Energy Division's Report on Interruptible Programs and Rotating Outages

February 8, 2001

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I. Executive Summary

This report, prepared by the Energy Division of the California Public Utilities Commission (the Commission or CPUC), seeks to improve the reliability of California's electric system by recommending improvements to the interruptible and rotating outage programs of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E).

These efforts are being undertaken as part of the Commission's rulemaking into the operation of its interruptible programs.[1] The purpose of the rulemaking, begun in October, 2000 is to:

(1) clarify the responsibilities of customers taking service under interruptible tariffs,

(2) coordinate the programs being offered and proposed in California,

(3) identify alternative means for customers to reduce energy usage and

(4) revise and update the Commission's priorities for curtailing customers during times of shortage.

A. Interruptible Programs

Interruptible programs operate by paying customers to curtail their energy usage when energy demand is high and the reliability of the electric system is threatened. PG&E, Edison and SDG&E have each operated interruptible programs, targeted mainly at industrial and large commercial customers since the mid-1980's. The cost of these programs has been over $220

[1] Rulemaking (R.)00-10-002 assigned to Commissioner Carl Wood

million per year and almost $2 billion since 1990. Edison also operates an air conditioning (A/C) cycling program in which customers allow Edison to cycle their air conditioner.

In exchange for these payments, California expected that these customers would be available to be curtailed when needed to maintain the reliability of the electric system.

Recent Experience with Utility Interruptible Programs

Actual operation of these programs in response to tight energy supplies has identified serious problems with the programs.

Pacific Gas & Electric

- Customers on PG&E's interruptible program (380 Megawatts (MWs)[2] of industrial/large commercial load) have shown that they routinely curtail when requested, achieving a compliance rate of 90-95%.
- These customers have found it difficult to respond to repeated, frequent requests to curtail (sometimes 2 or 3 times per day for up to 6 hours each time) without jeopardizing their operations, and in some cases public safety.
- Due to the dysfunctional wholesale energy market, PG&E has already exhausted almost its entire 380 MW interruptible program for calendar year 2001, leaving no program in place to help meet peak demand during the summer time.

[2] A MW is 1 million watts or 1 thousand kilowatts (kWs). A kW is 1 thousand watts.

Southern California Edison

- A significant number of customers on Edison's interruptible program did not interrupt despite contractually agreeing to curtail up to 25 times as part of their participation in the program and receiving almost $1 billion in reduced rates since 1990.
- Compliance with Edison's interruptible program has been in the range of 60-70% with only about 1,200 out of 1,800 MW of available load curtailing when requested.
- From numerous complaints the Commission has received, it appears that perhaps ½ of the customers who do interrupt when requested by Edison are facing severe economic dislocation from doing so.
- Numerous customers, including some schools and hospitals, "gamed" Edison's tariffs by unrealistically signing up their entire energy load as interruptible, and therefore subject to interruption.
- Edison has already utilized about half of its interruptible program for 2001.

San Diego Gas & Electric

- Prior to 2000, SDG&E operated a small (40 MW) interruptible program whose participants routinely curtailed when requested to do so.
- The Commission adoption of an artificially low rate due to a calculation error may have induced an additional 34 MW of load to join the program in 2000.
- In practice, these customers did not interrupt when called upon to do so. Therefore, SDG&E's program remains at about 40 MW.

In response to the rapid depletion of both Edison's and PG&E's interruptible programs, the Commission, in Decision (D.)01-01-056 temporarily suspended the operation of the utilities' interruptible programs while awaiting recommendations from this report.

General Findings

- There is a need for interruptible programs. Each MW hour (MWh) of interruptible load translates into approximately 1,000 residences that will not be subject to rotating outages for 60-90 minutes.[3]
- Interruptible programs for large customers are expensive and in many cases are comparable to energy costs in the current wholesale spot market (i.e. a customer on PG&E's program who is curtailed 100 hours per year receives the equivalent of $840 / MWh for their participation) and more than 10 times as much as the cost of procuring energy through long-term contracts.
- A key issue for consideration is how much should be paid to certain customers to reduce energy usage.
- There is a need to develop a replacement program to allow PG&E's existing interruptible customers to continue to be compensated for interrupting when needed.
- SDG&E's heating, ventilation, and air conditioning (HVAC) program should be considered more fully.

[3] Average customer load of 1 kW. There is not a one to one ratio since it takes time after the rotating outage to bring customers back on line.

- Various Independent System Operator (ISO) and utility programs need to be coordinated with any new program authorized by the Commission.
- All interruptible programs should be coordinated so that customers are only paid once for reducing their load. Economic incentives should be provided for interruptible programs, but they should not be pegged directly to dysfunctional wholesale energy prices.

Recommendations to Improve Existing Interruptible Programs

- Customers on Edison's interruptible program should not be allowed to "opt-out" of the program but should be given flexibility (increased time periods between curtailments) to meet their contractual obligations. Allowing customers to opt out of Edison's program could increase the frequency and extent of rotating outages faced by firm customers and would mean that ratepayers receive little or no benefit for the hundreds of millions of dollars interruptible customers have received through discounted rates.
- The existing interruptible programs should be made more flexible so that customers can better comply with them.
- Customers who can prove that they provide public health and safety benefits should be allowed to leave the interruptible program through an expedited advice letter process.
- Existing programs should be reopened to new customers, and participation should be increased by lowering the size threshold for participation and waiving the cost of installing necessary metering equipment.

New Programs Should Be Targeted At Specific Customer Groups

Larger Commercial and Industrial Customers

- This report proposes creation of a new interruptible program, similar to the existing program in which customers agree to be curtailed for a certain number of hours during the summer in exchange for a monthly discount.
- Customers who participate in this program would also be allowed to participate in a "pay-per-interruption" program once they have fulfilled their obligations under the new program.
- Customers should be allowed to participate in a new voluntary demand responsiveness program.

A/C Programs for Commercial and Residential Customers

- An A/C cycling program for commercial customers could provide significant peak load reduction.
- Edison's existing A/C cycling program for residential customers should be expanded and similar programs should be developed for PG&E and SDG&E in selected appropriate geographic areas of their service territory.

Programs that Promote Voluntary Efforts

- The Commission should work with the Governor's office and other agencies to recognize customers who achieve significant reductions in energy usage through voluntary activities.

- Certain customers should be allowed to participate in the Optional Binding Mandatory Curtailment (OBMC) program, whereby they agree to use less energy prior to the initiation of a Stage III rotating outage in exchange for being exempted from rotating outages if they meet certain targets.

B. Rotating Outage Programs

Only after all available load reductions have been achieved from interruptible customers will the utilities begin curtailing electric service to firm customers. This is done on a rotating basis with outages spread throughout different geographic areas, each area going without power for 60-90 minutes. These controlled outages are needed to avoid system instabilities that could result in uncontrollable, system-wide outages involving large portions of the western United States.

Utility Energy Response Plans

Utilities are required to maintain emergency response plans that describe how rotating outages are to be implemented. These plans are developed based on guidance contained in Commission decisions. The Commission's latest review of the emergency response plans was completed last year. Each plan is to guarantee that:

- There is an equitable distribution of the burden of outages,
- There is no direct relationship between first outage and economic production, and;

- Maximum load reduction occurs early so as to avoid rotating outages if at all possible.

In establishing procedures for initiating rotating outages, the Commission specified that utilities must have 40% of their peak load available for rotating outages in 5% increments, so at any one time up to 20% of customers may experience an outage for a one hour period.

In this report Energy Division notes that:

- PG&E's 2000 rotating outage plan complies with the intent of the Commission's orders in disbursing outages equitably between customers;
- SDG&E does not do as well in meeting the Commission's intent and may end up blacking out large contiguous geographic areas in order to meet its curtailment goals.
- Both Edison and SDG&E may also be treating customers served on manual circuits differently than customers served on automated circuits due to the need to send staff out to substations to manually switch circuits on and off.

<u>Essential Services Customers Are Exempt From Rotating Outages</u>

Commission decisions identify specific entities to be exempt from rotating outages because they provide "essential services." These essential services include:

- Fire fighting, police protection, and prison services;
- Hospitals with 100 or more beds;
- Air traffic control services; and,
- Certain sewer and water treatment facilities.

The Energy Division recommends that the Commission modify the essential customers list to exempt Bay Area Rapid Transit (BART) from rotating outages, implement mitigation measures to ensure the safety of San Francisco Municipal Railway (MUNI) passengers and staff, and examine whether other rail transit systems within California should also be exempt.

Currently, about half of all customers share the burden of rotating outages, while the other half are exempt. The report notes that there are many customers that, by happenstance, are exempt from rotating outages because they share a circuit with an "essential services" customer. For example, PG&E has approximately 2.0 million customers who receive service on a circuit that is exempt from rotating outages. Of these customers, only 1500 to 1700 are essential service customers. Thus, more than 1.9 million customers are not defined as essential service customers but are effectively exempt from rotating outages because they are served from one of the separately controlled distribution circuits that serve one or more essential services customers.

Recommendations For Increasing The Number Of Customers That Are Subject To Rotating Outages

The Energy Division recommends exploring specific options to reduce the number of customers exempt from rotating outages, thus spreading the burden of outages among the broadest possible population. Therefore, there should be further studies to see if it is technically feasible to include the following customers into rotating outage plans:

- Customers currently served on networked systems (such as PG&E's Downtown San Francisco and Downtown Oakland networks)

- Non-essential customers who are currently exempt from rotating outages because they share a circuit with an essential service customer
- Transmission level customers

Effects on Fuel Supply

Currently, electric utility facilities and supporting fuel and fuel transportation services critical to the continuity of the electric power system operation are defined as essential service customers and thus are exempt from rotating outages. The California Energy Commission (CEC) should coordinate with fossil fuel producers so that outages and interruptions can be coordinated to minimize disruptions.

Customer Notification

Energy Division is concerned whether the current system for notifying the public of planned rotating outages is as effective as possible given current communication technology. The trade-off between system cost and public security, and increased communication effectiveness, should be studied further.

Recommendations To Improve Notification

The Energy Division recommends the following changes to the utilities' obligation to notify customers of impending outages.

- A large number of the medical baseline customers require life support devices to survive. In a Stage 3 emergency, the utilities should be required to notify, by telephone, customers on life support equipment in the block(s) scheduled for outage.

- The state Office of Emergency Services (OES) and the Occupational Safety and Health Administration (OSHA) should examine plants to ensure that workers and the public are not unnecessarily endangered by forced electric outages.
- The utilities' rotating outage plans should include descriptions of their plans for notifying customers of imminent outages. The notification plans need to be made more accessible and should be expanded to include people and/or entities with special needs.
- The utilities should develop multilingual press releases and implement outgoing notifications to those customers on their essential services lists.
- The utilities need to assess the adequacy of their in-bound notification procedures to determine whether they have been able to handle the volume of calls they receive during rotating block outages and whether there is additional information that should be provided.

II. Purpose of the Report

In this report, Energy Division recommends improvements to California's investor owned utilities' electric system reliability through changes to two types of utility programs: interruptible programs and rotating outage programs. It describes the current interruptible programs and recommends improvements to them. It also describes and recommends new programs that, if adopted, would increase the interruptible load available to the utilities. Energy Division also reviews current curtailment, or "rotating outage", rules and makes recommendations to protect customers during an outage. Finally, in this report, Energy Division recommends areas for further study.

This report focuses primarily on recommendations that will affect electricity consumption by the customers of PG&E, Edison, and SDG&E, and thereby the operation of the electric system for the summer of 2001. Later stages of the Commission's formal inquiry into the operations of interruptible programs will examine longer-term issues.[4]

III. Background

A. Goal of Interruptible Programs

A properly designed interruptible program can help reduce the need to construct new power plants and improve the reliability of the electric system. California's three major investor-owned utilities, PG&E, Edison, and SDG&E, have operated interruptible programs since the mid-1980's. Interruptible programs generally operate by paying customers[5] to reduce their energy usage during times when energy demand is high. Customers willing to be interrupted

[4]Rulemaking (R.)00-10-002 is assigned to Commissioner Carl Wood.

[5]In discussing interruptible program participants, utilities use service account (service to a meter). Customers may have several service accounts. For ease of communication, this report uses customer when discussing a service account.

can be compensated for their participation through fixed payments (i.e. dollars per month for the right to be interrupted a certain number of times), a discount off their electricity rate, or on a pay-per-interruption event basis.

B. Cost of Interruptible Programs

Interruptible programs are not inexpensive. The cost of these programs, at least for larger customers, are comparable to, if not higher than, the prices currently being paid for energy in today's dysfunctional spot market for energy.

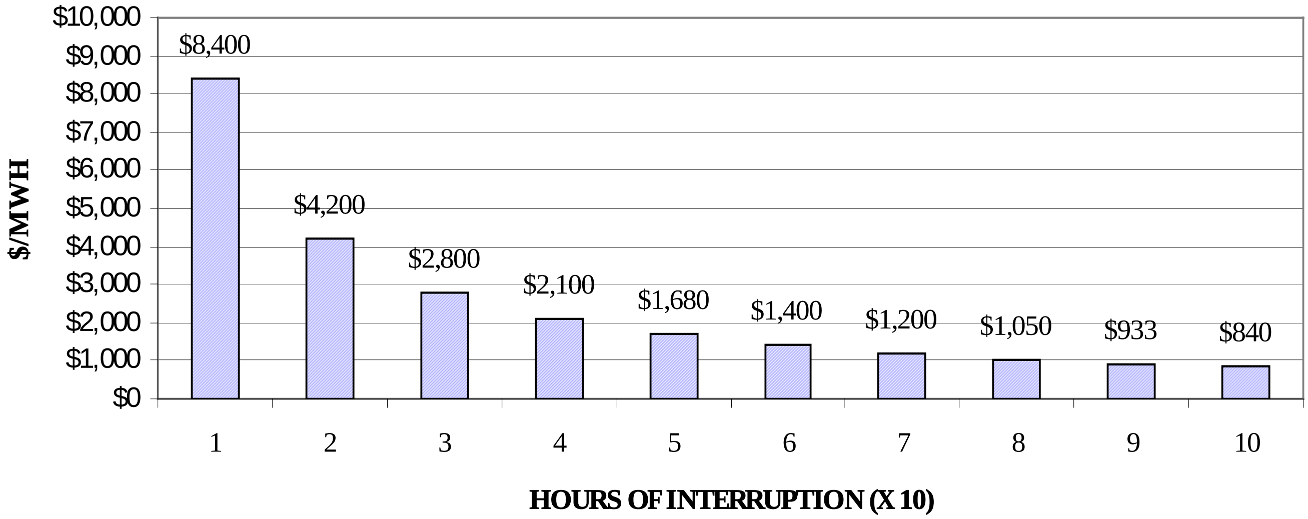
Interruptible programs currently cost Californians $220 million per year. Since 1990, Californians have spent over $2 billion for these programs (Table 1).

Table 1

	PG&E		Edison		SDG&E
Year	**Incentives ($M)**	**Penalties ($M)**	**Incentives ($M)**	**Penalties ($M)**	**Net Incentives ($M)**
92	$46	N/A	$147	$0	N/A
93	$46	$1.03	$112	$0	N/A
94	$46	N/A	$126	$0	N/A
95	$46	$2.67	$140	$0	N/A
96	$48	$0.80	$161	$0	$4.07
97	$47	$0.27	$195	$0	$3.37
98	$45	$1.13	$183	$8.3	$2.89
99	$49	$0.05	$184	$0	$1.90
00	$48	$2.16	$180	$92.4	N/A
	$421	**$8.11**	**$1,428**	**$103.7**	**$12.23**

A customer on PG&E's interruptible program, even if curtailed for the program's maximum limit of 100 hours, receives $840 for each MWh of energy saved ($84,000 per year / 100 hours, Figure 1). A customer on Edison's system, curtailed for the program limit of 150 hours, would receive between $500 and $800 per MWh of reduced load.

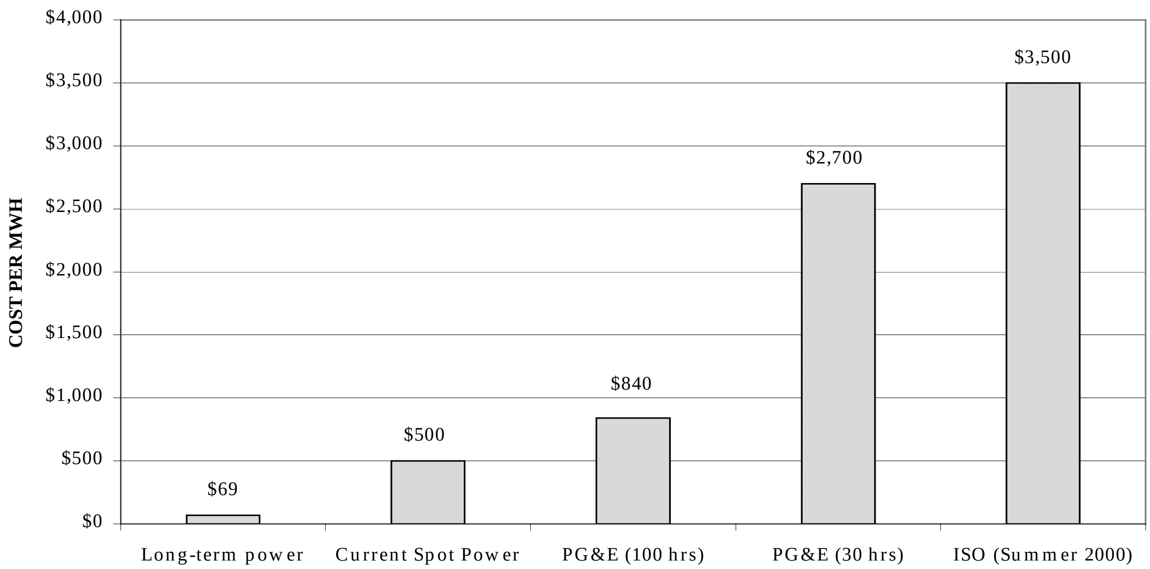
Figure 1
PG&E
PAYMENT PER INTERRUPTION



In years in which curtailments are less than the program maximum, the cost per MWh saved is even higher. For example in 1998 when PG&E experienced a then-record high 6 curtailments, the cost per MWh saved was in the range of $3,000 per MWh.

Additionally, as events over the past year have shown, there is a need to distinguish between the contractual obligations that a customer signed up for and their *expected* obligation. While customers may have contractually signed up to curtail 25-30 times per year, many customers appear to have calculated the expected number of curtailments as significantly less in weighing the relative economics of participation. Thus it appears the actual payment needed to provide incentives for people to interrupt could be even higher than the contractual terms. Figure 2 compares the cost of interruptible programs relative to the cost of acquiring new generation, either in today's spot wholesale market or under longer-term contract. As shown below interruptible programs can cost several times more than available generation.

Figure 2
Cost of Interruptible Programs Vs Generation



This can be seen by examining trends in program sign-up. When energy reserves are high, and therefore the potential for curtailments low, numerous customers appear willing to sign up for interruptible programs. It was for this reason that the Commission closed its interruptible program to new participants in 1993 for PG&E and 1996 for Edison.

Unfortunately, the converse is also true. When energy supplies are tight, and the probability of curtailments increases, customers want to leave existing programs and it is difficult to sign up new load at the same level of incentives.

C. Alternatives To Interruptible Programs

Interruptible programs must also be coordinated with other rate design and market structure issues. There are several ways to reduce demand during peak periods, of which interruptible programs are only one method.

Other methods include:

- **Charging customers market-based rates for their entire energy consumption.**

SDG&E, which has ended its rate freeze, charges its largest customers (above 100 kW) the direct price that it pays to acquire energy. This gives the largest customers a strong incentive to reduce their energy usage without any additional economic incentive from the utility. In large part, interruptible programs attempt to correct a mismatch between what a customer is paying in rates versus what it is costing the utility on the margin to acquire energy for that customer. For Edison and PG&E, industrial customers are currently paying rates for energy that are below what it is costing the utility to provide the energy. Data from SDG&E[6] show that high energy prices have reduced peak demand significantly in their service area. It was for this reason that the Commission denied SDG&E the authority to offer incentives to its largest customers to reduce energy usage, determining that the higher prices that these customers would pay for on-peak energy usage would give the customers significant incentive to conserve without the utility paying them to do so.

A drawback to charging customers the market price for energy is the rate shock due to currently high prices.

- **Charging customers for a portion of their energy usage at market-based prices (i.e. Tiered Rate Design)**

Another option to reduce peak usage is to charge customers high prices for only a portion of their energy usage, typically that above a certain level, for certain hours of the day. An example would be a two-tiered rate in which customers would receive 90% of their last year's usage at current rates, and pay either significantly higher or market-based prices for the remaining 10% of their usage. This approach would have the same

[6] Presentation to the ISO Board Meeting of October 4th.

effect as interruptible programs, namely reducing energy usage during peak periods.

For almost all commercial customers (greater than 20 kW for Edison and PG&E, greater than 10 kW for SDG&E) these customers are equipped with Time-of-Use (TOU) meters that record energy usage during three distinct time-periods (peak, mid-peak, and off-peak.) Applying a significantly higher energy charge to all or a portion of on-peak energy usage would also achieve the same goals that the utilties' interruptible programs would.

Rate design proposals such as these are being considered as part of the Rate Stabilization proceedings the Commission is currently undertaking. Reforms to the interruptible program should be coordinated with these efforts so that we are not paying customers to reduce energy usage at the same time that we are charging customers more to have them reduce energy usage.

- **Energy Efficiency Efforts**

Although many energy efficiency programs are designed to reduce total energy usage throughout the day (e.g. compact fluorescent light bulbs) they also have the effect of reducing peak energy usage. Other energy efficiency programs are specifically designed to improve efficiency by shifting energy usage away from peak periods to off-peak periods. Examples of this technology include Thermal Energy Storage, which shifts air conditioning load from the afternoon to the evening.

Another aspect of energy efficiency is to give customers greater control of their energy usage through technology that lets various appliances (such as air conditioners, refrigeration, lighting) cycle on and off over different time periods.

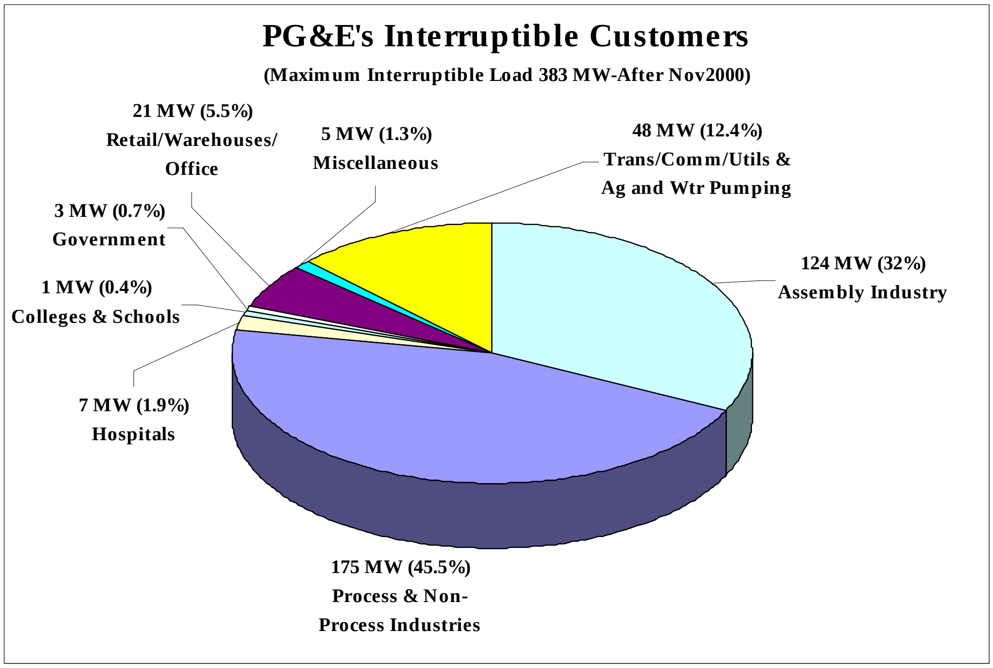
The Commission and the Legislature are addressing this peak reduction program through the Assembly Bill (AB) 970 process and proposed legislation addressing energy efficiency funding.

D. Current Interruptible Programs

1. Traditional

The major utility electric load interruption programs are targeted toward two customer classes: industrial and large commercial customers. Figures 3 and 4 provide a breakdown of the interruptible customers, classified by CEC type and the amount of interruptible load they represent[7].

Figure 3



Current interruptible programs require customers to be equipped with meters that record customers' usage over a given period of time (allowing the utility to verify compliance), to be equipped with special telecommunications equipment that the utility can use to notify the customer to reduce its

[7] Data was obtained from PG&E's and Edison's response to Energy Division's data request 1 and 2. In Figure 4, the 2,980 MW represents the information of each customer's maximum load that could be interrupted. When Edison's system peaks, Edison estimates that the total interruptible load is closer to 1,800 MW.

consumption, and to have large loads (making it efficient to target these customers.)

Table 2 shows the amount of traditional interruptible load covered by an interruption contract for each utility during summer of 2000, the cost of the program due to the discounts paid, and penalties. Table 2 also shows the amount of load and costs associated with the ISO's DRP program for the summer 2000. Some customers identify only a portion of their load as "interruptible," and so continue to receive electric service for the remainder of their load – their "firm" load -- during an interruption event.

Figure 4

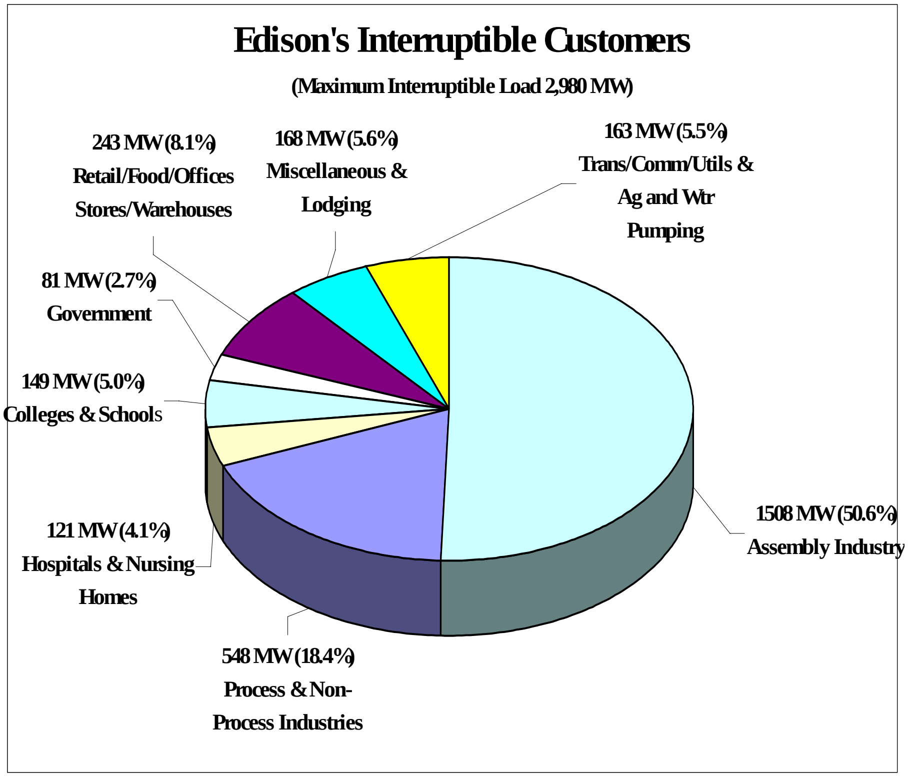


Table 2

Utility	Interruptible Load (MW)[8]	Average cost per MW	Penalty per MWh	Limit on hours per year
PG&E	500	$84,000	$4,200-8,400	30 events 100 hours
Edison	1,800	$86,000-118,000	$7,000	25 events 150 hours
SDG&E	40	$73,000	$1,760	80 hours
ISO	63	$124,000	$0	120 hours

Customers participating in these traditional load interruption programs receive a discount off of their electric rates of about 15%. The discount is tied to the energy use subject to interruption. In exchange, customers agree to be interrupted between 80 to 150 hours per year (depending upon the utility). Once notified, the customers have 30 minutes to reduce their load to their firm service level[9].

Customers who fail to comply with a request that they reduce their load are subject to significant penalties. Since the purpose of the program is to maintain the reliability of the electric system and minimize rotating outages, the non-compliance penalty is purposely set high. As little as 10 hours of non-compliance, and at most 25 hours, can eliminate the yearly benefit to a customer of participating in the program.

SDG&E's interruptible program varies slightly from the PG&E and Edison programs by providing discounted rates for time periods when interruptions are not called and setting higher rates for time periods when

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8 Approximate available interruptible load at peak.

9 A firm service level is the amount of load the customer does not want to interrupt. A customer with 600 kW of load may have a firm service level of 100 kW, meaning it will interrupt 500 kW when called.

interruptions are called. In addition, SDG&E's RTP-2 tariff (with about 8 MW currently enrolled) provides participants 24-hour notice before the load interruption is to take effect.

2. Air Conditioner Cycling

Edison is the only investor-owned utility that offers an air conditioning (A/C) cycling program in which it directly controls customers' power use. These programs are operated by having residential and commercial A/C units connected (usually by a radio link-up) to the utility. When electric demand is high, the utility transmits a signal to the enrolled customer's air conditioner to either turn it off for a set period of time, or more commonly, to cycle the air conditioner on and off over the course of an hour (usually 10 minutes on, twenty minutes off). In exchange, the customer receives a lower electric rate.

A/C is the major use of electricity in California during the summertime. The California Energy Commission estimates that about 14% (7,000 MW) of the state's peak energy demand of 50,000 MW is associated with commercial A/C. It estimates that an additional 14% of the state's peak demand is associated with residential A/C, for a total of 14,000 MW of peak demand.

Although Edison is the only investor-owned utility that offers an A/C cycling program. Sacramento Municipal Utility District (SMUD) and Modesto Irrigation District (MID) have programs similar to Edison's A/C cycling program.

Each of these programs generally operates only in the summer (Edison and MID) or is used only in cases of system emergency (SMUD and MID). Edison's program, for example, is limited to 15 interruptions during the summer, and each interruption can be no more than 6 hours. Edison operated its program 12 times in 2000, totaling less than 40 hours.

While an effective method of reducing residential and commercial load during crucial peak demand periods, Edison's A/C program is not state-of-theart. Edison's program was largely installed during the 1980s using technology that is significantly behind current capabilities. In addition, as customers have moved over time, a number of units with the installed technology are currently in residences where the occupants have chosen not to participate in the program. Edison also offers an agricultural and pumping program which functions similarly to Edison's commercial A/C program. Approximately 46 MW of load is available in this program.

3. Demand Responsive Programs

The third program currently in use by the investor-owned utilities is called "demand responsive programs." Demand responsive programs are intended to attract customers who are willing voluntarily to reduce their energy usage in exchange for monetary compensation during time periods when the day-ahead Power Exchange (PX) price is expected to be high. The theory is that having these customers reduce their energy usage will lower the total demand for energy which puts downward pressure on the PX market prices. The savings from the reduced energy prices are intended to outweigh the costs of the program.

In response to expected high prices in the PX during the summer of 2000, PG&E and Edison implemented experimental programs.[10] These programs pay customers per interruption event instead of offering rate discounts. In these programs, participating customers are notified a day in advance when electricity prices exceed a pre-set level. Customers may then interrupt at least 20 percent of their load from a baseline set by the previous 10-days' usage. Participants receive a payment based on the Day Ahead PX market price multiplied by the reduction in electricity use.

[10] PG&E's program is called E-BID and Edison's program is called VPRC.

E. 1992-1998 Experience -- Interruptible Programs Very Predictable

Up until 1999, the interruptible program operation was fairly predictable. The utilities enrolled customers, and the customers expected that interruptions could be called for under the program during the summer season (May through September). California's summer season was historically the period when peak demand occurred and was, therefore, when it was most likely that customers would be requested to interrupt load to ensure reliability and system integrity. Even during the summer season, interruptions were fairly unusual, and for Edison, practically unheard of until 1998. Table 3 below shows the number of curtailments from 1992 to 2000 and customer compliance.

Table 3

	PG&E		Edison		SDG&E
Year	**Number Of Curtailments**	**% Compliance**	**Number Of Curtailments**	**% Compliance**	**Number Of Curtailments**
92	1	93%	0	0	-
93	1	92%	0	0	0
94	0		0	0	0
95	5	96%	0	0	0
96	4	98%	0	0	6
97	1	97%	0	0	13
98	5	96%	4	56%	11
99	2		0	60%	1
00	20	96%	20	62%	14

One of the challenges in planning and evaluating the effectiveness of an interruptible program is that it is not possible to know, in advance, exactly how much load will be available when needed. The amount of load available at any given time depends on how much energy is being used by enrolled customers when an interruption event is called. California's historical peak summer season load data provides the utilities the best estimates of the amount of load available for interruption at any one time, although variations in load availability are still significant.

1. Summary of PG&E, Edison and SDG&E Performance

Each utility's experience with interruptible program effectiveness during this time period was unique. Edison had not called for interruptions under its program until 1998. In 1998, Edison called for interruptions four times. At the start of the 1999 summer season, Edison estimated that approximately 2,900 MW of interruptible load was enrolled in its program. It further estimated that only 1,800 MW of interruptible load would actually be available at system peak since not all customers were expected to be operating at maximum demand when called upon to reduce their loads, and some customers might not be operating at all.

In contrast, PG&E did actually interrupt load prior to 1998 to maintain system reliability. PG&E called for interruptions from one to five times each year between 1992 and 1998, with the exception of 1994. PG&E did not call for any interruptions in 1994. From this pre-1999 experience, PG&E estimated that 500 MW of interruptible load was available at system peak. Through 2000, PG&E's customers achieved a compliance rate in the range of 96% when called upon to reduce load. PG&E achieved much better compliance than Edison, as shown in Table 3.

SDG&E did not call for any interruptions from its interruptible program customers from 1993 through 1995. In 1996 through 1998, however, SDG&E called for interruptions from six to eleven times to maintain system reliability. At that time, SDG&E estimated that about 40 MW of interruptible load was available at system peak. Until 2000 SDG&E had experienced compliance at rates of 90% or above. In 2000, a significant number of new customers joined SDG&E's interruptible program.

2. Customer Base Fixed by Commission

During this 1992-1998 time period, the Commission began to limit the ability of customer's to enroll in these programs. The Commission limited PG&E's program to new customers only since 1993. Similarly, in 1996, the Commission limited Edison's program to new customers. Only new customers locating in the utilities' service territories were allowed to sign-up for electric service under the interruptible programs.

In order to plan for customer needs, the utilities required program participants to commit to the interruption programs for set time periods. Up until 1998, customers who signed up for Edison's program (about 85%-90% of Edison's customers) committed to give 5-years notice before leaving the program. Customers electing to participate in PG&E's program were required to join the program for a 3-year term, after which they would revert to a year-to-year program. SDG&E's program has not changed since before restructuring and requires participants to remain in the program for at least a year.

In 1998, with the start of electric restructuring, the Commission relaxed the 5-year notice requirement for Edison program participants, and allowed both PG&E and Edison program participants to leave the program during an annual "opt-out" period. The interruptible programs were then considered extremely costly (with annual costs of $200 million) when no system emergencies were envisioned. In October 2000, in response to concerns over tight energy supplies, the Commission temporarily suspended the opt-out provision for all Edison customers who first joined the program prior to April 1, 1998.[11]

[11] The Commission is scheduled to address the opt-out provision prior to March 31, 2001.

Before the suspension took effect, approximately 20 percent of PG&E's interruptible load (124 MW) chose to exit the program in 2000 after being called to interrupt an average of 28.5 hours during the summer.[12] Approximately 15 percent (15 MW) of Edison's interruptible load that was allowed to leave the program in 2000 actually did. SDG&E allows more frequent changes, but only had approximately 1 MW of interruptible load leave its program in 2000.

Although the dynamics of the market have caused some customers to leave the programs, additional customers may wish to join the interruptible programs; the amount of load available, however, may not be large. During the summer of 2000, both PG&E and Edison requested authority from the Commission to reopen their programs. The Commission allowed the programs to be opened to allow existing customers to sign-up, but it applied certain conditions.[13]

In response, Edison opened its program in August 2000 and enrolled an additional 135 MW of new interruptible load that was only available to May 2001. PG&E did not accept the Commission's conditions, so its program remains closed. PG&E did enroll 3 MW of new interruptible load from customers new to PG&E in 2000. SDG&E enrolled approximately 34 MW of new interruptible load in 2000, although many customers may have joined the program due to errors in the proposed rate schedule for this program which resulted in an artificially low rate. The Commission corrected the error that caused the artificially low rate in a subsequent decision. Many of the customers that signed up for the program

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[12] PG&E states its interruptible customers were called an additional 30-40 hours from late November to mid-December 2000.

[13] Resolution E-3689 allowed PG&E and Edison to enroll new interruptible customers, but limited the new customers' participation to May 31, 2001; in addition Edison customers were allowed to decrease firm service levels during an August adjustment period.

based on the artificially low rate may leave the program prior to February 1, 2001. According to SDG&E, the majority of these customers have failed to interrupt when requested to do so in 2000.

Table 4
Load Changes 2000

Utility	Non-firm Load Leaving (MW)	New Non-firm Load (MW)	Total Non-Firm Load (MW) 1/1/01[14]
PG&E	124	3	383
Edison	15	4 135[15]	1,828
SDG&E	1	34	79

F. Recent Experience -- Much Less Stable

In the post-electric restructuring time period, 1999 to present, the electric market has been very volatile, and interruptible program customers have been subjected to unpredictable energy service. In these past two years, California's investor-owned utilities have dramatically increased the number and frequency of interruptions called under the interruptible programs. The increased reliance on the programs has revealed serious compliance problems, and resulted in exhausting or nearly exhausting the ability to call for interruptions in the first quarter of 2001.

1. 1999-2000: Dramatic Increase In Interruptions

Over the summer of 2000 (May-September) PG&E had 8 events where it called for interruptions from all interruptible customers.[16] In those events,

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[14] Peak load reductions available from base interruptible programs as claimed by Utility.

[15] Enrolled in program on short-term basis

[16] Because the ISO calls for a specific amount of MW interruptions, some events do not require all customers to interrupt.

PG&E's interruptible customers reduced demand on average 490 MW, ranging from 341 MW to 567 MW. On average there was 19 MW of load that was not interrupted, but, under the program rules, should have been. In January 2001, when interruptible customers were called upon repeatedly to reduce their loads, preliminary estimates placed PG&E customer compliance at 90%. While this compliance rate remains substantially higher than that achieved by Edison and SDG&E, it represents a 5% reduction in average compliance relative to 1999 (Table 3).

Edison's traditional interruptible program customers reduced their loads in response to interruption calls an average of 1,213 MW in similar events in 2000, with an average of 636 MW of load that was not reduced, but should have been. Figures from 2000 show that only about 62% of Edison's interruptible load customers reduced load when requested (Table 3).

As stated above, Edison had not called for interruption of its industrial customers' consumption throughout the 1990's until interruptions were called in 1998. Based upon the relatively low compliance rate achieved in 2000, it appears that a number of customers that elected to join the Edison program were unable or unwilling to reduce load upon request.

2. Compliance Becoming A Serious Issue

With the number of interruptions calls increasing in 2000 to 14 for SDG&E and 20 each for PG&E and Edison, customers are finding it increasingly difficult to comply with the program rules. PG&E's compliance rate remains high in 2000 at 90%, but that rate is a drop from 95% in 1999. Edison's compliance rate remains steady, but at the relatively low rate of between 50%-62%.

Although Edison routinely reported to the Commission that it had 1,800 MW of participating load capable of being interrupted, actual operation of

Edison's program has shown that only about 2/3 of capacity (1,200 out of 1,800 MW) actually interrupt when requested.

To better understand Edison's relatively low compliance rate, staff directed Edison to provide customer-specific program participation data. After reviewing this data, staff concludes that Edison's low compliance rate has likely been caused by a number of customers who should never have signed up for Edison's program in the first place. These customers are unwilling or unable to reduce their energy use when requested. Numerous customers classified their entire load as interruptible in order to qualify for the lower rate. This includes many customers (such as hospitals and prisons) which are classified as "essential customers" and are therefore exempt from rotating outages under our rotating outage rules. Several schools also signed up for the program.

Although every customer enrolled in Edison's traditional interruptible program voluntarily signed a contract agreeing that they could be interrupted for up to 25 times per calendar year, many of these customers may not have fully appreciated the commitment in the contract. As a result, Edison's interruptible customers have incurred over $92 million in non-performance penalties for failing to reduce their load when required (Table 5).

Table 5

Edison's Customer Compliance and Penalties for 2000[17]

CEC BUILDING TYPE	AVAILABLE INTERRUPTIBLE LOAD (Avg. Start MW-FSL)	% COMPLIANCE	% NON-COMPLIANCE	PENALTIES
Ag and Water Pumping	16.83	74%	26%	$612,772
Assembly Industry	1032.52	70%	30%	$42,637,799
College / Trade School	64.4	65%	35%	$3,037,586
Food Store	29.6	49%	51%	$2,067,441
Government	59.8	44%	56%	$5,258,403
Hospital	88.4	40%	60%	$8,029,730
Lodging	31.3	64%	36%	$1,777,706
Medical Office	2.0	8%	92%	$271,039
Military	0.91	36%	64%	$78,657
Miscellaneous	60.3	22%	78%	$6,582,777
Nursing Home	2.51	2%	98%	$3,687,161
Office	43.6	36%	64%	$4,272,033
Other Process Industries	112	93%	7%	$1,097,246
Process Industry	130.2	91%	9%	$1,504,389
Retail Store	60.9	26%	74%	$7,209,803
School	25.5	60%	40%	$1,465,202
Trans / Comm / Utilities	47.3	85%	15%	$988,348
Warehouse	27.2	55%	45%	$1,864,153
Total	**1835.27**	**51%**	**49%**	**$92,442,245**

By January 2001, even participating customers that complied with interruption requests found it increasingly difficult to meet the program requirements. Interruptions of load to petroleum products producers that chose to participate in the interruptible programs caused the California Energy Commission to conclude that public health and safety may be jeopardized. Participating customers expressed concerns that the frequent and numerous calls for load reductions through the interruptible programs are making it increasingly difficult to conduct day-to-day business. On January 26, 2001, the Commission suspended the interruptible programs and penalties, without

[17] Data obtained from Edison's response to Energy Division's data request 1 and 3.

modifying the rate reductions, and called for participating customers to continue to comply with calls for interruptions on a voluntary basis.

3. 2001 -- PG&E Program Exhausted, Edison Program Likely Exhausted In March, SDG&E Program Has More Flexibility

Only four weeks into the new year, the tight energy supplies had already exhausted PG&E's "traditional" interruptible program. PG&E has already reached its 100 hour limit on program participation, north of path 15.[18]

For Edison, a somewhat similar pattern has emerged. Interruptible customers in Edison's service territory have already been interrupted, depending upon the customer, 11 or 12 times. The limit on interruptions in Edison's program is set at a maximum of 25 events or 150 hours. Therefore, about 50% of Edison's available traditional interruptible load has already been utilized.

SDG&E's program, with 80 hours available annually, has greater flexibility and is not at or nearing exhaustion.

Historically, the utilities, the Commission, and program participants expected that interruptible programs would be utilized almost exclusively during the summer months when energy demand in California and many interconnected states is significantly higher. Today, during this energy crisis, the programs have already been heavily used in January when peak load is only about 2/3 of expected summertime peak load.

Near exhaustion of the interruptible programs may be of significant consequence. The load traditionally available for interruption during the summer to avoid rotating outages, absent any action by the Commission, will not be available. Under this scenario, the likelihood of rotating outages during the summer increases.

[18] Path 15 is a major transmission corridor between northern and southern California.

G. Independent System Operator Programs

The ISO offered one interruptible program during the summer of 2000, and one program to encourage load to bid into the ISO's Ancillary Service Market. The ISO intends to offer both programs with modifications for the summer of 2001. The ISO's Demand Relief Program is similar to the utilities' existing interruptible program and compensates participants with both a flat monthly commitment fee and a fee for each MWh reduced. The Ancillary Services Load Program allows participants to bid into a market that may result in the participants reducing load if operating reserves begin to fall.

1. Demand Relief Program

The ISO instituted its Demand Relief Program (DRP) to provide additional demand reduction and prevent rotating outages during periods of energy shortage. The ISO's program was designed to attract new load that was not participating in any other interruptible program. The ISO's DRP program targets entities to provide demand reduction either by reducing the load of a single source or by reducing multiple sources. These entities can be electric utilities, electric service providers, or any other entity that can aggregate multiple sources.

Under the ISO's DRP program participants agree to curtail between the hours of 12:00 p.m. and 8 p.m. on business days. Program participants are required to curtail between 2 hours to 8 hours for any single emergency call. Although multiple load interruption calls could be made in a single day, loads will not be interrupted past 8 p.m. Program participants are required to be interrupted and off the system within 30 minutes after being notified. The ISO's program allowed for up to 30 hours of interruptions per month during July, August, and September and up to 15 hours of interruptions per month in June and October.

Table 2 summarizes the performance of the ISO's DRP program during the summer of 2000. The total average committed capacity in the summer 2000 was 63 MW. Customers complied 44% to 66% of the time when called to interrupt. Participants received an average payment of $124,000 per MW and $2,500 per MWh. The program made $7.8 million in total payments. The cost per MW within the program was significantly higher than that paid in the utilities' existing interruptible program.

The ISO has decided to offer the DRP program from June 1, 2001 through September 30, 2001. The ISO's proposed 2001 DRP program has been expanded to include loads with back-up generation (BUG) that would be utilized as a last resort prior to rotating outages. Loads with BUG will be subject to a maximum of 7 calls during the summer, with 0-3 hours for each call, for up to a total 21 hours of total curtailment for the entire DRP. The loads without BUG portion will be divided into two blocks with a specified 4-hour interruption, up to 24 hours of total curtailment per month.

The participants must meet the following eligibility criteria to be in the summer 2001 DRP Program:

1. Participants or load aggregator must provide an average demand reduction for a single facility or aggregated facilities greater than or equal to 1 MW;
2. Participants must have an interval meter;
3. Participants can not be enrolled in any utility interruptible[19] load programs, or any other demand reduction program for the same load that the participant intends to offer in the DRP;
4. Participants must provide proof that all necessary permits of operation or approvals from the Air Pollution Control District or Air Quality Management

[19] Customers who entered an interruptible program of Edison, PG&E or SD&G prior to November 1, 2000.

District for each individual BUG designated for participation in DRP;

5. DRP participants will be called after customers from the UDC's interruptible programs have been called by the ISO.

Participants in the summer 2001 DRP receive a fixed monthly demand reservation payment of $20,000 / MW-month, adjusted for actual average monthly performance, and a performance payment for each curtailment of $500 / MWh. Participants are not penalized when they fail to comply. Performance payments are proportional to the amount of load interrupted during a call. Participants receive increased payments for over performance and are decreased payments when the amount of load interrupted fails to meet contract obligations.

The ISO will receive program bids by February 6, 2001 and enter into commitments on or before April 15, 2001.

2. ISO Ancillary Service Load Program

The ISO will offer its Ancillary Service Load Program (ASLP) during 2001. The ISO is seeking Federal Energy Regulatory Commission (FERC) approval to implement the ASLP throughout the entire year. Under the ASLP program, participants bid their resources (interruptible load) into the ISO's markets for Non-Spinning, Replacement Reserves, and Supplemental Energy. The ISO has capped the total amount of capacity that the program will accept in bids to:

1. Non-spinning reserve	up to 400	MW of bids
2. Replacement reserve	up to 400	MW of bids
3. Supplemental energy	up to 1,000	MW of bids

ASLP participants must bid at least 1 MW of load to participate. Participants are allowed to aggregate loads

During 2000, more than 75% of the participants that responded were customers who participated in the interruptible programs of Edison, PG&E and SDG&E. However, participants who also participate in one of the utilities' interruptible programs are currently prohibited by this Commission from participating in the ISO's ASLP. Edison and PG&E have requested modifications of their rules to allow their interruptible customers to bid their load reductions into the ISO's ASLP program.

The purpose of the ASLP program is to maintain sufficient operating reserves so that it will not be necessary to initiate a Stage II curtailment. However, once a Stage II curtailment is initiated, the ISO can then direct the utilities to curtail these same interruptible customers at no cost. Therefore, it is unclear what benefit would be achieved by allowing interruptible customers to participate in these markets.

3. ISO Discretionary Load Curtailment Program

The ISO has proposed creating a program for loads not able to participate in the more structured interruptible programs or the ISO's DRP. The program, called the Discretionary Load Curtailment Program (DLCP) uses load aggregators, who must be certified by the ISO to participate. The program details are not final, but some of the proposed program components are available. When the ISO issues a warning notice for a specific operating day, the ISO will include a message that load aggregators should submit projected DLCP loads for that day. The ISO and load aggregators will communicate through the DLCP website. The ISO will confirm the accepted offers, based on need, and provide each aggregator the time and duration of its accepted curtailment. The program may operate year round and will pay participants on a dollar per MWh of interrupted load. The ISO is considering payments of $250/MWh. End use load participating in the DLCP can not be a participant in any of the utility interruptible load programs.

IV. Recommendations For Current Programs

A. Customers Must Meet Contractual Obligations

Based on recent curtailment events in Edison's service territory, it is clear that a number of customers voluntarily signed up for Edison's interruptible program despite being either unable or unwilling to curtail when requested to do so. While PG&E's program had a compliance rate in the 90-95% range, Edison's compliance was in the 50-60% range.

As a result, it appears that customers representing over 1,000 MW of interruptible load on Edison's system should not have been participating in the program. About 600 MW of load failed to curtail when requested to do so. A significant portion of the load that did curtail appeared to be able to do so only by significant disruptions to their operations, potentially jeopardizing the economic health of California.

Since almost all of these customers have been in the program since at least 1996, this means that these customers have received at least $300 million in reduced rates.

The Commission now recognizes that many customers either should not have signed up for the program or committed essentially all of their load as interruptible.

As the Commission noted:

> Interruptible customers now face increasingly serious consequences of being on interruptible tariffs, despite their voluntary choice to have subscribed for interruptible service, and their obligation to abide by the terms of the tariff. In fact, it appears that many customers, for a variety of reasons, chose to participate in the interruptible

> program despite being relatively unsuited to meet the program's requirements…
>
> These customers face the ongoing choice of curtailing electric service, or paying significant penalties. If they curtail service, for many customers this means closing their operations or businesses, with deleterious effects on themselves and the California economy. The harmful effects include lost sales, lost revenues, lost productivity, foregone wages, layoffs, unemployment, business not expanding in California, and businesses moving out of California…
>
> Alternatively, customers can continue to operate and incur large penalties. These penalties may threaten the financial integrity of their operations and businesses, and have the same deleterious effects on the California economy. (PP. 5-6, D.01-01-056).

As a short-term solution, the Commission suspended penalties, the tolling of hours, and the number of events in the current interruptible programs of PG&E, Edison and SDG&E.

In the longer term the Commission is faced with three options for customers who are in current interruptible programs:

1. Require customers to remain in the program under its existing operation;
2. Allow customers to opt out of the program without penalty;
3. Require customers to remain in the program but give them more flexibility in meeting program requirements.

Requiring most customers to remain in the program does not appear to be a viable option. As the Commission noted, these customers face a choice of either paying significant penalties or substantially reducing operations, neither of which is acceptable.

Each 1 MWh of interruptible load is equivalent to 1,000 homes that are not subject to rotating outages for one hour.[20] Allowing customers to opt out without penalty would also transfer the responsibility of bearing outages from the interruptible customers (who voluntarily signed-up for the program) to all other customers who have not enjoyed the benefits of reduced rates.

Allowing customers to opt out would also reward customers who essentially "gamed" the utilities' rate structure. Over 78% of all customers on Edison's program signed up over 99% of their load as being subject to interruption (Table 6). It is many of these customers who are now having trouble complying. While it is reasonable, and perhaps should be encouraged, for customers to nominate a realistic portion of their load as interruptible, customers should not be exempted from the consequences of over-nominating their load. For example, many customers could easily achieve a reduction of 10-20% through reasonable modifications (e.g. turning off excess lighting and miscellaneous equipment such as microwaves ovens, coffee pots, etc., signage, adjusting thermostats, temporarily shutting one of several assembly lines, shifting some operations to the evening, etc.)

[20] Assumes one home has a load of 1 kilowatt. 1,000 kilowatts equals 1 megawatt.

Table 6

Edison's Interruptible Program 2000

CEC BUILDING TYPE	# of Customers By CEC Building Type	Less than 99%	Greater than 99%	% of Customers Who Nominated 99% of load or More As Firm
Ag and Water Pumping	24	5	19	79%
Assembly Industry	713	197	516	72%
College / Trade School	37	7	30	81%
Food Store	19	0	19	100%
Government	56	4	52	93%
Hospital	59	14	45	76%
Lodging	43	3	40	93%
Medical Office	4	0	4	100%
Military	1	0	1	100%
Miscellaneous	53	9	44	83%
Nursing Home	2	0	2	100%
Office	54	7	47	87%
Other Process Industries	80	8	72	90%
Process Industry	69	17	52	75%
Retail Stores	109	26	83	76%
School	57	6	51	89%
Trans / Comm / Utilities	61	10	51	84%
Warehouse	43	9	34	79%
Total	**1484**	**322**	**1162 (78%)**	

Allowing customers to opt out, and waiving penalties would also send a mixed message to customers on firm rates who are being strongly encouraged to voluntarily reduce their energy usage by 5-10% by the Governor. A review of customers on Edison's interruptible rate schedule found that over 100 interruptible customers made a 0% reduction in their energy usage when called upon to curtail. An additional 94 customers achieved reductions of less than 10%.

There is also a problem of "good" interruptible customers also leaving the interruptible program if customers are allowed to opt out. While customers who have no intention of curtailing would leave the program, customers who historically are ideal candidates for interruptible programs could also leave in order to participate in new interruptible programs. Essentially, these customers could opt out of their existing obligation and then join the variety of new programs being developed. As a result all other customers could double-pay for interruptible load as interruptible customers "churn" from one program to another.

The third option, is to require customers to remain in the program but give them more flexibility in meeting program requirements. This proposal is discussed further in the section on flexibility.

B. Customers Should Be Given Flexibility To Meet Obligation

The Commission's existing interruptible programs were designed to achieve demand reduction over a few peak hours that were assumed to happen during the summer. The current energy situation, by contrast, appears to be one where energy supplies may remain tight over extended periods of time (For example, California has been operating under Stage III conditions for 23 straight days since January 15, 2001).

1. Obligation Based On Total Hours

One modification to the interruptible program to reflect this changed condition would be to reflect this new imbalance of supply and demand by spreading the number of curtailments over a larger number of hours while reducing the amount of load reduction requested at any one time. For example, rather than have the utility curtail its customers for 4 hours at 1,000 MW (4,000 MWh total), the utility would curtail 500 MW for 8 hours (4,000 MWh).

The effect of this program change would be to turn the interruptible program into a base-load resource (i.e. supplying smaller load reductions over the course of the day) instead of its existing role as a peak-load resource (providing significant reductions over a few hours.)

The relative advantages of this proposal are contingent on forecasted energy conditions for this summer. If the underlying structural problems facing California can be solved and adequate energy supplies obtained, then it would be preferable to keep the current focus of the interruptible programs on peak-load reductions. If, however, energy supplies are likely to be tight for extended periods, then spreading the operation of the interruptible program over a larger number of hours may be preferable.

The disadvantage of this approach is that, by focusing less on peak-load reductions, rotating outages may be greater than normal during peak periods. This should be more than offset by reduced amounts of outages throughout the rest of the day. Overall, there should be reduced outages as program compliance increases.

Converting to an hourly program would help existing interruptible customers meet their contractual obligations. While it appears clear that a number of customers are unable to comply with the existing program, converting the program to an hourly program should make compliance easier to achieve. A customer who cannot curtail all of its load when requested may well be able to achieve a consistent 20% reduction in energy usage over a longer period.

The following is a conceptual example of how the existing program could be converted to an hourly program. Edison currently has approximately 2,800 MW of load and 75 hours of curtailment left per customer. This is equivalent to 210,000 MWh of curtailment. Under an hourly program, rather than have customers achieve this reduction solely through requests to curtail during peak days, they could curtail over the entire course of the summer on-peak season (Monday-Friday noon to 6 p.m. for the period June through September). In this example, this would work out to an average of about 400 MW of load reduction over the entire 500 summer on-peak hours.

2. No Call Programs

Most of the customers on PG&E's and SDG&E's interruptible program, unlike Edison's, appear ready and able to curtail when requested to do so. Even for many of these customers, however, it is difficult to be interrupted either repeatedly (in some cases for up to 18 hours per day) or for several days in a row.

One option to resolve this is to increase the flexibility of the current interruptible programs. This could include options such as;

- Limiting the number of curtailment requests allowed over a certain period; or,
- Allowing customers to designate certain days as "no-call" days.

Under the first option, for example, limits could be placed, such as no customer could be called upon to curtail for more than two times in the course of a business day, or more than 3-4 times during the course of a business week.

This would allow customers sufficient time to restore operations, as well as ensuring that operations are not disrupted for significantly long periods of time. In some recent cases, interruptible customers who normally respond to interruptions by drawing down supplies from existing inventories, and then replenishing supplies after the interruption, were unable to do so due to repeated curtailments.

Another option, and one that is being recommended for new interruptible programs, is for customers to be allowed to designate a certain number of days as "no-call" days when they would not be required to curtail if requested by the utility. This option would allow greater certainty for those customers who need lead time for their energy-intensive operations or have production processes that require long periods of continuous operation.

3. Pay Backs Penalties Through Increasing Obligation

Customers who did not comply with interruptions already have incurred over $92 million in non-compliance fines in Edison's service territory. While many of these customers perhaps should not have been on the interruptible rate schedule, as the Commission noted in D.01-01-056, requiring customers to pay these non-compliance fines could have economic consequences on their ability to continue to produce products and/or provide service.

In D.01-01-056 the Commission stated that it would establish a process to review already incurred and/or paid penalties and determine if all, some, or none of these penalties should be waived.

Another option the Commission should consider is to allow customers to pay back their fines through going-forward energy reduction efforts. This option would be similar to the flexibility option discussed above in which the interruptible program's operation is converted to an hourly basis. Customers could pay down their penalties by reducing energy usage during peak energy hours. These energy reductions would be credited against the customer's penalty obligation.

C. Limited Review Mechanism Regarding Public Health, Safety and Welfare

The Commission should consider a limited mechanism to review continuation of customer load on interruptible programs when this load significantly affects the public health, safety and welfare. For example, some hospitals, prisons, schools, and universities have enrolled all, or nearly all, of their load in interruptible programs. It is not in the public interest to retain load in interruptible programs when that load is not reasonably available for interruption, and, if interrupted, jeopardizes the public health, safety and welfare.

Energy Division proposes that participants that believe that public health and safety may be jeopardized by their continued participation in an interruptible program be allowed to petition the Commission. To accomplish this, the Commission should adopt a mechanism which allows the Energy Division Director, in consultation with the participant, utility, and Assigned Commissioner, to assess requests from participants to either amend or abrogate their contracts.

The mechanism would require the utility to notify all interruptible customers of this opportunity, with a form attached. An interested participant customer would be required to return the form within 30 days to the utility. The form would require the customer to state its current level of firm and interruptible load. It would also require a verified statement[21] wherein the customer explains how the current level of interruptible load is inconsistent with public health, safety and welfare, and how the reduced (or zero) level of interruptible load would be compatible with public health, safety and welfare. The customer should also include any other necessary and relevant information to allow an informed decision on the application. Economic harm would not be considered a reason consistent with public health, safety and welfare. Rather, reasons beyond economic harm would be necessary to justify a claim based on public health, safety and welfare.

The utility would have 10 days to submit the customer's application by Advice Letter, along with its comments in support, partial support or opposition to the request. The Advice Letter would be served only on the Energy Division Director and the customer.

Unless suspended by the Energy Division Director, the Advice Letter would become effective in 5 days. The Energy Division Director would also be

[21] See Rule 88 of the Commission's Rules of Practice and Procedure.

authorized to rule on any other outcome than the one contained in the Advice Letter application. The ruling would be by letter served on the utility and customer. A dissatisfied customer or utility may appeal the Energy Division Director's determination to the Commission by the use of the expedited complaint procedure. (Rule 13.2 of the Commission's Rules of Practice and Procedure.)

V. Criteria for Evaluating New Interruptible Programs

A. Role of Interruptible Program Identifies Appropriate Criteria

Interruptible programs are needed because there may not always be sufficient generation to meet system needs. Consequently, interruptible programs are a substitute for generation. In the long term, generation may be less expensive than interruptible programs, but at the present time sufficient generation may not be obtained in time to meet system needs. Therefore, while interruptible programs appear to be necessary for the summer of 2001, longer-term programs should be evaluated against other alternatives – such as new generation or energy efficiency

In evaluating the cost of a program, the full cost of the program in dollars per MWh of load reduction should be considered. Programs should be evaluated on the expenditure necessary to obtain load reductions.

The reason for using a cost per MWh measure is to control for the variations in program costs and performance. Some programs require considerably higher start-up costs and continuing costs than other programs. Direct benefits to customers vary as do the expected load reductions. Administrative costs can also be significant. For example, a program serving large customers may have significantly lower costs per MWh of potential load reductions, than a program serving many smaller customers and similar or lower MWh load reductions.

B. Value of Lost Load

In evaluating a program, it is important to acknowledge the cost that is being avoided: the cost of rotating, 60 to 90 minute outages. Interruptible programs provide a hedge, a reserve of interruptible capacity that can be used to avoid or mitigate a targeted electricity blackout or total system failure. If the cost of a proposed program exceeds the projected cost of the outage, then the program should be rejected. These costs also need to be adjusted for risk. If the risk is high, the electric system should be willing to pay close to the cost of an outage, while if the risk is low, then less program cost should be incurred. For 2001, there is a general belief that there is a high risk of rotating outage, absent a strong interruptible program and perhaps even with one.

The cost of rotating, 60 to 90-minute outages is difficult to measure. Residential customers are inconvenienced. This inconvenience can be measured by survey, but surveys are subject to error because of limited experience with outages. Commercial and industrial customers can better quantify the cost of a ruined production run, or lost business from being closed for an hour, but effects on market share and future business are harder to ascertain. The impact of rotating outages on corporate planning and therefore on the State's future economy is also difficult to ascertain. Some commercial and industrial customers protect themselves from the costs of outages by purchasing generation to use either as a back-up, or as a daily supplement the power they receive from the grid, or by participation in interruptible programs. The customer's ability to avoid outage costs should also be considered in assessing the costs of an outage.

C. Program Interactions

In establishing new programs and modifying existing programs the Commission should avoid two pitfalls that result from having multiple programs: multiple payments for the same load reduction, and load reduction programs competing for the same customer.

Programs should be designed to prevent multiple payments for the same load interruption. The Commission and the ISO have tried to prevent the same load from participating in multiple programs. For example, the Commission has not allowed basic interruptible program participants to bid into the ISO's Ancillary Services Market. Similar protections should be considered for all programs.

The other pitfall to avoid is having multiple programs competing for the same customer. Programs should not be bidding against each other for participants. Coordination in necessary in program design so new programs are sufficiently differentiated from existing programs and payments offered are commensurate with required performance. Interruptible customers should choose between programs that best suit their operations, not because one program compensates better than another for the same load reduction. The goal of introducing new interruptible programs is to obtain incremental load that the ISO and utilities can use during an energy crisis.

D. Interruptible Program Performance Is Difficult To Predict. Some Experimentation Is Reasonable

Interruptible programs do not always deliver the load reductions purported to be participating in the program. This is caused by several factors, including normal load variations, non-compliance, and weather. Experimenting through pilot programs can increase the predictability of a program's performance in providing load reductions, and help test the cost effectiveness of the program.

Customers' loads vary significantly over time of day and time of year. Typically load available for interruption is measured at either coincident peak (interruptible capacity at the system's peak but not necessarily each customer's peak) or non-coincident peak (each customer's load measured at the customer's peak). There is no guarantee that the customer will be using the claimed peak when an interruption is called. Therefore, interruptible programs often do not produce 100 percent of the claimed benefit when called. For example, PG&E's traditional interruptible program recorded load reductions of 341 MW on one day and 567 MW on another with no significant variation in compliance. It was just that customers were using more loads on the second day and, therefore, had more loads to curtail. Edison's original forecast was that it would need about 3 MW of capacity signed up in order for 2 MW to be available at the time a load reduction was called. PG&E cancelled its air conditioner cycling program because too many participants did not use their air conditioners during peak hours and so the program provided little load relief.

Non-compliance also has significant effects on the load reductions obtained from interruptible programs. PG&E's program is small compared to Edison's program, but obtained over 90 percent compliance when called. Edison's program contained over 1800 MW, but only about 2/3 of the MW were available when called. The ISO's 2000 DRP obtained load reductions of 44 to 66 percent of the enrolled capacity. While staff has not analyzed the causes for the relatively low load reductions, staff believes that a significant portion of the failed load reduction is due to non-compliance. Therefore, the potential for non-compliance is an important factor in considering a program's potential performance and cost effectiveness.

Weather can be a large factor in assessing available load reductions. Air conditioners are more likely to be operating on hot days. In addition, the hotter the day the less efficiently air conditioners operate and the more loads they use. Dark and cloudy days lead to increase lighting usage. Conversely, sunny cool days have less air conditioning and lighting load available for interruption.

VI. Staff Recommends Five New Programs And Additional Study Of A Sixth Program

Energy Division recommends the Commission adopt five new programs for PG&E, Edison and SDG&E customers. Energy Division has selected programs it believes will have predictable results, as cost effective as the current interruptible programs, and will attract a wide variety of customers. Due to the energy crisis facing the state, which has led to the rapid exhaustion of the current interruptible programs, the anticipated demand / need for interruptible load this summer, and the recent suspension of the interruptible programs, Energy Division recommends both compulsory and voluntary programs. In developing these recommendations, Energy Division applied many of the criteria listed above. However, given limited time, poor data on cost effectiveness, and the substantial change in customer's willingness to participate in interruptible programs, Energy Division urges the Commission carefully weigh and consider the criteria for each program before adoption.

A. New Interruptible Program

This program has two tiers. Tier I, the "Traditional Element" described below, is similar to the existing interruptible programs in that it offers a monthly fixed discount for program participation. Tier 2 adds a "Pay-Per-Interruption" component. The program is open to all utility customers able to provide the interruptible load as required. PG&E, Edison and SDG&E customers who currently participate in an interruptible program may join after satisfying either the annual requirements or the appropriate exit criteria contained in tariffs and contracts. Many of PG&E's customers will be immediately eligible for Tier 2.

1. Traditional Element

Program requirements:

1. At least 200 kW of interruptible load, not otherwise committed to an interruptible program for the same time period;
2. A committed load reduction of at least 15 percent of the average peak load for 2000;
3. Participants must have an interval meter, if the customer does not have one, the meter will be provided free;
4. Participant must interrupt load within 30 minutes of being called;
5. Participants enroll for the summer season;
6. Commitment is for 25 hours of interruptions per month, although customers can interrupt additional hours for additional discounts;
7. The program is for 2001 only, although it may be extended to 2002;
8. Penalty for non-compliance is $6.00 / kWh of excess energy;
9. Interruptions are limited to 8 hours on any one day.

To add flexibility, program participants may identify up to 5 no-call days per month. On the no-call days, the customer cannot be called to interrupt. Each participant must nominate no-call days by the 20th of the preceding month. No-call days can not be accumulated month to month. No more than four no-calls may be used consecutively within the same month.

In addition, after meeting the required 25 hours per month commitment, participants may, for the remainder of that month, participate in Tier 2 utility program.

Customers new to the interruptible programs shall be paid in the same manner as participants in existing interruptible programs; they will receive discounts on non-firm energy use. Existing interruptible customers who have reached the program limits shall be paid discounts equal to $20,000 / MW / month of interruptible load that the customer commits to interrupt during the 2001 summer season. An existing participant's MW availability will be calculated based on the participant's seasonal average available load prior to interruption calls during the summer 2000.

2. Pay-Per-Interruption

Program participants may also participate in a pay-per-interruption program once they have complied with the required 25 hours in each month. In the pay-per-interruption program enrolled customers are notified of interruptions by their utility. Customers must notify the utility if they choose to interrupt within 15 minutes of the initial call. If a customer chooses to participate, the customer must interrupt its load within 45 minutes of the initial call. Participants would receive $500/MWh for interrupted load. This program is similar to the utilities demand responsiveness programs in that it pays customers per interruption event instead of offering great discounts.

B. Voluntary Demand Responsive Program

1. Program Description

This program is a revision and expansion of PG&E's and Edison's experimental demand responsive programs, operated in 2000. The program will be voluntary, participants choose whether or not to participate when called, and receive a small administrative penalty ($100/event) only if they chose to interrupt and then do not. The program payments are $150/MWh.

Like the experimental programs, this program is designed to be flexible. Participants are notified the day before interruption is required. It is hoped this will appeal to customers who cannot enroll, or are unwilling to enroll, in programs with shorter notification periods. Also, participants are not required to interrupt, and do not incur penalties, if they do not choose to participate when called. The flexibility offered by these programs may cause customers who otherwise could not participate in interruptible programs to enroll and thus provide additional benefit to the entire system by further reducing demand when it is most needed.

Participants are required to commit at least 20 percent of their load, when they agree to an interruption. Load is measured from a baseline established by information regarding the previous 10 day's usage.

The ISO is proposing the similar DLCP, although program details are not final, it appears to be based on a set payment for each kWh of reduced load. The ISO and the Commission should work together to establish complementary programs that offer customers the option to be paid on a per interruption basis.

Although demand responsive programs seem attractive to customers and provide load relief, the cost effectiveness has not yet been determined. Both PG&E and Edison are scheduled to provide detailed economic analyses of their respective programs on February 10, 2001. Energy Division recommends that a revised demand response program be offered for the Summer 2001 season, but utilities should be allowed to submit changes to reflect the economic analyses that will be submitted in February.

C. Air Conditioning Programs

1. Air Conditioner Cycling Program For Commercial Customers

This program is an expansion of Edison's commercial program, and will be a new program in PG&E's and SDGE's territory. Any customer in Edison's territory and customers in selected areas of PG&E's and SDGE's territory may participate[22]. Customers enroll for 40, 50, or 100 percent cycling and will have their air conditioners cycled off during Stage 2 emergencies (just as other interruptible customers). There is no limit on the number of times a

[22] To minimize program cost and ensure efficiency, PG&E's and SDGE's program will initially be geographically centralized and limited to areas likely to produce the most load reduction

participant may be called in a year, but calls are limited to the summer months. Participants are required to remain in the program through one full season. Additionally, during the season, a participant cannot decrease its cycling commitment, but may increase it.

Participants are paid a bill reduction for the four-month summer season (June-September) of:

40% Cycling	$ 2.50 / month / ton of connected air conditioning
50% Cycling	$ 5.20 / month / ton of connected air conditioning
100% Cycling	$12.00 / month / ton of connected air conditioning

The bill reduction is paid each month whether the customer is called during a given month.

Current participants in Edison's commercial A / C program are eligible to participate in the new program.

2. Air Conditioner Cycling Program For Residential Customers

Energy Division recommends that the Commission establish a residential air conditioner cycling program in PG&E's and SDG&E's service territories. The program should be limited to areas with relatively high air conditioning loads. Edison's program should also be reopened to new customers and expanded to include the additional program options. Based on discussions with the utilities, Energy Division believes that a limited number of control units can be installed for use during the summer 2001 season. However, maximum effort will be made to install as many units as is reasonably possible prior to and during the summer 2001 season. By summer 2002, Energy Division believes that market saturation can be achieved as installation crews and radio-control switch production meet anticipated participant demand.

Based on SCE's existing program, the proposal will install one-way radio-controlled switches on residential air conditioners. It will be an expansion of the current Edison residential program, and will be a new program in SDG&E's and PG&E's territory. Customers may enroll for 50 or 100 percent cycling and will have their air conditioners cycled off during Stage 2 Emergencies. Participants enrolled for 100 percent cycling shall not be cycled off for more than 16 hours in any one-day period. There is no limit on the number of times a participant may be called in a year, but calls are limited to the summer months. Participants are required to remain in the program through one full season. Additionally, during the season, a participant cannot decrease its cycling commitment, but may increase it.

SCE current tariffs call for payment of about $25 year for 50 percent cycling; this should be increased to $50 per unit per year for unlimited interruptions. SCE's tariff rate for 100 percent cycling should be increased from $88 to $150/year for unlimited interruptions. Some of the approximately 128,000 participants in Edison's existing residential air conditioner program may choose to switch participation to the new unlimited interruption program in order to obtain the greater incentive offered for an unlimited number of interruptions. Existing Edison air conditioner cycling program customers should be allowed to "upgrade" into the new unlimited interruption programs.

In PG&E and SDG&E territory, payment for 50 percent cycling should also be $50 per unit per year, and $150/year for 100 percent cycling and unlimited interruptions.

D. Optional Binding Mandatory Curtailment Program

1. Program Description

OBMC programs exempt customers from rotating outages in exchange for partial load curtailments during a rotating outage period. The customer is required to file with the utility an acceptable binding energy and load curtailment plan. The customer agrees to curtail electricity use on its entire circuit by the amount being achieved via rotating outages. The customer's plan would show how reduction on the entire circuit could be achieved in 5 percent increments to the 20 percent level and show how compliance can be monitored and enforced. The customer is required to curtail during every rotating outage and to maintain the curtailment during the entire rotating outage period.

The purpose of an OBMC program is to provide a reserve of curtailable load that can be called during a Stage 3 emergency before rotating outages are called. The program protects large customers from the significant economic harm they would experience during a rotating outage. OBMC customers receive no payment; they benefit from an exclusion from rotating outages rather than from monetary compensation. During a Stage III emergency, the ISO may determine that a rotating outage is necessary to maintain the state's electrical system. Participants in a OBMC program will curtail their load prior to the utility instituting a rotating outage. In return, participants will be exempt from the rotating outage.

The OBMC program is open to any demand-metered customer who can meet the required 20 percent load reduction. Participants are required to have interval meters and telemetry devices and must pay for any necessary equipment that they don't have.

Since the goal is load reduction on a single circuit, several customers on a circuit could file a joint binding plan to guarantee the required curtailment from the entire circuit. Utilities shall facilitate joint curtailment plans, including but not limited to notifying all customers of the program rules and coordinating communication between customers on the circuit. The utility will only be required to begin facilitation when one customer on a circuit expresses its intent to participate in the OBMC program.

2. Issues

The OBMC program provides an alternative to interruptible programs and so may discourage participation in those programs. Few customers have the ability to interrupt their load by the amount required by interruptible programs and further curtail the amount of load required by the OBMC program. Therefore customers will likely choose between the programs. The OBMC program, by exempting customers from rotating outages and only being called during Stage 3 emergencies, may be preferred over interruptible programs. Participants in interruptible programs are not exempt from rotating outages and are called more often, during Stage 2 emergencies. The OBMC program has up-front costs and does not provide any payments, but the value of interruptible payments may be less than the value of a rotating outage exemption. If customers prefer OBMC to interruptible programs, there will be more Stage 3 emergencies, but not necessarily more rotating outages. In addition, the program costs ratepayers significantly less than interruptible programs because no discounts are paid to participants. The primary costs are associated with program administration.

Establishing a baseline for the amount of load that must be curtailed is important. Two methods of calculating baseline are proposed. Both methods may induce behavior that places more stress on the electric system. Using the previous year as a baseline, customers will have less incentive to install energy efficient devices or to conserve, because their baseline will drop, making it more difficult to obtain load reductions. By using recent usage as a baseline, customers have an incentive to increase load and use energy less efficiently in order to increase their baseline so that it will be easier to meet load reductions when requested.

E. Residential And Government Recognition Program

1. Program Description

This program's purpose is to recognize and thank all residential and local government customers who reduce load by at least 7 percent. Customers who reduce their usage are recognized as energy savers. Customers that maintain the energy reduction for at least 2 consecutive months (May-October) receive a certificate of appreciation from the Governor. There will also be awards for the customers in each county with the largest residential energy reduction and for the largest energy use reductions by a city, local, or regional government entity.

Energy reductions will be measured from the customer's energy use in the same month in 2000. Customers on Time-of-Use (TOU) meters must show usage reduction during peak periods. The Commission will maintain a Web page listing customers being recognized.

In establishing the award criteria, extra credit should be given to those customers who make significant energy efficiency gains, and adjustments should be made for customers who moved usage to a different meter.

2. Estimate Of Impact

An estimate of the program's impact is a 250 MW load reduction during the peak period. The estimate is based on 25% of residential customers reducing their load by 7% during the peak period. There is about 15,500 MW of residential load during the peak period from PG&E's, Edison's and SDG&E's residential customers. The estimate does not reflect any load reduction that may be obtained from local governments.

F. SDG&E's HVAC Program Warrants Further Study

1. Program Description

SDG&E has designed a HVAC program that provides customers tools to better manage their load. Customers control when and how they reduce load. The program is open to large commercial bundled customers with HVAC and lighting loads above 250 kW. Each participant is provided communications equipment, software and interval meters at no cost. Participants must enroll in either the ISO's DRP with SDG&E acting as aggregator, or in SDG&E's demand responsive program.

To fund the program, SDG&E would seek funding from several sources. The California Energy Commission would provide funds for the demand responsive system including software and programmable appliances via funds appropriated in AB 970. Meters will be funded through the real time meter memorandum account. SDG&E has filed an application requesting authority. The energy incentive payments would be funded either through SDG&E's own demand response program or a similar program offered by the ISO.

2. Estimated Cost Of Program

SDG&E estimates the program will attract 600 customers with an average load of 3.125 MW. The average program cost in the first year (2001) is estimated at $521,036 / MW and $302,425 / MW annually thereafter. Based on the assumption of 300 MWh load reduction, the program cost for the first year is $5,427 / MWh and $3,150 / MWh annually. Energy Division confirmed with the California Energy Commission that the final approval of the contract is scheduled for February 7, 2001.

3. Further Study Is Warranted

Energy Division believes that the HVAC program has many desirable attributes including utility control of interruptions, low impact on building occupants, and puts controls in place that can be used to increase overall efficiency of building operations. However, the program is not as cost effective as other interruptible programs. The Energy Division recommends that the California Energy Commission, SDG&E, interested parties and the Energy Division staff explore ways to reduce program costs at the technical workshops to be convened in this proceeding.

VII. Current Rotating Outage Programs Protect Electrical System During Shortages, But Have Significant Limitations

Because electricity does not store well, the electric system must always be in balance. That means the same amount of electricity needs to be produced as is being used at any one moment. When usage exceeds generation the system becomes unstable. The results of instability in the electrical system vary from damage to motors and electrical equipment (e.g. refrigerators, computers, and other consumer devices), to damage to electrical systems causing blackouts in several states. To maintain system integrity, the ISO uses a range of operational contracts to reestablish balance. If these attempts prove insufficient, as a last resort, the ISO orders the utilities to reduce load through rotating outages.

Rotating outages are merely planned load reductions by shutting off customers' power. Different groups of customers are shut off, each taking a turn. Hence rotating outages, because the outage is rotated between groups of customers, one after another. The utilities are required to maintain emergency response plans that describe how rotating outages are to be implemented. These plans detail which customers will have their power shut off, in what order, and how long the rotating outages will last.

At times when “operating reserves”[23] remain low, after calling for load reductions from interruptible program customers under the programs described above and calls for conservation generally from all customers, it is necessary to force electrical outages to reduce system load and thereby maintain the integrity and reliability of the electric system. Controlled, forced outages avoid system instabilities that may result in uncontrollable, system-wide outages that could black out large portions of the western United States.

A. In The Early 1980s, The Commission Developed Rules To Deal With Both Energy Shortages And System Constraints

1. Genesis Of Rotating Outage Programs

In 1973, there was a sharp reduction in the availability of fossil fuel for electric generation in California resulting from curtailments in imported fuel supplies. At the same time, prices for fuel oil rose sharply. Following this was a drought year resulting in a reduction in the availability of electricity from hydroelectric generation facilities. To meet the potential energy shortages, the Commission issued various decisions in 1973 and 1974 ordering the investor-owned electric utilities to put into operation voluntary plans for conservation of electric energy and reduction of load by forced outage.

In 1974, Sections 2771-2776 were added to the Public Utilities Code. These sections reflected the Legislature’s concern that there be a plan for allocating electricity among customers in the event of a shortage of electricity or gas. In 1975, the Commission initiated a proceeding to establish priorities for both gas and electric use to implement sections 2117-2776. In 1976, after input from interested stakeholders, the Commission adopted a system of priorities for

[23] “Operating reserve” is a term used to describe the margin of generating resource required to meet consumer demand. The operating reserve is maintained to ensure reliable electric service at all times.

statewide reduction of electric service. The Commission ordered the utilities to file action plans which incorporate the priority system and forced load reduction methods. In the early 1980s, the Commission evaluated the utilities' proposed action plans, adopted a revised priority system for mandatory forced load reductions, and established procedures for initiating rotating outages. The Commission also ordered that the utilities' action plans be reviewed and revised annually to keep them up-to-date.

2. Definitions

Since the late 1970s through the mid-l990s, shortfalls in operating reserve that warranted forced outages under the utilities' approved plans have been very rare. Today, news media reports of electric system emergencies are becoming a regular feature. Although Californians may now be becoming used to hearing reports on the various "Stage " emergencies, they may not really understand the terminology.

The three stages of system emergencies relate to the extent of shortfall in operating reserve. A Stage 1 emergency is declared when forecast or actual energy reserves are less than 7 % of available capacity. A Stage 2 emergency is declared when energy reserves fall below 5% of available capacity. A Stage 3 emergency, the most severe, is declared when energy reserves fall below or are forecast to fall bellow 1.5% of available capacity. The ISO is charged with monitoring operating reserve and notifying market participants and state agencies when an emergency is likely. It declares emergencies when necessary. Certain actions are requested of utilities and customers by the ISO in each stage of system emergency.

In a Stage 1 emergency, the ISO asks consumers to voluntarily reduce their electric energy consumption. In a Stage 2 emergency, the ISO asks utilities to call for reductions of load from the participants in their interruptible programs. Involuntary, forced interruption of service to customers -- "rolling blackouts" or "rotating outages" – may be required during a Stage 3 emergency. Rotating outages are a last resort to protect the electric system, after all other measures have been taken.

In a rotating outage, electric service to "blocks" of customers is sequentially shut off for a period of 1 to 1 ½ hours. A block (sometimes called a "group") is a collection of circuits that are usually geographically dispersed. A circuit is a collection of wires connected to one breaker (switch) at a substation.

The block system allows circuits to be shut off widely throughout a service area, and not in geographic zones or by substations. Each block is comprised of a mix of electronically and manually controlled circuits. Electronically controlled circuits are operated remotely. Manually controlled circuits must be manually operated by personnel at the local substation. The need for manual operation increases the time it takes to shut off certain circuits. This, in turn, affects the total amount of load that may be shut off in a particular time period. PG&E, in particular, because of its large territory and number of unstaffed substations, may encounter a staffing problem when trying to dispatch operators to substations to take a block out of service upon short notice from the ISO of a Stage 3 emergency. As a result, Energy Division recommends PG&E be ordered to assign staff up to 24 hours per day at all potentially affected substations when a Stage 2 alert is declared in order to be ready to implement Stage 3.

3. Utility Action Plans

The utilities are responsible for reduction of their load in a Stage 3 emergency according to these three basic Commission principles:

1. Assure equitable distribution of the burden of outages,
2. No direct relationship between first outage and economic production, and
3. Maximum load reduction early so as to avoid rotating outages if at all possible.

In establishing procedures for initiating rotating outages, the Commission specified that utilities must have 40% of their peak load available for rotating outages in 5% increments, so at any one time up to 20% of customers may experience an outage for a one-hour period. The Commission also identified specific entities to be exempt from rotating outages because they provide "essential services" such as fire fighting, police protection, and prisons services. Hospitals with 100 beds or more, air traffic control services, and sewer and water treatment facilities are also essential services that are exempt from forced outages. These entities are called "essential use" customers. Since the 1980's, utilities have filed emergency rotating outage plans with the Commission and the Commission staff has worked with the utilities to adapt the plans to changing circumstances.[24]

PG&E's 2000 rotating outage plan is as close to the intent of the principles of the Commission's orders as can be expected, given technical and organizational limitations. SDG&E, on the other hand, deviates somewhat from the Commission's specifications. In particular, SDG&E does not have 40% of their coincident previous summer peak load available for outage in an "equitable" distribution. They would shut off about 22% of the load by interrupting entire substations. This would block out large contiguous geographic areas, which may also pose a security risk. SDG&E lumped all manually switched circuits for outage in one block, which will always be shut off last to allow time for staffing at the subject substations. SDG&E committed to remedy these deficiencies in their 2001 plan.

Edison's 2000 rotating outage plan provides a number of options. Its plan B, like SDG&E's plan, also falls short of providing 40% of its peak load for

[24] Appendix A is an excerpt from D.91548 describing the adopted Priority System for Rotating Outages.

outage. Edison's preferred plan C is based on circuit peak loads and may not meet the 40% coincident load requirement available for outage. Edison places non-automated circuits in separate outage groups. This grouping could affect whether customers served by automated versus non-automated circuits are treated equitably with respect to the sequencing and duration of outages. Like SDG&E, the number of circuits planned for shut off are not proportional to Edison's total automated versus non-automated circuits.

The utilities are required to update their curtailment plans and verify their essential use customer list by June 30 of every year. Changes could be implemented following the submission of their plans. Energy Division recommends that each utility be required to file a prioritized list of circuits that could be re-worked before the end of September, 2001. Priority would be based on cost and the amount of load that becomes available when "essential services" customers are removed from the circuit.

The utilities have built some flexibility in to their systems to adjust for special circumstances. For example, water and sewage utilities may request restoration of their circuits' power if it has been shut off for a particular incident such as fire fighting needs, hazardous spills, or flooding. This flexibility reduces the amount of load available for shut off in a Stage 3 emergency.

4. Customer Notification

The Commission's rules for notification of a rotating outage do not require direct notice to customers of an impending rotating outage. Large customers and other customers who demonstrate major economic damage or clear and imminent danger to health and safety will receive notification if time permits. Warnings are not guaranteed. All other customers are notified through mass media.

The utilities' emergency rotating outage plans include plans for notifying customers and for warnings. PG&E's plan calls for media announcements when Stage 2 emergencies are called. When a Stage 3 emergency is called, its call center will make an attempt to notify, by phone, life support customers if rotating outages are pending. SDG&E issues media advisories and mailings to caution life support customers to check their emergency equipment. When a Stage 3 emergency is probable or imminent SDG&E notifies major medical facilities, medical baseline and life support customers. SDG&E also contacts medical facilities, medical baseline and life support customers after the outage to ensure service is restored. Edison's emergency rotating outage plan does not provide details on notification.

One of the issues raised when considering notice of rotating outages is security. If effective notice is made to the areas experiencing, or soon to experience, electricity outages, then criminals will also be alerted of areas where alarm and other security systems are not working. This conflict results in warning of impending outages in general areas. This general notice works well with the system of rotating blocks. In the system, circuits shut off are dispersed throughout a service area, and not in geographic zones or by substations. This system ensures that customers without power during outages are not far removed from areas with power.

Energy Division is concerned whether the current system for notifying the public of planned rotating outages is as effective as possible given current communication technology. The trade-off between system cost and security, and increased communication effectiveness, should be studied further.

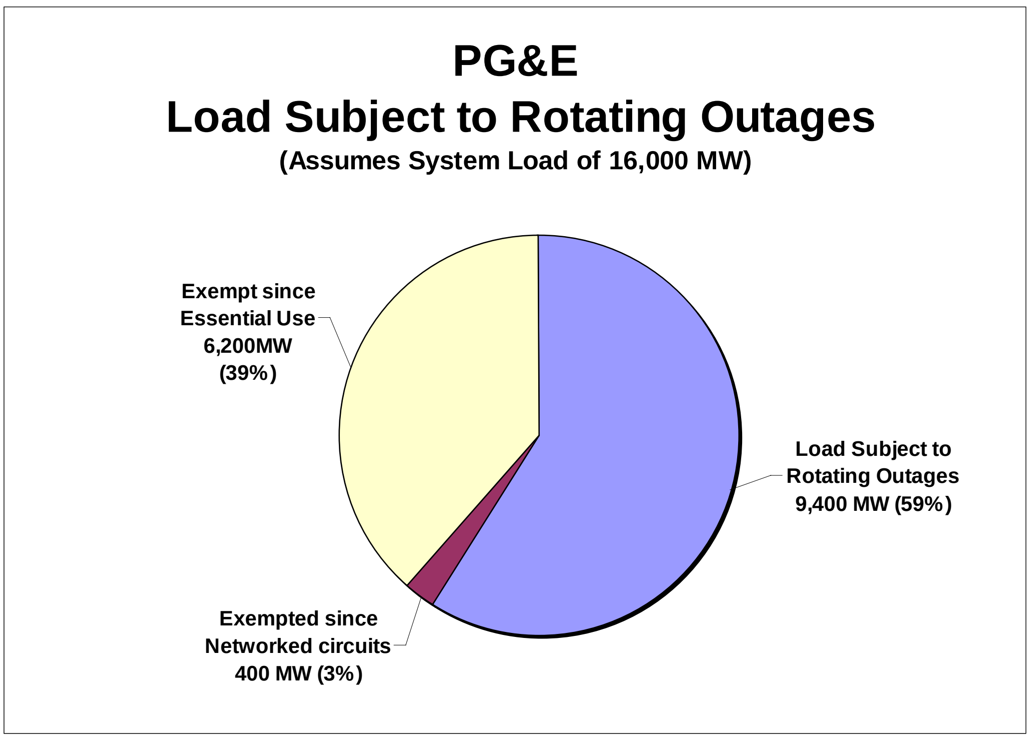
B. The Commission Rules Have Significant Shortcomings

1. Few Of The Customers Who Are Treated As "Essential" Meet The Definition

There are many customers that, by happenstance, are exempt from rotating outages. These customers share a circuit with an "essential services" customer. For example, PG&E has approximately 2.0 million customers who receive service on a circuit that is exempt from rotating outages. Of these customers, only 1500 to 1700 are essential service customers. Thus, more than 1.9 million customers are not defined as essential service customers but are effectively exempt from rotating outages because they are served from one of the separately controlled distribution circuits that serve one or more essential services customers.

2. Designating a Customer as "Essential" can Dramatically Affect Amount Of Load That Can Be Shut Off In An Emergency

Using PG&E's numbers as an example, more than 1.9 million additional customers could be available to be shut off in a Stage 3 emergency if they were not on circuits with "essential use" customers.



The inclusion of these customers would significantly increase the amount of load that could be shut off in an emergency. The decision to designate a customer as an essential services customer can significantly affect the amount of load available to be shut off, and, ultimately, the frequency of outages customers must face.

3. Certain Geographic Areas Are Treated As "Essential Service" Customers Because Of Network Design Limitations

Networks have current flow provided from multiple transformers simultaneously. Secondary networks are found in some dense urban areas. Although these networks exist in limited areas to improve local system reliability, they must be exempt from rotating outages due to their technical design. In PG&E's service territory, for example, there are approximately 20,000 electric customers and approximately 400 MW of total electric load that is served from the networked distribution facilities that provide service to downtown Oakland and San Francisco. This is a significant amount of load that is exempt from curtailment in an emergency.

4. Customers That Require Medical Life Support Equipment Are Not Defined As "Essential Service" Customers

Medical baseline customers include paraplegic, hemiplegic, quadriplegic, multiple sclerosis, or scleroderma patients and / or someone who must use medical life-support devices. PG&E, for example, provides electric service to approximately 48,000 medical baseline customers. This represents approximately 1.2 percent of PG&E's total number of residential electric service customers. Of the 48,000 medical baseline customers, 22,000 are classified as "life support" customers. Inclusion in this category usually indicates that at least one member of the household requires equipment to sustain, restore, or supplant a vital function. Even so, these customers are not defined as essential under the current rules.

5. Customers That Receive Service At Transmission Voltages Are Not Subject To Rotating Block Outages

When the Commission established procedures for rotating outages, few if any customers were served at transmission level voltages. Therefore, the procedures did not include transmission level customers in plans for rotating outages. Since that time a number of large customers receive service at transmission level voltages, but these customers are still not included in the pool of customers subject to rotating outages.

Some transmission level customers may not be able to be placed in the pool for rotating outages for technical reasons, but others could be. Different treatment of customers during rotating outages based only on service voltage creates equity concerns. Limiting the pool of customers subject to rotating outages increases the likelihood that service to a customer in the pool will be shut off, while the excluded customer is protected. Customers exempt from rotating outages also have less incentive to participate in interruptible programs that are designed to prevent rotating outages.

6. No Prohibition Against "Essential Services" Customers Signing Up For Interruptible Programs

In response to Energy Division data requests for information about the utilities' programs, the utilities provided information that revealed there are hospitals, schools, and prisons currently enrolled in interruptible programs. Even though these customers may have agreed to reduce their electricity consumption when called upon, some of these participants may be essential services customers that are not operationally capable of reducing load when called because of the essential nature of their operations. The Energy Division has heard from hospitals, schools and universities enrolled in interruptible programs that claim they cannot reduce load when called.

In the past, the Commission has not required utilities to screen interruptible program participants, based in part on the assumption that customers who are unable, or unwilling, to interrupt load on demand would not enroll in the interruptible programs. This approach recognized that customers enrolled in interruptible programs may have back-up generation or other abilities to reduce load when called.

VIII. Staff Recommends Changes To More Equitably Treat And Protect Customers During Rotating Outages

A. Changes To Improve Equity

Currently, about half of all PG&E's customers share the burden of rotating outages, while the other half are exempt. The Energy Division recommends exploring specific options to reduce the number of customers exempt from rotating outages.

1. Networks are exempt from rotating outages because it was considered technically impractical in 1980 when the exemption rules were established. PG&E's Downtown San Francisco and Downtown Oakland networks serve approximately 400 MW of load. The feasibility of including networks in rotating outages should be reexamined in light of technological advances over the last 20 years. The analysis should consider the costs and the number of essential use customers currently served by a network that would also need protection if the network were not exempted.
2. Because less than one in a thousand customers exempt from rotating outages is actually an essential services customer, it is important to examine the cost of reconfiguring circuits to narrow the exempted load. If

each essential services customer were on its own circuit, thousands of additional MW of load would be eligible for rotating outages. The cost of such reconfigurations should be examined and the most cost effective considered. Energy Division recommends a prioritized list be developed by each utility.

3. Some transmission level customers may not be able to be placed in the pool for rotating outages for technical reasons, but others could be. The Energy Division recommends utilities be ordered to include customers receiving service at transmission voltages in their rotating outage plans, subject to the essential services exemptions. When considering how to include transmission level customers in rotating outages, the unique characteristics of larger customers need to be considered. Some transmission level customers may prefer to decrease the number of potential outages, by increasing the duration of outages. Current rotating outage plans call for one hour to 90-minute outages. A transmission level customer may desire to be curtailed for a day at a time and then be exempt from the next outage or be enrolled in the OBMC program. Utilities should work with transmission level customers to propose interruptible programs that meet customer and utility needs.
4. Some essential services customers are participating in interruptible programs, up to and including their entire load. This appears contradictory because a customer cannot be both essential, and therefore exempt from interruption, and able to interrupt their entire load and pay a discounted rate at the same time. It is possible some customers are attempting to protect non-essential uses from rotating outages by claiming an essential use. These cases need to be investigated and the rules revised, if needed. It is also possible some essential use customers enrolled in interruptible programs in error. These cases also need to be explored.

5. Currently, electric utility facilities and supporting fuel and fuel transportation services critical to the continuity of the electric power system operation are defined as essential service customers and thus are exempt from rotating outages. The California Energy Commission should review the necessity of not curtailing and/or interrupting fossil fuel producers and make a recommendation to CPUC.

B. Changes To Protect Customers During Rotating Outages

1. A large number of the medical baseline customers require life-support devices to survive. These devices rely upon electricity to operate, and due to their essential nature, should have back-up generation. Before establishing service as a baseline customer, the utility should inspect the existing back-up generation to assure it will function during an electrical outage. In a Stage 3 emergency, the utilities should be required to notify, by telephone, customers on life support equipment in the block(s) scheduled for outage.
2. Many businesses get their electric service shut off during rotating outages. Some businesses, such as manufacturing plants, operate equipment that could affect employees and/or the general public's health and safety, in the event of power outages. OES/OSHA should examine plants to ensure that workers and the public are not unnecessarily endangered by forced electric outages.
3. As part of its protest to a PG&E request to amend its service rules, BART raised concerns that passenger safety could be impaired if its system was included in rotating outages.[25] The City and County of

[25] See PG&E Advice Letter 2019-E and related responses.

San Francisco raised similar concerns and included outages of traffic control devices as a potential safety hazard. The Commission's Rail Safety and Carriers Division has safety oversight responsibility for rail transit systems in California, including BART and MUNI. The Rail Safety and Carriers Division provided a report to the Energy Division recommending rail transit systems be exempt from rotating outages or mitigation measures be taken to ensure passenger safety (see Appendix B). PG&E has stated that it is technically possible to exempt BART from rotating outages without significant negative impacts on its emergency response plan. PG&E has also stated it is possible to give warning and delay implementing rotating outages that would affect the underground portion of MUNI's system until all trains were safely in a station or above ground. The Energy Division recommends the Commission modify the essential services list to exempt BART from rotating outages and implement mitigation measures to ensure the safety of MUNI passengers and staff. The Energy Division also supports the Rail Safety and Carriers Division recommendation that operators of other rail transit systems be encouraged to participate in the Commission's rulemaking proceeding and that the utilities serving these systems determine the feasibility of exempting them from rotating outages. Utilities and the operators of the rail transit systems should meet and present a joint proposal to the Commission for mitigating safety risks posed by rotating outages. Energy Division recommends the essential services list be expanded to include rail transit systems where there is a safety risk to passengers that cannot be mitigated.

IX. Utilities' Customer Notification Plans

The utilities' rotating outage plans should include descriptions of their plans for notifying customers of eminent outages. The notification plans need to be made more accessible and expanded to include people and/or entities with special needs. The utilities should develop multilingual press releases and implement outgoing notifications to those customers on their essential services lists. The utilities also need to assess the adequacy of their in-bound notification procedures to determine whether they have been able to handle the volume of calls they receive during rotating block outages. Also, they need to evaluate whether the necessary information has been communicated during an outage, or whether there is additional information that should be provided.

X. Appendix A

Decision 91548, Appendix B
Priority System for Rotating Outages

Essential Customers – Normally Exempt from Rotating outages

A. Government and other agencies providing essential fire, police, and prison services.
B. Government agencies essential to the national defense.
C. Hospitals with 100 beds or more.
D. Communication utilities, as they relate to public health, welfare and security, including telephones.
E. Navigation communication, traffic control, and landing and departure facilities for commercial air and sea operations.
F. Electric utility facilities and supporting fuel and fuel transportation services critical to continuity of electric power system operation.
G. Radio and television broadcasting stations used for broadcasting emergency messages, instructions, and other public information related to the electric curtailment emergency.
H. Water and sewage treatment utilities may request partial or complete RO exemption from electric utilities in times of emergency identified as requiring their service, such as fire fighting.
I. Areas served by networks, at utilities' discretion.
J. Binding mandatory Curtailment Plan

Any customer meeting both the criteria for Economic Damage and those following.

The customer would be required to file with the utility an acceptable binding energy and load curtailment plan. The customer would agree to curtail electric use on his entire circuit by the amount being achieved via rotating outages. The customer's plan would show how reduction on the entire circuit could be achieved in 5 percent increments to the 20[26] percent level and show how compliance can be monitored and enforced. Since the

[26] Changed from 50 percent by D.82-09-028.

required curtailment level would have been requested prior to the rotating outage stage, the customer would have to maintain the required reduction during all rotating outage periods. Several customers on a circuit could file a joint binding plan to guarantee the required curtailment from the entire circuit.

Note: Protection cannot be guaranteed because daily circuit switching may temporarily change a customers outage block and priority classification.

Economic Damage Customers

As circumstances permit, individual warning of RO plans would be given to large customers having demand of 300 kW or more, and to other customers upon their showing or need to show major economic damage or clear and imminent danger to personal health or safety, in order to qualify for this category. Individual timely warning could not be guaranteed either because of time, manpower, or communication limits, or because of daily circuit switching which could temporarily change a customer’s outage block number.

All Other Customers

Customers not qualifying for higher priority. Warning and other relevant information would be informed by mass media, and no special treatment or individual notification would generally be given.

XI. Appendix B

RULEMAKING 00-10-002
Report of the Rail Safety and Carriers Division
concerning the Interruptible Load Programs
Effect on Rail Transit Agencies

Purpose of this Section

On December 12, 2000, in Rulemaking 00-10-002, Commissioner Wood issued a Scoping Memo and Ruling. This section addresses the issues stated in Section 1.1(2) c of the Scoping Memo and Ruling, as follows:

The issues to be addressed in this proceeding are:

> c. whether or not trains and buses operating on the San Francisco Bay Area Rapid Transit District (BART) and the San Francisco Municipal Railway (MUNI) should be exempt from curtailments.

The Commission's Role Regarding Rail Transit Agencies

The Commission is the designated state agency for safety oversight of rail transit agencies. The Commission has safety oversight of trains. The Commission does not have direct safety oversight of buses operated by public transportation agencies.

California Rail Transit Agencies

The six major rail transit agencies in California are:
Bay Area Rapid Transit District (BART)
Los Angeles County Metropolitan Transit Authority (LACMTA)
Sacramento Regional Transit District (SRTD)
Santa Clara Valley Transportation Authority (SCVTA)
San Diego Trolley Incorporated (SDTI)
San Francisco Municipal Railway (MUNI)

Sources of Electric Power

BART receives its electric power from PG&E.

LACMTA receives its electric power from two sources, (DWP) and Edison. The LACMTA Red Line is powered by DWP. The LACMTA Blue Line is powered by Edison and DWP, with Edison power beginning approximately south of Washington Boulevard. The LACMTA Green Line is powered by Edison and DWP, with Edison power between Central Boulevard and Vermont Boulevard.

SRTD receives its electric power from Sacramento Municipal Utility District (SMUD).

SCVTA receives its electric power from PG&E for 20 out of 21 SCVTA substations. The remaining substation receives power from the City of Santa Clara.

SDTI receives its electric power from San Diego Gas & Electric.

MUNI receives its electric power from PG&E.

Safety Issues of Electric Power Curtailments

Each of the rail transit agencies operates, at least in part, in an exclusive right-of-way, including underground sections, tunnels, tubes, and / or aerial structures. These sections of track, some of which are several miles long, present accessibility challenges to emergency response personnel. The curtailment of electric power, combined with a fire or other emergency, would add the risk of death or severe injury to the passengers if a train were stranded in one of these sections of track. A rescue train would not have the electric power to reach the incident train. Self-evacuation of passengers is a possibility and would add risk.

The Commission requires each rail transit agency to develop and implement a system safety program plan and an emergency plan. An important element of the system safety program plan is the identification, categorization, and resolution of hazards. Hazards are normally categorized in terms of severity and probability of occurrence. Hazards that could result in death or severe injury, and could be expected to have a frequent or probable chance of occurring, are defined to be unacceptable hazardous conditions. The Commission requires the rail transit agencies to minimize, control, correct, or eliminate any unacceptable hazardous conditions.

The safest place for a passenger on the rail transit right-of-way is inside the vehicle. The curtailment of electric power would strand trains in locations that would probably require passengers to walk along the right-of-way to a safe location, such as a station. This would expose the passengers to safety hazards.

Passengers would be exposed to high-voltage electric power sources in the form of energized third rails and catenaries. Even though electric power is curtailed, there is still a danger of partial power or residual power if the passengers touched the third rails, catenaries, or the outside of the vehicles.

Passengers would be exposed to the hazard of falling, including from the doorway of the train into the right-of-way or from overhead structures to the ground below.

Passengers would be exposed to moving trains if the opposite direction track is energized or upon the restart of operations after the curtailment.

Conclusion

Electric power curtailments could result in safety hazards to passengers riding on rail transit systems.

Mitigation Methods

Mitigating methods could minimize any unacceptable hazardous conditions resulting from electric power curtailments.

The best method would be to exempt rail transit agencies from electric power curtailments. If the rail transit agencies cannot be exempted, alternative methods would need to be found.

One alternative would be to prohibit electric power curtailments on those sections of track that have limited access to emergency response personnel, such as underground sections, tunnels, tubes, and aerial structures.

Another alternative would be to provide sufficient time notification from the electric company to the rail transit agency to allow trains to reach a safe location, such as a station. This alternative would require the electric company and the rail transit agency to negotiate, develop, and implement procedures on notification.

Recommendations

The rail transit agencies should be exempt from the curtailment of electric power to protect the safety of the passengers.

If the rail transit agencies cannot be exempt from the curtailment of electric power, measures should be put in place to minimize the hazards to the passengers.

The six major rail transit agencies in California should be given the opportunity to participate in this proceeding.