c), (e), (f), and (h) on its Home Page or Open Access Same-Time Information System ("OASIS").

The ISO was already posting information pertaining to (d) and (g) on its Home Page.

On December 3, 2001, the ISO began publishing each IOU's actual Hourly Load and the ISO-forecasted Hourly IOU Load on its OASIS system. The ISO also began publishing the projected hourly Imbalance Energy requirement one hour before real time.

On December 6, 2001, the ISO received in full the first scheduled payment for amounts owed by CDWR.

On December 12, 2001, the ISO ceased providing CERS with the ISO-forecasted IOU net short position in the BEEP Stack, and CERS ceased making OOM purchases.

On December 14, 2001, the ISO received in full the second scheduled payment for amounts owed by CDWR.

The ISO hopes a return to a transparent, fully funded, and non-preferential market will enhance market participation, laying the groundwork for an eventual return to workably competitive markets that may not require the prescriptive price mitigation rightfully imposed by the Commission in the April 26 and June 19 Orders.

G. CONCLUSION

The ISO thanks the Commission for the opportunity to comment and report on the progress being made to stabilize the California electric market.

Respectfully submitted,

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Dated: December 14, 2001

Month	Month Total MW[12]	Developer	Project	Estimated Parallel Date[13]	Estimated Commercial Operations Date	MW
September 2001	40					
		Alliance Colton LC	Century	9/1/01	9/15/01	40.0
October 2001	71					
		Cal Peak	Enterprise	9/29/01	10/15/01	49.0
		PG&E National Energy Group	Mountain View II (Seawest)	9/15/01	10/15/01	22.0
November 2001	102					
		Cal Peak	Border LLC	10/17/01	11/5/01	49.0
		Spartech Plastics	Spartech Plastics		11/15/01	3.8
		Wellhead	Panoche	11/19/01	11/19/01	49.0
December 2001	537					
		Calpine	Gilroy Energy Center, Units 1 & 2	12/4/01	12/5/01	97.4
		Cal Peak	Panoche	12/5/01	12/8/01	49.0
		Wellhead	Gates	12/14/01	12/14/01	46.0
		Calpine	Gilroy Energy Center, Units 3 & 4	12/12/01	12/15/01	48.7
		Energy Transfer-Hanover Ventures LP	Midsun Generation Facility	12/17/01	12/20/01	22.0
		Calpine	King City Energy Center, LLC	12/14/01	12/21/01	48.5
		AES	Huntington Beach 3	12/12/01	11/2/01	225.0

[12] Based on estimated parallel date.
[13] Parallel date is the date the unit is first synchronized and delivering power to the grid, not the date commercial operation is declared.

Month	Month Total MW[12]	Developer	Project	Estimated Parallel Date[13]	Estimated Commercial Operations Date	MW
		Jefferson Smurfit Corporation	Smurfit Stone Container Corp	11/1/01	12/1/01	
January 2002	274					
		Cal Peak	Midway LLC	1/31/02	1/31/02	49.0
		AES	Huntington Beach 4	1/2/02	11/16/01	225.0
February 2002	261					
		Whitewater Energy Corporation	Whitewater Hill Wind Project	2/15/02	2/15/02	66.0
		Calpine	Watsonville Energy Center 1		2/28/02	146.0
		Cal Peak	El Cajon LLC	2/21/02	12/30/01	49.0
March 2002	238					
		Calpine	Gilroy Peaker, phase 2		3/1/02	146.1
		Cabazon Wind Partners	Cabazon Wind Generation	3/1/02	2/15/02	42.9
		Calpine	Calpine Greenleaf #2/Yuba City		3/1/02	48.5
April 2002	1,384					
		PG&E NEG	La Paloma Generating Project, Unit 1	2/20/02	4/1/02	255.0
		Calpine	West Sacramento Peaker		4/1/02	97.4
		Calpine	Delta Energy Center	2/15/02	4/1/02	880.0
		Permanente Corporation	Permanente Power Plant Martell		4/15/02	49.9
		Valero Refining Company -- California	Benicia Cogeneration Unit 1 and 2	4/1/02	3/30/02	102.0
May 2002	841					
		El Dorado Irrigation District	El Dorado Power House		5/1/02	21.0

Month	Month Total MW[12]	Developer	Project	Estimated Parallel Date[13]	Estimated Commercial Operations Date	MW
		Calpine	Los Esteros Critical Energy Facility		5/1/02	195.0
		Sempra Energy Resources	Elk Hills Generating Project	4/1/02	5/15/02	320.0
		PG&E NEG	La Paloma Generating Project, Unit 2	4/1/02	5/15/02	255.0
		ESA Holdings	21st Century Banning Project #2, Phase 1		5/1/02	49.6
June 2002	1,725					
		GWF	Henrietta Peaking Project		6/1/02	95.8
		Capitol Power	Ione Energy Repower		6/1/02	16.3
		PurEnergy	Kingsburg Peaker		6/1/02	50.0
		Cummins West	Cummins Diesel Peaking Project		6/1/02	88.0
		PowerCom	Mojave 1		6/1/02	15.0
		Texaco California Inc	South Star I		6/1/02	129.5
		PowerCom	Tehachapi 1		6/1/02	7.5
		Ameresco	Port of Sacramento		6/6/02	240.0
		PG&E NEG	La Paloma Generating Project, Unit 3	5/1/02	6/15/02	255.0
		Calpine	Watsonville Energy Center 2		6/18/02	48.7
		Cabrillo II (Dynegy)	(Multiple Projects)		6/30/02	583.0
		Panda West	Panda West 1	6/30/02	6/30/02	49.0
		Panda West	Panda West 2	6/30/02	6/30/02	49.0
		Panda West	Panda West 3	6/30/02	6/30/02	49.0
		Cal Peak	Mission LLC	6/6/02	2/28/02	49.0

Month	Month Total MW[12]	Developer	Project	Estimated Parallel Date[13]	Estimated Commercial Operations Date	MW
July 2002	1,548					
		GWF	Tracy Peaking Project Phase 1		7/1/02	184.0
		Duke Energy	Moss Landing Generating Project, Unit 1	3/15/02	7/13/02	530.0
		Duke Energy	Moss Landing Generating Project, Unit 2	4/15/02	7/13/02	530.0
		PG&E NEG	La Paloma Generating Project, Unit 4	6/1/02	7/15/02	255.0
		Calpine	Feather River Energy Center		7/1/02	48.7
August 2002	511					
		JD. DiNapoli	Spartan Energy Plant		8/1/02	100.0
		Spartan Power, LLC	Spartan Milpitas Energy Plant		8/1/02	96.0
		Intergen	La Rosita Expansion Project	8/1/02	8/12/02	315.0
September 2002	1,290					
		FPL	FPL Highwinds		9/9/02	150.0
		Sepmra Energy	Imperial Valley		9/9/02	600.0
		North American Power Group	Kern Power Plant Re-Powering		9/9/02	160.0
		Enerconnect	EnerConnect		9/9/02	380.0
December 2002	1,152					
		FPLE LLC	Wind Project (Windridge)		12/31/02	19.8
		Mountainview/AES	Mountainview Power Project		12/1/02	1132.0
TOTAL	9,972					

CALIFORNIA ISO

California Independent
System Operator

December 14, 2001

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: San Diego Gas & Electric Company, Complainant v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents, Docket No. EL-00-95-012; Investigation of Practices of the California Independent System Operator and the California Power Exchange, docket Nos. EL00-98-000; California Independent System Operator Corporation, Docket No. RT01-85-000; and Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in Western Systems Coordinating Council, Docket No. EL01-68-000

Dear Secretary Boergers:

Enclosed for electronic filing in the above captioned proceeding is the Second Quartely Report of the California Independent System Operator Corporation. In its April 26, 2001 Order, the Commission stated comments on this report are due 15 days from filing.

Thank you for your assistance in this matter.

Respectfully submitted

Margaret A. Rostker
Counsel for the California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010)

Dated at Folsom, California, this 14th day of December, 2001

____

Margaret A. Rostker
Counsel for the California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom, CA 95630