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. EL00-95-012, *et al***

FIRST 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.[1] In the April 26 Order, the Commission required the California Independent System Operator Corporation ("ISO")[2] to submit the following:

> 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,

---

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) ("April 26 Order").

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.

Establishing West-Wide Mitigation, And Establishing Settlement Conference."[4] In this order, the Commission renewed the requirement that the ISO submit quarterly reports to address, 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." In such 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. The results addressed in that filing have not changed substantially and no new analysis is available. A copy of those comments are provided as Attachment A. The ISO will update these analyses in its next quarterly update.

This report responds to the remaining issues in the Orders. It is organized as follows:

- Section I reports on new generation; and
- Section II describes demand response initiatives.

I. NEW GENERATION

As recognized by the ISO early last year and the Commission beginning in

---

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) ("June 19 Order").

5 June 19 Order at 62,567.

its December 15, 2000 order in this proceeding, adequate generating capacity is a critical feature of any successful restructuring initiative. Absent sufficient capacity reserves, strategically positioned suppliers can exercise market power through either physical or economic withholding and can drive spot market electricity prices to untenable levels.

Thus, beginning in the summer of 2000, the ISO undertook certain initiatives to address California's resource deficiency problem. First, in August 2000, the ISO issued an "Action Plan" that called for major and immediate steps to be taken with regard to the development of new generation, transmission investment, and demand response programs.[6] The ISO's plan, among other things, outlined three major proposals designed to address, in part, the generating resource deficiency in California:

(1) issue a request for bids for new peaking capacity that can be brought on-line by Summer 2001;

(2) develop a CASIO Outage Coordination Plan to ensure that planned outages for all existing and available generation are coordinated to ensure maximum availability of that generation, especially during peak periods, and to prevent physical withholding of such generation; and

(3) develop and file at FERC, a new generation interconnection policy that facilitates the entry of new market-based generation into the California and Western U.S. markets.

In addition to the ISO programs, the State of California undertook accelerated programs via Executive Orders of the Governor allowing the Energy Commission and the local Air Quality Management Districts to facilitate development of new generation for California as soon as possible. Each of these initiatives are

---

[6] In addition, the State of California passed Assembly Bill 970 (AB 970) whose

discussed in additional detail in the following sections.

While it is premature to assess the success of each of these programs, the ISO believes that these programs represent a significant step forward and address certain significant deficiencies of the California market. As both the Outage Coordination Plan and the New Generation Interconnection Policy are currently pending before the Commission, the ISO urges the Commission to expeditiously approve these proposals so that California can continue the work of stabilizing and reinvigorating the electricity market in the West.

A. ISO Summer 2001 Reliability Generation Program

1. Summary

Due to the control area-wide generation deficiency experienced throughout the summer of 2000, on August 24, 2000, the ISO issued a Request For Bids for Summer Reliability Generation ("RFB"). This RFB sought up to 3,000 MW of new generation within the ISO Control Area to provide additional peaking generating capacity to allow the ISO to operate the ISO Control Area to meet Applicable Reliability Criteria under peak demand conditions during summer periods. In response to the RFB, the ISO received seventy-nine proposals from twenty-four respondents on September 25, 2000. Ultimately the ISO contracted for 30 projects with a total capacity of 1,324.1 MW. The three-year contracts (the "Summer Reliability Agreements" or “SRAs”) entered into between the ISO and the project developers were structured such that the ISO has the right to call the unit for 500 hours from 10:00 a.m. to 8:00 p.m. beginning

---

purpose was to facilitate the siting of new generation and transmission in California.

on the later of June 1 or the facility's Commercial Operation Date and ending October 31 of each year. If the ISO dispatches the unit, the owner is required to find a buyer for and schedule the Energy from that unit in the forward markets, if possible. The SRA payments are a guarantee that the unit will be built and available for dispatch. They are not payments for Energy or Ancillary Services.

With the onset of the financial challenges in California, in particular the degradation of the credit ratings of the State's investor owned utilities and the ISO, a number of the summer reliability projects negotiated contracts with the California Department of Water Resources and terminated their SRAs with the ISO. Three of the remaining SRA units have obtained Commercial Operation as of September 1, 2001 for a total capacity of 96.51 MW.

2. Summer Reliability Agreement

Important features of the *Pro Forma* SRA issued with the RFB included:

- Three year terms beginning in 2001;
- An ISO right to call on the generation up to 500 hours each summer season (June 1 - October 31) in exchange for a fixed capacity payment;
- A requirement that the generation be scheduled in the forward markets to the extent possible;
- No provision for any variable payment for the energy the ISO dispatched. Consistent with the approach discussed below, the generator owner was to sell the energy into the markets (either through an exchange like the California Power Exchange Corporation or to another market participant via a bilateral arrangement); and
- The right of the owner to operate in the market of its own accord and keep the resulting market revenues. This would allow the generator Owner to earn Ancillary Service capacity revenues (so long as the ISO did not call on the energy from that capacity for reliability needs) as well as revenues from energy sales not associated with providing Ancillary Services. The ISO would reimburse the generator owner for imbalance energy charges

incurred if the ISO reduced the unit's output after it had been scheduled in the forward markets.

Costs associated with SRAs are recovered by the ISO as indicated in Section 2.3.5.1.8 of the ISO Tariff - Scheduling Coordinators are charged the costs based on, in each hour in the Summer Period (June 1- October 31), the ratio of the SC's metered Demand and exports to total ISO metered Demand and exports. This cost recovery approach is appropriate since the agreements would provide a reliability product to the ISO that would be beneficial to the entire ISO Control Area. The draft SRA was attached to the RFB to guide the respondent in structuring their bids.

3. Request for Bid Process

The initial RFB was released on August 24, 2000 and responses to the RFB were due on September 25, 2000, with the stated ISO intent of selecting winning respondents, if any, by October 4. This "fast-track" schedule was adopted to afford successful respondents as much time as possible to deal with siting, permitting and construction issues following their selection.

While the ISO requested bids for one-year agreements in the initial RFB, it indicated that bids for two and three year summer period commitments would be considered. The vast majority of responding bids were for three and five year commitments.

The total response to the initial RFB is shown in Table 1:

Table 1 - Summary of All Proposals Received

Population	Proposals	MW	Estimated Total Annual Cost* $ Millions	Average Cost $/kW	Low Cost $/kW	High Cost $/kW
All proposals	79	4,474	$950	$208	$41	$479

** In all the Tables, "Estimated Total Annual Cost" represents an estimate of the year 2001 costs based on the bids received*

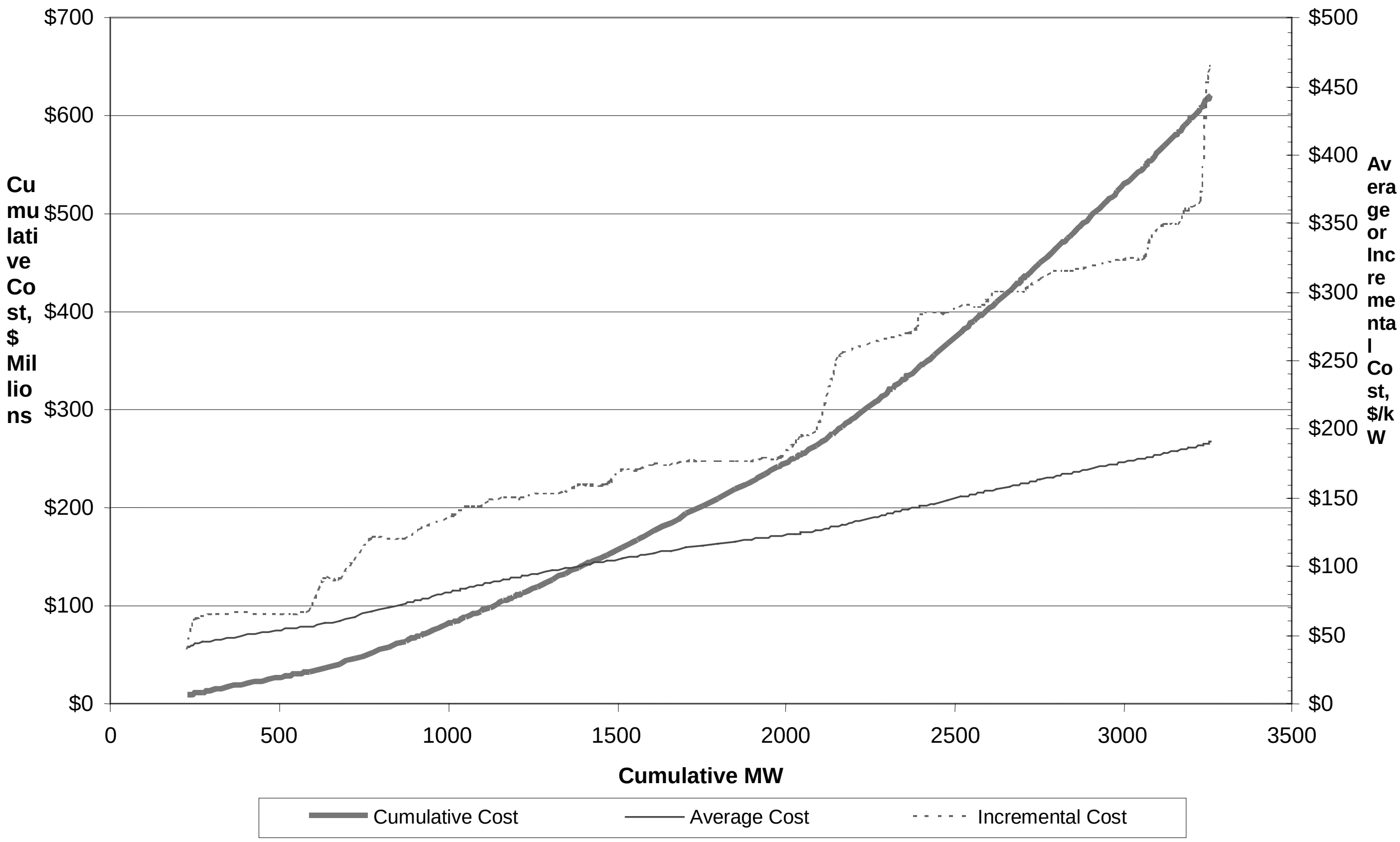
Management screened the responses to remove those that: (1) did not contain sufficient detail to allow meaningful review; and (2) offered projects that could not be brought on-line in time to meet the ISO's Summer 2001 reliability needs. The result of this screening is shown in Table 2:

Table 2 - Summary of Responsive Proposals

Population	Proposal s	MW	Estimated Total Annual Cost $ Millions	Average Cost $/kW	Low Cost, $/kW	High Cost $/kW
Screened Proposals	69	3,257	$621	$191	$41	$465

The following graph shows cumulative, average and incremental costs for the 69 projects summarized in Table 2. Projects were ranked from least expensive to most expensive. Cumulative year 2001 costs associated with the initial RFB responses (in millions of dollars) for a given MW total can be found at the intersection of the bold solid line and the left Y axis. Average costs for a given MW total (in dollars per kilowatt of installed capacity) can be found at the intersection of the solid narrow line and the right Y-axis. The incremental cost of the last project at a given MW total (in dollars per kilowatt of installed capacity) can be found at the intersection of the dotted narrow line and the right Y-axis.

Graph 1 - Cumulative, Average and Incremental Cost
Summer Reliability Generation
All Responsive Proposals



The 69 proposals shown in Table 2 break down by service area, fuel and technology as follows:

Service Area*	Units	2001 MW
MID	2	9
NCPA	1	45
APS	1	225
PG&E	341	2,360
SCE	13	131
SDG&E	9	285
SMUD	1	44
Hetch Hetchy	2	44
SVP	8	114
TOTAL	378	3,257

Fuel	Units	2001 MW
Diesel	118	275
Natural Gas	259	2,757
Unknown	1	225
TOTAL	378	3,257

Technology	Units	2001 MW
CT	72	2,284
Reciprocating Engine	305	718
Steam Turbine	1	30
Purchased Power	0	225
TOTAL	378	3,257

* Key:

MID = Modesto Irrigation District
NCPA = Northern California Power Agency
APS = Arizona Public Service Company
PG&E = Pacific Gas and Electric Company
SCE = Southern California Edison Company
SDG&E = San Diego Gas & Electric Company
SMUD = Sacramento Municipal Utility District
Hetch Hetchy = City and County of San Francisco, Hetch Hetchy Project
SVP = Silicon Valley Power (City of Santa Clara)

4. Benchmark Costs and Analysis

As part of the process of evaluating the responses to the RFB, the ISO developed a benchmark for proposal reasonability. Using cost information supplied by its generation consultant and cost recovery techniques supplied by a Utility Distribution Company, the ISO calculated a benchmark cost of $125/kW for a hypothetical 47 MW combustion turbine with $3 Million of interconnection costs, no net market revenues, and a 16.6% rate of return over a fifteen year term.

Presuming no net market revenues is a conservative assumption. The SRA permits generators to participate in markets as long as such participation does not impact the reliability services the ISO seeks under the agreement. Moreover, projects will derive revenues from the sale of Energy associated with contracted capacity when such capacity is dispatched by the ISO.

Additional criteria the ISO used in evaluating the proposals included the following:

- **Operation Date:** Could the new generation project meet the June 1, 2001 proposed Commercial Operation Date, or was the project proposed to be completed after the summer of 2001.

- **Contract Terms:** Did the developer request substantial deviations from the terms and conditions of the pro forma SRA.

- **Fuel capabilities:** While many large mobile diesel-powered generators are operating under statewide permits, the California Air Resources Board has opined that such mobile permits were not intended to cover the use of such generators as stationary sources. Such generators may still seek local permits, but the ISO was concerned about such prospects for licensing given that diesel emission particulates were recently declared to be carcinogens.[7]

- **San Diego Gas Limitations:** Constraints in SDG&E's gas transmission system may affect new projects' reliability of gas supply during peak summer

[7] During the summer of 2000, the ISO has been a part of a cross-organizational team comprising the US Environmental Protection Agency, California Energy Commission, local Air Quality Management Districts (AQMDs), and the California Air Resource Board (CARB). The charter of this team is to identify and eliminate barriers towards the resolution of the electric supply adequacy issue in California. In the spirit of committed collaboration, and to seek guidance on the environmental feasibility of the projects submitted in response to the RFB, the ISO shared non-sensitive response information with the local AQMDs and CARB. The districts had expressed significant concern regarding the installation and the permitting difficulties associated with diesel-fired generators in California. From the AQMD viewpoint, gas-fired generation with appropriate controls is more desirable than diesel units. The air districts are committed towards working with the owners of the facilities to expedite the permitting process while still preserving the environment and upholding the regulation.

electrical conditions.

- **Respondents Concerns:** The analysis showed that the bulk of the responses offered prices higher than the $125/kW benchmark calculated by the ISO. Respondents cited the following issues as justification for the offered prices:

  - **Market risk**. Respondents expressed concern about uncertainties over the future direction of price caps in the ISO's markets, citing the risk of reduced price caps as a reason for higher bids.

  - **Fuel price**. The price of natural gas has doubled from early 2000 to the time the RFBs were due in September.

  - **Fast-track, short-term, high-risk projects**. These projects incur more risk and therefore warrant more return.

  - **Emissions**. In some markets, emissions costs have increased from 75 cents per pound of NOx to more than $40 per pound of NOx, and the restrictions are tightening in future years.

  - **Low PX price**. One respondent pointed out that prices in 2000 may be an aberration and these projects could be at significant risk if PX prices return to pre-Summer 2000 levels.

Subsequent to the initial bidding process, the ISO initiated a subsequent solicitation inviting those parties that had previously submitted Summer Reliability Generation RFB responses to re-submit price offers over three, five and eight year terms. The ISO also invited respondents to re-examine any conditions they may have placed on there initial bids, and, if possible, remove them in their re-submitted bids. Some of the bids included time constraints that the ISO had to select them by September 30, 2000. The ISO requested those parties otherwise not change their previously submitted bids.

5. ISO Governing Board Process

On October 17, 2000, the ISO Governing Board determined that the ISO should negotiate agreements for the initial 3-year term. The ISO subsequently negotiated 30 agreements that are currently owned by 10 generation developers for a total of 1,324.1 MW as follows:

SRA	Site	Contract MW
Alliance	Colton (Drews)	40
Alliance	Colton (Century)	40
Cal Peak (DG)	Border	49
Cal Peak (DG)	El Cajon	49
Cal Peak (DG)	Escondido	49
Cal Peak (DG)	Midway	49
Cal Peak (DG)	Mission	49
Cal Peak (DG)	Panoche	49
Cal Peak (DG)	Vaca Dixon	49
Harbor Cogen	Harbor Cogen	30
NEO	Chowchilla	48.6
NEO	Red Bluff	48.6
NRG	Round Mountain	43
Panda West 1	Suisin City	49
Panda West 2	Suisin City	49
Panda West 3	Suisin City	49
RAMCO	Chula Vista	44
RAMCO	East Livermore	49.5
RAMCO	Escondido	44
RAMCO	Pleasanton	49.5
Tejas 1	Larkspur	43
Tejas 2	Larkspur	43
Tejas 3	Indigo 1	43
Tejas 4	Indigo 2	43
Tejas 5	Indigo 3	45
Tenaska	Vaca-Dixon	49.9
Wellhead	Fresno	18
Wellhead	Gates	45
Wellhead	Panoche	45
Wellhead	Stockton	22

6. Current Summer Reliability Project Status

Due to the Energy crisis in California and the subsequent downgrade in the credit ratings of Pacific Gas & Electric Company ("PG&E") and Southern California Edison Company ("SCE"), and the concomitant inability of the ISO to act as a creditworthy counter-party to the SRAs, the ISO sent copies of all the agreements to the California Department of Water Resources ("CDWR") in the hope that CDWR would act as a counter-party and ensure that the SRA generation would be on-line by Summer 2001. CDWR was authorized under state legislation to purchase the net short position of the investor-owned utilities. It was hoped that if the SRAs were converted to CDWR agreements, the financial longevity of the program would be certain. As of September 1, 2001, CERS has executed agreement with 17 of the original projects.

One project voluntarily was terminated in April 2001, leaving 11 projects still under contract with the ISO. Of these projects, four have reached Commercial Operation and are available for dispatch. The operational projects are as follows:

SRA	Site	Contract (MW)	Test (MW)	Commercial Operation Date
NEO	Chowchilla	48.60	48.60	6/13/01
Harbor Cogen	Harbor Cogen	30.00	17.91	6/15/01
NEO	Red Bluff	48.60	41.50	8/11/01
RAMCO	Chula Vista	44.00	37.10	8/23/01
	Total	171.20	145.11	

B. Outage Coordination Plan

As a result of inadequate infrastructure investment over the last few years (both generation and transmission) the ISO began an initiative to better coordinate generating plant outages. In addition to the basic need to improve the coordination of scarce resources, suppliers were able to exercise market power through strategic withholding of their resources. Such withholding took both the form of physical withholding (e.g., declaring units unavailable due to forced/unplanned outages) and economic withholding (e.g., bidding capacity and energy at excessive prices – prices far in excess of marginal cost). In order to prevent such strategic withholding the ISO identified the urgent need for: (1) better planned outage coordination in order to maximize the available of generation in California; and (2) the development of availability standards to provide incentives for generators to minimize unplanned outages.

In the November 1 and December 15 Orders in this proceeding, the Commission recognized a need for better coordination of planned outages. In the April 26 Order, the Commission held that, "[t]he ISO must be provided the authority to achieve greater systematic control over all units (including those of the IOUs) that the ISO must dispatch, *i.e.*, those units that have signed PGAs [Participating Generator Agreements]."[8] Accordingly, the Commission directed the ISO to "make a tariff filing within 15 days of this order proposing a mechanism for coordination and control of outages, including periodic reports to the Commission, consistent with the discussion in this order."[9] On May 11, 2001, in compliance with the Commission's directive, the ISO filed, among other things, an Outage Coordination proposal with the Commission ("May 11 Filing").

In the May 11 Filing, the ISO proposed to apply the outage coordination

---

[8] April 26 Order at 61,355.

[9] *Id.*.

requirements currently applicable to RMR Units and transmission facilities forming part of the ISO Controlled Grid to all Generating Units owned by any Participating Generator.[10] As stated in that filing, the proposal will provide the ISO with the authority to approve or deny planned outages for all Participating Generators, on an annual planning basis, which will enable the ISO to coordinate the planning of outages of both generating and transmission facilities. The ISO continues to believe that this coordinated approach to Generator outage scheduling will reduce the need for Generator Maintenance Outages to be modified or rescheduled due to System Emergency conditions. Additionally, a better-coordinated generation outage plan will help to minimize resource shortages which are the primary cause for the System Emergencies experienced to date. Moreover, the ISO believes that the May 11 Filing will make explicit the requirement of Participating Generators to provide the ISO with timely explanations of Forced Outages, so that the ISO can report questionable outages to the Commission, as required by the April 26 Order.

Finally, as the ISO previously has informed the Commission, the State is considering legislation that would implement the coordination of outages of all Generating Units in California, both inside and outside the ISO Control Area. In addition, the Governor of the State of California has also issued an Executive Order on outage and maintenance issues. The ISO believes the May 11 Filing is compatible with the Executive Order and so permits the ISO to comply not only

[10] The RMR Settlement is terminated December 31, 2001. At that time, any party can file a 205 or 206 and can potentially substantially change the RMR contract requirements. Therefore, it is imperative that the Commission rule on the ISO's proposed outage coordination plan as soon as possible to allow the ISO to implement it, and to facilitate outage coordination

with the Commission's April 26 Order, but also the current and likely future State legislation. Nonetheless, if necessary to comply with State law, the ISO may file changes to its outage coordination proposal to fulfill any additional obligations imposed by State law.

In light of the continuing and urgent need for better coordination on planned generation outages, the ISO strongly urges the Commission to approve the ISO's proposed outage coordination proposal, as contained in the May 11 Filing. More importantly, as California moves into its critical generation maintenance period (i.e., the Fall/Winter months), it is imperative that the Commission empower the ISO to develop a comprehensive and well-coordinated generator maintenance plan that ensures that the maximum level of generation is made available to serve California load.

C. New Facility Interconnection Policy

The CASIO clearly recognizes that if California is to attract new generation to the state, it is essential that California develop a clear and consistent policy for interconnecting resources to the ISO Controlled Grid. Absent such a policy, critical new generating resources will find it difficult to determine the procedures and costs of interconnecting to the ISO Controlled Grid and may decide to locate outside of California. In addition, development and implementation of interconnection procedures will guarantee that, consistent with the Commission's open-access principles, each new facility is treated in an open and non-discriminatory manner. Finally, and most importantly, by clearly establishing the cost-responsibilities of new generators interconnecting to the grid, the ISO can

---

of all Generating Units in the ISO Control Area.

reduce the uncertainty and risk of developers and thereby facilitate development of new capacity in California. Thus, over the past two years, the ISO endeavored, along with Market Participants, to develop comprehensive procedures governing the interconnection of new generating facilities to the ISO Controlled Grid.

The Commission also recognized the critical need for new interconnection procedures. In its November 1 and December 15, 2000 orders in this proceeding, the Commission found that standard procedures to facilitate the interconnection of new generators (or existing generators seeking to increase the rated capacity) were needed and directed the ISO to file generator interconnection procedures no later than April 2, 2001. November 1 Order, 93 FERC at 61,364-65 and December 15 Order, 93 FERC at 62,015.

Based on the Commission's directive and the critical need to finalize the ISO's interconnection procedures, on April 2, 2001 the ISO, along with the Participating Transmission Owners in California, filed a "New Facility Interconnection Policy" or "NFIP" (Amendment No. 39 to the ISO Tariff). Amendment No. 39 represented a comprehensive revision to the interconnection provisions of the ISO Tariff. Previously, 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 proposed to define these requirements in the ISO Tariff.

The new requirements would apply to: (1) each Generating Unit that seeks to interconnect directly to the ISO Controlled Grid; (2) each existing Generating Unit directly connected to the ISO Controlled Grid that has been re-powered and increased the total capability of the power plant; and (3) each existing Generating Unit directly connected to the ISO Controlled Grid that has been re-powered without increasing the total capability of the power plant but has changed the electrical characteristics of the power plant such that its re-energization may violate Applicable Reliability Criteria.

Pursuant to proposed Amendment No. 39, the ISO would receive and process all applications for interconnections and would oversee the performance of all necessary System Impact and Facility Studies. In order to clearly identify the cost responsibilities for New Facility Operators, Amendment No. 39 provided that a New Facility Operator's final cost responsibility will be based on actual costs and that a New Facility Operator shall pay the costs of planning, installing, operating and maintaining the following facilities: (1) Direct Assignment Facilities, and, if applicable, (2) Reliability Upgrades. Direct Assignment Facilities include the costs of connecting the new facility to the ISO Controlled Grid.

Reliability Upgrade Costs include the cost of facilities remote from the interconnection point, such as breakers, needed just to interconnect a new facility. However, as proposed in Amendment No. 39, New Facility Operator's shall be responsible for the costs of Reliability Upgrades only if the necessary facilities are not included in the ISO Controlled Grid Transmission Expansion Plan. Finally, Amendment No. 39 does not propose 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. As noted in the ISO's April 2 filing, the ISO believes that such upgrades are appropriately addressed pursuant to the procedures set forth in Section 3.2 of the ISO Tariff, Transmission Expansion**.**

The ISO continues to believe that Amendment No. 39 represents a significant step forward in addressing California's generating capacity resource deficiency. Amendment No. 39 will establish clear guidelines and cost responsibilities for interconnecting new generation to the ISO Controlled Grid, thus facilitating the entry of critical new capacity into the market. The ISO urges the Commission to expeditiously approve the ISO's proposed New Facility Interconnection Policy.

D. California Programs

The following report includes new power plants adding to California's electricity supply from January to September 2001 (July figures include cumulative totals from beginning of year). It is based on information obtained from the California Energy Commission's ("CEC") 2001 Generation Progress Report and reflects generating capacities derated for summer operation. ISO agrees with these figures and is aware of additional resources that were added to the control area by connecting to the Western Area Power Administration. Therefore, inclusive in Table – 5 below are new WAPA System resources that were not reflected by the CEC. Additionally, future megawatts projected to come on-line in a given month are based on the progress in completing power purchase agreements, permits, interconnections, and construction.

Table – 5: 2001 Generation Progress Report
Estimated Megawatts On-line by Month, July - December

Project Category	July	Aug	Sept	Oct	Nov	Dec
Increase Output from Existing Power Plants	0	13	2	20	12	468
Accelerate Construction of Approved Power Plants	504	817	0	0	0	0
Develop New Power Plants	137	389	195	457	347	122
WAPA (Sutter)	500					
Monthly Total	**1,140**	**1,219**	**197**	**477**	**359**	**590**
Cumulative Total	**1,328***	**2,547**	**2,744**	**3,221**	**3,580**	**4,170**

* Cumulative from January 2001

II. Demand Response Programs

Demand Response Programs are vital for both grid reliability and proper market operation. The ISO first identified the need for development of Demand Programs after the summer of 1998, when Demand was identified as an untapped resource that could help resolve the shortage of Ancillary Services supply. Further additional demand resources would help to mitigate high prices in the markets, while also adding price elasticity to the load demands on the grid.

FERC has also recognized the need for Demand Programs, and has supported ISO initiatives in this area. Most recently, the FERC Orders of April 26, 2001, and June 19, 2001 both reinforce the need for development of demand response programs.

To address the need for Demand programs, the California ISO initiated an aggressive development campaign with the cooperation of load participants and aggregators to develop 3 separate programs, each attracting a different type of load resource. One program, the Discretionary Load Curtailment Program (DLCP) was designed specifically to attract smaller loads that previously have been unable economically to participate in a Demand program. This section outlines the development of the ISO programs, some of the obstacles and lessons learned, and their operation. While the market and financial events of early 2001 hampered the success of the programs, they provide valuable foundation for future development. Also included is a preliminary look at the operation of the programs during the summer of 2001. The next quarterly report in December, 2001 will provide a more in-depth analysis of 2001 program performance and recommendations for the future of the ISO Demand programs.

A. Introduction

To develop the Demand Programs, the ISO formed an internal team, the Participating Load Working Group. This team worked over two years in collaboration with market participants to develop 3 separate and distinct programs. The first was the Participating Load Program that allows loads to bid directly into the ISO Non-Spin and Replacement Reserve and Supplemental Energy markets. The second program, the Demand Relief Program, functions as a last-resort emergency tool to prevent blackouts. The third program developed at the ISO, the Discretionary Load Curtailment Program, was designed to attract smaller loads, such as commercial lighting and A/C loads. This program operates through aggregators and gives loads more discretion while also giving the ISO operators a firm load curtailment commitment.

The ISO programs attracted new offers for over 1,100 MW of participation for summer 2001, but the effectiveness of those programs was undermined by the events in early 2001.

This report describes the ISO Demand program initiatives, including a history of program development, impacts during the spring of 2001 from the California Public Utilities Commission ("CPUC") initiatives, issues associated with the lack of creditworthiness in the California markets, and the late spring 2001 development of a state-promoted Demand Bidding Program.

B. Background of ISO Demand Program Development

It is important to note the context of the ISO involvement and leadership in

Demand programs. In addition to the economic advantages of demand participation in the markets, the resource shortage in California further encouraged development of programs that would attract demand participation.

At its inception in 1998, the ISO had no programs in place to facilitate Load participation in its markets and no programs of its own for Demand reduction in the event of System Emergencies. In 1998, the primary Load participation in the state came from the IOU interruptible service customers. They served as a valuable emergency tool for the ISO operators, providing nearly 2000 MW of Load that could be interrupted during a Stage 2 System Emergency (Operating Reserve below 5%) to prevent further deterioration of Operating Reserve that could require rotating blackouts.

Several factors drove the ISO toward a more active role in encouraging Demand participation in the markets and ISO-administered emergency Demand reduction programs. As part of the Ancillary Service Redesign project that grew out of the summer 1998 operational issues, Demand response was identified as a key resource that could provide resources to the grid and also add price responsive resources to the market. Also at that time, the CPUC interruptible programs were operable only through March of 2002, and there was no guarantee regarding their future renewal by the CPUC. The ISO believed that it should pursue alternatives and gain experience with managing emergency Demand reduction programs before the interruptible resources were terminated. Other entities in the state looked to the ISO to develop these new programs, as a part of the ISO's role in managing the grid, and because of our proven track record of quickly developing and implementing programs. As development progressed, it became more obvious that Demand response also played an important economic factor in the markets, with the promise of mitigating high prices by providing added resources.

C. Participating Load Program

Early in 1999 the ISO initiated a dialogue with Market Participants to develop the Participating Load Program ("PLP"). The program evolved to one that would allow Loads to provide Non-Spinning and Replacement Reserve and Supplemental Energy bids. (At this time, 10-minute markets were not yet in effect.) A key design element in early development was putting Participating Loads on a par with Participating Generators. This foundation turned out to be very restrictive, especially given the metering, telemetry, and dispatch requirements applicable to Participating Generators.

In October of 1999, the ISO Governing Board identified Participating Loads as a high priority as part of the ISO Market Redesign 2000 project, and urged ISO management to pursue Load participation aggressively. In response to this, the ISO created a special Participating Load Working Group to finalize the Participating Load Program and to expand Load responsiveness in California. The ISO filed the facilitating document, the *pro forma* Participating Load Agreement, with FERC in December 1999.

At this same time (December 1999 - January 2000) the 10-minute markets were emerging as a key part of the ISO's market redesign to manage uninstructed deviations. Feedback from stakeholders representing Loads indicated that the 10-minute settlement would jeopardize significant Load participation in the ISO's forward capacity and real-time markets. Additionally, the CPUC prohibited interruptible customers from participating in the ISO's Participating Load Program. This restriction constrained the development and recruitment into the program for small industrial customers.

In an effort to reduce the barriers to Load participation in the ISO's markets, the ISO developed a Technical Standard providing some additional flexibility for ISO market participation by Participating Loads beyond that available to Participating Generators. At this time, there was no off-the-shelf technology to provide the needed telemetry for aggregation of Loads. However, as a result of the PLP implementation effort this technology was developed. In addition, to address issues with financial risks, the ISO filed an amendment to the ISO Tariff in Amendment 29 to provide Participating Loads a partial waiver of the ISO Tariff's "No Pay" penalties.

However, the ISO's efforts to facilitate ISO market participation were not sufficient to overcome the barriers to market participation faced by most Loads. Consequently, large pumps serving the State Water Project have remained the primary providers of Load participation in the ISO's markets.

To assess performance of the load participation, the ISO studied HE16 during the summer of 2000. Non-Spin purchases from load reached a peak in August, averaging 502 MW. Replacement reserve purchases averaged 10 MW. Supplemental Energy purchases reached a peak in September of 103 MW. Performance during 2001 is expected to be somewhat lower due to water conditions.

D. Trial Summer 2000 Demand Relief Program

With ISO Governing Board encouragement and the various participant concerns with the Participating Load Program, the ISO Participating Load Working Group embarked on development of a new program, the Demand Relief Program ("DRP").

A workshop with over 100 participant attendees was held on Feb. 22, 2000 to focus on development of the DRP, which evolved into an emergency operating tool, similar to the investor-owned utility interruptible programs. At this time, the ISO decided to focus on a trial program for the summer of 2000, to expedite a workable program.

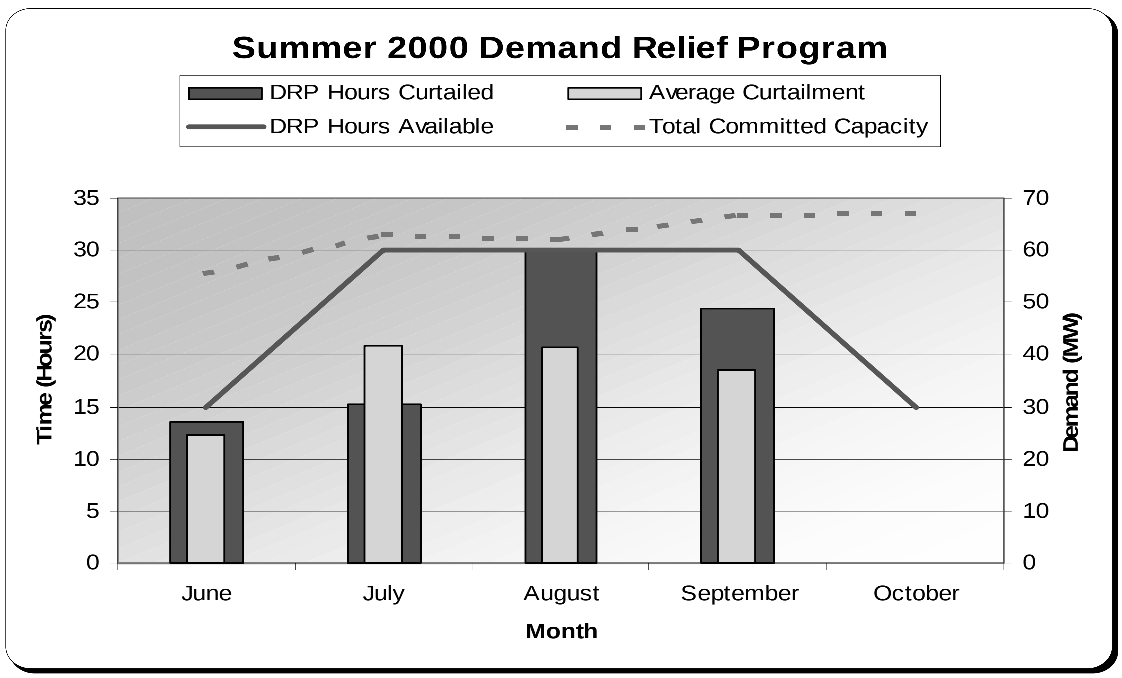
The trial Summer 2000 Demand Relief Program was approved conceptually by the ISO Governing Board in March, 2000. Key parameters of the trial Summer 2000 Demand Relief Program were:

- Program Operation – June 15, 2000 to October 15, 2000.
- Dispatchable for 2-8 hours in a day, up to 30 hours per month
- Dispatchable just prior to curtailment of interruptible loads (intended to provide more experience with the program)
- Pricing: A reservation payment, based on individual aggregator bids plus the Energy payment that flowed as a result of the Imbalance Energy created by the Demand reduction. (The Loads would gain the benefit of the imbalance price through the normal settlement system.)
- Cost allocation: Because of the system-wide benefit, costs allocated to all Scheduling Coordinators (SCs) based on metered Demand and exports.

E. Summer 2000 DRP Results and Lessons Learned

The Summer 2000 DRP request for bids ("RFB") attracted 180 MW of bids that were accepted by the ISO, at an average cost of $36,000 per MW-month. Although reservation prices were higher than desired, it was hoped that it would provide valuable experience to move forward with improved programs. Approximately 65-70 MW of Load ultimately entered into contracts to participate in the program by the end of the summer.

The chart below depicts the performance of the trial program during 2000.



A key lesson learned from the trial DRP involved pricing and payment. The capacity auction process produced high prices. Also, because bids weren't required to be Load-specific, there seemed to be a tendency for aggregators to contract with Loads to fill higher-priced bids first. The Energy payment was also a problem. Including the energy payment as part of the normal settlement process made it difficult for the SCs to disaggregate the DRP participation from other Energy settlements in their portfolio. Further complicating the Energy settlement was the change in price caps. During the summer of 2000 the market price caps were reduced first from $750 to $500 and later to $250. DRP participants assumed that they would be paid at the cap during a Demand reduction call because at the point of a call the ISO would be in a Stage 2 System Emergency, meaning all market bids would have been exhausted. As a result of this experience, the Summer 2001 DRP was designed with a preset capacity payment and a separate fixed Energy payment that operated outside the normal imbalance energy settlement process.

Another lesson learned from the summer 2000 development was to start much earlier to finalize the Summer 2001 program. The initial schedule set the stage for Governing Board approval of the Summer 2001 DRP no later than November 2000, giving participants December and January to market the program and provide bids that would be approved by the Governing Board in February 2001. This schedule would provide the aggregators more time to communicate and market the program, and also to finalize preparations, metering installations, contracting, etc. once the bids were accepted in February.

F. ISO Action Plan to Accelerate Generation, Transmission, and Demand Response in California, Submitted to the Governor's Office August 10, 2000 and Real Time Pricing

In July of 2000, the ISO developed a comprehensive list of "proposals" to help resolve the state's electrical crisis, some within direct ISO control, but many under the control of others. The list of proposals was submitted to state offices and the ISO Governing Board on August 10, 2000 and was entitled "ISO Action Plan to Accelerate Generation, Transmission, and Demand Response in California." The ISO used this Action Plan for 12 months as a high-level outline and provided regular updates to the ISO Governing Board and state officials on progress. However, the recommendations in the report have not been fully implemented.

One recommendation in the ISO Action Plan, not covered elsewhere in this report is the topic of Real Time Pricing. The California Energy Commission has led a long-term campaign to provide the metering and the direction to implement Real Time Pricing. The issue is under consideration before the CPUC.

G. Summer 2001 Demand Relief Program

Based on the Summer 2000 trial program, the ISO worked extensively during the Fall of 2000 internally and with Load participants, aggregators, and the investor-owned utilities to finalize the Summer 2001 DRP design. The ISO Governing Board approved the new design at its monthly meeting in November, 2000. The Summer 2001 DRP incorporated the following elements:

1. <u>Dispatch of the DRP after Interruptible Loads and before Stage 3</u> (A change from the Summer 2000 trial program, which was called just before the interruptible loads.) This was based on favorable feedback from local air quality regulation officials that could allow operation of back-up generators (BUGs) as a last resort before rotating outages Also, the proposed timing of the program would attract Load participation that could tolerate the lower expected frequency of calls just prior to Stage 3.
2. <u>Two Tier Program</u> – The first tier of the program consisted of Loads *without* back-up generators, and the second tier consisted of Loads *with* back-up generators. To match environmental requirements, the back-up generator portion of the program would be called after the first tier and be utilized as the last resort prior to rotating blackouts.

3. Program Operation – June 1 through September 30 (After initial approval, the ISO Governing Board authorized operation on a voluntary basis in May and October also.)

4. Cost Allocation – Similar to the summer 2000 program, the allocation was made to all Scheduling Coordinators (SCs) based on metered Demand and exports, reflecting the system-wide benefit of preventing rotating blackouts.

5. Two-part Payment Structure – A fixed monthly capacity reservation payment of $20,000 per MW, adjusted based on actual average monthly performance, and a performance Energy payment of $500/MWh for each curtailment.

6. Eligibility - Loads that were provided retail electric service pursuant to an interruptible rate schedule in 2000 prior to November 1, 2000 would not be allowed to participate in the Summer 2001 program. (This requirement was made to prevent simple migration of Loads from interruptible programs to the Demand Relief Program.)

At this point in time (December 2000 – January 2001), it is important to note broader events that influenced the development of Demand programs in California. The CPUC had initiated a Rulemaking proceeding on the interruptible tariffs in October, 2000. The markets went through difficult times in December and January as a result of a high level of Generating Units on outages and gas prices that had risen, for example, from $3 to $50. In light of the predictions of electricity shortages at that time, the CPUC expanded its proceedings to promote the introduction of more Demand programs. In January 2001 there were several Stage 2 and 3 System Emergencies, including rotating blackouts on January 11 and 12, 2001. Because of the north-south resource mix and Path 15 constraints, Northern California was hit harder than Southern California. (The PG&E interruptible Loads, considered to be a summer operational tool, were totally exhausted for the year before the end of February 2001.) At the January ISO Governing Board meeting, the ISO was encouraged to finalize the Discretionary Load Curtailment Program that was under development and to explore operation of the programs outside the summer months.

The response to the Demand Relief Program RFB in February 2001 was very encouraging. Bids were received totaling 590 MW. The ISO Governing Board approved the recommendation to accept those bids and directed ISO management to issue another RFB. The second RFB produced 540 MW, which were approved by the Governing Board in April. At this point, the ISO estimated that 700 MW would be ultimately be available through both DRP RFBs, allowing for some shrinkage that occurs during contract negotiation and implementation. A third RFB was in preparation when the creditworthiness issues prevented further solicitations.

H. Involvement of Back-Up Generators

Back-up generators were a major focus of the Summer 2001 Demand Relief Program development efforts. However, Loads with back-up generators were ultimately excluded from the program due to state environmental concerns.

When the ISO issued the original RFB in November, the Loads with back-up generators were assigned to a second tier to be called after the other Loads in the DRP. Ultimately, state officials became increasingly concerned that the inclusion of back-up generators in the DRP would encourage more diesel generator installations, and the RFB was retracted and never re-issued. Although the Participating Load Working Group, Load participants, and local air quality officials had worked for weeks to find an acceptable approach, back-up generators became a highly visible and important matter of state environmental policy – and ultimately had to be excluded from the DRP.

I. Discretionary Load Curtailment Program Development

In the fall of 2000 the ISO team embarked on development of a third demand program, called the Discretionary Load Curtailment Program. The ISO reviewed programs in other states, finding that much of their success had been linked to providing Loads more control or discretion over their curtailments.

The intent of the ISO Discretionary Load Curtailment Program was to attract significant voluntary curtailments before the ISO entered System Emergency conditions. In addition to attracting Loads that want control or discretion over their curtailments, this program was aimed at attracting smaller Loads, i.e. commercial lighting and air conditioning (A/C) Load that hadn't historically participated in a Demand response program. This program provided an Energy-only payment (ultimately set at $350/MWh) and provided Loads the control they desired in order to feel comfortable participating in a Demand response program. Equally important, it could at the same time provide to the ISO operators a "firm" curtailment commitment. This was a major breakthrough: Loads could participate on a discretionary basis, and because of operation through the aggregators, the ISO operators had the benefit of a "firm" curtailment commitment.

Key elements of the Discretionary Load Curtailment Program include:

- <u>Program Operation</u>: Year-round operation through March, 2002. Notifications are sent to SCs/aggregators upon ISO projecting a need for Demand response, based on the best available temperature, Load, and resource forecast, for specified hours of the next day, or later in the same day. Aggregators have 90 minutes to issue their voluntary curtailment notices and to "firm-up" the actual block of curtailment, and transmit back to the ISO.

- Cost: This program has an energy-only payment of $350 per MWHr. ISO management sought ISO Governing Board approval to set the price in the range of $250-500/MWh, depending on market conditions. (At this point, the CPUC was proposing a program called the Voluntary Demand Response Program (VDRP) for the bundled Loads of the investor-owned utilities. The VDRP design was modeled after the DLCP.) The ISO delayed final rollout of the DLCP pending the CPUC proceeding and a decision on pricing, intending to set the price at the same level and not have two very similar programs with different prices.
- Eligibility: Participants "sign-up" with aggregators, but actual curtailment is totally discretionary. Aggregators are certified by the ISO, providing the contractual, technical, communications, and verification mechanisms for interfacing with the ISO. Any Loads can participate provided they are not participating in other curtailment programs.
- Verification: The ISO depends on aggregators to implement their approved performance measurement plans, which could include providing interval meter data or other verification of the actual curtailments.

The Discretionary Load Curtailment Program had the potential to attract smaller Loads that could add significant resources to the California grid, operating through a voluntary, non-emergency program.

By May 2001, bids for the DLCP had been received from three aggregators for approximately 40MW. At that point it was anticipated that the similar investor-owned utility Voluntary Demand Response Program, released in April, would attract most of the Loads wishing to participate in a discretionary-type program. It also allowed for Loads that installed energy management systems to control lighting and heating, ventilating, and air conditioning systems to participate in a Demand response program. The ISO maintained the DLCP pending a more extensive sign-up for the utility program and also to provide a vehicle for unbundled or direct access Loads, or Loads that could not easily meet the VDRP interval metering requirements.

J. CPUC Interruptible Rulemaking Process

The CPUC Rulemaking on interruptible rate programs commenced in October 2000. Although not regulated by the CPUC, the ISO was considered a "Respondent" in the process and provided inputs to the development and coordination of the CPUC-jurisdictional programs. The CPUC interruptible proceeding was extended, resulting in a final decision April 4, 2001.

The CPUC decision proposed to revise and extend the interruptible rate program. At this point (April 2001), the ability to call on PG&E interruptible customers had already been exhausted for 2001 leaving the ISO with limited Demand reduction options. The SCE Loads still had approximately one-half of their allotted 2001 curtailment hours remaining.

The establishment of the investor-owned utility VDRP provided a comparable program for most potential Loads that might have participated in the ISO's DLCP, but the ISO was optimistic that the VDRP would be successful because the IOUs had better communication and marketing channels to the smaller Loads. The ISO directed bundled customer interest toward the VDRP, although one concern with the VDRP was its implementation so close to the summer months.

The CPUC decision also put in place an Optional Binding Mandatory Curtailment ("OBMC") program, which provided an option for some Loads to obtain an exemption of their circuit from rotating blackouts. The threat of rotating blackouts was prominent in everyone's minds at that time.

The programs implemented in the CPUC decision supplanted a significant portion of the ISO's Demand program initiatives. The CPUC concluded that interruptible customers should not also be able to benefit from participation in the ISO's Participating Load Program, despite the ISO's proposal to move these Loads from participation only during System Emergencies to participation in the ISO's regular markets. Further the ISO proposed an approach to eliminate the "double-dipping" and double counting concerns of the CPUC. In addition, the CPUC decided not to allow the IOUs to serve in the role of aggregators for the ISO's Demand programs. The ISO is hopeful that the Demand programs implemented by the CPUC will provide a sufficient amount of Demand reduction capability to more than make up for the associated reduction in participation in the ISO's Demand reduction programs. In any event, the ISO believes that more robust Demand programs can be implemented with better cooperation among the CPUC, the IOUs, and the ISO.

K. Creditworthiness Problems

The power crisis in California and its impact on the marketplace significantly undermined the ISO's ability to implement and administer its Demand programs. Participants became increasingly concerned over payments and insisted that the ISO provide assurances of payment if they curtailed.

To obtain financing for its Demand programs, the ISO sought financial backing from CERS. CERS faced a difficult challenge in implementing that commitment and ultimately issued a letter of intent to the ISO on June 21, 2001 that provided backing to the Demand Relief Program and the Discretionary Load Curtailment Program. Due to the implementation challenges that it faced in providing that financing commitment, CERS felt constrained to require a major redesign of the Demand Relief Program and to require that payment for the programs could only be made by way of a credit to normal bills of the bundled customers of the IOUs. For the same reservation payment, a Load would be required by CERS to be available for curtailment for 320 hours over 8 months of the summers of 2001 and 2002, as opposed to the original design of 96 hours over 4 months in 2001. Significant time was required to work out contracting details, direct payment to aggregators, etc. These changes added more uncertainty.

CERS subsequently agreed to pay the aggregators in the ISO's programs directly but would require a bilateral contract for the programs between CERS and any aggregator that might choose to participate in the CERS-financed program. The ISO would act as an "agent" of CERS performing the meter data gathering and verification work to continue the programs.

The ISO developed a draft contract for CERS to use with the aggregators for the DRP. This work was almost finalized but abruptly halted when the CPUC issued a draft decision on August 28, 2001 which reversed earlier state positions and prohibited cost recovery by CERS for any funding provided for the ISO's DRP and DLCP. The CPUC draft decision stated, "contemplated programs developed in conjunction with the ISO are not within the scope of the modified Rate Agreement."

Thus, the ISO has seen participation in its Demand programs for summer 2001 reduced to below 100 MW , in contrast to the anticipated 700 MW of participation.

L. California Demand Bidding Program ("DBP") Development

At a meeting in the state offices on May 14, 2001, members of Governor Davis' staff challenged the ISO and the investor-owned utilities with providing a price-responsive demand program that could compete with Generator bids.

The ISO worked extensively with the parties to offer its experience to develop the program and expedite implementation, and suggested a variation of the Discretionary Load Curtailment Program with multiple pricing tiers. At that time the DLCP (and the utility VDRP) were priced at $350/MWh. The new program would allow Loads to bid into multiple price levels, i.e. there might be four price levels at $200 increments between $100/MWh and $700/MWh. Further this program will allow smaller Loads to be aggregated by the utilities and also provides Loads with a curtailment confirmation the afternoon before the event, so that they can plan appropriately. Program implementation would depend heavily on the investor-owned utilities for marketing, aggregating and performance verification. Decisions regarding dispatch of the Loads were delegated to CERS as the creditworthy buyer. The ISO would become involved in dispatch decisions when the program participation was high enough that those dispatch decisions could have grid reliability impacts.

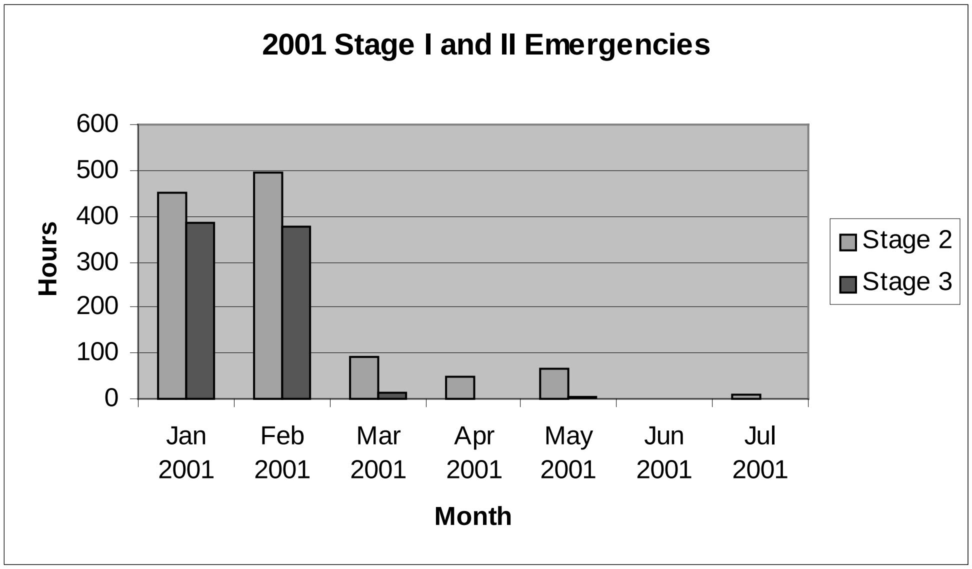
On June 9, 2001, Governor Gray Davis issued Executive Order D-39-01 that directed the ISO and the Department of Water Resources to implement voluntary, emergency load curtailment programs for commercial, industrial and other large customers of the IOUs for summer 2001 and summer 2002. After refinement by representatives of the ISO, IOUs, CPUC, and CERS, the program was approved by the CPUC on July 12, 2001. It went into operation on August 1, 2001, a major accomplishment by all involved.

Throughout August the bid quantities have been low, and, due to the unexpectedly low prices for Energy, have not been dispatched. The lowest price tier identified was $100/MWHr. Because price levels have been below $100 most of the time, CERS has not dispatched the Loads because Generation is cheaper. The ISO is concerned that unless some action is taken to encourage the Loads with a “dispatch,” even if uneconomic when directly compared to Generation prices, interest in this program will also be significantly reduced.

M. Summer 2001 Performance

Demand program results for the summer of 2001 have been disappointing on several fronts. The pump Load participation in the ISO Participating Load Program has been reduced due to water shortages. Many Loads dropped out of the ISO Demand Relief Program due to the market payment concerns. Others interested in the ISO DLCP shifted their interest to the IOU VDRP, then that program was terminated with the advent of the state Demand Bidding Program. Now participation in the Demand Bidding Program is uncertain because the program is not being used. Cool weather and voluntary conservation has temporarily ameliorated the power crisis, thereby reducing the need for Demand response. The cool weather further reduced Demand response, because energy prices in general have dropped. The interruptible Loads that were the foundation of Load participation at ISO start-up have been reduced from 2000 MW down to approximately 750 MW.

The number of Stage 2 and Stage 3 ISO System Emergencies for 2001 is shown below.



Only one Stage 2 System Emergency has been called since June 1, 2001. On July 3, 2001, the ISO declared a Stage 2 emergency that initiated dispatch of the IOU interruptible programs, the ISO DRP and DLCP, and the IOU Voluntary Demand Response Program. It is too early to determine the specific performance of the programs. The ISO has polled the DRP aggregators and believes no more than 50 MW of Demand reduction was provided from the DRP on that day. It is estimated that the DLCP produced 16 MW. While this low level of participation is in large part indicative of the payment uncertainties mentioned above, it is also believed that performance was reduced because some businesses had already closed for a long July 4th holiday.

The IOU Interruptible programs produced approximately 760 MW when called on July 3. Most of this was concentrated in the SCE service territory. This level of participation is consistent with participation in May, 2001 after the PG&E interruptible program was exhausted, but is far lower than the 1500 MW available in the summer of 2000.

N. Communications with Market Participants

In this section, the ISO outlines some key activities related to communications, metering, and program performance verification. In an effort to best meet the program design requirements for the ISO's Demand response program participants, the ISO held regular workshops and Conference calls. Information and suggestions gathered from these meetings was posted on an ISO web page dedicated to the ISO Demand response programs. Frequently asked questions were posted with responses and a discussion page was also created. The web page contained information on the processes and requirements for becoming involved in each of the specific ISO Demand response programs.

The programs required the collaborative effort of Load aggregators, Energy service providers, Utility Distribution Companies, Load management companies, municipalities, end-use Loads, and ISO certified Scheduling Coordinators. Therefore, the ISO solicited names for points of contact that enabled participants to know what entities were available for providing the various functions associated with the programs. The list of contacts was posted on the ISO Home Page. The ISO also established an e-mail distribution list dedicated to the Demand response programs, which was commonly used to send out meeting notices and program updates to the various entities.

It has been ISO's experience that having Demand program workshops, providing a discussion page on our web site, and responding to numerous phone calls and e-mails have allowed the ISO to develop sound and acceptable Demand programs. We have been impressed with our interfaces with the Loads, third-party aggregators, SCs, and meter data management agents (MDMAs) for the ISO Demand programs, and they have been very supportive of the programs and committed to provide real Load reduction for California when needed.

O. Metering Issues/Initiatives

The foundation of any Demand response program is the ability to accurately measure the amount of Demand curtailed when called upon. The ISO's DRP performance measurement must be derived from certified interval meters. Even with the ISO's early communication of the 2001 DRP design, the coordination and installation of interval meters was a time-critical issue. One associated benefit of the DRP, however, has been the increase in interval meters for end-use Loads participating in the ISO's programs.

A design feature of the 2001 DRP was that the settlement quality meter data used for the performance calculation would be derived from the normal retail-billing meter reads. This efficiency feature required only one meter read to provide the required data for retail billing, ISO normal market settlements, and DRP settlements. Unfortunately, this has been complicated due to the development of contractual relationships between the IOUs, their bundled customers, and the third-party Load aggregators.

The ISO also designed a unique aspect in the performance measurement of the DLCP. Although interval meters were preferred, the ISO also allowed DLCP participants to submit for approval a performance measurement plan. The plan can include methods other than interval metering for performance measurement, such as sample measurements, historic data, process controls, use of data loggers, and other performance measurements approved by the ISO. This allows participation by end-use Loads that have the ability to provide Demand response yet do not have interval meters.

P. Performance Validation and Verification

Beginning with the trial Demand Relief Program in 2000, the ISO instituted a validation and verification process. The process for summer 2001 required the contracted Loads to submit an implementation plan that included, among other items, the listing of all individual Loads (by a unique meter ID) that composed the contracted Demand.

The ISO Compliance group will verify DRP performance and validate the implementation plans through continuous monitoring of submitted settlement quality meter data and performing audits of the contracted Loads and their supporting entities.

The ISO established a 10-day baseline for its Demand Relief Program. We note that the subject of baseline calculations for Demand Programs requires more work, to hopefully improve and standardize baseline calculations that will further improve the accuracy of verification procedures.

Q. Future Recommendations

Conservation and Demand programs remain vital in California on a short term basis until more Generation is on line. Long term they add a level of price elasticity to Demand that would further improve the operation of the markets. But the future of Demand programs at the ISO and in California is unclear. Many Loads have been discouraged because of payment concerns, extensive use of the interruptibles, regulatory uncertainty, and lower prices. Coordination among the various state entities is not optimum. The newly formed California Power Conservation and Financing Authority may play a role in Demand programs as part of its charter to add needed resources in the state, but that is unknown at this time. The ISO will be evaluating future direction of its Demand programs during the fall of 2001and will report more on future plans in the next quarterly report.

IV. 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,

____

Charles F. Robinson
Margaret A. Rostker
California Independent System
Operator Corporation
151 Blue Ravine Road
Folsom, California 95630

Dated: September 14, 2001

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 September, 2001.

Margaret Rostker
Regulatory Counsel
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630