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Decision 02-04-060 April 22, 2002

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking into the operation of interruptible load programs offered by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and the effect of these programs on energy prices, other demand responsiveness programs, and the reliability of the electric system.	Rulemaking 00-10-002 (Filed October 5, 2000) Phase 2

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INTERIM OPINION ON INTERRUPTIBLE PROGRAMS AND CURTAILMENT PRIORITIES

1. Summary

Since the mid-1980s, electricity customers have been offered rate discounts for agreeing to interrupt their use of electricity when demand approaches supply. If demand exceeds supply after voluntary interruptions, utilities implement rotating outages based on Commission authorized curtailment priorities.

On April 3, 2001, in the midst of a serious electricity crisis, the Commission adopted important improvements to interruptible programs and curtailment priorities for Summer 2001. (Decision (D.) 01-04-006.) We now give further consideration to these matters for the period after Summer 2001. Specifically, we address (1) interruptible programs, (2) curtailment priorities, (3) priority for residential use in areas of extreme temperatures (Senate Bill (SB) 2X 68), and (4) disposition of certain memorandum account balances.

Regarding interruptible programs:

- Extend Programs: We extend the duration of programs now scheduled to terminate on or before December 31, 2002 for a period of about one year, to the conclusion of the rate design phase of each utility's next general rate case (GRC), or similar proceeding. We set a planning goal of 2,500 megawatts (MWs) for interruptible programs, and reduce authorized capacity and dollar limits accordingly. We decline to order a special report from utilities in August 2002, but continue to require monthly reports.

- Bill Limiter: We continue the bill limiter provision in the interruptible program tariffs of Southern California Edison Company (SCE). We continue its application to the portion of existing rates that were in effect before 2001, but end its application to the remainder of rates effective on the date of this order. We provide a limited, 15-day opt-out for bill-limited customers.

- Aggregation of more than two circuits for OBMC: We decline to authorize a tariff option for aggregation of more than two circuits by a single lead customer for participation in the Optional Binding Mandatory Curtailment (OBMC) Program.

- Alternate Workweeks: We do not recognize alternate workweek schedules for participation in OBMC, as recommended by California Steel Industries, Inc. (Cal Steel).

- SLRP: We modify the non-compliance provision of the Scheduled Load Reduction Program (SLRP) for consistency with meter data.

- OBMC: We authorize OBMC participation after an interruptible customer completes its monthly obligations under the interruptible program, but decline other proposed changes to OBMC. We authorize a pilot program to test OBMC 10-day baseline measurement normalized to reflect current conditions.

- CCPCFA: We decline to adopt the interruptible program recommendations of the California Consumer Power and Conservation Financing Authority (CCPCFA or Power Authority).

- SDG&E EAEI Program: We decline to give further consideration to the proposal of San Diego Gas & Electric Company (SDG&E) for an Electric Appliance Equipment Interruption (EAEI) program.

- CEC Proposals: We decline to adopt the surcharge or specific modifications to existing programs proposed by California Energy Commission (CEC). We authorize a pilot program to test CEC's recommended modifications to the Base Interruptible Program (BIP).

- Change in Firm Service Level: We deny SCE's petition for modification of D.01-04-006 regarding decreases in firm service level (FSL). Customers may increase or decrease FSL during each annual opt-out opportunity.

Regarding curtailment priorities:

- Hospitals: We continue essential customer status for hospitals with fewer than 100 beds.

- SNFs: We expand essential customer Category C to include skilled nursing facilities (SNFs) licensed by the California Department of Health Services (DHS). We order utilities to file and serve reports on circuit reconfigurations regarding circuits that serve SNFs. SNFs in Category M are transferred to Category C.

- Category M: We decline to adopt procedures for continuation of Category M status beyond September 6, 2003, and we remove Category M from the list of essential customers effective September 7, 2003.

- Water and Sewer Utilities: We direct respondent utilities to (a) notify water and sewer customers of essential customer Category H, (b) conduct a test of Category H exemption or restoration procedures, and (c) report the results of those tests. We decline to order that water and sewer utilities install backup generation. We decline to adopt the joint recommendation of SCE and Los Angeles County (LAC) to modify essential customer Category H to provide for "immediate" restoration of service, but order utilities to discuss their response as part of their report on testing Category H.

Regarding extreme temperatures:

- Special Priority: We decline to adopt a special priority of use for some customers based on extreme temperatures.

- Customer Education and Advance Notification: We adopt utilities' alternative recommendation for customer education and advance notification, but permit self-certification rather than require medical certification.

- Cooling Stations: We adopt utilities' proposal to use cooling stations. We encourage utilities to locate such stations, and consider working with customers to seek legislation, if necessary, to provide funding.

Finally, regarding memorandum account balances:

- Collection of Memorandum Account Balances: We require collection of balances in memorandum accounts that were created to track non-compliance penalties from October 1, 2000 through January 25, 2001. We permit a limited reconciliation of balances for Pacific Gas and Electric Company (PG&E) customers for the period from November 1, 2000 to April 30, 2001, and permit curtailment events during that period not to be counted toward the tolling of compliance for the level of non-compliance penalties in the subsequent year. We permit a limited opt-out for SDG&E customers who were interruptible customers for 12 months or less.

- Calculation of penalties: We deny Cal Steel's petition regarding scaling non-compliance penalties for the amount of compliance, but partially grant SCE's alternative proposal to the extent that we allow customers who originally opted-out of SCE Schedule I-6 in favor of OBMC to return to Schedule I-6 effective November 1, 2000. The customer may determine the FSL and may now exercise its November 2001 opt-out.

All matters are now resolved, with the exception of a petition for modification of D.01-09-020 filed on February 20, 2002 by Dr. Lee F. Walker, and the future of the demand bidding program (DBP). The proceeding remains open only for resolution of these two items.

2. Procedural Background

This proceeding was divided into two phases. (Scoping Memo and Ruling, December 12, 2000.) Phase 1 addressed interruptible programs and curtailment priorities for the near term, with a focus on Summer 2001.[1] Phase 2 addresses these issues for the period after Summer 2001.

2.1. Initial Phase 2 Record

A prehearing conference (PHC) regarding Phase 2 matters was held on September 7, 2001. The Phase 2 Scoping Memo and Ruling was issued on September 21, 2001.[2] The Scoping Memo identifies four core areas for Phase 2, and states several specific issues within the four areas.

As provided in the Scoping Memo, the record is based on filed and served documents in Phase 2. Those documents include various reports, comments,

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[1] Several decisions were issued in Phase 1, including D.00-10-066, D.00-12-035, D.01-01-056, D.01-03-070, D.01-04-006, D.01-04-009, D.01-05-089, D.01-05-090, D.01-06-009, D.01-06-053, D.01-06-085, D.01-06-087, D.01-07-025, D.01-07-029, D.01-07-035, D.01-08-018, D.01-08-071, D.01-09-020, D.01-10-008, D.01-11-031, and D.01-12-007.

[2] A Ruling on possible emergency voltage reduction measures to reduce the need for rotating outages was also issued on September 21, 2001. That Ruling transferred the voltage reduction issue from Investigation (I.) 00-11-001 to this rulemaking, and set a formal hearing for October 11, 2001. The issue was processed in parallel with other Phase 2 issues, and a separate decision was issued. (See D.02-03-024.)

reply comments, proposals, revised proposals, letters, petitions, and other pleadings described below.

On June 7, 2001, utilities began filing and serving monthly reports on interruptible and outage programs. On September 28, 2001, the Commission's Water Division filed and served a report regarding the effect of rotating outages on water and sewer utilities. Comments were filed and served by the Association of California Water Agencies (ACWA), Coachella Valley Water District, Office of Ratepayer Advocates (ORA), Internal Services Department of the County of Los Angeles (LAC), and City and County of San Francisco (CCSF).

On October 12, 2001, respondent utilities filed and served reports on hospitals with fewer than 100 beds, SNFs, and proposals for curtailment priorities recognizing the effect of extreme temperatures. Also on October 12, 2001, initial proposals on all Phase 2 issues were filed and served by PG&E, SCE, SDG&E, California Manufacturers and Technology Association (CMTA), California Industrial Users (CIU), CEC, and ORA. The Commission's Energy Division facilitated workshops on October 29 and 30, 2001 on all Phase 2 issues.

By letter to Commissioner Wood dated October 30, 2001, CCPCFA submitted comments and proposals on interruptible programs. On November 9, 2001, comments on initial proposals, comments on CCPCFA proposals, plus revised proposals, were filed and served by PG&E, SCE, SDG&E, CIU, CEC, ORA, LAC, The Utility Reform Network (TURN), and California Large Energy Consumers Association (CLECA).[3] Comments were also received from THUMS Long Beach Company, and Ancillary Services Coalition (ASC).

[3] CLECA's letter of October 18, 2001 seeking inclusion on the Phase 2 service list was treated as a motion to intervene, and granted by Ruling dated October 26, 2001.

While petitions for modification may generally be filed at any time, the September 21, 2001 Scoping Memo provided guidance for parties filing petitions for modification regarding two OBMC issues. As a result, a petition for modification of D.01-06-087 was filed and served by CMTA, and a petition for modification of D.01-04-006 was filed and served by CIU. Responses were filed and served by PG&E and SCE.

On November 16, 2001, reply comments were filed and served by PG&E, SCE, SDG&E, CMTA, CIU, ORA, TURN, LAC, CLECA, the California Independent System Operator (CAISO), and Environmental Defense.[4] Reply comments were also submitted by ASC.

Motions for evidentiary hearing were due by November 21, 2001. No motions were filed. The matter was submitted for decision on November 30, 2001.

2.2. Supplemental Phase 2 Record

On December 10, 2001, Cal Steel filed and served a petition for modification of D.01-04-006 regarding calculation of non-compliance penalties for customers who elected to opt-out of SCE's interruptible program. SCE filed and served a response in opposition.

On December 18, 2001, SCE filed and served a petition for modification of D.01-04-006 regarding changes in firm service level of existing interruptible

[4] Environmental Defense concurrently filed and served a motion to intervene, which was granted by Ruling dated December 28, 2001. Both SCE and SDG&E filed and served errata on November 19, 2001 to their reply comments dated November 16, 2001.

customers. CMTA and Chromalloy Los Angeles[5] filed and served responses in opposition, and ORA responded in support. SCE filed and served a reply.

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[5] A motion of Chromalloy Los Angeles to intervene in this proceeding was granted by Ruling dated January 30, 2002. Chromalloy also filed a complaint against SCE on this issue. (C.01-11-018.)

On December 21, 2001, with permission from the Administrative Law Judge (ALJ), joint supplemental comments were filed and served by LAC and SCE. These comments supplement those filed in November 2001 on essential customer Category H and exemption from rotating outages for water and sewer agencies. Also with permission from the ALJ, PG&E filed and served a response; ACWA, LAC and SCE filed and served reply comments.

By Ruling dated January 11, 2002, the record was reopened to consider inclusion of a letter dated December 13, 2001 from the California Department of Water Resources (DWR) to the CAISO. CEC filed an objection to inclusion of the DWR letter, and utilities jointly responded in disagreement with CEC's objection.

By Ruling dated January 23, 2002, a CEC motion was granted to reopen the record to re-evaluate certain cost data associated with various demand responsiveness programs. Comments and objections were filed and served by CIU, PG&E, SDG&E, with reply comments filed and served by SCE and CEC.

By Ruling dated February 13, 2002, the DWR letter and several documents were included in the Phase 2 record. All matters were submitted effective February 4, 2002 (the filing date of the last round of pleadings).

A motion for Final Oral Argument was granted by Ruling dated April 5, 2002. By Ruling dated April 11, 2002, the proceeding was reopened regarding the ratemaking treatment for revenue effects of the bill limiter. SCE was directed, and others were invited, to file further information on this issue by April 15, 2002. Final Oral Argument was held on April 15, 2002, and the proceeding was resubmitted on April 16, 2002.

3. Interruptible Programs

We address the four core areas and issues in the same order as identified in the September 21, 2001 Scoping Memo and Ruling. The first core area involves modifications to existing interruptible programs. We began each section by stating the issue.

3.1. Extend Rolling Blackout Reduction Program

> **Issue**: Should any program scheduled to terminate before December 31, 2001 be extended from its scheduled termination date to December 31, 2002.

The only program due to expire before December 31, 2002 is SDG&E's Rolling Blackout Reduction Program (RBRP). The RBRP permits SDG&E to call on customer-owned emergency backup generators (BUGs) during a CAISO-declared Stage 3 event to reduce demand that must otherwise be met by system resources. The program was authorized for one year, at SDG&E's request, and will expire on May 31, 2002. (D.01-06-009.)

SDG&E proposes an extension through at least December 31, 2002. We adopt SDG&E's recommendation, but extend the program through completion of SDG&E's next rate design proceeding (with completion expected by April 2004). Extension through at least the end of 2003 is recommended by CMTA and CIU for nearly all programs, and is consistent with our extension of all programs below.

SDG&E states that the program has 35 customers from which a load reduction of 73.56 MW could potentially be realized during a Stage 3 emergency. (Joint Comments, October 12, 2002, page 2.) The program has been well received by customers. In fact, SDG&E has no other operational interruptible program that reaches this level of participation and amount of interruptible load.

No Stage 3 events have been called since RBRP was approved. Thus, there is no operating experience to show a need for any program revisions. We authorized a program in June 2002 which we believed reasonable and workable, and believe RBRP as authorized is still such a program. We are persuaded by SDG&E that this program merits continuation.

3.1.1. Program Type, Cost, Pollution, and "Free Riders"

TURN objects to continuation of the RBRP in it current form. TURN argues that the RBRP is not a demand reduction program, is expensive, causes pollution, and includes a high percentage of "free-riders" (i.e., participating customers who had already installed backup generation to meet their own needs). We are not inclined to make changes based on further argument of points that were so recently addressed in D.01-06-009.

For example, in relation to denying capacity payments we said that the RBRP is a demand reduction program, not a program for providing generation capacity to the grid. (D.01-06-009, mimeo., page 9.) TURN disagrees, and asserts that the program is being offered under the guise of a load reduction program when it is actually a supply-side generation program. TURN presents no new or compelling evidence or argument which convinces us to modify our view.

TURN asserts that the RBRP energy payment of $0.20/kWh is excessive. TURN proposes, however, that all programs (with the possible exception of OBMC) be combined into one new commercial/industrial program beginning in 2003. TURN's new program stresses energy payments (to focus on pay-for-performance results) rather than capacity or reservation payments (which are paid whether or not the customer is asked to perform). TURN proposes energy rates of up to $1.00/kWh for the first 20 hours, and up to $0.50/kWh for the next 130 hours, along with a capacity payment of $20/kW-year. TURN does not

convincingly show, however, why the existing RBRP energy payment of $.20/kWh is excessive compared to the prices in its proposed replacement program.[6]

We agree with TURN that price is an important matter. As a result, when authorizing RBRP we declined to adopt either the proposed capacity payment or proposed interconnection allowance, and substantially reduced the proposed energy payment. We considered several competing factors in reaching that decision and are not persuaded by TURN to revisit that issue now. If the price at any time is either too high or too low, a rapid adjustment mechanism is available. (D.01-06-009, mimeo., page 11.)

We agree with TURN that there are environmental concerns. We addressed those concerns by requiring customers to be responsible for compliance with all federal, state and local laws and regulations, including those regarding air quality. (D.01-06-009, mimeo., page 5.) Further, we conditioned approval of Schedule RBRP on environmental dispatch. (D.01-06-009, mimeo., page 12.) We are not persuaded by TURN that further mitigation is necessary or that this concern justifies program termination on May 31, 2002.

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[6] In its November 16, 2002 Reply Comments, TURN states that energy payments paid to interruptible customers in a pay-for-performance incentive should be net of avoided energy charges. TURN's reply comments state that SCE's interruptible customers would avoid paying $0.20/kWh in energy payments during on-peak hours. Thus, it appears that TURN's new program might pay up to $0.80/kWh and $0.30/kWh (rather than up to $1.00/kWh and up to $0.50/kWh), at least on SCE's system. Assuming this is a correct reading of TURN's proposal, and that SDG&E's on-peak energy charges are similar to SCE's, TURN does not explain why $0.20/kWh for RBRP is excessive compared to a net payment of $0.80/kWh or $0.30/kWh.

TURN correctly asserts that we primarily want customers to participate in existing programs (e.g., BIP, OBMC), and that we said continuation of RBRP beyond one year should be based on assessment of experience in Summer 2001. TURN states that experience in 2001 clearly demonstrates that RBRP is not needed in the future. We disagree. The experience in Summer 2001, and the lack of RBRP operation, do not by themselves support continuation or cancellation of this program. We believe that the general need for interruptible programs, such as RBRP, has not ended and that it is reasonable to continue RBRP along with other programs.

Finally, we considered the "free rider" problem in our rejection of the proposed capacity payment. (D.01-06-009, mimeo., page 9.) We authorized payment for the costs of incremental operation, but not fixed capacity costs, in part to address this concern. We declined to provide either a capacity payment or interconnection allowance because we did not intend to use the program to facilitate installation of new BUGs. We noted that customers already have incentives to install BUGs. (D.01-06-009, mimeo., page 9.) We concluded that there is little or no overlap between BUGs used to meet the customer's own emergency needs and those that will be used in the RBRP to maintain system reliability. (D.01-06-009, mimeo., page 14.) TURN fails to present any compelling evidence or argument that justifies revisiting that issue now.

3.1.2. Relation to OBMC

ORA proposes that all existing programs be consolidated into one or two programs by 2003. For example, ORA suggests that the RBRP be consolidated with OBMC, and that circuit exemption from rotating outages rather than cash be the incentive for participation.

We generally decline to consolidate existing programs (as discussed more below). We also note that different customers respond to different incentives. Cash and outage exemption are not interchangeable benefits to all customers. It is reasonable to have both, depending upon the program to which the customer subscribes.

Further, according to SDG&E, many RBRP participants are small, and share a circuit with many other customers. Small RBRP participants are not eligible for OBMC, as now designed, without several customers presenting a joint circuit plan. The benefit of RBRP may be lost, in part or whole, without this coordination, but neither ORA nor any other party present a compelling proposal that would ensure the same benefits are secured after program redesign.

Thus, we are persuaded to continue the program without change through conclusion of the next rate design proceeding, as we do with all other programs below.

3.2. Duration of All Programs

> **Issue**: Should programs scheduled to terminate on December 31, 2002 be extended, and, if so, should megawatt and total program dollar limits adopted in D.01-04-006 be modified.

At the commencement of this proceeding, all interruptible programs were scheduled to expire on March 31, 2002. We agreed with the majority of Phase 1 parties, however, that the need for these programs was unlikely to end by March 31, 2002. We stated that we could not extend these programs indefinitely, but decided to extend the expiration date to December 31, 2002, with both capacity and expenditure limits. (D.01-04-006, mimeo., pages 20, 78-81.) We resolved to again consider extensions, program redesign, and program limits in Phase 2, as necessary.

Respondent utilities state that there is insufficient information at this time to assess the value of interruptible programs for 2003 and beyond. Utilities propose that each utility be instructed to prepare a report in August 2002 evaluating customer participation in existing programs, stating an estimate of costs, and recommending ratemaking treatment. They suggest that parties be given an opportunity to comment on each report, and that they will simultaneously submit advice letters to continue programs they believe to be necessary. If the Commission disagrees with utilities' assessments, utilities recommend that there be an informal effort to reach resolution by September 30, 2002 and, absent resolution by that date, that the Commission open a limited proceeding to review issues on program continuation.

We decline to adopt this approach. Reports submitted in August 2002 cannot contain much data, if any, regarding actual Summer 2002 experience. This is the case whether they are submitted at the end of the month, or at the beginning, as CLECA recommends.

Moreover, respondent utilities' proposal lacks adequate information about the necessary schedule (e.g., amount of time needed to pursue informal resolution, to initiate and conduct a limited proceeding, to inform customers of the results, to permit subscription to new programs). We agree with CMTA that a "'wait and see' approach is simply not compatible with the need for forward planning by most businesses," and that waiting until the third quarter of 2002 to make a decision on these programs jeopardizes participation, even if programs are extended. (CMTA Reply Comments, November 16, 2001, page 2.)

We seek an approach that permits parties to provide better information and recommendations, and that allows adequate time for the Commission to make informed, reasonable decisions. Moreover, now is the time to consider an approach that allows us to once again integrate interruptible programs with the comprehensive review of rates and rate design that occurs in each utility's general rate proceeding.

3.2.1. Extend to Next General Rate Case or Similar Proceeding

CMTA and CIU recommend extension of programs through at least December 31, 2003, with capacity and dollar limits modified consistent with expected conditions. In particular, CMTA requests that the Commission provide some badly needed certainty by promptly extending existing programs through 2003.

We agree, and extend programs through the date of the final decision in the rate design phase of each utility's next GRC or similar proceeding. This is an extension through 2003 or early 2004.[7]

We do this because electricity supply and demand issues are sufficiently unpredictable that an extension of interruptible programs, with updated goals

[7] SCE tendered a notice of intent (NOI) in December 2001 to file a general rate case (GRC) application. We expect a rate design decision for SCE by November 2003. PG&E tendered an NOI on April 15, 2002. (D.02-04-018.) We expect a rate design decision for PG&E by December 2003. SDG&E will file a cost of service application about December 2002 for test year 2004 (D.01-10-030), and rate design will follow in a later phase of the cost of service application, or a rate design window proceeding. In either event, we expect a rate design decision for SDG&E by April 2004. Absent action to modify or terminate programs in those subsequent proceedings, we expect that programs will continue.

and limits, is reasonable. We expect estimation of supply and demand to become somewhat more predictable and stable when adequate new supply is added to California's resource base, the role of multiple state agencies and other entities is clarified, the remarkable conservation achieved in 2001 is or is not secured for the long term, and the profoundly dysfunctional electricity market is permanently reformed. Extension through the rate design decision in each utility's next GRC or similar proceeding provides time for some, if not all, of these events to unfold. It also permits examination of interruptible rates and rate design in the context of each utility's overall rates and rate design.

We agree with CLECA that there has not been a large subscription to the new programs we authorized in 2001. This is at least in part because it takes time to market programs, and for customers to make informed decisions. A reasonable extension will provide an opportunity to pursue marketing of stable programs for Summers 2002 and 2003.

Interruptible programs serve as a type of insurance policy against uncertainty. They function to provide statewide grid reliability, and reduce the probability of experiencing rotating outages or catastrophic system collapse. Some level of interruptible programs will probably always be desirable, as long as prices are reasonable for customers and ratepayers. As TURN says, "interruptible programs are insurance policies that need to match insurance premium payments to the value of the item being insured." (TURN Reply Comments, November 16, 2001, page 2.) We will have the opportunity in each GRC or similar proceeding to assess need, program design, rate design, rate levels and other factors.

Interruptible programs in some cases can also serve as a type of system resource. We will also have the opportunity in each GRC or similar proceeding to assess need, program design, rate design, rate levels and other factors for interruptible customers to function in this way. We may there consider, for example, payments that vary depending upon whether the resource commitment is for one year or more than one year.

This approach does not foreclose the Commission from instituting another rulemaking to examine interruptible programs on a statewide basis. We expect electricity markets to return to some level of stability, however, and we seek to return regulation to some level of normalcy. Normal operations permit review of all utility matters in a GRC or similar proceeding. If the need arises for separate or special statewide treatment of interruptible programs we may initiate a separate proceeding. We may also explore statewide treatment of interruptible programs in integrated resource planning or procurement proceedings. Parties may propose issues for future Scoping Memos in relevant proceedings that include statewide review of interruptible programs. Moreover, any interested person may petition for a special statewide proceeding. (PU Code Section 1708.5.) Absent initiating a special proceeding on our own, including the issue in another relevant proceeding, or granting a petition to do so, we adopt an approach that will promote reasonable reform from our current extraordinary approach.

3.2.2. Modified Capacity and Dollar Limits

We previously authorized up to 5,000 MW and $500 million per year for costs related to interruptible programs and curtailment priorities. We stated that we may reduce capacity and dollar limits going forward based on monthly reports or other information. (D.01-04-006, mimeo., page 81.)

The monthly reports filed for results through December 31, 2001 show total subscribed interruptible load of about 1,420 MW (at the 5% level for OBMC, and minimum Demand Bidding Program (DBP) response). CEC recommends a planning goal of 2,500 MW for demand responsiveness programs in 2002. We adopt this recommendation, and set a goal of 2,500 MW through the next GRC or similar proceeding. We reduce capacity and dollar limits accordingly, in the same proportion as previously authorized. The result is:

**INTERRUPTIBLE PROGRAM
AND CURTAILMENT PRIORITY LIMITS
UNTIL EACH UTILITY'S NEXT GRC
OR SIMILAR PROCEEDING**

UTILITY	INTERRUPTIBLE PROGRAM LIMIT (MW)	TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION)
PG&E	1,000	100.0
SCE	1,375	137.5
SDG&E	125	12.5
TOTAL	2,500	250.0

The monthly reports show no expenditures for curtailment priority limits, with the exception of about $1.5 million for SCE in 2002. This is a sufficiently small component that we do not separately adjust the SCE total. As already authorized, a respondent utility may file and serve an application, as needed, to adjust these capacity and dollar limits.[8] (D.01-04-006, mimeo., page 80, and Ordering Paragraph 17, as renumbered by D.01-04-009.)

The planning goal of 2,500 MW is reasonable given that current interruptible programs provide about 1,500 MW. The goal allows for successful program marketing to substantially increase existing demand responsiveness capacity by about 1,000 MW. Moreover, according to CEC, capacity of 2,500 MW will provide California system operators with about 5% of Summer 2002 projected load (44,000 to 47,000 MW) to be immediately responsive to necessary

[8] As discussed more below, PG&E Advice Letter 2110-E regarding a proposed air-conditioning cycling program will be addressed by a subsequent decision or resolution. That decision or resolution may include an increase in program limits for PG&E, if necessary.

system conditions. No party disputes the reasonableness of having 5% of demand responsive to system conditions.

We clarify that we do not view this 5% planning goal as a system resource to be dispatched by system operators, but as a margin against uncertainty and risk in Stage 2 and 3 emergencies. The majority of customers have told us that they do not want to be considered part of California's electricity resource base. (D.01-04-006, mimeo., page 30.) They do not expect to be routinely interrupted. Rather, their business is conducting their business, not buying and selling electricity, nor constantly monitoring the electricity market to make decisions about curtailing operations. An interruptible program as a system resource is generally a second best solution. The first best solution is adequate supply of safe and reliable electricity at just and reasonable rates.

Parties may wish to propose rates for interruptible programs in upcoming rate design proceedings that differentiate payment based on customer role. Payment may differ depending upon whether the customer provides insurance against occasional risks, or is a resource upon which California may call each and every year to meet demand (e.g., equivalent to a peaking resource). Payment for insurance may consider the likelihood of that insurance being used (i.e., expected experience). Payment to a customer providing interruptible load that is equivalent to a system resource might reflect the duration of the commitment (e.g., one year or 10 years), similar to payments to qualifying facilities.

We emphasize the importance of interruptible programs in California's future. We expect utilities, parties and customers to undertake all reasonable efforts to meet the statewide goal of 2,500 MW. We adopt limits to prevent these programs from spiraling out of control if conditions unexpectedly and dramatically change,[9] but we remind parties that any party may file a timely pleading if, in the party's judgment, program limits should be adjusted upward or downward (e.g., a utility may file an application; a utility or any party may file a petition for modification).

Just as provided in the Phase 1 decision, each utility may include costs, and must include revenues, incurred implementing the decisions in this order in its interruptible program memorandum account. (D.01-04-006, mimeo., page 77). Reasonable implementation expenses not otherwise already recovered through existing rates, or offset by other revenues, are subject to later recovery. Moreover, as we said in Phase 1:

> "We will review the balance in each memorandum account for reasonableness before authorizing recovery but, absent incompetence, malfeasance, or other unreasonableness, we would expect to authorize full recovery of all dollars spent by utilities for these programs…" (D.01-04-006, mimeo., page 78.)

3.2.3. Utility Reports

We decline to direct that utilities file a special report in August 2002. Rather, we direct that utilities continue to file and serve regular reports monthly. (D.01-04-006, Ordering Paragraph 4.) These reports will continue to inform the Commission and parties about program progress and costs. They will also

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9 TURN is concerned, for example, that customers will take unfair advantage of the option to annually change their FSL to the disadvantage of other ratepayers. We do not share this concern, but consider the adopted capacity and dollar limits as one method to apply some guidance and control to these programs without adopting unreasonable expectations or constraints.

provide useful information to parties as we transition ongoing assessment of interruptible programs and tariffs to GRCs or similar proceedings, and may assist with the framing of data requests in those proceedings.

The reports, however, will not be necessary after conclusion of those proceedings. Unless directed otherwise by subsequent order, each utility may terminate the filing and service of its monthly reports effective the date that the final decision is mailed in the next GRC or similar proceeding that addresses interruptible tariffs.

Further, we order utilities to meet with Energy Division staff to improve these monthly reports going forward, to the extent that existing reports fail to adequately provide necessary information consistent with our orders. For example, each report must state megawatts subscribed, program costs, and program revenues, among other things. PG&E and SDG&E should include an estimate of program revenues from existing rates, as does SCE. SCE and SDG&E should include a table with megawatts subscribed, as does PG&E. SDG&E should include program cost information in table form, as do PG&E and SCE. Utilities should agree with ED staff on a common report and table format.

We also directed that utilities report any other relevant information the Commission should know to be reasonably informed. This should include the amount in authorized memorandum accounts. Current monthly reports do not include this information. We understand this to mean the balances are zero. Utilities should, going forward, specifically report a zero, or other, balance in these memorandum accounts. The reports should also specifically state the total subscribed megawatts and incurred annual costs compared to the megawatt and dollar limits.

Further, the reports should contain information, when relevant, on energy supply and other information utilities otherwise proposed to include in their August 2002 report. Utilities should agree with Energy Division on the subjects and timing of this additional information. Energy Division may solicit comments from parties on the nonrecurring information to include in one or more special monthly reports, and when that nonrecurring data should be included.

We also change the date for filing monthly reports from the 7th of each month to the 21st. As SDG&E points out, this will permit more accurate reporting by the use of monthly closing figures for each program, and improve consistency of data across reports.

3.2.4. Program Consolidation

TURN recommends that all current programs end by December 31, 2002. TURN proposes that after 2002 all interruptible programs be combined into a single commercial/industrial interruptible program that relies heavily on a "pay for performance" incentive. According to TURN, that incentive would be accomplished by a relatively large energy payment, and a minimal capacity payment. TURN suggests not deferring consideration of program structure until utilities file reports (e.g., in August 2002 and after), but that the Commission decide now that any future program structure will be based on a pay for performance model.

TURN makes a reasonably strong case for its program structure. We are persuaded by CEC, CMTA, and others, however, that the most reasonable approach is to offer a portfolio of options, including various pricing structures. As CEC says, "most customers are not in favor of a 'one demand responsiveness program fits all' philosophy." (CEC Proposals, November 9, 2002, page 13.)

ORA also recommends consolidating programs into one or two going forward, seeking to promote customer understanding, increase participation, and reduce administrative burden. We are not persuaded by ORA that program consolidation would necessarily result in those benefits any more than would a portfolio of options.

Nonetheless, TURN, ORA and others may propose alternative program structures as appropriate in each utility's GRC or similar proceeding. We will not prejudge those outcomes in this decision, but will reach decisions in those proceedings based on the best information presented at that time.

3.2.5. Cost Benefit Analysis

ORA also recommends that utilities be ordered to submit cost-effectiveness analyses in future reports (e.g., the August 2002 suggested by utilities). ORA suggests that utilities use the Commission's Demand Side Management (DSM) Standard Practice Manual for Cost Benefit Analysis, often used to analyze energy efficiency programs. We decline to adopt this recommendation.

The DSM Manual is very useful for its intended purpose, but appears not as useful here. PG&E alleges, for example, refinements to the DSM Manual would be necessary to reasonably evaluate the efficacy of an air conditioner cycling program with 100% versus 50% cycling capability, or the value of a curtailment program with daily, weekly, monthly or annual limitations.

Each party must support proposals it makes in GRCs and other proceedings regarding interruptible programs. We encourage each party to employ the best cost-effectiveness analysis and tools available, but will not specify a single approach.

3.3. Bill Limiter

Issue: Should the bill limiter provision currently reflected in the interruptible program tariffs of SCE terminate on March 31, 2002.

3.3.1. Background

Bill limiters for SCE Schedule I-3 and I-5 interruptible customers were first adopted in SCE's 1992 GRC decision. (D.92-06-020, 44 CPUC2d 471, 528.) The purpose was to mitigate the bill impact of transferring Schedule I-3 and I-5 customers of record on December 31, 1992 to Schedule I-6 on January 1, 1993, given the lower level of interruptible credit in Schedule I-6. According to SCE, the bill limiter capped these customers' bills to a total of no more than 15% in 1993, and 30% in 1994, above what would have otherwise been their I-3 or 1-5 bills based on December 1992 rates.

Legislation adopted in 1993 prohibited reductions in interruptible credit levels during 1995 and 1996. (Public Utilities Code Section 743.1.) Public Utilities Code Section 743.1 was amended in 1994 to extend the prohibition through 1999. It was amended again, in 1996, to continue the prohibition against reductions through March 31, 2002.[10]

According to parties, there are approximately 100 customers representing about 200 MW of load subject to the bill limiter. SCE states that in its 1995 GRC, the bill limiter reduced revenues from eligible customers by about $25 million annually, and rates from all other large power customers (Schedules TOU-8

[10] Public Utilities Code Section 743.1(b) currently states in pertinent part that "[i]n no event shall the level of the pricing incentive for interruptible or curtailable service be altered from the levels in effect on June 10, 1996, until March 31, 2002."

and I-6) were increased by an equivalent amount. SCE says the annual revenue deficiency for 2002 is about $54 million, with about $35 million for the nine-month period from April 1, 2002 through December 31, 2002.

According to SCE, the increased revenue deficiency results from surcharges adopted by the Commission in 2001. (D.01-03-082 and D.01-05-046.) Of the $54 million annual deficiency, SCE says $25 million is recovered by the revenue shift to other large customers, and $29 million is not currently recovered from any customer class. SCE reports that under currently effective ratemaking treatment pursuant to the Settlement Agreement between SCE and the Commission, however, the additional revenue shortfall results in a lower "surplus" to be contributed towards recovery of the balance in the Procurement Related Obligation Account (PROACT). (Resolution E-3765.) SCE states that the resulting effect is to extend the PROACT recovery period (and extend application of Settlement rates) for all customer classes.

3.3.2. Termination

SCE seeks clarification of whether or not the bill limiter provision expires on March 31, 2002, or December 31, 2002 (the sunset date for Schedule I-6, as extended by D.01-04-006). We direct that the bill limiter continue, but its application be limited to the portion of existing rates that were in effect before 2001.

3.3.2.1. Public Utilities Code Section 368(a)

CIU asserts that D.01-04-006 extends all interruptible programs, and all components of those programs including the bill limiter, through December 31, 2002. This is incorrect.

The bill limiter provision is Special Condition 14 of Schedule I-6, which states in relevant part: "This Special Condition expires on January 1, 1999." A footnote further explains: "This scheduled change [i.e., expiration on January 1, 1999] is suspended due to the rate freeze mandated by Assembly Bill 1890 and implemented through Public Utilities Code Section 368(a)." Public Utilities Code

Section 368(a) provides that rates shall remain at certain levels until the earlier of March 31, 2002, or the date on which certain Commission-authorized costs are fully recovered. After March 31, 2002, rates may, but are not required to, remain at levels specified by Section 368(a).

Nothing about our order in April 2001 (D.01-04-006) extending interruptible programs in general, or I-6 specifically, disturbed Public Utilities Code Section 368(a), or its application to I-6. The I-6 tariff filed by SCE pursuant to D.01-04-006 contained the bill limiter through the date of the rate freeze implemented by Public Utilities Code Section 368(a). No protests were filed on this point. Those tariffs became effective five days after filing, unless suspended by the Energy Division Director. (D.01-04-006, Ordering Paragraph 1.) The Energy Division Director did not suspend the tariffs for non-compliance on this point. The I-6 tariff became effective with the bill limiter provision subject to Public Utilities Code Section 368(a). This is fully consistent with D.01-04-006.

3.3.2.2. Bill Limiter Purpose

Through March 31, 2002, the bill limiter will have been in effect for nine years and three months. Assuming an average savings by eligible customers of $25 million per year for 9.25 years (through March 31, 2002, based on 1995 GRC estimates), these customers have enjoyed reduced rates of $231.25 million. If there have been approximately 100 customers over this period, each customer has enjoyed an average of about $2.3 million in reduced rates.

As CLECA and others point out, rates for customers have increased over time, even with the bill limiter. Nonetheless, the bill-limited total charges have been reduced compared to what they would otherwise have been.

The rate surcharges adopted in 2001 expanded the revenue impact of the bill limiter. We now think it reasonable to implement a change in application of the bill limiter to maintain the original revenue shift without expansion.

3.3.2.3. Bill Limiter and SCE/CPUC Settlement Agreement

CIU states that permitting the bill limiter to continue without change through March 31, 2002, but expiring on December 31, 2002, would be consistent with the approach taken in the recent Settlement Agreement between SCE and the Commission, approved by U.S. District Court Judge Ronald S.W. Lew. (United States District Court, Central District of California, Western Division, Case No. 00-12056-RSWL(Mcx).) In support, CIU says two primary purposes of the Settlement Agreement are to: (1) avoid instability and uncertainty for ratepayers, the State of California and SCE, and (2) protect customers from the potential impact of further volatility in electricity prices. (CIU Proposals October 12, 2001, page 6, footnote 3, citing Settlement Agreement, Recital F.) CIU concludes that extending the bill limiter is consistent with these purposes. We disagree.

We do not accept that modifying application of the bill limiter causes instability, uncertainty and volatility in electricity prices. The bill limiter has consistently been subject to termination, beginning in 1995, then deferred to 1996, to 1999, and finally to on or about March 31, 2002. This information has always been available to customers. Implementing a change in its application to maintain the original revenue shift does not cause instability, uncertainty or volatility. Moreover, CIU does not convincingly explain how deferring the end of the bill limiter by about nine months makes any material difference in this result.

CIU also asserts that the Settlement Agreement says "continuation of retail rates that produce revenues in excess of SCE's current costs [meets certain goals]…without further retail rate increases." (CIU, Proposals October 12, 2001, page 6, footnote 3, citing Settlement Agreement, Recital E.) According to CIU, extension of the bill limiter end date would be consistent with meeting these goals without a rate increase.

We do not accept that modifying application of the bill limiter is a rate increase. Rather, it maintains a revenue shift within one customer class. No rates are increased.

Moreover, even if the modified application is incorrectly viewed as a rate increase, we note that the Settlement Agreement specifically prevents rate decreases. It does not, however, prevent rate increases. (Settlement Agreement, Section 2.2(a).)

Finally, CIU claims SCE represents the parties' intent to be that: (1) rates not be increased, (2) the Settlement Agreement not change any rate, and (3) the Settlement Agreement expressly preserves the rates SCE is already charging. (CIU Proposals October 12, 2001, page 6, footnote 6, citing SCE' Reply Brief in Support of Entry of Stipulated Judgment at page 10.) The Settlement Agreement does not increase or change any rate, and it preserves the rates SCE is charging. In particular, the Settlement Agreement does not increase or change any Schedule I-6 rate, including the bill limiter. All terms and conditions of Schedule I-6 are preserved with the Settlement Agreement.

3.3.2.4. Modified Application

We are not persuaded that the bill limiter should continue without modification. We decline to continue to apply the bill limiter to surcharges adopted in 2001. To do so absent other adjustment results in lower surplus

credited to the PROACT balance, with all customers affected by an extension of the PROACT recovery period. While we could raise large power customer rates or other rates by $29 million per year to offset this effect, no party makes a convincing showing that this is an efficient and equitable outcome.

On the other hand, we decline to end the bill limiter completely. Absent other adjustment, ending the bill limiter would result in most large power customers continuing to pay an extra $25 million per year. This would result in large customers paying a disproportionate share of the surplus credited to the PROACT. While we could reduce rates for large power customers by $25 million to offset this effect, we decline to do so. No party makes a convincing showing that this is an efficient and equitable outcome. Moreover, the balance of benefits and burdens weighs in favor of continuing the nearly 10-year, long-standing policy of some revenue shift within the large power class.

Thus, we continue the bill limiter to the extent it applies to the portion of rates in effect before 2001, and discontinue its application to the remainder of rates. In this way bill limited interruptible customers will receive the same benefit already found reasonable and paid by other large power customers. (D.06-04-050.) Moreover, it neither unreasonably disturbs the PROACT recovery period, nor does it require any offsetting rate increase or decrease. We will examine and consider further treatment of the bill limiter, including the possibility of its complete elimination, in SCE's next GRC.

3.3.3. Limited Opt-Out

The Schedule I-6 tariff adopted and approved pursuant to D.01-04-006 leaves no doubt the bill limiter may expire in whole or part on or about March 31, 2002. The Settlement Agreement does not in any way disturb this conclusion. As a result, we direct that application of the bill limiter to rate adjustments adopted in 2001 and beyond end on the effective date of this order.

Assuming some customers may have been confused, we permit SCE to offer a 15-day opt-out period for customers subject to the bill limiter. This opt-out period should begin within 30 days of the date of this order. These customers may opt-out of their interruptible tariff effective the date application of the bill limiter changes, or effective with the beginning of their next billing period, similar to the opt-out authorized in D.01-04-006. They may also opt-out, as may any interruptible customer, during the next annual opt-out, in November 2002.

SCE, CIU, CLECA, and others, are concerned that changes to the bill limiter may cause customers otherwise subject to the bill limiter to convert to firm service, thereby causing the system to lose up to 200 MW of interruptible load. We are comfortable with these customers making this choice based on their needs, ability to continue to be interrupted, and rate levels. Existing interruptible discounts are still attractive compared to firm service rates. We seek to have a base of interruptible load available for Summer 2002 upon which system operators can reasonably rely. This opt-out opportunity will allow these few customers to re-evaluate their situation. A bill-limited customer who elects to opt-out may enroll in any other program (e.g., BIP) on a current and going-forward basis without restriction.

3.4. Aggregation of More Than Two Circuits for OBMC

> **Issue**: Is it necessary or feasible to develop a tariff option for aggregation of more than two circuits with a single lead customer for the purpose of participation in the OBMC program (D.01-06-087, Ordering Paragraph 3).

On June 19, 2001, Wolfsen, Inc. (Wolfsen) petitioned for modification of the OBMC program. Wolfsen proposed allowing a single customer to aggregate its load on up to 15 circuits for purposes of OBMC participation. We granted the petition in part, by permitting aggregation of load on two circuits, and directed respondent utilities to hold a workshop to develop a more complex OBMC circuit aggregation program for Commission consideration through a petition for modification. (D.01-06-087, page 8 and Ordering Paragraph 3.) Respondent utilities suggested that this matter be included in the Phase 2 workshops. The Assigned Commissioner agreed. (Scoping Memo, page 2.)

No party now affirmatively advocates allowing a single customer to aggregate its load on more than two circuits for participation in OBMC. Respondent utilities state that they do not believe further aggregation should be incorporated into the OBMC program without a showing of significant benefit to the overall system, and to ratepayers at large. We remain concerned that aggregation of more than two circuits could pose administrative and tracking problems. (D.01-06-087, mimeo., page 7.) Therefore, we decline to direct development of a tariff option for aggregation of more than two circuits with a single lead customer for the purpose of participation in the OBMC program.

3.5. Alternate Workweeks

> **Issue**: Should the 10-day baseline for purposes of participation in the OBMC program recognize alternate workweeks, as proposed by Cal Steel (D.01-06-087, page 14).

On June 21, 2001, respondent utilities jointly petitioned for modification of the OBMC program, including changes to the calculation of the 10-day baseline. In response, Cal Steel proposed that similar days for purposes of the baseline be grouped as (1) weekends and holidays, (2) mid-week full operation days, and (3) mid-week scheduled reduced operation days.

We granted respondent utilities' petition with slight change. We declined to adopt the recommendation of Cal Steel, but invited parties to revisit the issue in a workshop. (D.01-06-087, mimeo., pages 11-15.) At utilities' suggestion to promote efficiency, the Assigned Commissioner included the issue in Phase 2 workshops, and as an item in the list of Phase 2 issues. (Scoping Memo, page 2.)

Cal Steel offered nothing in Phase 2 to support its proposal. Respondent utilities do not support Cal Steel's recommendation. Neither CMTA, nor any other party, proposes separating weekday baseline measurement into mid-week full operation days and mid-week scheduled reduced operation days.

Therefore, absent need for this change demonstrated and supported through a specific proposal, we decline to consider the Cal Steel alternative workweek proposal further. We consider other proposed changes to OBMC below, including various modifications to baseline measurement.

3.6. Other Modifications

> **Issue**: Should other modifications and consolidations be adopted.

Parties propose several other modifications and consolidations of interruptible programs. In the following sections, we evaluate: (1) modification of SLRP, (2) modifications of OBMC, (3) interruptible program proposals suggested by the CCPCFA, (4) SDG&E's EAEI program, (5) interruptible program proposals made by the CEC, and (6) SCE's petition for modification of D.01-04-006 regarding changes to the FSLs of existing interruptible customers.

3.6.1. SLRP

PG&E and SDG&E propose a slight modification to the SLRP tariff regarding non-compliance. The current tariff provides in part that:

> "…the energy usage during the on-peak period for the four weekdays following a curtailment, unaffected by program operations and excluding holidays, will be evaluated and cannot exceed the customer's posted baseline amount."

PG&E and SDG&E propose that it be revised to state (the change is underlined):

> "…the energy usage during the on-peak period for the four weekdays following a curtailment, unaffected by program operations and excluding holidays, will be evaluated and cannot exceed the customer's posted baseline amount <u>by more than 15%</u>."

According to PG&E and SDG&E, the proposed modification relates to load shifting for customers that do not have 12 months of interval data, or for customers whose current year's consumption varies by more than 5% from the previous year's same month consumption. They assert that this modification is necessary to keep non-compliance rules consistent for those with and without interval meter data history.

No party opposes this modification. The proposal is in the public interest to maintain consistency, and is adopted.

3.6.2. OBMC

Several changes to OBMC are proposed. We generally decline to adopt these proposals. OBMC was recently modified to provide significant additional flexibility. (D.01-06-087, mimeo., pages 11-15.) These modifications have not been tested, given lack of OBMC implementation since they were adopted. With one exception (regarding monthly requirements discussed below), we agree with SCE that no further changes in baseline calculation should be adopted unless and until the current revised baseline methodology has been tested and found deficient.

3.6.2.1. Similar Days

The 10-day baseline is now measured by using the immediate past 10 similar days. Similar days are either business days, or weekend days and holidays.

CMTA proposes that past similar days be defined as "days when the customer's business was in operation." According to CMTA, this does not require the utility to differentiate between weekends, holidays, and two types of weekdays (such as the Cal Steel proposal), but only requires that utilities use the customer's past similar days of electrical usage.

We are not persuaded by CMTA to complicate OBMC baseline calculations in this way. Customer usage may vary for any number of reasons, with variations reflecting more than just whether or not the customer's business was in operation. Further, the definition of "in operation" may be subject to many interpretations.

Moving away from clear, objective criteria will result in increasingly individually tailored baselines. This will be relatively more difficult for utilities to administer, and we are not persuaded that the advantages outweigh the disadvantages. Thus, we decline to adopt CMTA's recommendation.

3.6.2.2. Temperature Correction

CMTA proposes that a temperature correction be built into the calculation of similar days for customers whose loads are significantly affected by changes in ambient temperature. According to CMTA, if the customer's load during the

10 similar days is 10 MW and a 15% OMBC reduction is ordered, the customer must reduce load to 8.5 MW. CMTA says, however, that if the day the OBMC is called is hotter than the 10 similar days, and the customer's actual load is 12 MW when OBMC is called, a reduction to 8.5 MW requires about a 30% reduction in load.

We decline to adopt CMTA's proposal for universal application, but adopt a pilot program below to test this and other concepts. We agree with PG&E that a temperature adjusted baseline calculation eliminates the benefit of the customer knowing with certainty their targeted maximum load level for each curtailment event. That is, a customer would not know the temperature correction factor until after the event.

Further, temperature adjustment unreasonably complicates the baseline calculation, and significantly increases the burden on the utility. We are not persuaded that the potential benefits of a temperature adjustment outweigh the disadvantages.

3.6.2.3. Stage 1 and 2 Days

CMTA also proposes elimination of Stage 1 and 2 days from the past 10 similar days for calculating the baseline. Otherwise, CMTA asserts, OBMC customers have no incentive to voluntarily reduce operation during Stage 1 and 2 days since it will make compliance during a Stage 3 day more difficult.

We decline to adopt this proposal. Excluding Stage 1 and 2 days allows customers to maintain a relatively high OBMC baseline. This could result in a customer providing less load reduction during Stage 3 than during Stages 1 and 2. At the same time, the customer might participate in what can be lucrative interruptible programs during Stages 1 and 2.

Further, the likely contiguity of Stage 1, 2 and 3 days means that eliminating Stage 1 and 2 days from the definition of similar days could result in a participant's baseline being calculated from "similar days" that are potentially weeks removed from current conditions. The rationale of adopting a 10-day baseline compared to other periods, such as one year before, is to maintain some reasonable relationship with current conditions. We are not persuaded that the benefit of eliminating Stage 1 and 2 days, if any, outweighs the disadvantage of the probable distancing of the baseline calculation from current conditions.

3.6.2.4. Real Time Profile Option

CMTA urges incorporation of a real time profile option for baseline measurement. In this way, according to CMTA, customers can successfully respond based on actual conditions. Customers whose load substantially increases due to short-term high temperatures, for example, and who would otherwise find it extremely difficult to reduce usage from a 10-day baseline, may still participate and provide benefit to the system.

We decline to adopt this recommendation for universal application, but adopt a pilot program below to test this and other concepts. While a real-time basis has some advantages, it presents its own set of problems. For example, OBMC customers with a real time baseline would have an incentive during the later part of a Stage 2 event to ramp-up their load, thereby reducing the burden of a subsequent 5%, 10% or 15% reduction.

CMTA states that "gaming" can be addressed in any number of ways, but offers no proposals. We decline to make an already relatively complex system more complex by adopting an optional method of baseline calculation, and then developing additional terms and conditions to prevent abuses.

CMTA generally says we “should refrain from making abrupt changes in the programs…” (CMTA Reply Comments, November 16, 2001, page 2.) We think this suggestion applies here.

We do not, however, oppose a test of OBMC 10-day baseline measurement that more closely reflects real time consumption. In comments on the Draft Decision, CMTA proposes a pilot program wherein the customer’s 10-day average load profile is adjusted (normalized) to reflect conditions on the day of the OBMC event. CMTA says gaming may be addressed by normalizing the customer's load profile over a several hour period immediately preceding the OBMC event (e.g., four hours). CMTA reports that representatives of PG&E and Silicon Valley Manufacturers Association have worked with CMTA on the outline of a test, and the respective parties believe the approach under discussion holds promise.

We direct Energy Division to convene a workshop within 20 days of the date of this order to work with PG&E, CMTA and other interested parties on implementation details for a pilot test program. PG&E should file and serve an advice letter with accompanying tariffs within 10 days of the date of the workshop. The advice letter will become effective 10 days after filing unless suspended by the Energy Division Director. PG&E should file and serve a report upon conclusion of the test program.

3.6.2.5. Days to Exclude From Baseline

If its other recommendations (e.g., temperature adjustment, real time load profile) are unlikely to be adopted, CMTA says it is willing to simplify and narrow the scope of its proposals to achieve some incremental improvements in OBMC baseline calculation. The current 10-day baseline calculation allows (a) 15-day ramp-up and ramp-down adjustments, (b) exclusion of up to 10-days when those days are provided in advance to the utility, and (c) exclusion of up to two days permitted after the fact. As an alternative to its other proposals, CMTA recommends that the number of days which a customer may exclude from the 10-day baseline under options (b) and (c) be increased from 10 and two days, respectively, to 15 and 10 days, respectively. Because, according to CMTA, this will not address all problems, CMTA also suggests that once per year each customer be allowed to select a baseline measured by either (a) the past 10 similar days or (b) real time. (Petition for Modification of D.01-06-087 filed on November 9, 2001.) We decline to adopt these proposals, and deny CMTA's petition for modification.

The design of each program must consider the amount of flexibility to give customers. The final balance seeks to meet as many competing needs and interests as possible between participating customers, the utility and other ratepayers. There is only a limited amount of flexibility that can reasonably be permitted here, however, since OBMC is designed to replace firm service interruptions. There must be actual, measurable and dependable load reductions when OBMC is called, or the program has limited or no value. If OBMC is not dependable, additional firm service customers must be interrupted at the time of system need.

The original OBMC program did not permit excluding any days when calculating the baseline. Flexibility was added in June 2001, permitting exclusions of up to 10 and two days in options (b) and (c), respectively. (D.01-06-087.) No OBMC events have occurred since June 2001. There is insufficient actual experience and data to justify program modification.

CMTA asserts that its suggested changes are "modest" and will not impair the reliability of the OBMC program, while providing customers with needed flexibility. We are not persuaded. CMTA does not, for example, construct a hypothetical case to show that the increased days of exclusion from the baseline measurement can or will result in the same or similar operation over a sample period. We decline to make the recommended modifications without supporting data or example. The existing balance between competing interests is, and remains, reasonable.

3.6.2.6. Minimum 30-Minute Notice

OBMC participants are now provided no less than 15 minutes, and possibly up to 29 minutes, to reduce load after notification. In its comments, CMTA recommends that customers be provided notice at least 30 minutes before being required to reduce load under the OBMC program. In the alternative, CMTA recommends that the penalty for failure to reduce load for the first half-hour of the outage be eliminated if the customer still achieves the required reduction on the circuit for the first full hour, and for the remainder of the outage. (October 12, 2001 Comments, page 6.)

In its petition for modification, CMTA says that, as a compromise, it proposes during the first hour of the OBMC event that compliance be measured over the full hour rather than in half-hour increments. (November 9, 2001 Petition, page 5.) In subsequent hours, compliance is measured in half-hour increments. CMTA asserts that the customer will still need to meet the required reduction in the first hour, but will not be penalized if it fails to be in full compliance during the first 30 minutes. CMTA claims this is a modest measure to give customers more flexibility without impairing overall load reduction. Further, CMTA says it is reasonable in light of limited experience and the unproven nature of advance notification by the utility.

We adopt neither proposal, and deny CMTA's petition for modification. We acknowledge that customers may have difficulty achieving 5%, 10% or 15% reductions from their baseline with limited advance notification. The balance that must be struck, however, is between the benefit provided to the OBMC customer (i.e., exclusion from rotating outage), and the benefit that the OBMC customer must provide to the system (i.e., real time load reduction when needed). We are not convinced that we should disturb the existing balance.

An entire advance notification infrastructure is now in place, and several methods of advance notification are available before outages occur. (See D.01-09-020, mimeo., page 26 for a complete discussion.) For example, the CAISO provides forecasts both 48 and 24 hours in advance of expected rotating outages. The CAISO provides frequent updates to the public during periods of forecast electricity emergencies. Executive Order D-38-01 requires that the CAISO notify utilities and public agencies one hour in advance of any firm load curtailment. Each utility is in turn required to notify the public and the media no less than one hour in advance of any reduction in electricity output, including the time and location where the anticipated blackout will occur. Individual customers may also receive energy alerts regarding Stage 1, 2, and 3 emergencies from the State of California. As experience is gained, this advance notification system will become a powerful tool to inform customers.

Utilities also maintain direct notification paths with OBMC and other customers by several means (e.g., by customer account representatives using telephones, electronic mail, pagers). As SCE says, under expected circumstances, OBMC customers will have received both Stage 2 and Stage 3 warnings by electronic mail and pager in advance of potential rotating outages.

As a result, the notification infrastructure now in place gives us confidence that the period of time during which an OBMC customer should develop a reasonable expectation of a rotating outage will be in excess of 30 minutes. We agree with SCE that further expansion of the specific notice requirement to OBMC customers, or measuring results over the first full hour, could have the unreasonable effect of delaying load relief, and necessitating increased firm load curtailments.

3.6.2.7. Monthly Interruptible Contract Requirements

In comments, CIU proposes that interruptible customers be permitted to participate in OBMC after meeting their interruptible contract obligations, whether on a daily, weekly, monthly or annual basis. For example, CIU says an interruptible customer could participate in OBMC after completing the full six-hour per day load reduction required by the interruptible tariff. If there is any conflict between programs, CIU proposes the customer be required to first meet its interruptible obligation.

In its petition, CIU limits the proposal to the interruptible customer first meeting its monthly interruptible obligation. CIU states this revised proposal results from discussions at the workshop, and a compromise between differing parties.

PG&E responds to CIU's petition with qualified support, and states that once it has reviewed operational issues it will be prepared to report back to the Commission. No further report was made, and we are not persuaded that those operational issues, if any, cannot be resolved.

SCE supports CIU's petition with one exception. SCE states that for customers who are participants in both I-6 and OBMC, there is the potential for a monthly simultaneous I-6/OBMC event in which the customer satisfies the final increment of its 40-hour monthly requirement under I-6 but the event continues. Until the 40^{th} hour, SCE says the customer would have been required to reduce load from the lower of its FSL[11] or OBMC baseline. Under CIU's proposed modification, however, SCE asserts that at the end of the 40^{th} I-6 hour the

[11] Firm service level (FSL) is the load level to which the customer agrees to reduce when requested by the utility pursuant to interruptible service tariffs.

customer would be permitted to adjust its load to the OBMC compliance level. SCE says that for a customer with a very low FSL, this circumstance could result in the customer remaining in compliance while significantly increasing its load during the critical emergency. We agree with SCE's concern.

For example, a customer with an FSL of zero, but an OBMC baseline of 40 MW, might be able to increase its load from zero MW (FSL) to as much as 38 MW (a 5% reduction from the OBMC baseline) and still be in full compliance. This could occur even though the Stage 3 emergency continues, and would necessitate even greater firm load curtailments in the form of rotating outages for other customers. Such an adverse system impact is inconsistent with the fundamental goals of these programs. We believe, as does SCE, that the incidence of this particular circumstance is likely to be infrequent, but the potential system impact if it does occur could be significant.

As a result, we adopt CIU's petition with the modification proposed by SCE. During an overlapping event, the present provision remains in effect and the customer will be required to continue to reduce load to the lower of FSL or OBMC baseline during the entire length of that particular OBMC event. For all subsequent OBMC events during that month (or year, after the annual requirements are met), the customer may reduce load from the OBMC baseline.

3.6.2.8. Lead Customer

CMTA proposes that the "lead customer" concept be deleted from OBMC, and that all customers on a circuit who agree to participate in OBMC bear responsibility in proportion to their individual loads. In support, CMTA asserts that very few, if any, customers on shared circuits participate in OBMC. The lead customer concept is one obstacle to greater participation, according to CMTA.

Under the lead customer approach, one customer must notify other customers on the circuit of the OBMC event. Further, the lead customer is responsible for circuit compliance, along with administration of penalties. CMTA says these duties should be the responsibility of the utility. PG&E and SCE oppose CMTA's proposal.

We decline to adopt CMTA's recommendation. OBMC is designed to provide overall system benefits with the expectation that the largest customers on a circuit agree among themselves how to meet program requirements. In exchange, the entire circuit receives the substantial benefit of an exemption from rotating outages. If the lead customer is unable or unwilling to shoulder liability on behalf of the entire circuit, the lead customer may agree with other customers on an allocation of responsibility. Customers may formalize their agreement by contract, providing maximum flexibility, while retaining program responsibility with customers. We think this is reasonable.

On the other hand, requiring all customers to participate in proportion to their load unnecessarily and unreasonably limits program flexibility. Customers may now agree to any allocation of load reductions, along with compliance and penalties. We are not convinced that this flexibility should be removed.

Further, CMTA's proposal would convert a circuit level program to a customer level program. This would require the utility to offer each participating customer on the OBMC circuit an individualized load reduction plan, but create a circuit-wide exemption from rotating outages. The utility would incur additional costs and burdens for compliance measurement and contract administration, including sorting out liabilities and potentially settling liability disputes. This unreasonably increases the burden on the utility not contemplated within the OBMC program.

The OBMC program places the burden "on the customer to demonstrate that the proposal is realistic, workable, measurable, and enforceable." (D.01-04-006, mimeo., page 37.) Several customers on a circuit, however, may propose that the utility administer the program, including allocation of penalties for noncompliance. If the plan is reasonable, we would expect the utility to agree. CMTA may consider developing a standardized plan for utility administration of OBMC, and work with each utility to approve such plan. We decline, however, to adopt CMTA's proposal to vacate the lead customer concept, or to limit the possible types of OBMC plans to one requiring all customers to participate in proportion to their individual load.

3.6.2.9. Costs Allocated to Large Customers

TURN proposes that OBMC program costs be allocated only to large power customers. In support, TURN asserts that program benefits accrue solely to those few industrial customers who participate (receiving an exemption from rotating outages) and not the rest of the system as a whole. We disagree.

Industrial customers are not the only beneficiaries of OBMC. Rather, the entire system benefits by having OBMC circuits reduce load by prescribed amounts. The amounts are generally equivalent to the reduction in system load sought by rotating outages (e.g., 5%, 10% or 15%). Moreover, these reductions are required for the entire duration of the system rotating outage (e.g., several hours), and are not limited to the duration of a rotating outage on one circuit or block (e.g., 60 to 90 minutes). We are not persuaded by TURN to limit OBMC cost recovery to only the industrial class.

3.6.3. CCPCFA Comments

By letter dated October 30, 2001, CCPCFA offers comments on capacity payment interruptible load programs. It also lists nine steps to create a

framework for actualizing "the low-cost peaking insurance that we need to ensure system performance through next summer."

We appreciate CCPCFA's proposals, and will endeavor to work with CCPCFA, as with all state and federal agencies, to benefit California. CCPCFA's suggestions, however, are not sufficiently specific to adopt without additional development. We comment on a few of CCPCFA's concepts.

3.6.3.1. Existing Programs and Load Aggregators

CCPCFA proposes that the Commission:

> "create and fund through…[utility] rates an interruptible program that had a capacity payment either to an individual customer or an aggregator of customers in exchange for the right to interrupt load on short notice at a specified number of hours per year." (CCPCFA letter to Commissioner Wood dated October 30, 2001.)

All three respondent utilities already have Commission-approved interruptible programs that provide a capacity payment in exchange for the right to have the load interrupted a specified number of hours per year. We generally decline to authorize the use of load aggregators, with limited but specific possible exceptions (e.g., energy efficiency programs, air conditioner cycling programs). Utilities largely offer the same products to the same customers as aggregators. We are not persuaded that the existing system needs to be duplicated.

PG&E reports that it incurs significant ongoing administrative costs with each customer participating in load reduction through load aggregators. PG&E bases this on its experience coordinating with load aggregators in the CAISO's demand response program. We are hesitant to add another layer of cost on an already burdened electricity system absent clear evidence that these additional costs are necessary and reasonable.

The proposal also does not adequately develop how we would monitor and supervise load aggregators. The existing dysfunctional electricity market has provided opportunities for abuse of ratepayers and other participants. Great care must be taken to avoid creating additional opportunities for abuse.

3.6.3.2. Program Potential

The CCPCFA says its proposed program has the potential to create a large pool of interruptible megawatts that can function as peaking resources. CCPCFA says it has received proposals totaling in excess of 2,000 MW that would benefit from such an approach.

We are encouraged by this opportunity, but are dubious of the potential. First, the majority of businesses have told us they want and need to conduct their business, not become part of California's electricity resource base. Second, to the extent some businesses are willing and able to become the equivalent of a reliable, dependable peaking resource that can be called upon every year to satisfy summer peak load, this can be achieved within the range of existing programs (e.g., BIP, RBRP, DPB). Third, CCPFA does not state at what price the 2,000 MW may become available. Without price information, we cannot evaluate whether or not this opportunity is reasonable and worth pursuing. Finally, it is not clear how much, if any, of this 2,000 MW is new capacity, or simply repackaging megawatts already subscribed under existing programs.

3.6.3.3. Cycling of Air Conditioners

The specific example given by CCPCFA involves using aggregators for satellite-directed cycling of air conditioners. We agree there is merit in this idea. In fact, we said in April, 2001:

> "The CEC estimates that 14,000 MW of air conditioning load (28% of total load) occurs during the state's summertime peak demand of 50,000 MW…
>
> This is a potentially vast, untapped source of interruptible electricity. Properly partnered with companies such as Comverge, respondent utilities and ratepayers can enjoy benefits with the providing company taking the financial risk. This opportunity needs further exploration.
>
> Therefore, we order PG&E and SDG&E to explore reasonable options for implementing air conditioner cycling, and other electric motor interruption, programs targeted to residential and commercial customers…
>
> PG&E…and SDG&E shall each file and serve an advice letter no later than May 1, 2001. The advice letter shall analyze and report on alternatives, and seek approval of the most reasonable alternatives, including proposed tariffs for implementation…
>
> We caution PG&E and SDG&E that we are convinced one or more air conditioning cycling programs should be approved in each service area. This is the opportunity for PG&E and SDG&E to propose what each believe are the best options for their areas. That is, the advice letters of PG&E and SDG&E should seek approval of the options that each utility finds most reasonable." (D.01-04-006, mimeo., pages 35-36; also see Ordering Paragraph 1 and Attachment A, Item 2.3.4.)

On May 1, 2001, PG&E filed Advice Letter 2110-E. On January 14, 2002, the Energy Division conducted a workshop to discuss PG&E's proposal. The workshop included considering third party (aggregator) implementation of a pay for performance air conditioner cycling program. In a subsequent decision or resolution we will address PG&E's Advice Letter and air conditioner cycling program.

On May 1, 2001, SDG&E filed Advice Letter 1320-E, in which it proposed an EAEI program. Below, we discuss SDG&E's Advice Letter and its EAEI program, which includes air conditioner cycling.

3.6.3.4. CCPCFA Loan And Repayment

The CCPCFA proposes that the Power Authority loan money to qualified parties. The loan would be used to finance installation of necessary equipment and payment of incentives. Concurrently, CCPCFA apparently envisions the Commission approving a program to collect money from customers for repayment of the Power Authority loan. CCPCFA asserts that the result would be peaking capacity available for use by the CAISO or other entity.

A CCPCFA financed loan is intriguing. Absent better understanding of the flow of funds, responsibilities, costs and benefits, however, we decline to participate in a CCPCFA loan arrangement at this time.

3.6.3.5. Capacity Payment

Finally, the CCPCFA proposal includes a capacity payment, but no additional energy payment. Our current portfolio of programs offers this option. We generally think there is room in a portfolio of choices for several types of programs, including different compensation possibilities (e.g., capacity payments, energy payments, exclusion from rotating outage).

3.6.3.6. Conclusion

We appreciate the CCPCFA's thoughts and suggestions. We will continue to develop our programs with their comments in mind.

3.6.4. SDG&E EAEI Program

SDG&E proposes cancellation of its proposed EAEI program. We agree.

SDG&E first proposed the EAEI program on May 1, 2001, in compliance with our order for SDG&E to explore and propose reasonable options for implementing air conditioner cycling and other electric motor interruption programs. (D.01-04-006, mimeo., page 36, and Ordering Paragraph 1, Attachment A, Item 2.3.4; Advice Letter 1320-E.) The proposed program involves residential and commercial air conditioner cycling, curtailment of small commercial lighting, and curtailment of domestic hot water heaters.

As SDG&E points out, however, SDG&E was also ordered to conduct a Residential Demand-Responsiveness (Smart Thermostat) Pilot Program through December 31, 2004. (D.01-03-073.) This pilot project utilizes internet technology to adjust residential heating and air conditioning thermostats.

We are persuaded by SDG&E that it should be allowed to focus its efforts on one program at this time. The Smart Thermostat Pilot Program is underway, with customers being recruited and thermostats being installed. SDG&E states that the Smart Thermostat Pilot Program will be completely operational by Summer 2002. By comparison, the EAEI program has not been approved, a vendor contract has not been awarded, customer recruitment has not begun, and reaching the goal of 5,000 operational switches is unlikely for Summer 2002. SDG&E reports that focus group studies show more interest in Smart Thermostat than EAEI. Limited resources should be devoted to the program with the greater potential for customer participation.

Withdrawal of the proposed EAEI program means we will not direct SDG&E to pursue commercial air conditioner cycling, curtailment of small commercial lighting, and curtailment of domestic hot water heaters. We will continue to pursue residential air conditioner cycling through the Smart Thermostat project. We now think it best to defer pursuit of commercial air conditioner cycling in SDG&E's area, however, until we have more data. Also, we accept SDG&E's assertion that only small load reductions are likely from commercial lighting and domestic hot water heaters. Many commercial customers have already adjusted their lighting load. As a result, there is a reduced potential MW load base from which to secure savings, the amount of "free ridership" with this program would likely be high, and additional savings are better pursued through further light fixture replacement. Finally, the relatively high load diversity of domestic electric hot water heaters reduces the potential for savings.

Withdrawal of the EAEI program also means we permit customers to override the cycling signal. That is, in the Smart Thermostat Pilot Project the customer may override the cycling/curtailment signal, while that is not allowed in EAEI. We are persuaded to pursue the Pilot Program for now, and review whether or not to permit customer override in the future based on review of the Pilot Program results.

TURN argues that both TURN and the Commission agreed that the interruptible program of choice would be air conditioner cycling, not the Smart Thermostat or other program, citing D.01-04-006 in support. To the contrary, the Commission authorized the Smart Thermostat Pilot Program in March 2001. In April 2001, we directed that SDG&E file an Advice Letter proposing an air conditioner and other electric motor cycling program. We always contemplated reviewing the proposed program before its adoption. While we expressed enthusiasm for an air conditioner cycling program in our April 2001 order, we must now consider the proposed program in relation to other alternatives, costs and benefits. We are persuaded that a better use of limited resources is to allow

SDG&E to first implement the Smart Thermostat Pilot Program, and rely on results of the pilot program before pursing a competing program.

3.6.5. CEC Proposals

CEC makes several proposals for interruptible programs. First, CEC proposes a non-bypassable surcharge of $0.001/kWh, assessed on all customers who receive distribution service. Second, CEC proposes replacing the current DWR DBP with a renewed, modified VDRP.[12] Third, CEC proposes modifications to the current BIP.

CEC's program proposals generally seek to lower the minimum load drop requirement from 100 kW to 50 kW in order to encourage participation by smaller customers. CEC also recommends the use of load aggregators to facilitate program participation. For its modified BIP, CEC proposes changing the performance measurement from a "fixed" amount (reflective of FSL) to a "variable" amount (reflective of more current usage calculated on a moving 10-day baseline) to provide flexibility and promote participation.[13] Also for its modified BIP, CEC proposes adding an additional energy incentive payment of $0.10/kWh for incremental load reductions beyond the committed load reduction, and $0.35/kWh for incremental load reductions distinct from committed load reductions.

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[12] The VDRP was authorized in April 2001 (D.01-04-006), and replaced by the DBP in July 2001 (D.01-07-025).

[13] The original VDRP, the DBP, and the CEC's proposed VDRP for 2002 all rely on a 10-day baseline to measure the customer's load reductions. (D.01-04-006, Attachment A, Item 2.2.2; D.01-07-025, Attachment A, Item 2.6.3.7.)

We decline to adopt the surcharge or modified VDRP, but we authorize a two-year pilot program to test the merits of a modified BIP.

3.6.5.1. Surcharge

CEC says it proposes a surcharge because utilities are unhappy with cost recovery treatment authorized in D.01-04-006. Further, CEC reports that utilities are concerned with CEC program proposals if additional costs are funded through memorandum account balances with deferred recovery. We are not persuaded that these reasons justify a surcharge.

We have adequately addressed cost recovery, and specifically considered and rejected funding through a surcharge. (D.01-04-006, D.01-07-029.) CEC fails to convince us that our prior decisions should be revisited or reversed.

CEC's proposed surcharge would generate an additional amount of approximately $200 million per year. CEC fails to show that funds collected in current rates are inadequate to fund existing programs, or are insufficient to fund expanded programs. In fact, SDG&E specifically states that the proposed surcharge "would be excessive for SDG&E programs as they are currently designed." (Reply Comments, November 19, 2001, page 11.)

Utilities may seek increases in total annual program dollar limits as needed. (See, for example, D.01-04-006, mimeo., page 80.) Utilities have made no such request, and make no convincing showing that current limits are inadequate.

We also agree with TURN that collecting up to an additional $200 million per year without a specific purpose must be done with great caution. We decline to adopt CEC's proposed surcharge.

3.6.5.2. Replace DBP With VDRP

CEC asserts that the DWR DBP is an unfunded, moribund program and recommends revival of a modified VDRP in its place. We decline to adopt this proposal.

DWR suspended the DBP on December 15, 2001, but states that the program will be available in June 2002, or in the event of a Stage 2 or 3 emergency, whichever occurs first. Thus, the program will be available as needed no later than June 2002 to the same extent that it has at any time been available. A replacement program is unnecessary.

Further, the cost consequences of CEC's proposal are not clear. Implementation costs can be significant because a modified VDRP program with reduced minimum load drop requirements would be open to a substantially larger pool of customers. These costs may exceed potential benefits. We are not inclined to make these changes without more and better information.

At the request of the Governor, parties and the Commission undertook great effort to develop, authorize and implement the DBP. Normal procedures were waived, and the program was implemented expeditiously. CEC fails to convincingly show that DPB should now be replaced with a different program. To the extent program details should be changed, parties may file a petition for modification of D.01-07-025, fully explaining the reasons and proposing specific replacement language. (Rule 47 of the Commission's Rules of Practice and Procedure.) To the extent funding and cost recovery should be considered further, parties may participate in other appropriate proceedings to accomplish that goal.

Nonetheless, we keep this proceeding open to examine the future of the DBP. DWR may or may not be able to fund the DBP for Summer 2002. We want continuation of this program, or a smooth transition to a similar program, because this or a similar program provides unique flexibility for customer participation and payment based on performance. Customers are familiar with DBP, and both hardware and software are in place for its implementation. The Assigned Commissioner and Administrative Law Judge should seek comment on alternatives as appropriate for our further consideration and resolution before this summer.

3.6.5.3. Pilot Test of Modified BIP

Parties raise several concerns that lead us to decline global modification of BIP. Nonetheless, we are sufficiently intrigued with CEC's proposals that we authorize a pilot program.

For example, concerns arise with CEC's proposal to expand the customer base. CEC identifies four groups as potential participants in an expanded program.[14] CEC fails to convincingly show why most of these customers are not already participating, or cannot participate, in existing programs.

Further, just as with the proposed revival of VDRP, the cost-effectiveness of a modified BIP is unclear. Reducing the minimum load requirement will produce a significantly larger pool of candidates. As PG&E points out, many small customers may be ill equipped to participate in capacity reduction interruptible programs because of the nature of their businesses or hours of operation. There must be reasonable confidence in a customer's willingness and ability to participate before incurring substantial costs for implementation and reservation (capacity) payments.[15] Before doing so, we need better information.

CEC is concerned that the best possible uses be made of recently installed interval (real time) meters. We are confident that this is the case even without

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[14] These are (1) former ISO demand relief participants, (2) existing CEC Assembly Bill 970 program participants, (3) prospective CCPCFA loan program participants, and (4) other participants with peak demand greater than 200 kW.

[15] CEC reports that PG&E, SCE and SDG&E have about 14,435 customers in the 200 kW to 500 kW range. Program implementation costs for 14,000 new customer participants in this kW range at a cost of $2,500 per customer would be $35 million. Incentive payments of $7/kW-month for 14,000 customers each contributing an average of 75 kW of load reduction would be about $88 million per year, and at $8/kW-month would be about $101 million per year.

reducing the minimum load drop requirement for interruptible programs from 100 kW to 50 kW. Customers who have received, or will soon receive, interval meters are being switched to time-of-use (TOU) schedules, and many are eligible for and evaluating interruptible programs or the PBIP. Moreover, the meters allow collection of data that customers may use for conservation and other load management purposes independent of interruptible programs. We decline to incur potentially substantial additional costs for interruptible program implementation and incentive payments by reducing the minimum load drop requirement without better information. To the extent not used for interruptible programs, interval meters are nonetheless useful for TOU rates as well as other important programs and purposes.

Thus, we decline to revise the BIP as proposed, but will study CEC's proposed program modifications. A pilot study will permit testing the merits of opening interruptible programs to smaller customers, and measuring response on a "variable" basis (i.e., 10-day baseline) rather than a "fixed" basis (i.e., FSL). It will allow testing cost-effectiveness before full implementation.

We adopt a Pilot Base Interruptible Program (PBIP) to last two years. The adopted principles and details are stated in Attachment A. We number the program in sequence based on programs adopted in Phase 1. (D.01-04-006, Attachment A.)

We adopt CEC's concept that transmission system contingencies may justify calling a localized block of participants. We implement the pilot in Santa Clara County based on helping to alleviate regional system constraints in that area.[16] The program will be implemented when the CAISO declares a Stage 2 emergency, or when transmission system contingencies justify calling a localized block of participants. We initially cap the pilot program at 50 MW.[17]

We increase the incentives to $8.00/kW-month, and $0.15/kWh for energy reductions in excess of the customer's committed load reduction. Smaller customers need a larger incentive to participate since the benefits are likely to be modest compared to the customer's total operating expenses. This occurs when a customer's electricity expenses are already a relatively small percentage of total expenses, and savings from load curtailment are moderate, as is likely with smaller customers.

To permit reasonable assessment of participation and operation, participants must agree to complete an annual customer survey. PG&E, CEC and the Energy Division should discuss the details of the customer survey. Energy Division will be responsible for preparation of the final survey. PG&E will transmit the survey to participants, compile survey results, and report the results.

CEC's proposed program would be triggered when the CAISO declares a Stage 2 emergency and CAISO operating reserves are less than 5%. CAISO states that it would prefer the single requirement of a Stage 2 system emergency being declared (i.e., reserves are expected to fall below 5%). Otherwise, the CAISO states that it would be required to make additional determinations not associated

[16] See I.00-11-001.

[17] Committed load reduction of 50 MW would require payments of $4.8 million per year at $8/kW-month.

with its normal staged emergency procedures. We think a single requirement is reasonable.

Some parties express concern about the role of aggregators. CEC acknowledges that its recommendation to use aggregators cannot be implemented until several details are resolved. We agree, and decline to authorize the use of aggregators in the pilot program.

Within seven days of the date of this order, PG&E should file an advice letter including the necessary tariffs to implement the pilot program. The tariffs will become effective 10 days thereafter, unless suspended by the Energy Division Director. Any party who wishes to protest the advice letter for the purpose of seeking tariff suspension must file and serve its protest within nine days of the date of the advice letter, to ensure that the Energy Division Director has time to consider the protest before the tariffs otherwise become automatically effective.

PG&E should file and serve reports monthly, within 15 days after the end of each month, to permit monitoring of this program. The reports shall include details on program initiation and rollout (e.g., training, marketing, recruiting); customers (e.g., participation rates, demographics); identification of barriers to customer participation; costs (e.g., startup, operating); operations (e.g., number of interruptions called during each month, customer compliance, assessed penalties); annual customer survey results; and any other information reasonably necessary to assess the costs and benefits of the program. The monthly reports need to be served only on Phase 2 parties that ask PG&E for copies of the reports.

3.6.6. SCE Petition for Modification Regarding Changes to FSLs

Finally, regarding other proposed modifications, SCE petitions for modification of D.01-04-006. SCE seeks to clarify that an SCE interruptible service customer may not decrease its FSL during the annual November opt-out period. In its reply to responses, SCE further explains it seeks confirmation that SCE customers currently served on closed interruptible rate schedules[18] cannot decrease their FSLs during the annual November opt-out period reinstated by D.01-04-006. We deny SCE's petition.

3.6.6.1. Background

Beginning in 1998, SCE's interruptible customers were permitted to increase their FSL once per year, normally during a 30-day window beginning each November 1. The increase might be partial or total—that is, to partially or completely "opt-out" of the interruptible program.

On October 19, 2000, we temporarily suspended SCE's annual opt-out opportunity. (D.00-10-066.) In particular, we suspended until March 31, 2001 the portion of SCE's interruptible tariffs that allowed "interruptible customers to either opt-out of the interruptible program or change their firm service levels for a 30-day window" beginning November 1, 2000. (*Id.*, Ordering Paragraph 1.) We lifted the suspension a few months later. (D.01-04-006.)

The issue arises because, according to SCE, approximately six of SCE's nearly 600 interruptible service customers requested a decrease in their FSL during the annual 30-day opt-out period that began November 1, 2001. SCE

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[18] SCE reports that its closed interruptible rate schedules are Schedules I-6, RTP-2-I, and TOU-8-SOP-I.

reports that it denied these requests. SCE now petitions for modification of D.01-04-006 to clarify that decreases are not permitted.

3.6.6.2. Discussion

We used the same language to lift the suspension in April 2001 that we used to apply the suspension in October 2000. That is, for example: "we lift the suspension…[and] allow customers to elect to opt-out or change firm service level…." (D.01-04-006, mimeo., page 17.)

SCE argues that lifting the suspension returned SCE and its customers to the position immediately prior to when the suspension was applied. SCE concludes that only increases in FSL were allowed during the November 2001 opt-out window. This is incorrect.

In support of lifting the suspension, we noted that market conditions had dramatically changed from those that existed in prior years. We permitted customers to make necessary and reasonable changes in FSL so that California would have a base of interruptible load upon which to rely for the difficult period ahead. Among other things, we did this to avoid having to unreasonably rely on penalties to drive customer compliance. (*Id.*, pages 15-16.) The change was not limited to increases in FSL.

We also noted that normal variations in customer operations justified lifting the suspension. We said that businesses and other customers (e.g., universities) grow, modify processes, and make other changes over time. We concluded that:

> "It is reasonable to allow customers to periodically reassess their situations and either opt-out or change firm service levels to better match current market and business realities with their abilities to interrupt load." (*Id.*, page 15.)

We also said:

> "In addition to this opt-out or readjustment, lifting the suspension means customers may annually reassess and make changes as necessary beginning in November 2001." (*Id.*, page 17.)

SCE filed tariffs pursuant to D.01-04-006. The tariffs refer in Special Condition 3 to "adjustments" rather than "increases" in FSL. This language is consistent with our decision that customers should be allowed to periodically adjust (i.e., increase or decrease) FSL in order to secure a reliable interruptible resource base, to reflect normal changes in customer operations, and to avoid unreasonable reliance on penalties to drive compliance.

SCE says that the only decision language discussing the direction of changes in FSL mentions increases, citing language saying customers may "increase their firm service level as of November 1, 2000." (*Id.*, Attachment A, page 1.) This is only a partial reading of our decision, and is not determinative of SCE's petition.

The cited language reflects the fact that lifting the suspension back to November 1, 2000 involved the issue of whether customers could increase their FSL to avoid penalties that had accrued from October 1, 2000 through January 25, 2001. As SCE points out, no customer sought a retroactive decrease in FSL. Rather, the singular concern raised by interruptible customers was how to get out of the program without penalty, or how to decrease penalties by retroactively increasing their FSLs. The adopted language in this one specific case was not intended to negate our goal of letting customers change their FSL during the following November adjustment window.

SCE asserts that interruptible schedules to which lifting the suspension applied are closed to new customers, and that the Commission confirmed this in

D.01-04-006. SCE concludes that since these existing schedules are closed, decreases in FSLs are not allowed.

SCE is correct that several interruptible schedules are closed to new customers. Nonetheless, we allowed existing customers then, and allow those customers now, to remain on those schedules, while at the same time permitting changes in FSL. The fact that such schedules are closed to new customers does not require that we limit existing customers to increases in FSL. Rather, we permit customers to make necessary and reasonable changes, thereby allowing California to have a more reliable base of interruptible load upon which it may reasonably depend.

ORA asserts that SCE's petition should be granted because the cost of discounts used as an incentive to create interruptible load is too high. We agree that these programs are not inexpensive and, to address this concern, have placed megawatt and dollar limits on each utility's programs. We are not persuaded by ORA, however, that cost concerns drive whether or not to grant SCE's petition.

Within 30 days of the date of this order, SCE should notify the approximately six customers whose FSL decrease request was denied in November 2001 that each customer has a 15-day window to now elect to reduce its FSL. The FSL reduction will be effective the same date as it would have been if it had been granted by SCE in November 2001.

4. Curtailment Priorities

The second core area involves modifications to existing curtailment priorities.

4.1. Hospitals With Fewer Than 100 Beds

> **Issue:** What is the effect of including hospitals with fewer than 100 beds on the list of essential customers, including the effect on the number of circuits and megawatts that are available for rotating outage. (D.01-04-006, Ordering Paragraph 12, as renumbered by D.01-04-009.)

Hospitals with fewer than 100 beds are now included in essential customer Category C. (D.01-04-006.) As a result, all hospitals are normally excluded from rotating outages. On doing this, we said:

> "…we have little specific information on the effect of this change. We order this change because we are persuaded by the limited information we now have that rural hospitals have an immediate need for protection during the crisis we face for Summer 2001. We will revisit this issue in Phase 2, however. We direct that respondent utilities submit specific information in Phase 2 on the effect this change has had on mandatory curtailments, and the effect on the number of circuits and megawatts that are available for rotating outage." (D.01-04-006, mimeo., page 64.)

Utilities report that including hospitals with fewer than 100 beds in Category C has had the following effects:

Reduction In System Resources Available For Rotating Outage By Including Hospitals With Fewer Than 100 Beds In Category C

Line No	Utility	Reduction in Load Available for Rotating Outage (MW)	(From %)	(To %)	Reduction in Number of Circuits
1	PG&E	915	51.0	46.4	107 [1]
2	SCE	1,269	55.4	49.7	191 [2]
3	SDG&E	0	remains above 40%		0

Note: These results are based on assuming all customers conditionally awarded Category M status (D.01-09-020) submit their Statement of Authenticity and become fully included in Category M.

[1] Approximately 135 circuits are involved, of which about 28 also serve at least one other essential customer that is not a small hospital. Thus, a net of 107 circuits are removed from rotating outage.

[2] Approximately 382 circuits are involved, of which about 191 also serve at least one other essential customer that is not a small hospital. Thus, a net 191 circuits are removed from rotating outage.

We have previously determined that each utility must maintain at least 40% of its load available for rotating outage to avoid involuntary load shedding and general system collapse. (D.82-06-021, D.01-04-006, D.01-06-085, D.01-09-020.) We continue to apply that criterion here. The evidence shows that including hospitals with fewer than 100 beds in Category C does not jeopardize the 40% limit for any utility. Thus, we retain the inclusion of hospitals with fewer than 100 beds in Category C.

ORA suggests that essential customers in sparsely populated areas, such as small hospitals, should install backup generation, renewable self-generation, or energy conservation measures to cut peak demand by 20% (e.g., weatherization, lighting improvements, energy efficiency appliances). ORA argues that it is not equitable to other 'non-essential' ratepayers to exclude a limited subset of non-essential customers from rotating outages simply because they share a circuit with a small hospital. ORA says its suggestions will improve equity. We are not convinced.

We recently clarified that an exemption from rotating outages for a hospital is not dependent upon the status of backup or standby generation.

(D.01-04-006, mimeo., page 65.) Nothing suggested by ORA convinces us to revisit this issue now. Further, nothing suggested by ORA convinces us that there should be a different standard for hospitals in rural compared to urban areas.

The fact is that non-essential customers enjoy an exemption from rotating outages when they share a circuit with an essential customer. There is no distinction in this result based on the type of essential customer (e.g., hospital, police station, fire station), or location (e.g., densely or sparsely populated area). To the extent there is an equity effect, PG&E points out that in many, if not most, instances the number of customers on each circuit located in remote areas is less than the number on each circuit in densely populated areas. Therefore, the number of non-essential customers obtaining an exemption from rotating outages by sharing a circuit with an essential customer is likely to be larger in the more densely populated areas, and the equity effect, if any, may be more acute in urban than rural areas. Nothing advanced by ORA convinces us to make a distinction for hospitals based on population density, or size of hospital.

Moreover, respondent utilities are reconfiguring circuits to narrow exempted load to more nearly match exemptions with essential customer status. These projects are being undertaken where cost-effective and reasonable, and may include reconfigurations affecting rural hospitals.[19] (D.01-04-006, mimeo., pages 45 and 65; also Ordering Paragraphs 4, and 5.) Circuit reconfiguration for

[19] The Energy Division Director has authorized the following circuit reconfiguration projects: 223 circuits representing 905 MW for PG&E, 169 circuits representing 575 MW for SCE, and 30 circuits representing 171 MW for SDG&E. This totals 422 circuits representing 1,651 MW.

small hospitals is a better approach to addressing the concerns of non-essential customers enjoying exemptions from rotating outages, increasing the pool of available customers for rotating outages, and equity than is the creation of additional requirements for small hospitals regarding backup generation, renewable self-generation, or energy conservation measures.[20]

4.2. Skilled Nursing Facilities

> **Issue:** What is the effect of including skilled nursing facilities on the list of essential customers normally excluded from rotating outages. (D.01-04-006, Ordering Paragraph 13, as renumbered by D.01-04-009.)

4.2.1. Background

By Assigned Commissioner's Ruling (ACR) dated March 23, 2001, SNFs were not included in Category C (hospitals), or otherwise included in the list of essential customers normally excluded from rotating outage. This result was based on the lack of information regarding the effect of maintaining at least 40% of available load for rotating outage. We affirmed this result in April 2001. (D.01-04-006, mimeo., page 65.) Nonetheless, we directed utilities:

> "to provide specific information no later than in Phase 2 on the effect of extending this exemption [from rotating outages] to skilled nursing facilities, including the number of circuits and megawatts removed from rotating outages. The evaluation will include an estimate of the resulting effect, if any, on mandatory

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[20] With the exception of hospitals (essential customer Category C) and SNFs (which we address below), utilities must evaluate the adequacy of standby generating equipment for all essential use customers, and consider removing them from the list of essential customers. (D.82-06-021 (June 2, 1982), Findings of Fact 2 and 3, Cal. PUC LEXIS 537; D.01-04-006, mimeo., page 65.)

> curtailments, and the 40% criterion. Finally, respondent utilities must also consider circuit reconfigurations in Phase 2 that would narrow exempted load by isolating skilled nursing facilities." (D.01-04-006, mimeo., page 66; Ordering Paragraph 13, as renumbered by D.01-04-009.)

We later established essential customer Category M.[21] We received and considered nearly 10,000 applications for Category M, including many from SNFs. We found that we could not include all SNF applicants in Category M, but were able to grant that status to 88 SNFs. (D.01-09-020, mimeo., page 18.)

The Commission's consultant in the Category M process (Exponent) recommended that we give further consideration to investigating the feasibility of exempting all SNFs. We adopted that recommendation, noting we were concerned:

> "that the population within SNFs…is among the most vulnerable in our society. Some of these patients would have been in acute care hospitals a few years ago, but are now discharged to SNFs…" (D.01-09-020, mimeo., page 19.)

We stated that we might later be able to include all SNFs in the list of essential customers. (*Id.*)

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[21] Category M provides an opportunity for an individual customer to be classified as an essential customer (i.e., normally excluded from rotating outage). To qualify, the customer must show that inclusion of the customer in a rotating outage presents unacceptable jeopardy, or imminent danger, to public health and safety. The jeopardy or danger must be beyond economic harm or inconvenience to the customer. Rather, it must be jeopardy or danger to wider public health and safety. (D.01-05-089, mimeo., page 3.)

4.2.2. Data

Respondent utilities submitted data in compliance with D.01-04-006. The data generally shows that including SNFs in the list of essential customers is feasible.

Respondent utilities report these results using slightly different bases for determining eligible SNFs. PG&E used a list provided by the California Association of Health Facilities (CAHF), while SCE and SDG&E used Standard Industrial Classification Code (SIC) 8051. Utilities urge that the Commission select a single, objective, uniform source for identifying SNFs if the Commission includes SNFs as essential customers. Utilities point out that the California

Department of Health Services oversees licensing of SNFs, and propose that the Commission rely on DHS certification for this purpose.

Utilities submitted revised data based on DHS licensed facilities. The data shows that including SNFs in the list of essential customers would have the following effects:

Reduction In System Resources
Available For Rotating Outage By Including SNFs
In The List Of Essential Customers

Line No	Utility	Reduction in Load Available for Rotating Outage (MW)	(From %)	(To %)	Reduction in Number of Circuits
1	PG&E	1,150	46.4	40.6	130 [1]
2	SCE	648	49	46	63 [2]
3	SDG&E	211	54	49	31 [3]

Note: These results are based on assuming all customers conditionally awarded Category M status (D.01-09-020) submit their Statement of Authenticity and become fully included in Category M.

[1] Approximately 320 circuits are involved, of which about 190 also serve at least one other essential customer. Thus, a net of 130 circuits are removed from rotating outage.

[2] Approximately 303 circuits are involved, of which about 240 also serve at least one other essential customer. Thus, a net of 63 circuits are removed from rotating outage.

[3] Approximately 68 circuits are involved, of which about 37 also serve at least one other essential customer. Thus, a net of 31 circuits are removed from rotating outage.

Utilities state that they each need an additional 60 to 90 days to determine which circuit reconfiguration options, if any, are available.

4.2.3. DHS Certification and Category C

We agree with respondent utilities that a common basis should be used to identify eligible SNFs. Utilities propose reliance on DHS certification. No other party opposes this basis, or offers an alternative. Use of a CAHF list or SICs is not as precise as DHS licensure, since there may be an element of self-identification in the use of SICs or other methods that is removed by the DHS certification and license process. We adopt respondent utilities' proposal to use DHS certification and licensure as the basis by which a SNF may be eligible for essential customer status.

Based on the available data we may expand Category C to include DHS licensed SNFs while maintaining our 40% criterion. Therefore, we include SNFs in Category C. We modify Category C to state: "hospitals and skilled nursing facilities." The 88 SNFs included in Category M are transferred to Category C.

4.2.4. Circuit Reconfiguration Studies

Including SNFs reduces the PG&E load available for rotating outage precariously close to the 40% limit.[22] While it is acceptable to move close to the 40% limit, we seek to preserve the largest reasonable percentage possible on each utility's system. We do this since each percentage reduction otherwise places the burden of rotating outages on a smaller base of remaining ratepayers. We also want to maintain the largest reasonable percentage to permit essential customer status for other customers as may be needed over time (e.g., additional rapid rail transit systems or portions thereof).

We direct each respondent utility to complete the circuit reconfiguration report on SNFs contemplated in our April 2001 order, and file and serve that

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[22] The 40.6% result for PG&E may be closer to about 43%, however. This is because PG&E has already been authorized by the Energy Division Director to complete circuit reconfiguration projects on 223 circuits totaling 905 MW, and not all of those reconfigurations are reflected in the 40.6% result.

report within 60 days. (D.01-04-006, Ordering Paragraph 13, as renumbered by D.01-04-009.) We use the process already adopted in D.01-04-006 for the filing and service of each report, as well as the filing and service of comments, responses or protests. (D.01-04-006, Attachment D.) Further, just as already determined in D.01-04-006, we reaffirm that the Energy Division Director may authorize respondent utilities to implement cost-effective, reasonable circuit reconfiguration projects, including those for SNFs, to isolate essential from non-essential customers up to a cumulative total of $5 million for PG&E, $5 million for SCE, and $1 million for SDG&E.[23] (D.01-04-006, Ordering Paragraph 5.)

4.2.5. Other Conditions

To promote equity, ORA recommends that SNFs, just as small hospitals, be required to install backup generation, renewable self-generation, or energy conservation measures to cut peak demand by 20%. We decline to adopt ORA's recommendation here for the same reasons we decline to adopt the recommendation above for small hospitals.

Moreover, regarding conservation measures, we are not convinced that there is any basis to impose a different requirement on SNFs than we do on other customers. That is, we do not require police or fire stations, whether in urban or rural areas, to implement energy conservation measures to maintain eligibility for essential customer status. Similarly, we do not do so for SNFs.

We also foresee difficult administrative issues with ORA's proposal. For example, it would be problematic to find a SNF, police station or fire station to be essential if it meets a 20% conservation standard, but to be non-essential if it only

[23] This reaffirms but does not increase existing dollar limits.

succeeds in reaching 19% conservation. Even if this is reasonable, which we find it is not, ORA fails to propose a basis for measuring the 20%. Thus, we are not convinced by ORA, and decline to burden parties further by requiring implementation proposals and recommendations.

4.2.6. Self-Generation

Finally, SDG&E states that the Commission should reject ORA's recommendation to tie exemption from rotating outages to self-generation. SDG&E argues that either the customer is or is not essential. According to SDG&E, that determination does not depend upon whether the customer installs self-generation.

Essential customer classification is not dependent upon whether or not the customer has self-generation. That is, each customer is or is not essential based on the customer's service to the community as determined by our essential customer categories (e.g., police, fire, prison, national defense, hospitals), or other factors which result in essential customer status (e.g., areas served by networks, transmission level customers, OBMC participants). We remind utilities, however, that they are required to assess the adequacy of an essential customer's backup or standby generation, and consider removing that customer from the essential customer list, with the exception of hospitals. (D.01-04-006, mimeo., pages 65-66; D.01-06-085, mimeo., pages 13-14; D.01-09-020, mimeo., page 15.)

We clarify that by adding SNFs to Category C, we do not require that utilities consider the adequacy of backup or standby generation for SNFs, just as they need not do so for hospitals. The patient population in SNFs is among the most vulnerable in our society, just as is the population within hospitals. The basis for excluding consideration of backup or standby generation for hospitals was that the applicable regulations of the Office of Statewide Planning and Development regarding minimum backup generation for hospitals do not result in sufficiently safe and reliable electricity to satisfy the Commission's definition of essential uses for hospitals. (D.01-04-006, mimeo., page 65.) Any similar regulations for SNFs are just as likely not to satisfy our expectation of essential uses for SNFs. Thus, we do not require utilities to consider removing a SNF from Category C based on an assessment of the adequacy of the SNF's backup or standby generation.

4.3. Category M

> **Issue**: What procedures, if any, should be adopted to consider continuing the essential customer status for those customers granted Category M status in D.01-09-020 past September 6, 2003.
>
> **Issue:** What procedures, if any, should be adopted to consider additions to, or subtractions from, the list of Category M customers adopted in D.01-09-020 for the period after September 6, 2003.

Absent a specific order to the contrary, the Category M essential customer status now awarded to 405 customers expires on September 6, 2003. (D.01-09-020, mimeo., page 25, Ordering Paragraph 9; D.01-12-007.) Parties recommend various approaches for the continuation or termination of Category M.

Respondent utilities recommend a self-identification process with submission of evidence on public health and safety, similar to the process used in June 2001. CMTA proposes that existing Category M customers be allowed to re-certify their status for an additional two years (to September 6, 2005) upon a showing that there has been no material change in the nature of the customer's essential status. ORA asserts that Category M status should not be extended beyond September 6, 2003, and recommends that Category M customers be directed to install backup or self-generation by September 6, 2003. In the alternative, ORA suggests that a Category M customer may maintain that status upon completion of building weatherization appropriate for their geographic area, and passing an energy audit or achieving energy conservation of 15% to 20%.

4.3.1. Expiration on September 6, 2003

We decline to continue the award of Category M status beyond September 6, 2003. The status should expire as planned, and no replacement process should be adopted. We base this on the same reasons that applied when we first determined that Category M should expire on September 6, 2003. (D.01-09-020, mimeo., pages 23-25.) Nothing presented in Phase 2 changes our conclusion.

First, the conditions that led the Governor to declare a State of Emergency on January 17, 2001 are not expected to remain indefinitely. Rather, we expect the electricity market to reasonably soon return to one that operates efficiently and equitably without extraordinary measures.

Second, customers change as economic conditions evolve and time passes. The award of Category M status was not intended to be a government benefit that accrues indefinitely to only a select group of individually named customers. The status was intended to address relative risk for some customers during a temporary State of Emergency.

Third, the Category M process was expensive and burdensome on customers, parties and the Commission. The process was reasonable given the State of Emergency, but it is unlikely that a similar level of cost and burden will need to be repeated.

Fourth, we do not want Category M status to forever remove incentives for customers to make health and safety modifications to their operations. It was reasonable in the particularly difficult and troubled recent past to protect public health and safety by excusing some customers from rotating outages. In the long run, however, we want each business to be exposed to the risk it places on the community, and have the incentive to take whatever steps are reasonable to mitigate or eliminate that risk.

Fifth, to the extent Stage 3 events occur in the future, rotating outage notification procedures are in place and we expect that they will improve with experience. Adequate notification will reduce, if not eliminate, the need for the total exemption awarded Category M customers.

Finally, we expect each customer awarded Category M status to not only have the right incentives, but to take the necessary, appropriate and reasonable steps to reduce or eliminate any significant risk to public health and safety when that customer is exposed to an outage. The outage may be from any cause, including weather, accidents, or supply shortages. Steps a customer might take include changing its production process or technology, updating equipment, instituting new safety procedures and measures, or installing self-generation. Reasonable measures, as necessary, should be in place by September 6, 2003.

4.3.2. Backup or Self-Generation

ORA recommends that Category M customers be directed to install backup or self-generation. While we agree with ORA that customers must be prepared for outages, we decline to adopt ORA’s proposal.

Each customer should make the necessary evaluations and implement reasonable solutions on its own. Self-generation may or may not be the only, or the best, solution. Part of the customer’s assessment may include whether or not the customer faces exposure to liability if the customer fails to take necessary and reasonable precautions that result in harm to individuals and the community upon the occurrence of an electricity outage. We are comfortable letting customers make those decisions.

4.3.3. Energy Efficiency Alternatives

ORA recommends a Category M customer might maintain that status upon completion of building weatherization, and passing an energy audit or achieving energy conservation of 15% to 20%. We do not adopt this approach.

Linking exempt status to implementation of weatherization, audits, and energy conservation measures would fail to comprehensively consider public health and safety, to the extent that remains the driving criterion. Further, implementation of such measures would require adoption of criteria and standards. None are proposed, and we are not inclined to craft our own.

4.3.4. Eliminate Category M

We also remove Category M from the list of essential customers effective September 7, 2003. We previously said that we would not eliminate Category M since use of the category may continue to be necessary at intermittent times. The problem with continuing Category M is that there will be an on-going expectation of its use. We decline to foster that expectation. Further, there will be no procedure in effect for processing applications. Thus, there is no need to continue Category M.

4.3.5. Reminder of Notice

Finally, we remind respondent utilities to notify by August 7, 2003 each customer granted Category M essential customer status that the customer's essential customer status will expire on September 6, 2003. (D.01-09-020, mimeo., page 35.) In addition, that notice should state that there is no procedure for the continuation of Category M status. A draft notice should be provided to the

Commission's Public Advisor no later than 30 days before the notice is mailed, and utilities should incorporate changes recommended by the Public Advisor.

4.4. Water and Sewer Utilities

> **Issue**: What additional measures, if any, should the Commission adopt for normally exempting water and sewer utilities from rotating outages based on public health and safety.

For the reasons explained below, we adopt a test of Category H notification and emergency restoration procedures, decline to order installation of backup generation, decline to amend Category H, and direct respondent utilities to address specific matters in subsequent reports.

4.4.1. Background

Water and sewer treatment utilities are essential customers in Category H. (See Attachment B for the list of essential customers.) They may request partial or complete rotating outage exemption based on an emergency. The requested exemption may be before a rotating outage begins or, if during a rotating outage, to seek partial or complete service restoration.

We first reached this result in April 1980 (D.91548, 3 CPUC2d 510). We determined that we should not grant a blanket exemption from rotating outages to all water and sewer utilities. We were persuaded by staff that in many cases automatic exemption would preclude electric utilities from implementing rotating outage plans, since so many circuits would be excluded.[24] (D.92315

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[24] This is still the case today. SCE reports, for example, that it has nearly 9,000 water and wastewater service accounts, of which approximately 4,300 are subject to rotating outages, representing 7,000 MW, or 31% of SCE's load.

(October 8, 1980), 1980 Cal. PUC LEXIS 842.) Failure to successfully implement rotating outage plans could result in automatic under-frequency load shedding, and lead to general system failure.

We clarified, however, that discretion was not left to the utility. Rather, if a water or sewage facility makes a good faith request (i.e., refraining from an exemption request unless absolutely required to ensure the public's health and safety), "we fully expect the utility to grant it." (D.92315, 1980 Cal. PUC LEXIS 842.)

The issue resurfaced in Phase 1. We there declined requests to modify Category H to provide complete exemption from rotating outages for water and sewer utilities, noting that these entities generally have backup generation, or other capacity for operation and storage during power interruption. (D.01-04-006, mimeo., pages 67-69.) We stated we are confident that water and sewer utilities can, and will, communicate clearly with respondent utilities during emergencies. We balanced the competing interests of granting more exemptions against the detrimental effect this has on remaining non-essential customers, and concluded that a blanket exemption should not be given.

Many water companies subsequently applied for Category M essential customer status, based on their individual circumstances. Our consultant, Exponent, ranked these applicants lower relative to other applicants. This lower ranking was based on most of these entities having backup generation or storage facilities, and backflow protection systems, thereby reasonably mitigating danger to public health and safety from rotating outages of moderate duration. We agreed with that ranking. (D.01-09-020, mimeo., page 11.)

Several entities questioned the ranking and, as a result, we directed Water Division to prepare a Report. (D.01-09-020, mimeo., pages 30-31.) Water

Division reports that adequate protection systems are in place, but recommends that emergency restoration procedures contemplated by Category H be tested to minimize adverse effects on public health and safety. Water Division also recommends that water and sewer companies be excluded from Category M. Finally, in the instances where some additional protection is needed, Water Division proposes that "water companies with pressurized systems and sewer companies install backup generators on wells with the largest pumping capacity or the lead wells" to ensure system integrity. (Water Division Report, September 28, 2001, page 3.)

Various Phase 2 pleadings support or oppose Water Division's recommendations. LAC initially recommended in its comments and reply comments that (1) electric utilities be required to certify all water companies have been notified of Category H, (2) SCE implement testing of the communication procedures expected in Category H, and (3) 16 specific water agencies with inadequate backup generation or supplies, but who are in areas of high risk for fire in Los Angeles county, be granted blanket exemption from rotating outages. LAC and SCE ("joint parties") continued to consider this issue, and subsequently filed joint supplemental comments. Joint parties agree that LAC's concerns can be met without creating permanent exemption for some water agencies by amending the language of Category H.

4.4.2. Notification and Testing of Category H Procedures

Water Division, LAC, utilities and several parties propose that each respondent utility notify each of its water and sewage treatment customers of Category H, and test the emergency restoration procedures. No party opposes this plan. We adopt this recommendation.

In particular, each respondent utility should notify[25] each of its water and sewer customers[26] of Category H. Similar to the procedure adopted in other orders, utilities should serve a copy of the draft notice on the Commission's Public Advisor, and incorporate changes recommended by the Public Advisor. (D.01-04-006, Attachment E.) Notification to water and sewer customers should be completed within 45 days of the date of this order. Finally, each respondent utility should file and serve a verified statement certifying that the notice was completed, with a copy of the notice attached to the statement. (Rule 2.4 of the Commission's Rules of Practice and Procedure.) The statement should include any other relevant information necessary to reasonably inform the Commission about completion of notice.

Each respondent utility should also conduct a test of the emergency exemption or restoration procedure permitted in Category H. The test includes not only the utility, but some or all of its water and sewer entity customers, and may potentially include some or all of hundreds of fire departments, districts and agencies. PG&E states that it is not opposed to the testing of service restoration procedures, but believes fire departments need to coordinate with their serving water agencies in such tests. We generally agree, but direct that

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[25] In many, if not all, instances this is actually re-notification. For example, SDG&E points out that it has formal procedures in place for water utilities to use when a Category H exemption is required, and has already informed water utilities of these procedures.

[26] This includes public and privately owned utilities, agencies, districts, and any other water or sewer entity that is a customer of respondent utility.

each utility take the lead responsibility to develop, conduct, and analyze the test, plus report the results to participants and the Commission.

The test may involve mapping hydrants to water suppliers and service accounts, identifying sewer pumping service accounts, linking those service accounts to electricity distribution circuits, correlating those circuits to rotating outage implementation plans, and assessing the feasibility of fire agencies notifying the utility as part of engine dispatch procedures when responding to a fire. The test need not, however, include all water and sewer customers, nor all fire departments, districts and agencies. Rather, utilities should identify a reasonable sample of water and sewer customers, and fire departments, districts or agencies, for the purpose of the test. The utility should take the lead responsibility in designing the test, and accommodate input from entities that will participate in the test.

The test should be conducted within 120 days of the date this order is mailed. Each respondent utility should file and serve a report on the test and its results within 60 days of the date the test is completed. The report should be served not only on the Phase 2 service list, but also on each entity that participates in the test. Except for service on the Commission, each respondent utility may serve a Notice of Availability on the service list, even if the report is less than 75 pages (unless a party has previously informed respondent utility of its desire to receive a complete copy).[27]

[27] Rule 2.3 of the Commission's Rules of Practice and Procedure.

4.4.3. Backup Generation

We decline to adopt Water Division's recommendation to direct water and sewer utilities to install backup generation. As LAC points out, this is not necessarily a viable alternative without further information about (1) cost;

(2) agency or utility budgets; (3) economics of this investment, particularly for small entities; (4) methods of financing this investment, particularly for small entities; (5) permitting and installation limitations, if any; and (6) our authority to order entities we do not regulate to make a particular, specific investment.

4.4.4. LAC and SCE Proposed Language

Joint parties state that LAC's concerns can be met without creating permanent exemptions for certain specifically named water agencies by amending the language of Category H to read:

> "Water and sewage treatment utilities <u>or firefighting entities</u> may request <u>immediate</u> partial or complete rotating outage exemption from electric utilities in times of emergency identified as requiring their service, such as [fire] fighting <u>fires</u>." (Additions underlined, deletion in brackets.)

We decline to adopt the joint proposal of LAC and SCE.

4.4.4.1. "Firefighting Entities"

Joint parties assert that the first proposed addition (i.e., to add "or firefighting entities") will give firefighting entities standing with the electric utility. With standing, joint parties assert that the entity may directly request partial or complete exemption on behalf of the water agency whose facilities are needed to fight a fire without having to go through the water agency.

This first modification is not necessary. We have already clarified that all authorities with emergency powers have such standing. The item is of sufficient importance that we address it again.

The issue was discussed in the decision creating Category M. (D.01-05-089.) SDG&E there asked that the Commission explicitly recognize a respondent utility's ability to comply with directives of local authorities, such as police or fire, to override a circuit exemption, or order that power be restored during an outage, as needed for public health and safety. We stated our agreement, but clarified that this action must be coordinated with the CAISO, to the extent reasonable and necessary, to prevent widespread system collapse. We concluded that no amendment to the list of essential customers was necessary.

Specifically, we said:

> "Respondent utilities should comply with valid orders of responsible police or fire authorities, and other authorities with emergency powers, to exempt a circuit from outage, or order a circuit re-energized, based on public health and safety. To the extent such orders are implemented, however, they must be executed to the extent reasonable and necessary in coordination with, and with the agreement and approval of, the California Independent System Operator (CAISO). The CAISO must be involved as necessary so that such action will not jeopardize a widespread system collapse.
>
> "Respondent utility must coordinate as needed with the CAISO since a local emergency official cannot be expected to know and consider the status of the entire statewide electrical system. When properly coordinated and approved with the CAISO as needed, however, respondent utility should comply with valid orders of responsible local emergency officials.
>
> "…we agree with SDG&E…that respondent utilities may implement a valid order from responsible police, fire, or similar authority with emergency powers, for immediate protection of public health and safety when jeopardy or danger is imminent, to the extent properly coordinated with the CAISO, as needed.
>
> While we make this clarification at SDG&E's request, we decline to modify the list of essential customers. SDG&E does not allege that it lacks the authority to respond to a proper order of responsible local authority with emergency powers, and we are not convinced that respondent utilities lack that authority. To prevent any possible confusion, we clarify that

> respondent utilities may do so when properly coordinated with the CAISO. We are not convinced, however, that this must be explicitly stated in an amendment to the list of essential customers in the Priority System for Rotating Outages." (D.01-05-089, mimeo., pages 5-7.)

The same reasoning applies to joint parties' first proposed modification. Even if we would consider this modification (which we do not), we would decline to limit standing to firefighting entities. That is, all authorities with emergency powers already have standing to make requests to electric utilities in the furtherance of public health and safety. If we list one, we would need to list all. We are not persuaded that we must complicate the description of Category H by including an exhaustive list.

4.4.4.2. "Immediate"

Joint parties argue that the second proposed addition (i.e., to add "immediate") conveys the urgency with which service must be restored. According to joint parties, firefighting efforts could otherwise be greatly hindered by delay in executing the request. We are not convinced.

Water and sewer utilities, as well as authorities with emergency powers, may request anything with regard to partial or complete rotating outage exemption. The request may be for immediate exemption or restoration. Alternatively, it may be a conditional request (e.g., restoration conditioned upon a downed line first being removed to protect firefighters, police, other personnel, or the public from danger). Category H need not qualify or limit the type of request that may be made. We expect utilities to respond appropriately to all reasonable requests made in good faith.

We clarify that the request must be reasonable and that we expect the utility to grant all reasonable requests. In determining whether a request is reasonable, the utility may need to coordinate with the CAISO. For example, a request from a firefighting entity might be reasonable based on limited information available to that entity, but be unreasonable if the CAISO determines that re-energizing the circuit would result in collapse of the electricity grid throughout the entire state. Similarly, a request from a firefighting entity for immediate restoration may at first appear reasonable, but in fact be unreasonable until the utility has communicated with the water agency to determine that re-energization can be done safely. The utility must balance all necessary public health and safety considerations. We expect the utility to do so, and respond appropriately.

This discussion is not intended to give utilities unreasonable discretion in deciding whether and when to grant a request for rotating outage exemption from a water or sewer utility, or an appropriate authority with emergency powers. Rather, it is to clarify that we fully expect each utility to respond appropriately to all reasonable requests made in good faith. That means to immediately re-energize a circuit, if that is what is reasonable.

4.4.4.3. "Fighting Fires"

Joint parties state that their third proposed modification (i.e., to replace "fire fighting" with "fighting fires") seeks to clarify that dispatching fire resources to a reported fire incident constitutes an emergency justifying an exemption, but a firefighting agency may not request an exemption merely under the guise of its "general firefighting" responsibilities. For example, joint parties state that high fire danger conditions themselves are not the type of identified emergency for which an exemption should be ordinarily granted.

We agree with this distinction, but decline to authorize revised language. Category H applies "in times of emergency…such as fire fighting." The fire fighting example is the action and activity of fire fighting. It is not the generalized condition of a fire department being poised in an emergency mode 24 hours per day to engage in "fighting fires." We are not convinced that the proposed language of "fighting fires" provides any more clarity than the existing language of "fire fighting."

4.4.4.4. Effort of Joint Parties

While we do not adopt joint parties' proposal, we appreciate the effort that they undertook. In particular, LAC states that it devoted substantial time and resources that were exceptional for its size and budget.[28] These efforts have served a good purpose. For over 20 years, Category H has contemplated communication during an emergency. The efficiency of that communication depends upon knowledgeable participants making reasonable and timely requests to the right entity, and responsible individuals acting appropriately.

LAC worked with the LAC Fire Department and SCE to identify a Very High Fire Hazard Severity Zone, potentially vulnerable water companies, and methods to address their concerns. LAC and SCE have identified circuits that serve high risk areas, examined how geographic information systems (GIS) data can be shared, and have agreed to a test identifying accounts and circuits. They have also agreed to coordination between the LAC Fire Department and various water agencies to notify SCE when fire engines are dispatched to a fire in a Very High Fire Hazard Area. We applaud their efforts, and are confident that this will

[28] LAC represents a large body of interests. According to LAC, the LAC Fire Department protects an area of 2,278 square miles with a population of 3.8 million people, of which a total of 998 square miles meets the criteria of Very High Fire Hazard Severity Zone, or Fire Zone 4.

permit effective and efficient communication if the Category H procedures must be used.

4.4.4.5. Decline Limited Permanent Exemption

Joint parties' amended language was proposed in place of permanent exemption for 16 water agencies in areas of high fire risk. While we decline to adopt joint parties' proposed rewording of Category H, we are not persuaded to provide permanent exemption for these 16 agencies as an alternative.

Current Category H language reasonably meets the needs expressed by joint parties. Utilities will conduct a test of Category H procedures. We expect joint parties, and other parties as appropriate, to continue to work closely to address any reasonable concerns. Thus, neither revised language nor permanent exemption is needed.

4.4.5. Amount of Time for Service Restoration

Parties raise another concern regarding "immediate." PG&E states that it "uses best efforts to restore service as soon as practical once a request is obtained…" (PG&E Response, January 4, 2002, page 2.) According to PG&E, there is always a certain amount of time that is required before service can be restored, and neither the Commission, parties, customers nor the public should expect the level of response to be "immediate." PG&E says that an individual may be required to travel to the substation to activate a switch and re-energize a circuit if the circuit is not SCADA controlled.[29] Thus, even if the request is for immediate restoration, that may not be possible, according to PG&E.

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[29] SCADA stands for Supervisory Control and Data Acquisition (SCADA). SCADA-controlled circuit switching devices are remotely controlled.

LAC and ACWA reply that, if PG&E cannot provide an "immediate" response upon request, then the Commission should order exempt status for water and sewer agencies on circuits which PG&E cannot immediately restore. We decline to adopt this recommendation.

LAC and ACWA present no information on the number of circuits, megawatts, or percentage of system load that would remain for rotating outage if their recommendation is adopted. We cannot balance the interests of water agencies against the interests of all other customers without further information. For the reasons discussed below, however, we are not inclined to order production of that data.

SDG&E states that if "immediate" means "instantly," then immediate is neither a feasible nor realistic expectation and, even if possible, it would not necessarily be safe (e.g., if there is a downed line that must first be removed). We agree. SDG&E asserts that it begins immediate processing of a request to allow implementation as soon as possible. This is reasonable.

Immediate processing is also what we understand is done by SCE when joint parties state:

> "SCE and LAC are jointly developing an expedited notification process by which LAC can contact SCE at the time fire resources are dispatched, <u>so that SCE can begin immediately processing the exemption request at the earliest opportunity</u> after the fire emergency is identified." (Joint Supplemental Comments, December 21, 2001, page 4; emphasis added.)

This is also what we understand PG&E does when it undertakes "best efforts to restore service as soon as practical."

LAC further argues that if "PG&E cannot provide <u>rapid</u> restoration…" the Commission should order exempt status for the involved circuits. (LAC Reply, January 9, 2002, page 3; emphasis added.) LAC does not define "rapid." We are persuaded that PG&E's "best efforts" are consistent with "rapid."

We conclude that "immediate processing" and "best efforts" to restore service as soon as it is safe and practical are reasonable expectations in implementing an exemption or restoration request under Category H. The communication process must be efficient, and responsible persons must apply reasonable judgment during an emergency. LAC does not convince us that PG&E's description of its response requires that circuits on which water agencies are served be permanently exempted if they are manually, not SCADA, controlled.

Nonetheless, to promote a more complete understanding we direct each utility to address this matter in its report on the test of its Category H procedures. Specifically, each utility should discuss its "immediate processing," or "best efforts." The report should also address the amount of time before an employee can be at the site of a manually de-energized circuit if a restoration order is given.

5. Extreme Temperature

> **Issue:** Implementation of residential use priority in areas of extreme temperature (Senate Bill 2X 68).

We agree with utilities that the public interest does not require providing priority in electricity use to residential customers who experience extreme temperatures. Nonetheless, we apply reasonable caution and adopt respondent utilities' alternative proposal, with some modifications. We adopt utilities' proposal for customer education and advance notification, but permit self-certification rather than require medical certification. We adopt utilities' proposal to use cooling stations. We encourage utilities to locate these stations, and consider seeking legislation, if necessary, to provide funding. We reject ORA's proposal to establish a penalty for outages over 90 minutes. Utility costs for customer education, advance notification, administrative costs to locate cooling stations, and other reasonable costs to implement the orders herein may be included in interruptible program memorandum accounts for consideration of future recovery.

5.1. Background

In 1976, the Commission established priorities in the use of electricity among customers. (D.86081, 80 CPUC 157.) In 2001, we were directed to consider the potential effect of extreme temperatures on the health and safety of residential customers, and consider providing additional priorities in use. (Senate Bill X2 68, amending Public Utilities Code Section 2772.) To the extent we determine that it is in the public interest to provide priority to customers experiencing extreme temperatures, we were directed to provide priority only when temperatures are extreme. We were also directed to consider alternatives, such as reducing the duration of an outage, or imposing the outage earlier or later in the day.

5.2. Extreme Temperature Rotating Outage Exemption

Utilities state that a temperature-based priority in use is both unwise and unworkable. They do not recommend adoption of priority based on extreme temperatures. No party argues in support of such priority.

We do not find that it is in the public interest to create priority in use for residential customers based on exposure to extreme temperatures. The undisputed medical evidence is that health risks associated with short-term power interruptions (up to 90 minutes) are low. Health risks from extreme heat and cold occur most often after chronic or prolonged exposure (e.g., typically more than two days for heat, and over eight hours for cold).

Further, we have provided rotating outage exemptions for all hospitals and DHS licensed SNFs. A significant part of the population most vulnerable to extreme temperatures is thereby already exempt from rotating outages.

We also carefully consider the feasibility of implementing rotating outages based on extreme temperatures. We are persuaded by utilities that there is no operationally feasible and fair method to do so.

There are basically two approaches that might be used. First, regions traditionally subject to extreme temperatures might be exempted. There are several problems with this approach.

Defining areas with precision and specificity is difficult. This approach would also essentially place the entire burden of rotating outages on customers who live in more temperate areas, and effectively reward customers who already consume a greater proportion of electricity in less temperate areas. Further, even temperate areas can suffer extreme temperatures. SCE reports, for example, that 85% of its service area, including every climate zone, has experienced temperatures of 100 degrees or more at some time in the last decade.

It is also unlikely that any geographically based regional exemption could be accommodated within the existing 40% load margin requirements. Finally, a geographically based exemption would be disruptive to implement. Utilities have established rotating outage blocks made up of geographically dispersed circuits. This minimizes the impact of rotating outages on any one contiguous geographic region. Exempting a contiguous region based on temperature would require utilities to excise individual circuits from numerous rotating outage blocks. This would increase operational complexity, and inequitably increase the duration and frequency of outages for nonexempt customers.

A second approach would be to provide exemptions based on "real time" or actual temperatures. There are also several problems with this approach.

Defining "extreme" would be difficult. Also, the definition may be different for various regions of the state. For example, utilities point out that a temperature of 95 degrees would be extreme for the residents of San Francisco and many coastal regions at any time of the year, but such temperature would not be extreme for the residents of Borrego Springs or many inland areas during several months of the year.

There are also operational problems. A single circuit can extend for many miles. Utilities report that they do not have reasonable access to temperature data that corresponds with the locations of circuits. Even if a mechanism were created for access to such data, temperatures would vary along the circuit. Given that utilities have thousands of circuits, the task of monitoring, evaluating, and implementing actual temperature-based exemptions would become unworkable.

Further, utilities would be expected to administer temperature-based exemptions on short notice, and revise their rotating outage plans with little time. Adjusting complex rotating outage plans based on "real time" factors would be difficult, and substantially increase the complexity of an already complex system.

Finally, safety may be compromised. Utilities rely on pre-established approaches for automatic and manual curtailment of circuits, taking into account such things as the location of essential customers. The systems contain a significant amount of preprogrammed information to ensure operational flexibility to meet system demands while minimizing the chances for error.

These systems cannot easily accommodate last minute, real time changes without increasing the risk of errors, and potentially compromising public health and safety.

Therefore, we are persuaded that employing temperature-based exemptions would create unacceptable operational and equity problems. Even if such a system could be created, we are not persuaded that the benefits would be worth the costs, particularly given the existence of a feasible alternative.

5.3. Alternatives: Reducing Duration or Imposing Outage at Another Time

Utilities assert that reducing the duration of the outage, such as to 15 or 30 minutes, is infeasible and inequitable. We agree. None of the problems identified above are resolved by reducing the duration of the outage, while shorter outages would likely create their own set of problems.

We also agree with utilities that imposing the outage earlier or later in the day would be similarly infeasible and inequitable. Again, none of the implementation difficulties identified above are resolved by moving the time of the outage, while time shifting the outage would likely create its own problems. Moreover, rotating outages are most probable during periods of peak demand, which tend to correlate to periods of peak temperatures. Limiting rotating outages to periods of moderate temperature (i.e., early morning or late evening) would, in many if not most cases, insulate certain areas from rotating outages altogether.

5.4. Adopted Alternative: Education, Notification, Cooling and Heating Stations

Utilities propose using education, notification, and cooling stations as an alternative to temperature based rotating outages. We adopt this alternative, with some modifications.

The alternative is based on the report of utilities' medical expert. According to the expert, heat-related illnesses include heat cramps, heat syncope (fainting), heat exhaustion, and heat stroke, while cold-related illnesses include hypothermia and frostbite. The illnesses range from mild to life-threatening, but the expert states that the health impacts are known and preventable with a good warning system, a focus on prevention and public awareness, and an appropriate community based response.

5.4.1. Education

Utilities report that there is considerable literature showing customers can, with relatively minimal effort, take appropriate precautions to protect themselves from the consequences of a short power disruption during extreme weather conditions. For example, during a heat storm persons should drink fluids (even if not thirsty or active), stay indoors, take a cool shower or bath, limit outdoor activity, stay in shaded areas, and dress in light colored and loose clothing. Those at particular risk (e.g., seniors) should be contacted at least twice per day during a heat storm. Utilities propose disseminating this information by bill insert. We adopt this proposal.

Within 60 days of the date of this order, utilities should include an insert in each customer's bill providing reasonable education about protecting vulnerable customers during periods of extreme heat or cold. This bill insert should be repeated periodically, as reasonable and necessary.

Further, utilities should include reasonable education material in their use of mass media at the time of an extreme temperature occurrence. Utilities should also make a reasonable effort to target outreach to vulnerable populations, such as persons who are in assisted living centers that are not SNFs.

5.4.2. Advance Notification

An entire advance notification infrastructure is now in place, and several methods of advance notification are available before outages occur. (See D.01-09-020, mimeo., page 26 for a complete discussion.) These methods include media (e.g., radio, television, newspapers), websites (e.g., CAISO, Office of Emergency Services, utilities), and individual alert services (e.g., from the State, from private companies). The systems may include notification by pagers or other electronic means. Customers can take reasonable actions to be informed, and those with health concerns can take appropriate precautionary measures.

Utilities propose an additional accommodation for customers who are vulnerable to extreme temperatures. Utilities recommend an individual, automated telephone message to identified temperature sensitive customers prior to implementation of rotating outages, similar to the notification now provided to life support and critical care customers. (D.01-04-006, mimeo., pages 56-59.) We adopt this proposal, and add this notification to our Priority System for Rotating Outages. (See Attachment B, Item 2.A.)

Utilities propose that eligibility for this special advance notification be based on medical certification. Utilities are concerned that there is significant potential for abuse, resulting in individualized notification to a virtually uncontrollable number of residential customers. We are not persuaded, and decline to adopt the medical certification requirement for several reasons.

First, we think the potential for abuse is small. Customers already have many ways (including several without cost) to obtain advance notification, as described above. The incremental benefit of telephone notification is minimal. In contrast, it is not an increased baseline allowance (as with medical baseline), nor is it a reduced bill (as with special rates for low income customers), either of which may provide real economic gains to a customer, and would be more likely to be subject to abuse.

Second, the medical certification form proposed by utilities is complex and long. We reject burdening California's doctors and health care infrastructure with yet another form, the benefits of which do not justify the costs.

Finally, the form requires release of personal and private medical information to the utility. The burden on the customer of being required to release this otherwise confidential information is excessive compared to the public good derived by possibly preventing some abuse of the program.

As a result, we permit customers to self-certify for advance, individual telephone notification. We require that the customer essentially complete the first page of utilities' proposed form. We modify the form to remove references to medical certification, include members of the customer's immediate household, and include a short description of possible health conditions that qualify for this advance notification. Further, we require the customer to sign the form stating that the customer or a member of his or her immediate household has a health related vulnerability to extreme temperatures. Our adopted form is in Attachment C. Utilities may work with parties, Energy Division and the Public Advisor to further revise the form (e.g., to promote simplicity), and submit a revised form for approval by advice letter.

We agree with utilities that certification should be for two years, and re-certification should be required every two years, or by December 31 of the year the application is set to expire. Utilities must mail a re-certification form to the customer no less than 60 days in advance of the date the customer would otherwise be deleted. The utility may not remove the customer if for any reason the re-certification form is not mailed to the customer, and may not remove a customer until at least 60 days after the form is mailed.

To address abuse, utilities may request supplemental information from individual customers to verify temperature sensitivity. The supplemental information may not request release of confidential medical information. Doctor certification of vulnerability to extreme temperatures is limited to a request that the doctor certify based on his or her best medical judgment that the patient has increased risk of health related illnesses (compared to the average patient) if exposed to a rotating outage of 60 to 90 minutes during a period of extreme temperature. Utilities are not required to request supplemental information, but may do so at their discretion.

We may later permit utilities to universally require medical certification, but only upon a showing of program abuse. To obtain this relief, each utility may file an Advice Letter. The Advice Letter must include evidence that demonstrates there is abuse, and propose a form for medical certification. Absent a very compelling showing, however, we will not permit a form that requires the patient and doctor to release otherwise private and confidential patient health information. Rather, all that we will require is that the doctor certify increased relative risk of health related illness.

5.4.3. Cooling Stations

Utilities recommend that the Commission establish cooling stations at premises that are air-conditioned and already on distribution circuits that are exempt from rotating outages. These premises might be police stations, fire stations, hospitals, or local community centers on exempt circuits. This will allow customers to obtain temporary relief from extreme heat during the limited duration of a rotating outage affecting their residence, without reducing the number of circuits available for rotating outage. We agree.

Utilities recommend the Commission establish cooling stations, but we are not convinced that we need to be involved. It is the utility, not the Commission, with information showing which community centers and other customers are on exempt circuits. We are not persuaded that we need to order utilities to give us that information before utilities can use it in bill inserts and mass media. Further, utilities can reasonably work with police stations, fire stations, hospitals, community centers, and other customers, to determine whether or not each customer is willing and able to be a cooling station.

In some instances a candidate cooling station may be unable to perform this civic service without compensation. The compensation may be needed to offset costs incurred for providing cooling station services. We encourage utilities to consider working with such candidate customers to seek legislation, if necessary, to provide requisite funding.

5.5. Penalty for Outages Over 90 Minutes

Based on its reading of the report submitted by utilities' medical consultant, ORA concludes that an outage of 60 minutes does not present a medical risk, while a outage longer than 90 minutes does. ORA proposes that utilities be penalized for outages over 90 minutes absent extenuating circumstances. We decline to adopt this recommendation.

The risk of adverse health effects increases with the duration of exposure to extreme temperatures. We are not persuaded, however, that 90 minutes is a reasonable limit for that exposure in relation to rotating outages. Utilities' medical consultant reports that adverse outcomes from exposure to intense heat or cold mostly occur after chronic exposure of more than several hours or days. The remaining risks from shorter exposures can be reasonably mitigated with education, advance notification, and cooling and heating stations.

Further, operational factors during a Stage 3 emergency dictate some reasonable flexibility. For example, a slightly extended rotating outage may prevent operational complications and reduce risk to the grid at large, in some particular circumstances. Alternatively, the CAISO might notify the utility that Stage 3 may expire minutes after the transfer to another rotating outage block. A utility might extend the outage to the existing block for a few minutes rather than cause another block to be interrupted for only a short time, thereby maintaining the availability of that next block for the entire duration of a subsequent Stage 3 event.

Utilities report that they are committed to outage durations of 60 to 90 minutes, and would only extend an outage beyond 90 minutes if there are extenuating circumstances. System operators should be free to use reasonable discretion within existing law, orders and rules. There is no evidence that any utility is improperly implementing rotating outages such that further guidance or constraints are needed. There is no evidence that lack of defined penalties has adversely affected implementation of electricity emergency rotating outage plans. We are not persuaded the medical evidence demonstrates that outages must be limited to 90 minutes, or that utilities should be automatically penalized for outages over 90 minutes.

Moreover, as PG&E points out, we retain discretion to investigate and sanction specific utility action if a utility fails to comply with existing standards and Commission directives. We may also investigate and sanction unreasonable conduct.

6. Memorandum Account Balances

> **Issue:** What should be the disposition of balances in memorandum accounts created by D.01-01-056 (for penalties paid and due under interruptible tariffs between October 1, 2000 and January 25, 2001).

6.1 Background

Effective January 26, 2001, we granted waiver of penalties for an interruptible customer's non-compliance with interruption requests based on a threat to public health and safety. (D.01-01-056.) This waiver continued until lifted by subsequent order in April 2001. (D.01-04-006.) Also in January 2001, we directed that utilities not bill customers for already incurred penalties, and track all penalties in memorandum accounts, for the period from October 1, 2000 through January 25, 2001. We stated that we would later give consideration to the balances in these accounts, with the possibility of waiving past penalties as part of our reassessment of the interruptible program. (D.01-01-056, mimeo., pages 1-2.)

6.2. Memorandum Account Totals

PG&E reports a memorandum account balance of $7.0 million, with approximately $1.7 million accrued during November and December 2000, and approximately $5.3 million during the second and third weeks of January 2001. PG&E says, however, that the $5.3 million might end up being less for two reasons.

First, PG&E states that tariff restrictions do not allow non-compliance penalties in a given year to exceed 200% of the participant's annual incentive level. As a result, PG&E does not apply non-compliance penalties until the following year. PG&E says the estimated $5.3 million non-compliance penalty for 2001 maybe somewhat reduced for those customers where the penalty exceeds twice their annual savings.

Second, PG&E explains that its interruptible program has a two-tier penalty level. This structure rewards customers who have achieved complete compliance during the previous year by reducing their non-compliance penalty level in the subsequent year by half (from $8.40 per kWh to $4.20 per kWh). According to PG&E, 27 interruptible customers may have their penalty rate reduced during 2001 if the non-compliance penalties are waived for the period from October 1 through December 31, 2000. PG&E states that the lowering of the penalty rate would also somewhat reduce the estimated $5.3 million for 2001.

SCE reports that non-compliance penalties for the period October 1, 2000 through January 25, 2001 totaled $199.8 million, but that the memorandum account balance is zero. According to SCE, this results from application of the limited, special opt-out for SCE customers. (D.01-04-006.) SCE customers were permitted to opt-out back to November 1, 2000 and have their non-compliance penalties waived in exchange for paying the firm service rate. SCE says penalties totaling $181.5 million (out of the $199.8 million) were waived in exchange for customers opting-out back to November 1, 2000 and paying the firm service rate. SCE asserts that it billed customers who continued on the interruptible program the remaining amount of $18.3 million for penalties incurred from October 1, 2000 through January 25, 2001, after adjustment for an increase in FSL, if any.

SDG&E states that its memorandum account balance is $1.6 million. Of this amount, SDG&E says $1.4 million is unpaid and due.

6.3. Require Collection of Balances

We require collection of the balances in the memorandum accounts. We do this for several reasons. First, granting a wavier of penalties to those customers who committed to a load reduction but did not comply would be inequitable to those who similarly committed but did comply.

Second, it would be inequitable to those customers who funded the interruptible rate discounts. That is, interruptible rate customers receive a rate discount funded by other customers in exchange for agreeing to penalties for non-compliance. It would be unfair to provide benefits in the form of both discounts and waivers of penalties to interruptible customers without any compensation to non-interruptible customers in return.

Third, everyone suffered from energy shortages and high prices during the energy crisis in the fall of 2000 and spring of 2001. This included all ratepayers, not just interruptible customers. Interruptible customers tend to be large, sophisticated customers capable of measuring risks associated with opportunities (e.g., reduced energy prices). While we suspended non-compliance penalties going forward in January 2001, it is unreasonable to expect non-interruptible ratepayers to provide an economic cushion to interruptible customers retroactively to October 1, 2000.

Fourth, interruptible customers had the opportunity to opt-out. If they did not, they were obligated to perform only within the limits of the program.

Fifth, we determined that non-compliance penalties should be waived from January 26, 2001 through April 2001 based on a threat to public health and safety. This provided an economic cushion to interruptible customers because it was in the public interest. CMTA, CIU and others seek wavier of the penalties back to October 1, 2000, largely arguing this result would be equitable, but do not convincingly show that this is necessary to promote public health and safety.

Finally, non-compliance can be an issue at any time. It would send the wrong message to waive penalties now for a period that was not subject to a State of Emergency and did not involve jeopardy to public health and safety in the same way that it did beginning later in January 2001. We seek to provide clear and consistent treatment within programs. Thus, to be fair and reasonable to all parties, balances in memorandum accounts must be collected.

CMTA and others argue that collection of balances for PG&E is unreasonably harsh since collection will be 15 to 18 months after the event. To the contrary, the customers knew that they were subject to a penalty when they failed to comply with the interruption request. We directed utilities to defer collection pending our further consideration of the matter, but there was never a statement that penalties during the October 1, 2000 through January 25, 2001 time period were waived, only that the matter was being considered. (D.01-01-056.) In fact, there would have been no need to track the balances in memorandum accounts if the decision had already been made to waive the balances. There is no element of harshness, surprise or unfairness in now directing utilities to collect memorandum account balances.

6.3.1. SCE

SCE has already billed the $18.3 million in balances due for the period October 1, 2000 through January 25, 2001. No further action is needed.

We note, however, that SCE billed the balances prematurely. Some SCE interruptible customers presumably elected to opt-out in April 2001 on a current basis, or not opt-out at all but to remain in the program. Unlike customers who opted-out back to November 1, 2000, these customers did not make the decision to have penalties waived in exchange for paying firm service rates. Waiver of penalties for those customers was not resolved until now since the decision to opt-out in April 2001 or stay on an interruptible schedule was independent of the wavier of penalty issue. Similarly, penalties incurred, if any, by customers for failure to comply in October 2000 have not been addressed until now.

If we had come to another decision, we would order SCE to refund the $18.3 million collected or billed. We do not reach that result, however, so no such order is necessary. We encourage SCE to carefully read our decisions to avoid creating issues where none would otherwise exist.

6.3.2. PG&E

We direct that PG&E customers pay memorandum account balances but permit one variation. PG&E customers may make a one-time "opt-out" decision similar to the one offered to SCE customers. In PG&E's case, the decision is an accounting matter and will serve to reconcile the memorandum account balance, but it will not change the schedule upon which the customer was served after April 2001. It will also not disturb any change the customer might have made in the November 2001 opt-out period.

SCE customers in April 2001 were permitted the option to opt-out back to November 1, 2000. We permit PG&E customers to ”opt-out” or reconcile these balances for essentially the same reasons (e.g., dysfunctional market). (See, D.01-04-006, mimeo., pages 13-19.) It would be unfair to PG&E customers to have let SCE customers undo the economic penalties that otherwise accrued, but not do the same for them. Further, some PG&E customers have facilities and accounts in SCE’s service area, and some business competitors of PG&E customers are served by SCE. Uniform treatment between service areas promotes reasonable equity.

6.3.2.1. Reconciliation Period November 1, 2000 Through April 30, 2001

The reconciliation should be for the period November 1, 2000 through April 30, 2001. We use November 1, 2000 for the same reasons we did so for SCE. This promotes administrative ease, customer understanding, and minimization of disputes over effective dates and resulting dollar amounts.

We select April 30, 2001 also in relation to the experience of SCE customers. SCE customers who elected to opt-out or change FSL back to November 1, 2000 made this choice in a 15-day window that ran through May 9, 2001 (then extended to May 29, 2001). An SCE customer could have elected as early as April 24, 2001 to opt-out and, effective immediately, be treated as a firm customer from November 1, 2000 on. Alternatively, the SCE customer could have made this decision as late as May 29, 2001. We apply a uniform date to end the reconciliation for PG&E customers for the same reasons we elect a uniform start date. April 30, 2001 is a reasonable uniform date to select within the range of dates applicable to SCE customers.

We also use April 30, 2001 as a uniform date to promote equity for PG&E customers. That is, the bargain with each November annual opt-out is reduced rates for the next 12 months in exchange for a maximum number of interruptions. PG&E's total annual hours of interruption were nearly fully used by the end of January 2001, and PG&E's customers had a very high rate of compliance. PG&E customers complied with the maximum number of interruptions, and are due rate discounts for the rest of the year. We select an early date within the range of dates for the reconciliation period to provide a reasonable balance of the remaining interruptible rate discounts.

Therefore, PG&E should conduct a one-time opportunity to reconcile account balances. Customers should be given a 15-day window to exercise this option beginning upon service of notice to customers. The option should permit the customer to elect total "opt-out" of the interruptible program, or a change in FSL, for the six-month period of November 1, 2000 through April 30, 2001. The customer may "opt-out" in whole or part, and have penalties waived in exchange for paying the firm service rate.

The "opt-out" for PG&E customers, however, does not change the service the customer received beginning May 1, 2001. That is, the customer was in fact, and remains, an interruptible customer from May 1, 2001 through the November 2001 opt-out period. Further, whatever decision the customer makes now regarding reconciliation of the memorandum account balance will not disturb the customer's decision in November 2001 to have remained in, or opted-out, of the interruptible program.

6.3.2.2. Tolling of Curtailment Events and Program Turnover

PG&E also points out the issue of whether or not to count curtailment events in the memorandum account period toward the tolling of compliance. If the events are counted, and the customer complied, the non-compliance penalty in the subsequent year is reduced by half. On the other hand, if the events are counted, and the customer did not comply, the penalty remains at its full level. Similarly, if the events are not counted, the resulting compliance rate will be affected, and that may change the subsequent non-compliance penalty.

The events in this case should not be counted toward compliance. That is, we took an extraordinary action for SCE customers, and we do so for PG&E customers, because of the unique market circumstances in late 2000 and early 2001. Just as we now allow PG&E customers to reconcile balances for those extraordinary events, we do not tally the unusual experiences during those events in a way that penalizes the customer for later events. As long as the customer met compliance criteria during periods other than the memorandum account period, the subsequent non-compliance penalty should be reduced by half.

Finally, ORA states that it does not object to an opt-out for PG&E customers back to November 1, 2000 similar to that provided SCE customers but that doing so would be unfair to PG&E's other ratepayers. This would be the case, according to ORA, since SCE customers who elected to opt-out were restricted from participating in another interruptible program for 12 months. ORA points out that PG&E customers cannot be similarly restricted. Rather, ORA says the PG&E customers will opt-out to avoid penalties, but still receive interruptible rate discounts.

We do not find this to be an impediment to our adopting the "opt-out" or reconciliation option for PG&E customers. The restriction for SCE customers was to "prevent unreasonable turnover between similar programs without benefit to the state." (D.01-04-006, mimeo., page 19.) The reconciliation option provided here does not involve the same issue of turnover between programs.

6.3.3. SDG&E

We direct SDG&E to bill its customers for memorandum account balances since SDG&E interruptible customers were free to switch to another tariff at any time. The only exception is customers on the interruptible tariff for 12 months or less. Customers on SDG&E's A-V rate for 12 months or less were offered a unique opt-out window between January and March 2001. (D.00-12-058.) In order to provide the same option for those SDG&E customers that we provide PG&E customers, we differentiate treatment based on whether these 12 months or less customers already switched or stayed on the A-V1 rate.

First, we direct SDG&E to waive penalties for customers on Schedule A-V1 for 12 months or less who switched (or were switched) to another rate schedule prior to summer 2001. These customers have paid the higher annualized rate of Schedule AL-TOU, and have paid the "price" for having penalties waived for the November 2000 through January 25, 2001 period. This customer group should be provided a rebate of the penalty amounts because they were already on the otherwise applicable tariff.

Second, we direct SDG&E to send another "opt-out" notice to those customers on the A-V rate for 12 months or less who decided to stay on Schedule A-V1. These customers continued to enjoy the benefits of lower annualized rates on Schedule A-V1 compared to Schedule AL-TOU. They should be allowed to waive incurred penalties if they opt-out of Schedule A-V1 effective with their next billing cycle and do not accrue the benefits of this rate for 12 months. The 12-month restriction is applied since these customers would otherwise be rewarded by waiver of penalties but also be allowed to continue to enjoy the benefits of the discounted prices on Schedule A-V1. Reasonably similar treatment between customers of SCE, PG&E and SDG&E requires that SDG&E customers be permitted to waive accrued penalties in exchange for opting-out of the Schedule A-V1 rate for 12 months given the seasonality of rates in SDG&E Schedule AL-TOU compared to the lack of seasonality in Schedule A-V1. After 12 months, the customer may again participate in an interruptible program to the extent provided by SDG&E tariffs. SDG&E should provide reasonable notice to its customers of the decisions herein after coordination on the notice with the Commission's Public Advisor.

6.4. Ratemaking

TURN recommends that we direct utilities to return collected memorandum account balances to ratepayers. Otherwise, TURN fears that these non-compliance penalties may end up with shareholders. We decline to adopt this proposal.

TURN offers no compelling reason to disturb existing ratemaking treatment. As SDG&E points out, the balance in the memorandum account should be treated just as it otherwise would be treated absent the Commission action to suspend collection of some non-compliance penalties. To do otherwise would be to select one source of revenue gains but ignore revenue shortfalls. We decline to engage in a separate, complex balancing of various revenues without a very convincing reason to reverse existing regulatory treatment.

6.5. Cal Steel Petition for Modification

Cal Steel petitions for modification of D.01-04-006 with respect to the manner in which interruptible customers are permitted to "opt-out" of the program in favor of firm service. Specifically, Cal Steel asks for modification of the rule governing calculation of the amount of interruptible discount which must be repaid when a customer opts-out of the program. This in turn is related to the amount due from the memorandum account balances. SCE opposes Cal Steel's petition, and offers an alternative. We adopt SCE's alternative in part.

6.5.1. Cal Steel's Situation

Cal Steel is an SCE I-6 customer with an FSL of 5 MW, average load of 38 MW, and momentary peak load sometimes more than 60 MW. Due to plant improvements and expansions over the past 10 years, Cal Steel found it was unable to reduce its demand to 5 MW during curtailments called in Summer 2000, but did reduce demand to between 6.5 MW and 8.5 MW. Cal Steel says it was prevented from adjusting its FSL or opting-out of the interruptible program during the normal opt-out window in November 2000 due to Commission suspension of that window. (D.00-10-066.) In spite of its best efforts to comply with curtailment requests, Cal Steel says it became subject to penalties of about $1.3 million due to its inability to reach the 5 MW FSL during November and December 2000, and January 2001, even though it substantially complied each time.

Cal Steel says it changed its preference from the interruptible program to the OBMC program because of its concern for the safety of plant, equipment and employees in the event of an unannounced rotating outage. Cal Steel reports that it was not permitted to participate in both an interruptible program and OBMC, however, so it opted-out of the interruptible program when allowed to do so in April 2001. (D.01-04-006.) To avoid penalties of about $1.3 million, Cal Steel elected to opt-out back to November 1, 2000, and repay the interruptible discount of $669,318.

Cal Steel says repayment of the full discount is unfair since it was 95% compliant with requested interruptions during this period, and that repayment of the discount should be adjusted to reflect the degree of compliance. Cal Steel recommends a minimum of 80% compliance to qualify for this adjustment. If modified as requested, Cal Steel says it would owe SCE about $33,466 rather than $669,318.

6.5.2. Adopted Alternative

We decline to adopt Cal Steel's proposal. We agree with SCE that Cal Steel's proposal places an unreasonable administrative burden on SCE. It requires SCE to review, revise, and recalculate rate discounts for all customers who opted-out by applying a scaling factor based on complex calculations of actual performance. The proposal would create unknown but possibly significant revenue impacts on SCE and, in many if not all cases, require SCE to refund already repaid discounts in part or full. It would also require similar treatment for PG&E, given our decision above regarding reconciliation of memorandum account balances. This would unreasonably increase the administrative complexity for PG&E.

The dilemma faced by Cal Steel in large part resulted from our decision in April 2001 not to permit a customer to participate in both a capacity based interruptible program and OBMC. (D.01-04-006, Attachment A, Item 2.4.9.) We changed that decision within weeks after Cal Steel made its decision to opt-out by permitting OBMC participants who are the only customers on their circuit to also participate in a utility operated capacity interruptible program. (D.01-05-090, Ordering Paragraph 2.)

SCE proposes that the remedy is to modify D.01-05-090, and allow customers placed in that unique situation to return to the I-6 schedule effective November 1, 2000 at a higher FSL, effectively eliminating noncompliance penalties while permitting participation in both programs. We agree. This approach is less complex, and does not penalize the few customers placed in this unique dilemma due to the timing of our decisions.

We modify D.01-06-087 (which modified D.01-05-090) to permit such customers to return to Schedule I-6. They may do so back to November 1, 2000 at a higher FSL (higher than when they were originally on Schedule I-6), thereby effectively eliminating noncompliance penalties. (See Attachment D, Item 2.4.9.5.) The customer must pay the appropriate firm and interruptible rates based on the selected FSL for that period (i.e., repay interruptible discounts for the portion of the load that is converted to firm, in exchange for waiver of non-compliance penalties). We also modify D.01-06-087 to reflect the fact that the DBP replaced the Voluntary Demand Response Program (VDRP) in July 2001 pursuant to D.01-07-025. (See Attachment D, Items 2.4.3 and 2.4.10.) Further, we modify D.01-06-087 to reflect our allowing an interruptible customer to participate in OBMC after meeting its monthly obligation, subject to limitation during an overlapping event. (See Section 3.6.2.7 above, and Attachment D, Item 2.4.9.4.)

We allow the customer to determine the FSL effective November 1, 2000, and decline to adopt SCE's proposal to base the FSL on the maximum load recorded during relevant periods. The customer must live with the adjusted FSL not only for the period from November 1, 2000 through April 30, 2001, but also for the period after May 1, 2001. We let the customer "replay" the decision based on allowing participation in both programs. We are not persuaded by SCE that the customer's options must or should be limited to promote efficiency, equity, or any other objective. To the contrary, equity is promoted by allowing the customer to make the most reasonable choice after elimination of the timing dilemma caused by our two decisions.

We also excuse May and July 2001 from this recalculation. Schedule I-6 curtailments were called in these two months. Cal Steel and other similarly situated customers, however, had left I-6 and were on OBMC. It would be unreasonable to retroactively apply a penalty for those two months for failure of the customer to comply with I-6 interruptions when the customer was not an I-6 customer at that time. It would be similarly unreasonable to provide an I-6 discount for those two months.

We also clarify that this decision does not affect the November 2001 opt-out period. Pursuant to this order, the customer may adjust FSL back to November 1, 2000, and participate in both I-6 and OBMC. In November 2001, however, the customer would have had its annual I-6 adjustment opportunity. In this case, these few customers may now exercise their November 2001 adjustment. This is because they have been operating as firm customers on OBMC since about May 2001. It will have no actual effect on their operations if they opt-out in part back to November 1, 2000, and then make another opt-out adjustment in November 2001. It is equitable, however, to allow these customers to have the November 2001 adjustment just as any other customer, since we now allow them to make an election back to November 1, 2000 which affects the decision with which they would otherwise have been presented in November 2001.

SCE should notify Cal Steel and any other similarly affected customer of the change made herein within 30 days of the date of this order. Customers should have 15 days to make accept or reject this opportunity.

7. Conclusion

We have resolved all issues identified in the Phase 2 Scoping Memo with the possible exception of the DBP. We have ruled on all outstanding petitions for modification, except one. We decline to devote additional resources of the Commission, parties and customers to consider late Category M applications.[30] (D.01-09-020, mimeo., page 22.)

Thus, except for the one unresolved petition and the DBP, all matters are now resolved, moot, or need no further consideration. The proceeding is left open only for resolution of the two remaining items.

8. Service of Decision on Category M Applicants

Notice of the availability of the draft and final decisions was served by letter on over 10,000 Category M applicants (including those who applied either timely or late). Recipients of the letter were directed to the Commission's web page to access a copy of the draft and final decisions, or to call the Commission for copies. The letter was served by electronic mail on those with electronic mail addresses, and by regular mail on all others.

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[30] These are Category M applications filed after 5:00 p.m. on June 4, 2001 but received by June 15, 2001.

9. Comments on Draft Decision

On March 14, 2002, the draft decision of Presiding Officer and Assigned Commissioner Wood was served on, or notice of the draft decision provided to, parties in accordance with Sections 311(g)(1) of the Public Utilities Code, and Rule 77.7. The draft decision was also served by electronic mail on parties with electronic mail addresses. In addition, the draft decision was published on the Commission's web site.

Timely comments were filed and served on April 3, 2002 by PG&E, SCE, SDG&E, CMTA, CIU, CLECA, CEC, ORA, TURN, LAC, Chromalloy Los Angeles, CCSF, and CAHF. Timely reply comments were filed and served on April 8, 2002 by PG&E, SCE, SDG&E, CIU, CEC, ORA and TURN. Final oral argument was held on April 15, 2002.

We make several changes to the draft decision based on comments, reply comments and final oral argument. For example, the final decision states that consideration of interruptible programs in GRCs does not foreclose the Commission from opening another rulemaking to look at this matter on a statewide basis, or taking up the issue in a future resource planning, procurement, or other proceeding. We affirm that interruptible programs may be a resource as well as insurance against risk. We state our expectation that utilities, parties and customers apply reasonable efforts to meet the interruptible program capacity goals. We modify application of the bill limiter. We order Energy Division to work with parties to develop a pilot program to test a modified OBMC baseline, we will give further consideration to the DBP, we extend and define the test location for the PBIP from the San Jose area to Santa Clara County, we clarify cost recovery for costs expended implementing orders in this decision, we delete the use of heating stations, we better explain our authorization of limited memorandum account recovery for SDG&E, and we include waiver of discounts as well as penalties for May and July 2001 in our adoption of SCE's alternative to Cal Steel's petition for modification.

Findings of Fact

1. SDG&E's RBRP has been well received by customers, it has had a successful implementation, and SDG&E has no other operational interruptible program that reaches the same level of participation and amount of interruptible load.

2. No Stage 3 events have been called since RBRP was approved, but the need for interruptible programs, such as RBRP, has not ended.

3. Cash and outage exemption are not equal or interchangeable benefits to all customers.

4. Reports submitted by utilities in August 2002 to use in determining whether or not to continue interruptible programs beyond December 2002 cannot contain much, if any, information on actual Summer 2002 experience.

5. Moving consideration of interruptible programs back to GRC or similar proceedings permits examination of interruptible rates and rate design in the context of each utility's overall rates and rate design but does not foreclose consideration of interruptible programs on a statewide basis in other proceedings.

6. An extension of interruptible programs through the final decision in the rate design phase of each utility's next GRC on similar proceeding provides an opportunity to pursue marketing of stable programs for Summers 2002 and 2003.

7. Total subscribed interruptible load through December 31, 2001 is about 1,420 MW (at the 5% level for OBMC, and minimum DBP response).

8. CEC recommends a planning goal of 2,500 MW for demand responsiveness programs in 2002.

9. Interruptible capacity of 2,500 MW will provide California system operators with about 5% of Summer 2002 projected load to be available for interruption based on system conditions.

10. SCE's Schedule I-6 bill limiter (for customers transitioning from Schedules I-3 and I-5 to I-6) began on January 1, 1993.

11. The bill limiter provision in Schedule I-6 is Special Condition 14, which in turn refers to Public Utilities Code Section 368(a).

12. Through March 31, 2002, the bill limiter will have been in effect for nine years and three months, reducing rates over this period by about $231.25 million (assuming $25 million per year based on the 1995 GRC estimate), or about $2.3 million per customer (assuming an average of about 100 customers).

13. The bill limiter has consistently been subject to termination, beginning in 1995, then deferred to 1996, to 1999, and finally to on or about March 31, 2002.

14. Modifying application of the bill limiter maintains the revenue shift within one customer class; does not increase any rate; and will not cause instability, uncertainty or volatility in electricity prices.

15. SCE large power customer rates (Schedules TOU-8 and I-6) are $25 million per year more than they otherwise would be to offset the $25 million annual revenue deficit caused by the bill limiter.

16. Continuing to apply the bill limiter to surcharges adopted in 2001 without an offsetting rate increase results in lower surplus credited to the PROACT balance (with all customers affected by an extension of the PROACT recovery period), while ending the bill limiter without an offsetting rate decrease would result in other large power customers continuing to pay an extra $25 million per year (with large customers paying a disproportionate share of the surplus credited to the PROACT).

17. Aggregation of more than two circuits for OBMC can pose administrative and tracking problems.

18. Limiting on-peak energy usage for SLRP to no more than 15% of the customer's posted baseline promotes consistency in non-compliance rules for those with and without interval meter data history.

19. Defining past similar days for OBMC baseline calculation as "days when the customer's business was in operation" complicates baseline calculations; increasingly moves away from clear, objective criteria toward individually tailored baselines; and will be relatively more difficult for utilities to administer.

20. A temperature adjusted OBMC baseline calculation eliminates the benefit of the customer knowing with certainty their targeted maximum load level for each curtailment event and it complicates the baseline calculation for each utility.

21. Use of a 10-day OBMC baseline normalized to reflect conditions on the day of the OBMC event (e.g., adjusted for temperature or production variations) may be a useful option for some customers participating in the OBMC program, provided that it can be kept administratively simple after first being evaluated in a pilot program.

22. Excluding Stage 1 and 2 days from the OBMC baseline calculation allows a customer to maintain a relatively higher OBMC baseline, potentially resulting in the undesirable outcome of the customer providing less load reduction during Stage 3 than during Stages 1 and 2.

23. The likely contiguity of Stage 1, 2 and 3 days means that eliminating Stage 1 and 2 days from the definition of similar days for the OBMC calculation could result in a participant's baseline being calculated from "similar days" that are potentially weeks removed from current conditions.

24. OBMC customers with a baseline more reflective of real time have an incentive during the later part of a Stage 2 event to ramp-up their load, thereby reducing the burden of a subsequent 5%, 10% or 15% reduction, and the extent to which this might occur can be observed in an OBMC baseline pilot program test.

25. There is only a limited amount of flexibility that can be permitted in OBMC baseline calculations since OBMC is designed to replace firm service

interruptions and, if OBMC does not produce dependable load reductions when called, additional firm service customers must be interrupted at the time of system need.

26. An entire infrastructure to provide advance notification of rotating outages is now in place; several methods of advance notification, beginning up to 48 hours in advance, are available before outages occur; and advance notification procedures will improve with experience.

27. Further expansion of the notice requirement to OBMC customers in advance of a rotating outage, or measuring results over the first full hour rather than half hour, could have the effect of delaying delivery of load relief to the system, ultimately necessitating increased firm load curtailments.

28. An undesirable outcome of granting CIU's proposal that interruptible customers be permitted to participate in OBMC after meeting their monthly interruptible contract obligations is that during a simultaneous I-6/OBMC event (in which the customer satisfies the final increment of its 40-hour monthly requirement under I-6 but the event continues), some customers may increase load (e.g., from an I-6 FSL of zero to the OBMC baseline less the percentage required reduction of 5%, 10% or 15%) and be in compliance even though the Stage 3 emergency continues, thereby forcing additional rotating outage reductions on other customers.

29. Requiring all OBMC customers to participate in proportion to their load unnecessarily and unreasonably limits program flexibility, but OBMC customers may agree to proportional participation if they wish.

30. Industrial customers are not the only beneficiaries of OBMC, but the entire system benefits by having OBMC circuits reduce load by prescribed amounts

generally equivalent to the reduction in system load resulting from rotating outages.

31. Utilities largely offer the same products to the same customers as aggregators, and load aggregators generally add another layer of cost on an already burdened electricity system.

32. SDG&E was ordered in March 2001 (D.01-03-073) to conduct a Residential Demand-Responsiveness (Smart Thermostat) Pilot Program, the program is underway, customers are being recruited, thermostats are being installed, and operation is expected by Summer 2002.

33. SDG&E's EAEI program has not been approved, a vendor contract has not been awarded, customer recruitment has not begun, and reaching the goal of significant program operation by Summer 2002 is unlikely.

34. The Commission has already addressed cost recovery for interruptible programs, and has specifically considered and rejected funding through a surcharge.

35. CEC's proposed interruptible program surcharge would generate an additional amount of approximately $200 million per year.

36. No evidence shows that funds collected in current rates are inadequate to fund existing programs, or are insufficient to fund expanded programs.

37. DWR reports that the DBP will again be available no later than June 2002, and it will be available to the same extent that it has at any time been available.

38. Most of the customers identified by CEC as potential participants for its proposed modified BIP program can participate in existing programs.

39. CEC's proposals to modify VDRP and BIP potentially involve significant implementation and operating costs, and the benefits in relation to those costs are uncertain.

40. A pilot test of CEC's proposed BIP will permit first assessing several issues including (a) the merits of opening interruptible programs to smaller customers; (b) the merits of measuring response on a "variable" basis (i.e., 10-day baseline) rather than a "fixed" basis (i.e., FSL); and (c) the cost-effectiveness of program modifications.

41. Allowing interruptible customers to annually make changes in FSL (both increases and decreases) permits California to (a) have a more secure base of interruptible load upon which it can rely, (b) reduce reliance on penalties to drive customer compliance, and (c) recognize normal variations in customer operations.

42. Including hospitals with fewer than 100 beds in essential customer Category C does not jeopardize the criterion that at least 40% of a utility's load be available for rotating outage.

43. Certification and licensure of a SNF by DHS is a relatively precise and objective method of identifying SNFs eligible for essential customer Category C.

44. Including DHS licensed SNFs in essential customer Category C does not jeopardize the criterion that at least 40% of a utility's load be available for rotating outage.

45. Regulations for hospitals regarding minimum backup generation do not result in sufficiently safe and reliable electricity to satisfy the Commission's expectation of essential uses for hospitals, and similar regulations for SNFs are just as likely to not satisfy Commission expectation of essential uses for SNFs.

46. The award of Category M status was not intended to be a government benefit that accrues indefinitely to only a select group of individually named customers, but was intended to address during a limited time the relative risk to public health and safety when some customers are exposed to a rotating outage.

47. Adequate notification of rotating outages will reduce, if not eliminate, the need for the total exemption awarded Category M customers.

48. Each customer can make its own evaluation of the best methods to be prepared for electricity outages (e.g., changing its production process or technology, updating equipment, instituting new safety procedures and measures, installing self-generation) and can implement necessary and reasonable solutions on its own without direction from the Commission.

49. Continuing Category M beyond September 6, 2003 will create an expectation of its continued use.

50. Water utilities, sewer utilities, and all authorities with emergency powers, may request either immediate or conditional exemption or restoration of electric service to a water or sewer utility under current provisions of Category H.

51. The Category H fire fighting example is the action and activity of fire fighting during an emergency, not the generalized condition of a fire department being poised in an emergency mode 24 hours per day ready to engage in fighting fires.

52. LAC and ACWA present no information on the number of circuits, megawatts, or percentage of system load that would remain for rotating outage if exempt status is given to circuits on which a water or sewer agency is served which PG&E cannot restore immediately upon a Category H exemption or restoration request.

53. “Best efforts” is consistent with “immediate processing” and “rapid restoration” for implementation of an exemption or restoration request under Category H.

54. The undisputed medical evidence is that health risks associated with short-term power interruptions (up to 90 minutes) are low, while health risks from

extreme heat or cold occur most often after chronic or prolonged exposure generally in excess of eight hours.

55. There is no operationally feasible and fair method to implement rotating outages based on extreme temperature.

56. The adverse health effects of extreme heat and cold are known and are preventable with a good warning system, a focus on prevention and public awareness, and an appropriate community-based response.

57. There is limited potential for abuse of a notification system that alerts self-identified temperature sensitive customers of rotating outages by an individualized, automated telephone message.

58. Parties who advocate a general requirement for medical certification of a customer's temperature sensitivity before the customer may receive an automated telephone message of rotating outage do not show that the benefits of medical certification exceed the burdens on an already stressed medical system, nor that the release of otherwise confidential medical information is reasonable and necessary to prevent possible but unlikely abuse.

59. Cooling stations on circuits already exempt from rotating outages can provide air-conditioning during periods of extreme temperature without reducing the number of circuits available for rotating outage.

60. Automatically penalizing a utility for an outage over 90 minutes (unless the utility can show extenuating circumstances to justify the outage) reduces operator flexibility that might be necessary given operational factors, is unnecessary given no evidence that the lack of penalties has adversely affected implementation of outages, and is unnecessary given the Commission's ability to investigate and sanction specific utility action in violation of law, or Commission order or rule.

61. Granting a wavier of non-compliance penalties tracked in memorandum accounts for customers who committed to a load reduction but did not comply would be inequitable to customers who similarly committed but did comply, and would be inequitable to customers who funded the interruptible rate discounts.

62. Interruptible customers generally had the opportunity to opt-out, but if they did not, they were obligated to perform only within the limits of the program.

63. Waiver of non-compliance penalties from October 1, 2000 through January 25, 2001 is not necessary to promote public health and safety.

64. Uniform treatment between PG&E and SCE customers of the limited opt-out back to November 1, 2000 is equitable.

65. A uniform date of November 1, 2000 to begin the limited opt-out period for PG&E customers promotes administrative ease, customer understanding, and minimization of disputes over effective dates and resulting dollar amounts.

66. A uniform date of April 30, 2001 to end the limited opt-out period for PG&E customers is consistent with the experience of SCE customers.

67. Unique market conditions in late 2000 and early 2001 justified the extraordinary opt-out opportunity permitted SCE customers, and justifies similar treatment for PG&E customers, including not tallying curtailment events during the memorandum account period toward the tolling of events to determine the level of subsequent non-compliance penalties.

68. SDG&E interruptible customers were free to switch to another tariff at any time, except those customers on the interruptible tariff for 12 months or less who were offered a one-time opt-out opportunity from January through March 2001 but without an opportunity to reconcile unpaid penalties incurred between October 2000 and January 2001.

69. SDG&E's A-V rate is unique in that it is an annualized rate with no imbedded seasonality component, in contrast to firm service rates which differ significantly between summer and winter months, creating a much lower winter firm service rate than the corresponding winter non-firm service rate. The non-firm service rate (Schedule A-V1) is lower on a 12-month basis than the corresponding firm service rate.

70. Cal Steel's proposal (for recalculating non-compliance penalties during the opt-out period) places a significant administrative burden on SCE (to review, revise, and recalculate rate discounts for all customers who opted-out by applying a scaling factor based on complex calculations of actual performance), and would create unknown but possibly significant revenue impacts.

71. The dilemma faced by Cal Steel in large part resulted from the Commission's decision in April 2001 not to permit a customer to participate in both a capacity based interruptible program and OBMC, with that decision changed in May 2001, only weeks after Cal Steel made its decision to opt-out.

72. A less complex remedy to Cal Steel's dilemma which provides similar relief is to allow customers placed in that unique situation to return to Schedule I-6 effective November 1, 2000 at a higher FSL, effectively eliminating noncompliance penalties while permitting participation in both programs.

73. Schedule I-6 curtailments were called in May and July 2001, but Cal Steel and other similarly situated customers had left I-6 and were on OBMC.

74. All issues identified in the Phase 2 Scoping memo are now resolved, are moot as a result of the decisions herein, or need no further consideration, with the exception of the DBP.

75. Notice of the availability of the draft and final decisions was served by letter using regular or electronic mail on over 10,000 Category M applicants

(including those who applied either timely or late), with recipients of the letter directed to the Commission's web page to access a copy of the draft and final decisions, or to call the Commission for copies.

Conclusions of Law

1. SDG&E's RBRP should be extended through completion of SDG&E's next rate design proceeding (with completion expected by April 2004), consistent with the extension of all interruptible programs, and RBRP should not be consolidated with OBMC.

2. The availability of all interruptible programs should be extended through the date of the final rate design decision in each utility's next GRC, or similar proceeding for SDG&E, and continue until modified or terminated thereafter.

3. A planning goal of 2,500 MW for interruptible load programs should be adopted through the date of the final rate design or similar decision of each utility, and total capacity and dollar limits should be reduced in the same proportion as previously authorized:

INTERRUPTIBLE PROGRAM
AND CURTAILMENT PRIORITY LIMITS

UTILITY	INTERRUPTIBLE PROGRAM LIMIT (MW)	TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION)
PG&E	1,000	100.0
SCE	1,375	137.5
SDG&E	125	12.5
TOTAL	2,500	250.0

4. Utilities should continue to file and serve monthly reports on interruptible programs and curtailment priorities and, unless directed otherwise by subsequent order, each utility should terminate the filing and service of its

monthly reports effective the date that the final decision is mailed in the next proceeding that addresses interruptible tariffs.

5. Utilities should meet with Energy Division staff to resolve issues regarding monthly reports.

6. Interruptible programs should not be combined into one or two programs but a portfolio of programs should continue to be offered.

7. Public Utilities Code Section 368(a) provides that rates shall remain at certain levels until the earlier of March 31, 2002 or the date on which certain Commission-authorized costs are fully recovered.

8. D.01-04-006 extended interruptible programs in general, including SCE Schedule I-6, but did not disturbed Public Utilities Code Section 368(a), or its application to I-6.

9. The bill limiter should continue to apply to the portion of rates in effect before 2001, and its application to the remainder of rates should end on the effective date of this decision.

10. Modifying application of the bill limiter on the effective date of this order does not conflict with the Settlement Agreement between SCE and the Commission.

11. SCE Schedule I-6 bill-limited customers should be permitted a special 15-day opt-out; the special opt-out should begin within 30 days of the effective date of this order; the customers should be permitted to opt-out effective the date application of the bill limiter is modified, or effective with the beginning of their next billing period; and this special opt-out should not disturb any choices normally available to any customer during the next annual opt-out in November 2002.

12. A tariff option should not be adopted that allows for aggregation of more than two circuits with a single lead customer for the purpose of participation in the OBMC program, as proposed by Wolfsen.

13. The SLRP tariff should be modified such that the on-peak energy usage for the four weekdays following a curtailment cannot exceed the customer's posted baseline amount by more than 15%.

14. An interruptible customer should be permitted to participate in OBMC after meeting its monthly interruptible contract obligation, subject to the customer during an overlapping interruptible/OBMC event being required to continue to reduce load to the lower of FSL or OBMC baseline during the entire length of that particular event.

15. All other proposals to change OBMC should be rejected (e.g., change OBMC baseline to recognize alternate workweek schedules, adjust for similar days, temperature correction, Stage 1 and 2 days, exclusion of more days in advance and after the fact; offer a real time profile option; provide more notice before being required to reduce load; measure non-compliance over the first hour rather than half-hour; modify the lead customer concept; allocate OMBC costs only to large power customers).

16. Energy Division should convene a workshop to work with PG&E and interested parties on implementation details for a pilot program to test normalizing OBMC 10-day baseline to reflect conditions on the day of the OBMC event, and PG&E should file and serve an advice letter for pilot program implementation.

17. SDG&E's EAEI program should be cancelled, and Advice Letter 1320-E should be rejected.

18. CEC's proposed non-bypassable surcharge of $0.001/kWh, and CEC's proposed modified VDRP, should be rejected.

19. CEC's proposed modified BIP should be approved as a pilot test with limited further modifications.

20. PG&E should file an advice letter including the necessary tariffs to implement the PBIP, with the tariffs becoming effective 10 days thereafter, unless suspended by the Energy Division Director.

21. Protests to PG&E's OBMC pilot program and PBIP advice letters, if intended to request suspension by the Energy Division Director, should be filed and served within nine days of the date of each advice letter.

22. SCE's December 18, 2001 petition for modification of D.01-04-006 regarding changes in FSL should be denied and, within 30 days of the date of this order, SCE should notify the approximately six customers whose FSL decrease request was denied in November 2001 that each customer has a 15-day window to elect to reduce their FSL effective the same day it would have been reduced if it had been granted by SCE in November 2001.

23. Hospitals with fewer than 100 beds should continue to be included in essential customer Category C.

24. Essential customer Category C should be amended to include SNFs, and eligible SNFs should be those licensed by the California DHS.

25. Each respondent utility should complete the circuit reconfiguration report on SNFs contemplated in our April 2001 order, and file and serve that report within 60 days.

26. The Energy Division Director may authorize respondent utilities to implement cost-effective, reasonable circuit reconfiguration projects, including

those for SNFs, to isolate essential from non-essential customers up to the dollar amounts authorized in D.01-04-006.

27. Utilities should not be required to assess the adequacy of backup or standby generation for SNFs and consider excluding SNFs from essential customer Category C on the basis of that assessment, just as utilities are not required to do this for hospitals.

28. Category M status awarded to any customer should expire on September 6, 2003, and no replacement process should be adopted.

29. Category M should be removed from the list of essential customers effective September 7, 2003.

30. Each respondent utility should (a) notify each of its water and sewage treatment customers of Category H, plus file and serve a verified statement certifying completion of the notice, (b) test Category H emergency restoration procedures, and (c) file and serve a report on the test, including discussion of "immediate processing" and "best efforts" in restoring service pursuant to a Category H request.

31. Permanent exemption from rotating outage should not be provided to the 16 water agencies identified by LAC in areas of high risk for fire.

32. Special priority of electricity use, including an exemption from rotating outages, should not be provided for temperature-sensitive residential customers based on exposure to extreme temperature.

33. A modification of respondent utilities' alternative plan to address temperature sensitive residential customers should be adopted, including education, advance notification by automated telephone message (based on temperature-sensitive customer self-certification), and the use of cooling stations.

34. ORA’s proposal to penalized utilities for outages over 90 minutes absent extenuating circumstances should be rejected.

35. Respondent utilities should collect non-compliance penalties tracked in memorandum accounts for the period October 1, 2000 through January 25, 2001, subject to a one-time reconciliation of balances for PG&E customers, and a similar treatment for SDG&E customers on interruptible schedules 12 months or less recognizing the unique differences in SDG&E’s tariffs.

36. PG&E’s reconciliation of balances should be for the period of November 1, 2000 through April 30, 2001 (wherein PG&E customers may opt-out of interruptible service in part or whole and have penalties waived in exchange for paying firm service rates), and this reconciliation should not disturb any change the customer might have made in the November 2001 opt-out.

37. Curtailment events in the memorandum account period should not be counted toward the tolling of compliance as it relates to the non-compliance penalty in the subsequent year for PG&E.

38. Cal Steel’s December 10, 2001 petition for modification of D.01-04-006 (with respect to the calculation of non-compliance penalties for interruptible customers who opted-out) should be denied, and SCE’s alternative should be adopted in part with the customer allowed to choose the FSL.

39. This proceeding should remain open.

40. A paper copy of the draft and final decisions should not be served on Category M applicants unless requested by the applicant.

41. This order should be effective today so that the important, time-sensitive decisions can be implemented in the public interest without unreasonable delay (e.g., adjust application of the bill limiter, provide needed certainty to customers about interruptible programs and curtailment priorities for Summer 2002, initiate

the PBIP, clarify adjustment in FSL for SCE customers, provide essential customer status for SNFs, test procedures for essential customer Category H, implement the adopted extreme temperature program, dispose of memorandum account balances).

INTERIM ORDER ON INTERRUPTIBLE PROGRAMS AND CURTAILMENT PRIORITIES

IT IS ORDERED that:

1. Within five days of the date this order is mailed, respondent utilities Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall each file and serve an advice letter with revised tariffs. The advice letters with revised tariffs shall implement the directions in this order and Attachment E. Each advice letter with tariffs shall be in compliance with General Order 96-A. The advice letters and tariffs shall become effective five days after filing, unless suspended by the Energy Division Director. The Energy Division Director may require a respondent utility to amend its advice letter and tariffs to comply with the orders herein, and may require a respondent utility to file and serve individual advice letters and tariffs as needed to separately implement portions of today's order.

2. The November 9, 2001 petition for modification of Decision (D.) 01-06-087 filed by California Manufacturers and Technology Association (regarding changes in the Optional Binding Mandatory Curtailment (OBMC) program baseline measurement and calculation of penalties during the first hour of an OBMC event) is denied.

3. The November 13, 2001 petition for modification of D.01-04-006 filed by California Industrial Users (regarding interruptible customers participation in OBMC after monthly interruptible obligations are met) is granted to the extent provided herein.

4. SDG&E's Advice Letter 1320-E (regarding a proposed Electric Appliance Equipment Interruption program) is rejected.

5. Energy Division shall convene a workshop within 20 days of the date of this order to work with PG&E, California Manufacturers and Technology Association and other interested parties on implementation details for a pilot program to test normalizing the 10-day Optional Binding Mandatory Curtailment (OBMC) program baseline to reflect conditions on the day of the OBMC event. PG&E shall file and serve an advice letter with accompanying tariffs within 10 days of the date of the workshop. The advice letter shall become effective 10 days after filing unless suspended by the Energy Division Director. A protest to PG&E's OBMC baseline pilot program advice letter shall be filed and served within nine days of the date the advice letter is filed if the party filing the protest seeks tariff suspension. PG&E shall file and serve a report within 60 days of the date the test is concluded.

6. Within seven days of the date this order is mailed, PG&E shall file and serve an advice letter that includes a tariff to implement the Pilot Base Interruptible Program (PBIP). The tariff shall become effective 10 days after filing, unless suspended by the Energy Division Director. A protest to PG&E's PBIP advice letter shall be filed and served within nine days of the date the advice letter is filed if the party filing the protest seeks tariff suspension.

7. The priority system for rotating outages stated in this order and in Attachment B shall supercede the existing priority system 30 days from today, and shall be implemented by each respondent utility. Each skilled nursing facility (SNF) licensed by the California Department of Health Services shall be included in essential customer Category C. SNFs in Category M shall be transferred to Category C effective 30 days from today. Within 30 days of today, each respondent utility shall notify each SNF customer of its inclusion in

essential customer Category C. Each SNF shall be exempt from rotating outages regardless of the status of backup or standby generation.

8. Respondent utilities shall file and serve the adopted reports and studies shown in Attachment F. Unless directed otherwise by subsequent order, each utility may terminate the filing and service of its monthly report on interruptible programs and curtailment priorities effective upon the date that the final decision is mailed in the next rate design phase of its general rate case, or similar proceeding, in which the Commission addresses interruptible programs. PG&E shall continue to file monthly reports through the completion of the PBIP test. Respondent utilities shall meet with Energy Division staff to discuss bringing monthly reports into compliance with prior and current orders, adopting a consistent report and table format, and addressing the subject and timing of the inclusion of additional nonrecurring information discussed in this order.

9. The December 18, 2001 petition for modification of D.01-04-006 (regarding changes in firm service levels) filed by SCE is denied. Within 30 days of the date of this order, SCE shall notify each customer whose request in November 2001 to reduce its firm service level was denied that each such customer has a 15-day window to now elect to reduce its firm service level. The reduction shall be effective the same date as if SCE had granted the original request in November 2001.

10. The Energy Division Director may authorize respondent utilities to implement cost-effective, reasonable circuit reconfiguration projects, including circuit reconfigurations involving SNFs, to isolate essential from non-essential customers up to the total dollars authorized in Ordering Paragraph 5 of D.01-04-006 (i.e., a cumulative total of $5 million for PG&E, $5 million for SCE, and $1 million for SDG&E).

11. Essential customer Category M shall expire on September 6, 2003, and Category M shall be removed from the essential customer list effective September 7, 2003. No later than August 7, 2003, each respondent utility shall notify each customer awarded Category M status that the customer's Category M status expires on September 6, 2003.

12. Each respondent utility shall, within 15 days of the date of this order, provide a draft notice to the Commission's Public Advisor. The draft notice shall inform water and sewer customers of Category H. Each respondent utility shall include the comments of the Public Advisor in preparing the final notice. Each respondent utility shall, within 45 days of the effective date of this order, serve a copy of the final notice on each of its water and sewer customers. Within 45 days of the date of this order, each respondent utility shall file and serve a verified statement certifying service of the final notice on each such customer, with a copy of the final notice attached to the statement. The statement shall also include any other relevant information necessary to reasonably inform the Commission about completion of the notice.

13. Within 120 days of the date of this order, each respondent utility shall conduct a test of the emergency exemption and restoration procedure permitted in Category H. Each respondent utility shall take the lead role and responsibility to develop, organize, conduct, analyze, and report the results of its test. The test shall include a reasonable sample of water and sewer customers. Each respondent utility shall accommodate input from all entities that will participate in the test, and include each entity's suggestion to the extent reasonable. Each respondent utility shall file and serve a report on the test and its results within 60 days of the date the test is completed. The report shall also include a discussion of the amount of time required for each utility to respond to a request for

exemption or restoration, including an explanation of "immediate processing" or "best efforts." The report shall be served on each party who requests a copy, and on each participant. Except for service on the Commission, each respondent utility may serve a Notice of Availability on parties, even if the report is less than 75 pages (unless a party has previously informed respondent utility of its desire to receive a complete copy).

14. Each respondent utility shall, within 15 days of the date of this order, provide a draft bill insert to the Commission's Public Advisor. The draft bill insert shall inform customers and other persons about reasonable health and safety precautions that may be taken during times of extreme temperature. Each respondent utility shall include the comments of the Public Advisor in preparing the final notice. Within 60 days of the date of this order, each respondent utility shall serve the final notice as a bill insert. The bill insert shall be repeated periodically, as reasonable and necessary. Each utility shall also include reasonable similar education material in their use of mass media at the time of extreme temperature. Each respondent utility shall also make a reasonable effort to target outreach to vulnerable populations, such as persons who live in assisted living facilities that are not SNFs.

15. Each respondent utility shall employ a system of advance notice by individualized, automated telephone message (or other reasonable individualized message) to each residential customer or person in the customer's household whose health is identified to be at risk when exposed to extreme temperature. Each respondent utility shall use the form in Attachment C for this purpose. The availability of this form shall be noticed to all customers by bill insert within 60 days of the date of this order. A draft of the bill insert notice shall be provided to the Public Advisor within 15 days of the date of this order,

and utilities shall incorporate the suggestions of the Public Advisor for the final bill insert. The certification shall be for a period of up to two years, and the customer or person shall re-certify by December 31 of the year the certification is due to expire. A utility shall not remove a customer or person if for any reason the re-certification form is not mailed to the customer or person at least 60 days before the customer's eligibility for this advance message is due to expire.

16. Each respondent utility shall undertake a reasonable effort to identify cooling stations within its service area, and include information on those stations in bill inserts and mass media, as appropriate.

17. Each respondent utility shall collect balances in memorandum accounts established by D.01-01-056 (used to track non-compliance penalties for the period October 1, 2000 through January 25, 2001). PG&E and SDG&E shall allow affected customers to make a one-time reconciliation as provided in Attachment E.

18. The December 10, 2001 petition for modification of D.01-04-006 filed by California Steel Industries, Inc. is denied. D.01-06-087 is modified as provided in Attachment D. Respondent utilities shall, within 30 days of the date of this order, provide notice to each customer affected by modification of D.01-06-087 of those modifications. The SCE customers affected by the timing of D.01-04-006 and D.01-05-090 shall have 15 days after the date of notice to accept or reject the opportunity provided in the modification of D.01-06-087. (Attachment D, Item 2.4.9.5.)

19. The following program and dollar limits shall apply effective the date of this order to program implementation by respondent utilities until later modified or eliminated:

INTERRUPTIBLE PROGRAM AND CURTAILMENT PRIORTY LIMITS

UTILITY	INTERRUPTIBLE PROGRAM LIMIT (MW)	TOTAL ANNUAL PROGRAM DOLLAR LIMIT ($ MILLION)
PG&E	1,000	100.0
SCE	1,375	137.5
SDG&E	125	12.5
TOTAL	2,500	250.0

The megawatt limits apply to the total megawatts that may be subscribed to interruptible programs at any one time without further Commission authorization, including currently subscribed amounts. If a currently subscribed megawatt transfers from an existing program to a new program (e.g., by exercising an opt-out option), that megawatt shall not be counted twice against the program total. The dollar limits apply to the total dollars to be spent by each respondent utility on an annual basis for total interruptible program costs, and new costs implementing changes to curtailment priorities, without further authorization. These limits shall apply separately for each calendar year. These dollar totals include amounts funded in current rates, and those recorded in the memorandum account of each respondent utility.

20. A paper copy of this decision shall not be served on any Category M applicant, unless that applicant specifically requests a paper copy.

21. This proceeding remains open solely to address the petition for modification of D.01-09-020 filed on February 20, 2002 by Dr. Lee F. Walker, and for further consideration of the Demand Bidding Program.

This order is effective today.

Dated April 22, 2002, at San Francisco, California.

LORETTA M. LYNCH
President
HENRY M. DUQUE
CARL W. WOOD
GEOFFREY F. BROWN
MICHAEL R. PEEVEY
Commissioners

ATTACHMENT A

Pilot Base Interruptible Program (PBIP)

Note: The PBIP is numbered in sequence based on programs adopted in Phase 1. (D.01-04-006, Attachment A.)

2.6. Pilot Base Interruptible Program (PBIP)

2.6.1. Events: Limit to one four-hour event per day, and no more than three consecutive days; limit to 10 events per month, and 120 hours per calendar year.

2.6.2. Opt-Out: Annual opt-out option in November, effective in January.

2.6.3. Capacity Payment: Incentive of $8.00 per kW-month as a credit on the customer's bill for committed interruptible capacity.

2.6.4. Energy Payment: There is no energy payment for load reductions specified in the participation agreement for which there is a capacity (incentive) payment. The customer is eligible to be paid for energy reductions beyond the customer's load reduction commitment at an energy rate of $0.15/kWh. The total energy payment shall be calculated as the difference between recorded energy usage and the baseline less the committed load curtailment amount times the energy rate.

2.6.5. Baseline: Baseline for evaluating load responses shall be the average of the immediate past 10-days prior to the curtailment event, excluding weekends, holidays, curtailment events, and when a customer was subject to a rotating outage. The baseline will be calculated on an hourly basis using the average of the same hour for the immediate past 10 days.

2.6.6. Implementation: A load curtailment event may be triggered when a Stage 2 emergency is called or when transmission system contingencies justify calling a localized block of participants. The utility and California Independent System Operator (CAISO) may arrange to segment participants into more than one block with one or more blocks called upon individually. If more than one block is created, then the CAISO and utility shall arrange to call upon blocks in an unbiased manner relative to the nature of the emergency.

2.6.7. Penalty: Failure to satisfy the load reduction commitment shall result in a penalty of $6.00 per kWh for each kWh of load curtailment that is not provided. Participants have 30 minutes from the time they are notified of the event by the utility to accomplish the agreed upon load curtailment.

2.6.8. Participants: This program is open to customers with peak demands greater than 200 kW with an interval or real time metering system who can commit to curtail at least 15% of their maximum load or 50 kW, whichever is greater, per event.

2.6.9. Other Programs: Load can only be committed to one program at a time, and participants shall only be paid once for a load reduction. Customers currently enrolled in another utility interruptible program must complete all annual obligations in that program before being eligible for the PBIP.

2.6.10. Duration, Area, MW: The PBIP shall last two years, and be conducted in Santa Clara County. Subscribed megawatts of interruptible load for the test shall not exceed 50 MW.

2.6.11. Annual Survey: All customers who subscribe to the PBIP must agree to complete an annual customer survey that will assess and evaluate customer participation and program operation.

(END OF ATTACHMENT A)

ATTACHMENT B

PRIORITY SYSTEM FOR ROTATING OUTAGES

1. **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 and skilled nursing facilities.

   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 rotating outage exemption from electric utilities in times of emergency identified as requiring their service, such as fire fighting.

   I. Areas served by networks, at serving utility's discretion.

   J. Rail rapid transit systems as necessary to protect public safety, to the extent exempted by the Commission.

   K. Customers served at transmission voltages to the extent that (a) they supply power to the grid in excess of their load at the time of the rotating outage, or (b) their inclusion in rotating outages would jeopardize system integrity.

   L. Optional Binding Mandatory Curtailment Program (OBMC): Any customer, or customers, meeting the following criteria.

   The customer must file an acceptable binding energy and load curtailment plan with the utility. The customer must agree to curtail electric use on the entire circuit by the amount being achieved via rotating outages. The customer's plan must show how reduction on the entire circuit can be achieved in 5 percent increments to the 15 percent level, and show how compliance can be monitored and enforced. The customer must maintain the required reduction during the entire rotating outage period. The required curtailment level is requested prior to commencement of Stage 3. Several customers on a circuit may file a joint binding plan to guarantee the required curtailment from the entire circuit. Each utility shall facilitate communication between customers on a circuit if any customer expresses interest in enrolling in the OBMC program.

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

M. Limited other customers as necessary to protect public health and safety, to the extent exempted by the Commission.

Note: Category M is removed from the essential customer list effective September 7, 2003.

N. Petroleum refineries, vital ancillary facilities, and other customers in the critical fuels chain of production, to the extent exempted by the Commission. Petroleum refineries are facilities that separate or alter the components in crude oil, and convert the components into usable fuels or feedstock for further processing. Vital ancillary facilities are facilities that, if curtailed during a rotating outage, would cause one or more petroleum refineries to significantly curtail production, initiate a controlled shutdown, or initiate an emergency shutdown. Eligible refineries and vital ancillary facilities must be firm electricity service customers served at transmission level, or served at distribution level in an outage block exempt from rotating outages.

2. Outage Notification

A. Life Support, Critical Care and Temperature Sensitive Customers

Life support, critical care and temperature sensitive customers shall be notified by recorded or other message of a rotating outage to which they will be affected. The call is not required until a rotating outage is imminent. Utilities must undertake their best efforts to inform these customers. Individual timely warning cannot be assured because of time, manpower, or communication limits, or due to daily circuit switching which may temporarily change a customer's outage block number.

B. Large Customers, Economic Damage Customers, and Danger to Health and Safety

As circumstances permit, individual warning of rotating outages will be given to large customers having demand of 300 kW or more. It will also be given to other customers upon their showing to the utility of major economic damage, or clear and imminent danger to personal health or safety. Individual timely warning cannot be guaranteed, however, because of time, manpower, or communication limits, or due to daily circuit switching which may temporarily change a customer's outage block number.

C. All Other Customers

Warning and other relevant information may be provided by mass media, with no special treatment or individual notification generally given.

(END OF ATTACHMENT B)

ATTACHMENT C

APPLICATION BY TEMPERATURE SENSITIVE CUSTOMER

IMPORTANT INFORMATION

This application provides the means for a customer who has a health condition which places the customer at increased health risk from temperature extremes to receive advance notification of rotating power outages (rolling blackouts) in the customer's area. The application may also be used by a customer for a person living in the customer's immediate household with a temperature sensitive health condition. The advance notification will be by phone call to the telephone number designated by the customer.

Persons who qualify for this advance notification are those with a health condition that places them at increased risk, compared to the average person, for poor health and illness when exposed to temperature extremes. These conditions include, but are not limited to:
cystic fibrosis, cardiac conditions, peripheral vascular disease, chronic illnesses, or the use of any of several medications, such as beta-adrenic blockers, diuretics, seizure medications, tricyclic antidepressants, or calcium channel blockers.

Completion and acceptance of this form will enable the utility to attempt to notify the customer in advance of a rotating outage. Individual timely notification, however, cannot be guaranteed because of time, manpower, or communication limits, or because of daily circuit switching which may temporarily change the customer's rotating outage block. **Acceptance of this form <u>will not</u> provide an exemption from rotating outages.**

Incomplete or false information on this application may cause us to postpone, deny adding, or to remove your name from the advanced notification list. You must also agree to let us know if:

1. The person with the qualifying status no longer lives at this address.
2. The medical condition or medication at issue is no longer a factor.

COMPLETE THIS PORTION. *(PLEASE PRINT)*

1. Name of customer or qualifying resident:

____

NAME

2. If qualifying resident is not the utility customer, please state the utility customer's name and the relationship of the qualifying resident:

____

CUSTOMER NAME RELATIONSHIP OF QUALIFYING RESIDENT

3. Telephone number for advanced notification:

____

4. Customer's Electric Utility Account Number:

____

5. Service Address:

____
STREET UNIT NUMBER

____
CITY STATE ZIP CODE

6. Mailing address for qualifying resident (if different than service address):

____
STREET UNIT NUMBER

____
CITY STATE ZIP CODE

I hereby certify that the above information is true and correct, reflecting my increased sensitivity to extreme temperatures, or that of a member of my immediate household.

______________________________ ________________
SIGNATURE OF APPLICANT **DATE**

Note: The completion of this application will provide advanced notification to qualifying resident for 2 years. A new application must be submitted and approved by the utility no later than December 31 of the year the application is set to expire for the customer to continue to receive notification.

UTILITY USE ONLY Time approved: ☐ 2 yr
Customer account number:
______________________________ Approved/Denied by:
Date received: ______________________ ______________________________

(END OF ATTACHMENT C)

ATTACHMENT D

MODIFICATION OF DECISION 01-06-087

Decision (D.) 01-06-087, Attachment A (which in turn modified D.01-05-090, Attachment A) is modified to (a) reflect the replacement of VDRP with DBP, (b) permit firm service level customers who complete their monthly obligation to participate in OBMC subject to some limitation during overlapping events, and (c) permit some customers who opted-out of SCE Schedule I-6 to again become an I-6 customer. Sections 2.4.3, 2.4.9.4, 2.4.9.5, and 2.4.10 are deleted and replaced with the following complete sections. (The changes are underlined for easy identification.)

2.4. Optional Binding Mandatory Curtailment Program

Elements of Optional Binding Mandatory Curtailment (OBMC) Program, which is an alternative to rotating outages, designed to achieve the same load reductions, at times of emergencies, as rotating outages.

2.4.1 The OBMC program exempts participants from rotating outages if they can reduce the load on their entire circuit by the required amount for the entire duration of every rotating outage.

2.4.2 The OBMC program operates only when firm load reductions are required (i.e., concurrent with rotating outages) by the customer's electric distribution utility.

2.4.3 The baseline used to determine if the required load reduction has been obtained will be the average load of the immediate past 10 similar days during the period of the interruption. Similar days are either business days or weekend days and holidays. The 10 similar days will exclude days when the OBMC program operated and paid VDRP <u>or Demand Bidding Program (DBP)</u> load reductions. <u>(The VDRP was replaced by the DBP in July 2001 pursuant to D.01-07-025.)</u> An OBMC participant may exclude the following periods from the 10-day baseline: (a) a period of 15 calendar days designated in advance both for ramp-up and ramp-down of operations during which period the baseline will be the circuit load for the most recent prior day, not the average of the prior 10 similar days; (b) up to 10 days per calendar year as determined by the customer and designated in advance to accommodate conditions in the customer's operations that affect the 10-day baseline' and (c) up to two exclusions from the 10-day baseline where unplanned outages or other events cause the circuit load to deviate substantially from normal conditions. The customer shall provide at least 10 calendar days' prior notice to the utility when exercising option (a); at least seven calendar days' prior notice when exercising option (b); and notice within one calendar day after the outage or event when exercising option (c).

2.4.4 Load reductions will be requested in increments of 5%.

2.4.5 Participants must have the ability to reduce circuit load by 15%. The baseline used to determine if the 15% reduction can be met is the prior years, same month, average peak period usage, adjusted for major changes in facilities. However, the customer must be able to produce at least a 10% load reduction based on the criteria in 2.4.3.

2.4.6 UDCs are required to facilitate circuit aggregation when requested by a customer. In addition, UDCs shall allow individual customers whose facilities are served by more than one circuit to aggregate the load of two such circuits for purposes of the OBMC program, subject to the following limitations:

2.4.6.1. The lead customer shall commit in the OBMC agreement that it has not, and will not, receive any payment from any customer on any OBMC circuit for any action related to the OBMC program.

2.4.6.2. A single customer (with a single tax identification number) must be the lead customer for purposes of the OBMC program for all circuits involved in the circuit aggregation.

2.4.6.3. Participants must have the ability to provide the necessary load reduction in each local geographic area covered by the aggregation.

2.4.7. The failure to reduce load as required will result in penalties equal to $6/kWh for all excess energy, as measured during each half-hour of the rotating outage. If a participant fails to reduce circuit load to within 5% of the required amount, as measured during the entire duration of the rotating outage, on two occasions in any one-year the customer's participation in the program shall be terminated and the customer shall be prohibited from participating in an OBMC program for five years.

2.4.8. Program participants shall pay the cost of any equipment required to participate in the program.

2.4.9. OBMC participants who are the only customers on their circuit may participate in a utility operated capacity interruptible program as long as that program requires the reduction of load to a pre-established firm service level (FSL).

2.4.9.1. Acceptable interruptible programs include but are not limited to the BIP, SCE's I-6, PG&E's E-20 non-firm, and SDG&E's AV-1 and AV-2.

2.4.9.2. If a customer participates in both a capacity interruptible program and the OBMC program, the required OBMC reduction shall be applied to the lower of the 10-day baseline or the customer's FSL. For example, a customer with a FSL of 8 MW and a 10-day baseline of 10 MW that is called for a 10% OBMC reduction would be required to reduce load to 7.2 MW.

2.4.9.3. Only load reductions below the lower of the customer's interruptible FSL and the 10-day baseline are counted toward compliance with the OBMC.

2.4.9.4. When a participant in a capacity interruptible program has completed its <u>monthly or</u> annual obligations under that program, the load reduction requirements in 2.4.9.2

and 2.4.9.3 will no longer apply for that time period (i.e., for the remainder of the applicable month or year), except that if an OBMC event is simultaneously in effect at the time that the capacity interruptible program obligations (monthly or annual) are met, then 2.4.9.2 and 2.4.9.3 shall continue to apply until the OBMC event is terminated.

2.4.9.5. An SCE OBMC customer who opted-out of Schedule I-6 in April or May 2001 effective back to November 1, 2000 pursuant to D.01-04-006 may again become a Schedule I-6 customer back to November 1, 2000 at a FSL of the customer's choice. Such customer shall not be subject to Schedule I-6 penalties or discounts for May and July 2001, and may also exercise an adjustment in the November 2001 opt-out period.

2.4.10. OBMC participants may participate in the VDRP or DBP program, but shall not be paid for any load reductions occurring during an OBMC call.

2.4.11. OBMC participants shall not participate in the ISO's DRP or in a utility program that aggregates load for the ISO's DRP.

(END OF ATTACHMENT D)

ATTACHMENT E

CHANGES TO CURRENT INTERRUPTIBLE PROGRAMS, NEW PILOT BASE INTERRUPTIBLE PROGRAM, AND ESSENTIAL CUSTOMERS

R.00-10-002

1. CHANGES TO CURRENT INTERRUPTIBLE PROGRAMS

1.1 Extend All Programs: All existing interruptible programs are extended until modified or terminated in the rate design phase of each respondent utility's next general rate case or similar proceeding.

1.2 SCE Bill Limiter:

1.2.1 The bill limiter shall continue to apply to the portion of rates which were in effect before 2001. The bill limiter shall not apply to the remainder of rates effective on the date of this decision.

1.2.2 Bill limited customers shall have a 15-day opt-out period. The opt-out shall begin within 30 days of the date of this order. Bill limited customers may opt-out effective the date that the bill limiter ends, or effective with the beginning of their next billing cycle, similar to the opt-out authorized in D.01-04-006. These customers may also opt-out during the next annual opt-out opportunity, in November 2002.

1.2.3 A bill limited customer who opts-out now may enroll in any other interruptible program on a current and going forward basis.

1.3 Scheduled Load Reduction Program: The current tariff shall be modified to provide that "…the energy usage during the on-peak period for the four weekdays following a curtailment, unaffected by program operations and excluding holidays, will be evaluated and cannot exceed the customer's posted baseline amount by more than 15%."

1.4 Optional Binding Mandatory Curtailment Program:
See Attachment D.

1.5 Memorandum Account Balances:

1.5.1. Respondent utilities shall collect memorandum account balances established by D.01-01-056 to track non-compliance penalties from October 1, 2000 through January 25, 2001.

1.5.2. PG&E shall allow its customers to reconcile balances for the period November 1, 2000 through April 30, 2001.

1.5.2.1. The affected customer shall have a 15-day window to make this election, which begins upon notice by PG&E of this option.

1.5.2.2. PG&E shall perform notice of this opportunity on potentially affected customers within 30 days of the date this order is effective.

1.5.2.3. The customer may elect to increase its FSL in whole or part from November 1, 2000 through April 30, 2001, and pay the appropriate firm service level rate for this period.

1.5.2.4. Interruptible service non-compliance penalties for this period shall be refunded if already collected, or billing will cease if bills have been rendered.

1.5.2.5. The election to opt-out in part or whole will not affect the service the customer received, and the bills due, on and after May 1, 2001.

1.5.2.6. The election to opt-out in part or whole does not change the customer’s decision in November 2001 to have remained in or opted-out of the interruptible program.

1.5.2.7. Curtailment events during the memorandum account period (October 1, 2000 through January 25, 2001) do not count toward the tolling of compliance for determining the level of non-compliance penalties during the subsequent year.

1.5.3. SDG&E shall allow customers who were interruptible customers for 12 months or less the option to reconcile their account balances, taking into account the difference between SDG&E's Schedule A-V1 and seasonal firm service rates. Customers who opted-out or were switched to other schedules prior to Summer 2001 shall be provided a rebate of memorandum account penalty amounts. Customers who remained on Schedule A-V1 shall be allowed to opt-out effective with the next billing cycle but shall not be permitted to return to an interruptible tariff before 12 months after the opt-out is effective.

2. **Normalized OBMC Baseline Pilot Program:** Energy Division shall hold a workshop within 20 days of the date of this order to develop implementation details, and PG&E shall file and serve an advice letter and tariffs within 10 days of the date of the workshop to implement the pilot program.

3. **PILOT BASE INTERRUPTIBLE PROGRAM**: See Attachment A.

4. **ESSENTIAL CUSTOMERS**

4.1 **Category C and Reconfiguring Circuits**: Within 60 days, PG&E, SCE and SDG&E shall each file and serve a report. The report shall study circuit reconfiguration options for skilled nursing facilities, consistent with the studies identified in D.01-04-006.

4.2 **Category M**

4.2.1. Category M shall expire on September 6, 2003.

4.2.2. Customers with Category M status will be notified by August 7, 2003 that the status will expire on September 6, 2003.

4.2.3. Category M shall be removed from the list of essential customers effective September 7, 2003.

4.3 Category H (Water and Sewer Entities)

4.3.1. Within 45 days, respondent utilities shall notify water and sewer customers of Category H.
4.3.2. Within 120 days, respondent utilities shall test Category H notification, exemption and restoration procedures.
4.3.3. Within 60 days of completion of the test, respondent utilities shall file and serve a report on the test.
4.3.4. The report shall also discuss the amount of time necessary to perform exemption or restoration.

4.4 Temperature Sensitive Customers

4.4.1. Respondent utilities shall provide information by bill insert, mass media and other reasonable means on how temperature sensitive customers may protect themselves during period of extreme temperature.
4.4.2. Respondent utilities shall provide an individual, advance warning message of a rotating outage to customers identified as sensitive to extreme temperature. Utilities shall use the application form in Attachment C to identify these customers.
4.4.3. Respondent utilities shall undertake a reasonable effort to identify cooling stations within their service areas, and include that information in bill inserts and other media as appropriate.

(END OF ATTACHMENT E)

ATTACHMENT F

ADOPTED STUDIES AND REPORTS

1. **STUDIES AND REPORTS:** Each respondent utility shall file and serve the following reports and studies:

ITEM NO.	STUDY OR REPORT	DATE DUE
1	Monthly report on interruptible and outage programs shall continue. (Decision Section 3.2.3.)	By the 21st of each month
2	PG&E Report on Normalized OBMC Baseline Pilot Program (Decision Section 3.6.2.4.)	Within 60 days after test conclusion
3	Monthly Report by PG&E on PBIP. (Decision Section 3.6.5.3.)	By the 15th of each month
4	Study of circuit reconfiguration for skilled nursing facilities. (Decision Section 4.2.4.)	Within 60 days
5	Test and report on Category H. (Decision Sections 4.4.2 and 4.4.5.)	Test within 120 days; report within 60 days of test

A. **Item 1**: Monthly reports shall be filed in this proceeding. They shall be served on Energy Division (three copies), and any party who requests a copy.

A.1. Unless specifically directed otherwise, the monthly report need not be filed or served after the final decision is mailed in the rate design phase of the utility's next general rate case, or other similar proceeding, in which the future of interruptible programs is decided.

A.2. Each respondent utility shall meet with Energy Division to address (a) inclusion of necessary information in compliance with Commission decisions, (b) inclusion of additional nonrecurring information when relevant (e.g., energy supply), and (c) development of a common report and table format.

B. Items 1-5: Each report or study shall be filed in this proceeding, and served on the service list. Service is limited to Energy Division (three copies) and those parties who specifically request a copy. Except for service on the Commission, each respondent utility may serve a Notice of Availability on the service list, even if the report is less than 75 pages, unless a party has previously informed respondent utility of its desire to receive a complete copy. (Rule 2.3 of the Commission's Rules of Practice and Procedure.) Items 2 and 3 apply to PG&E only. Utilities shall serve a copy of the Category H test report on all participants whether or not participant specifically requests a copy.

2. COMMENTS, RESPONSES, PROTESTS: Parties may file and serve comments, responses or protests to a filed report or study, and shall file and serve such pleadings within 15 days of the date the report or study is filed and served. Respondent utility and other parties may file and serve a reply within 10 days. An Assigned Commissioner or Administrative Law Judge may change these dates by ruling.

(END OF ATTACHMENT F)