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CALIFORNIA ENERGY COMMISSION

Review of Current Southern California Edison Load Management Programs and Proposal for a New Market-Driven, Mass-Market, Demand-Response Program

CONSULTANT REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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Prepared by
G. H. Weller
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Under contract to
Southern California Edison
Coordinated by
Consortium for Electric Reliability Technology Solutions
for the Public Interest Energy Research Program
California Energy Commission

Environmental Energy Technologies Division

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Disclaimer

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[1] This report does not necessarily represent the opinions of the Southern California Edison company.

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Acronyms

AC	alternating current
ACCP	Air Conditioner Cycling Program
AMR	automated meter reading
ASLP	Ancillary Services Load Program
BIP	Base Interruptible Program
CANCEL	customer approved non-critical electric loads
CAISO	California Independent System Operator
CBOE	Chicago Board Options Exchange
C&I	commercial and industrial
CERTS	Consortium for Electric Reliability Technology Solutions
CPUC	California Public Utilities Commission
CSEB	customer-specific energy baseline
CT	combustion turbine
dB	decibel
DBP	Demand Bidding Program
DC	direct current
DLC	direct load control
DSM	demand-side management
DWR	Department of Water Resources
ERB	emergency rotating blackout
FSL	firm service level
HVAC	heating, ventilation, and air conditioning
IDR	interval data recorder
ISO	independent system operator
kbps	kilobytes per second
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
LAN	local area network
LCR	load control receiver
MHz	megahertz
MW	megawatt
OBMC	Optional Binding Mandatory Curtailment
PG&E	Pacific Gas and Electric
RF	radio frequency
RTO	regional transmission organization
RTP	real-time pricing
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SLRP	Scheduled Load Reduction Program
T&D	transmission and distribution
TOU	time of use
VHF	very high frequency

Abstract

Utility load management programs, including direct load control and interruptible load programs, constitute a large installed base of controllable loads that are employed by utilities as system reliability resources. In response to energy supply shortfalls expected during the summer of 2001, the California Public Utilities Commission in spring 2001 authorized new utility load management programs as well as revisions to existing programs. This report provides an independent review of the designs of these new programs for a large utility (Southern California Edison) and suggests possible improvements to enhance the "price responsiveness" of the customer actions influenced by these programs. The report also proposes a new program to elicit a mass-market demand response to utility price signals.

I. Introduction

This is the second report prepared for Southern California Edison (SCE) as part of the Consortium for Electric Reliability Technology Solutions (CERTS) research program on Load as a Resource (Kueck et al. 2001). In the first report, SCE's existing load management assets were assessed to determine what would be entailed in making a transition to using them as reliability resources in a restructured electricity industry (Weller 2001). While that report was in preparation, California's electricity markets underwent tremendous stress. In response to this stress, California utilities had numerous occasions to call upon their load management programs. The California Public Utilities Commission (CPUC) initiated a major proceeding to consider modifications to these programs (CPUC 2001).

In the spring of 2001, the CPUC responded to energy supply shortfalls expected during the summer of 2001 by authorizing new utility load management programs as well as revisions to existing load management programs for all three of California's investor-owned utilities. This report provides an independent review of the designs of these programs for SCE and suggests possible improvements to them with the goal of enhancing the "price responsiveness" of the customer actions influenced by the programs. The report also proposes a new program aimed at eliciting a mass-market demand response to utility price signals.

A price-responsive customer incentive methodology is especially important for sending "correct" market information to customers. By incorporating a price-responsive customer interface into load management programs, a utility can begin to educate customers about the true dynamic nature of the pricing (i.e., the cost of generating electricity) that prevails in the electricity marketplace. In the long run, this education will help the utility implement future customer-interactive, price-responsive programs that are even more dynamic than those suggested here.

The report reviews the CPUC-ordered load management programs offered by SCE, both Commercial & Industrial (C&I) and Residential / Small Commercial (Mass Market). Each program is described, and suggestions are made for modifying the program's delivery mechanism to improve operational efficiency. These suggestions include technical changes that would increase load-reduction contributions without changes in program tariffs. In addition, suggestions are offered to help move the existing program closer to a market-driven, price-responsive load management system.

The report is organized as follows:

Section II of the report focuses primarily on the current C&I load management programs at SCE. We summarize the program definition, customer delivery mechanism, and project design / technology for each program. Also, we offer suggestions for enhancing each program's operation and customer acceptance. These suggestions are aimed primarily at making the program more price-responsive in relation to the real-time value of the load impact delivered by the program to the electricity system. Section II ends with the description of a completely new system based on an existing SCE satellite system for emergency load management at major C&I sites located throughout the state.

Section III addresses the Air Conditioner Cycling Programs (ACCPs) for residential customers. We offer several suggestions that could significantly enhance the financial performance of the existing program (i.e., the amount of load reduction it delivers) as well as its design. All of the recommended changes can be implemented without any change in the existing program tariff.

In the final subsection of Section III, a new program, the Customer Choice Load Management program is proposed to address two key issues associated with legacy load management systems: 1) cost effectiveness related to payment of customer incentives and lack of correlation between customer incentives, and 2) the actual market value of the load reduction that these incentives deliver to the electricity system. The discussion describes how the two main benefits of load management systems to the electricity grid – reliability and economics – can both be addressed in an effectively designed load management system.

In the Customer Choice Load Management program, the customer's incentive for participation is derived almost entirely from the customer's ability to sell energy into the spot market, while giving the utility [or applicable independent system operator (ISO) or regional transmission organization (RTO)] the ability to manage electricity demand during generation shortages. The market-based approach for this program is similar to a modified version of options trading in which a customer selects a selling price (a strike price[2]). The utility manages the transaction on the customer's behalf. Customer compensation is derived entirely from the sale of energy into the spot market. There are no ongoing fixed incentive payments that must be funded from the program's internal budget. The system dispatcher can take advantage of the contribution that this arrangement offers to system reliability at any time that the system reaches an appropriate level of need. Although the Customer Choice Load Management program as described in this report is focused primarily on the mass market, a variation could also be developed to address the C&I market.

Section IV – Recommends next steps.

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[2] The Chicago Board Options Exchange defines options as contracts in which the terms are standardized and give the buyer the right but not the obligation to buy or sell a particular asset (e.g., energy) at a fixed price (the strike price) for a specific period of time (until expiration).

II. C&I Load Management Programs

A. Programs based on the existing SCE Load Management System /Technology Base

UU1. Optional Binding Mandatory Curtailment Program (OBMC)

a. Program Definition & Summary

The optional binding mandatory curtailment (OBMC) load-reduction program exempts customers from rotating outages in exchange for partial curtailment of their entire circuit during every rotating outage. Prior to participation in the program, customers are required to file an OBMC plan that is acceptable to SCE. Each participating customer must make a minimum of 15% of their entire circuit load available for curtailment during every rotating outage. If any one customer does not have enough curtailable load to provide the 15% minimum requirement, customers on the same circuit may jointly submit one OBMC plan outlining how they can provide the 15% minimum requirement by combining total curtailable circuit load. OBMC participants may be able to participate in other capacity-interruption programs, such as the Interruptible Program, the Base Interruptible Program, or the ISO Demand Relief Program.

b. Customer Delivery Methodology

A customer wishing to participate in the OBMC program is required to:

- File an acceptable binding load curtailment plan with SCE for reducing electricity use on the customer's entire circuit.
- Show how 5, 10, or 15% reduction on the entire circuit can be achieved.
- Present a plan that is realistic, workable, measurable, and enforceable, and show how compliance can be monitored and enforced.
- Reduce load by 5, 10, or 15% during every rotating outage.
- Coordinate with others on the circuit to achieve load curtailment.
- Sign a contract.

SCE is required to:

- Facilitate joint curtailment plans by notifying customers with loads of 500 kilowatts (kW) or more about the program.
- Coordinate communication and meetings between the customers on a circuit when any one customer expresses interest in participating.
- Provide OBMC program materials.
- Ensure that plan results in "overall improvements" to the electricity system.

Customer benefits:

- Participation exempts customers from rotating outages.
- Customers contribute to solving energy crises.

Customer penalties:

- Failure to reduce load results in a penalty of $6/kilowatt hour (kWh) of excess energy compared to a baseline level of consumption.

c. Project Design / Technological Description

The “technology” used to implement the OBMC program is primarily traditional C&I metering equipment that can record and present interval usage data, which can be used to verify the customer’s / circuit’s compliance with program requirements. Compliance is determined relative to a baseline of previous usage. The baseline is the average load of the immediate past 10 similar days during the period of interruption, excluding other OBMC events. The actual load reduction percentage is the proportion of the load that is shed during the interruption, compared to the baseline.

d. Suggestions for Enhanced Operation and Customer Acceptance

One of the major challenges associated with this program is that, because of the relatively diverse nature of businesses that may share the same geographical location, the number of customers on a particular feeder who are interested in participating may not be sufficient to qualify the entire feeder. In other words, similarity in customers’ geographic location may not correlate to similarity in their electricity usage.

To address this challenge, we suggest that, if individual metering is available, SCE not require that entire feeders participate in the program, and that SCE play a proactive role in the load reduction. The use of direct load control (DLC) technology that is already available, combined with the technological enhancements described in the air conditioner cycling portion of this document (Section III), would allow SCE to implement load reduction on a customer’s behalf. Automated control would help customers participate in the program and provide more predictable load reduction than is possible if customers are responsible for taking action to reduce load. It is possible that customers could benefit from this control capability even during non-emergency conditions by implementing energy-conservation / demand-management measures targeted at reducing energy costs. This control capability could be offered to the customer as a value-added element associated with the customer’s participation in the OBMC program.

An alternate technology that could be deployed, if the load is large enough to justify the cost of the equipment, would be the SCE Ultra-Net satellite-based Supervisory Control and Data Acquisition (SCADA) system. This satellite system is described below in the new technology section for C&I customers (Section IIB subsection 2, below). It could be used to supplement the current OBMC program. Either technology allows for customers to sell energy to the grid on a real-time basis, which would create an opportunity for customers to generate revenue for themselves that is not incentive based, because the market would be providing the income. The energy sales would most likely take place under non-emergency conditions and would simply complement the existing system.

The ability to eliminate specific feeders from a rotating outage remains a difficult issue. The best course may be to transition the entire load within a rotating outage block over to a SCE-controlled scenario, so that there will be enough demand management available to eliminate rotating outages altogether. In the meantime, the possible exemption of certain feeders can be supported, but the overall 15% reduction would probably have to be maintained to ensure that enough load reduction is available to protect the system's reliability.

2. C&I I-6 Interruptible Rate Options Program (I-6, RTP-2-I, TOU-8-SOP-I)

a. Program Definition & Summary

The I-6 Interruptible Service demand-side management (DSM) program is specifically limited to business operations that use 500 kW or more of power. The program offers lowered energy and time-related demand charges for the portion of power usage that a customer is willing to interrupt when requested by SCE. The I-6 Interruptible rate was closed to most customers on November 26, 1996 but remains available to eligible customers.

b. Customer Delivery Methodology

The I-6 Interruptible rate remains available to business customers who use 500 kW or more and meet one of the following eligibility criteria:

- A customer currently on an interruptible rate who is expanding operations and adds new load can also have the new load served under an interruptible rate. This additional load will be treated as interruptible load unless the customer contacts SCE before the new load is added.
- A current customer who opens a new service account with new load is allowed to put the new load on an interruptible rate as long as the new load was not previously serviced by SCE.
- Customers new to SCE's service territory are allowed to put their loads on an interruptible rate.

Customers currently served under interruptible rates continue to be subject to the terms and conditions of their interruptible contracts.

"Essential Use" customers (those whose operations are deemed essential to the health and safety of California citizens) are exempt from rotating outages to the maximum extent possible. Essential Use customers may remain in the I-6 program, but they must complete and submit an "Essential Use" customer declaration. This states that the customer voluntarily elects to place part or their entire load in the interruptible program, because the customer has adequate back-up generation or other means to interrupt load on request by SCE, while continuing to meet their essential needs.

Rate Discount:

The amount by which electricity rates are reduced for participants in SCE's interruptible rate program depends on customer demand, the time of day and season when the customer uses energy, and the amount of electricity the customer designates as interruptible. The portion of the customer's electricity usage designated as "firm service" (non-interruptible) is billed under a time-of-use (TOU) rate, such as TOU-8. The interruptible rate applies only to the portion of a customer's power usage designated as "interruptible."

Sign-up Costs for SCE's Interruptible Rate Program:

In general, an SCE customer served under the interruptible program must install a Remote Terminal Unit (RTU) to connect the customer's account to the interruption notification system and to monitor the real-time usage of electricity at the customer's site. The cost of RTU must be paid in full by the customer prior to the unit's installation by SCE. The RTU is owned by SCE, so it must be installed in a location that is accessible to SCE during reasonable hours for maintenance and repair.

Customer Obligations:

Customers taking service under an interruptible rate schedule agree to several conditions, including those listed below.

Firm Service Level (FSL):

The FSL is the minimum amount of electricity that the customer determines is necessary to meet their basic operational requirements during an interruption. Interruptible customers are requested to reduce electrical load to a designated FSL or non-interruptible level within 30 minutes of being notified by SCE of an interruption. In exchange for the agreement to reduce electrical load to the designated FSL, SCE serves participating customers at lower rates, whether or not an interruption event occurs, for all usage above their FSL.

Essential Use customers may not commit more than 50% of their maximum demand to the program.

NOTE: For the purpose of calculating the FSL minimum for essential use customers, the maximum demand is the average of the Essential Use customer's monthly maximum demand for each of the most recent 12 months. Essential Use customers must also state in their declarations that they are able to meet their essential needs at this FSL.

Penalties:

Penalties or excess energy charges may apply to customers who fail to reduce load to their FSLs during an interruption. Interruptible customers have 30 minutes from the time they initially receive the signal indicating the beginning of an interruption to comply fully with the request to interrupt load. Penalties may be assessed for each interruption event during which a customer fails to reduce electricity usage to the predetermined FSL. The penalties range from $7.20 to $9.30 per kWh of excess energy consumed during the interruption, depending on the customer's service voltage level.

Customers who began service on the I-6, RTP-2-I, TOU-8-SOP-I rate schedules from August 3, 2000 through August 31, 2000, must interrupt when notified by SCE or be subject to being back billed for all the interruptible discounts they received from the time they began interruptible service. These customers also may incur all applicable excess energy charges for failure to reduce to their FSL during an interruption event.

No penalties were charged for any I-6 customer during the period January 26 to April 19, 2001. Penalties were reinstated effective April 20, 2001.

Contractual Requirements:

An interruptible rate agreement is available through SCE representatives. In this agreement, customers must designate which service accounts will participate in the program.

Customer "No Insurance" Declaration:

An existing I-6 customer who wants to continue on the program has from April 24, 2001 to May 24, 2001 to submit a declaration to SCE that they do not have insurance, which would reimburse them for losses resulting from utility-initiated interruptions under I-6. Because the 30-day period extends beyond the 15-day contract termination window, the customer will not be released from the program or its requirements but may be subject to paying the otherwise applicable tariff rate until the declaration is received. If a customer increases their FSL, a declaration is required. No declaration is required if a customer terminates their interruptible service contract

Customers will be back billed for the period of time during which they had this insurance. If that period of time cannot be determined, customers must repay the discounts they received during the entire time they were served under the I-6 rate. In addition, these customers will be removed from the program. Once removed from the I-6 program, a customer is not eligible to participate in another rate reduction program for one year.

Increasing FSL during the April 24 to May 9, 2001 window requires that an amendment to the I-6 Contract for Interruptible Service be signed by the customer and submitted within this time period. If the amendment is not signed and submitted during this period, the customer will remain on I-6 at their previous FSL.

Customer Responsibilities during an Interruption:

SCE notifies customers of an interruption by sending a signal to the RTU or an automated message to a dedicated telephone. A call by SCE to the dedicated telephone or activation of the RTU is notification that the customer must reduce electricity usage to FSL. Because interruptions can occur at any time, someone needs to be available to respond to an interruption event whenever a customer's electricity usage exceeds the customer's FSL. The interruption system is tested monthly. If an actual interruption is called during the monthly test, the test is canceled immediately, and the customer is notified of the actual interruption.

Customers with an RTU:

When the RTU receives an interruption signal, its alarm sounds. The alarm can be silenced at that time if the “Acknowledge” button on the RTU is pressed. Customers have 30 minutes from the time the signal is sent by SCE to comply fully with the request to interrupt. Failure to acknowledge the signal does not excuse a customer from the obligation to reduce electrical load to FSL. If a customer does not comply with the notice to interrupt, excess energy charges and/or back billing may apply.

When an interruption event concludes, SCE sends another signal to the RTU, again sounding its alarm. As before, pressing the “Acknowledge” button will silence the RTU's alarm. If the “Acknowledge” button is not pressed at the conclusion of an interruption event, the alarm will silence after 10 minutes.

Note: If SCE is unable to communicate with the RTU during an interruption event (for example, if the RTU is undergoing maintenance by SCE), the back-up dedicated telephone is used to notify customers of the interruption event.

Customers Notified by a Dedicated Telephone:

Customers notified of an interruption via dedicated telephone rather than RTU receive an automated telephone call. Customers have 30 minutes from the time of the call to comply fully with the request to interrupt. If a customer does not comply, excess energy charges and/or back billing may apply. Failure to acknowledge the signal (e.g., not answering the phone) does not excuse a customer from the obligation to reduce electrical load to FSL. When the interruption event concludes, SCE notifies customers via their dedicated telephones of the end of the event and the option exceed FSL.

Interruptions During a Power Outage:

RTUs are equipped with a back-up battery, which powers their audible alarms, LED displays, and dry contacts for up to eight hours during a power outage. If SCE initiates an interruption at a time when the customer’s site is without power, the RTU receives the interruption event signal, causing its alarm to sound and its activation lights to illuminate. When this notification is received, the customer is expected to take action to ensure that their system will not draw more than its FSL once power is restored to the facility.

c. Project Design / Technological Description

RTU Installation and Access:

In general, SCE notifies a customer of an interruption by means of an RTU installed at the customer’s site. Each customer participating in the interruptible rate program is responsible for providing a communication cable from the RTU to an SCE interface enclosure. Because SCE owns the RTU, the RTU must be installed in a location accessible to SCE during reasonable hours for maintenance and repair.

Isolated Power Supply:

The RTU must be powered at all times and must be connected to a power source [115-volt alternating current (AC), supplied through conduit from a dedicated 15-amp or 20-amp circuit breaker] isolated from the electrical load that is subject to interruption.

Telephone Lines:

In general, customers with interruptible service must install two telephone lines – one connected to the RTU and – another connected to a dedicated telephone as a back-up notification system if the RTU is inoperable or undergoing maintenance. The dedicated telephone lines should:

- Not have dial-out capability because their only purpose is to receive calls from SCE. No other calls should be made on these lines.
- Have unlisted telephone numbers. Only SCE calls should be received on these lines.
- Be direct lines. Calls cannot go through a switchboard or voice message recorder (answering machine).
- Be located in an area where they can be answered immediately at all times.

Interruptible customers with an RTU:

The RTU is the official means used by SCE to notify customers that an interruption event is under way. The back-up dedicated telephone is used only if the RTU is unavailable (e.g., undergoing maintenance). Interruptible customers may not use interruptible Website, PageNet paging service, e-mail notification service, or SCE's toll-free 888 telephone number as alternative means of receiving SCE's interruption notification. Failure to answer an RTU signal or call from SCE on the dedicated telephone line resulting in failure to comply with an interruption notification may result in penalties as noted above.

Interruption Frequency and Duration:

An interruption may take place when operating reserves are forecast to drop below 5% within the next operating hour. When that happens, the California Independent System Operator (CAISO) directs SCE to reduce load by a specific amount. SCE then notifies its interruptible customers to reduce electricity usage to FSL according to the protocol described above.

There can be no more than 25 interruption events per year, and these events cannot exceed six hours per day, four events per calendar week (defined as Sunday through Saturday) or 40 hours per month or 150 hours per year.

CAISO can call for an interruption event at any time.

Monthly Test:

To verify that the RTU and dedicated telephone equipment are working properly, SCE conducts a communications test on the first Tuesday of each month between 8 a.m. and noon. This test is identical to an actual interruption event except that customers are not required to reduce electrical load and are not subject to penalties. Customers who have installed automatic load-shed systems on the RTU may install timer devices or other mechanisms to avoid automatic load reduction during a test. Although customers are not required to participate in the monthly test, many use the test to check external alarm systems and practice internal procedures and communications for handling actual interruption events.

Acknowledging the RTU Test Signal:

To formally acknowledge an interruption signal on an RTU, customers press the "Acknowledge" button. Customers are not required to acknowledge the RTU signal during a monthly test. However, failing to depress the "Acknowledge" button during an actual interruption event does not dismiss the customer from the obligation to reduce electricity usage to FSL. Test results are gathered and available within 48 hours after the monthly test through each customer's SCE representative.

Customers without an RTU receive monthly test calls on their dedicated telephones.

d. Suggestions for Enhanced Operation and Customer Acceptance

In most interruptible load programs, especially at other utilities, participating customers receive rate discounts that far exceed the market value of the load reduction they make available. Customer incentives should instead be tied to the actual market value of energy or capacity at the time of curtailment. This program modification would require customers to become dynamic participants, voluntarily offering energy to the market at their pre-selected price (referred to above as the Strike Price), which would be based on their internal financial / process requirements. Customers could participate in the market at their discretion, and SCE could facilitate desired responses to market price signals. Customers who want access to the market under an interruptible rate option would have to continue to offer the FSL for which they are currently contracted. In other words, the same FSL would still be available to CAISO as has been available under the existing interruptible program, but customer compensation would be based on the market value of the interrupted energy usage. SCE could pass the full market value of the saved energy on to the customer or retain some portion to cover administrative costs; most utilities are considering some form of "profit" sharing to help ensure the cost effectiveness of these types of programs.

An ongoing customer concern is the relatively short notice (30 minutes) specified in the tariff for load curtailment. If the program is modified as suggested above, this concern should be eliminated. That is, under normal circumstances when CAISO is in a position to call for an interruption, the market price would most likely have already met the customer's pre-selected sell price. Therefore, the load would already be off line, eliminating "last-minute" or crisis scenarios for participating customers. The emergency provisions of the rate could remain in effect as a backup so that the load would always be available for reduction when necessary for system reliability.

3. Base Interruptible Program (BIP)

a. Program Definition & Summary
BIP is an interruptible rate designed for customers with greater than 100 kW of demand who can reduce their electricity usage by 15% of load, with a minimum of 100 kW for each interruption. In exchange, customers receive a monthly rate credit based on the difference between the customer's maximum demand and the customer's selected FSL. In contrast with the I-6 program, BIP offers increased incentives and is designed to allow more flexibility in program interruptions. Penalties apply if participants do not reduce power use when asked to do so.

BIP program summary:

- Open to customers who can commit to curtail at least 15% of load, with a minimum of 100 kW/event.
- Activated during ISO Stage II events.
- No more than one four-hour interruption per day.
- No more than 10 events per month and 120 hours per year.
- Customers receive credit of $7.00/kW/month.
- Customers are penalized $6.00/kWh for excess energy use during interruption.
- Bill credit is based on difference between each month's average period demand and customer's selected FSL.
- New participants are given an interval meter without charge if needed.
- BIP participants may not participate in the CAISO Ancillary Services Load Program (ASLP).

b. Customer Delivery Methodology

Eligibility:

BIP is available to customers eligible for service under rate schedule TOU-8 and existing customers on I-6 who complete their annual obligations on those programs. Former I-6 customers are eligible to sign up for BIP if they have been off I-6 for 12 months.

Customer Obligations:

Customers taking service under BIP agree to several conditions, including the following:

FSL:
See Firm Service Level explanation under C&I I-6 Interruptible Rate Options Program above.

Telephone Lines:
See Telephone Lines description under C&I I-6 Interruptible Rate Options Program above.

Interruption Frequency and Duration:

Load may be interrupted when operating reserves are forecast to drop below 5% within the next operating hour. When that happens, CAISO directs SCE to reduce electrical load by a specific amount. SCE then notifies its interruptible customers to reduce electricity usage to their FSL within 30 minutes of receiving the notification. CAISO can call for an interruption event at any time.

Rate Discount:

The amount by which each BIP participant's electricity rate is reduced depends on the customer's demand, the time of day and season when the customer uses energy, and the amount of electricity the customer designates as "interruptible." The customer's usage designated as "firm service" (non-interruptible) is billed under a TOU rate, such as TOU-8. The interruptible (reduced) rate applies only to the portion of the customer's usage designated as "interruptible."

Customers are paid a credit of $7.00/kW/month. The bill credit is based on the difference between the customer's maximum demand during each month and the customer's selected FSL. The customer's maximum demand during the month is the sum of the monthly kWhs consumed by the customer during the peak period (on-peak for summer and mid-peak for winter) divided by the number of hours in the period that month.

Penalties:

Penalties or excess energy charges may apply to customers who fail to reduce load to FSL during an interruption event. Interruptible customers have 30 minutes from the time they receive the signal indicating the beginning of an interruption to comply fully with the request to reduce load. Penalties may be assessed for each interruption event during which the customer fails to reduce electricity usage to FSL. The applicable penalties are $6.00 per kWh of excess energy consumed during the interruption event, depending upon the customer's service voltage level.

Contractual Requirements:

An interruptible program contract is available through SCE representatives. In the contract, customers must designate which service accounts will participate in the program.

Supplemental Interruptible Program Status Information:

SCE resources that provide information about the status of potential or current interruptions include:

- Interruptible Program Status Telephone Line, (888) 334-7764, available toll-free, 24 hours a day, 7 days a week.
- Internet Interruptible Program Website (http://www.scebiz.com/I-6), displays interruptible program status and other related information.
- E-mail Notifications Service, which emails CAISO notices to participating interruptible customers as the notices are received. (The timely delivery of these notices depends on the transmission abilities of the Internet Service Providers involved).
- PageNet Early Warning Paging Service, which is used to contact participating interruptible customers with CAISO notices as they are received.

In some cases, interruption information may change rapidly, which can delay the manual process of posting information onto any of the above systems.

c. Project Design / Technological Description
Equipment needed:

New participants need:

- SCE's interval meter, which can record electricity usage at 15-minute intervals. If a customer doesn't already have an interval meter, SCE will install one at no charge.
- One dedicated telephone line, so the customer can receive interruption notices as described above under Customer's Obligations. The customer must provide the phone line and telephone.

d. Suggestions for Enhanced Operation and Customer Acceptance

As with the I-6 program above, a transition to a real-time, market-based, compensation model is suggested to directly link the value of the load reduction delivered under this program to the market value of the load at the time of the load-shedding event. Changing the system so that it is not associated only with system emergencies will permit customers to earn financial rewards any time the market price is at or above each customer's pre-selected sell price. If customers have the choice of reducing load at any time in response to price signals, they will become accustomed to making load reductions. As noted in the I-6 section, most customers' sell prices would likely be reached prior to an emergency event, so most customers would not have to respond to 30-minute load reduction notices. If enough customers participate in all of the curtailable programs, enough loads would be reduced in response to market prices so that the emergency provisions of the tariffs would never have to be implemented. Conceptually, this recommendation amounts to dividing interruptible tariffs into economic and reliability components. Having both components in one tariff ties customers more closely to actual utility operations and thereby makes them better partners during emergencies.

<u>4. Demand Bidding</u>

a. Program Definition & Summary

The Demand Bidding Program (DBP) offers SCE's bundled-service customers the opportunity to receive a bill credit for voluntarily reducing power without being exposed to the financial penalties that have traditionally been associated with load reduction programs. DBP customers can receive higher incentives than those offered in the past by similar programs. Because DBP is voluntary, it offers customers flexibility in making power reduction commitments.

b. Customer Delivery Methodology

Eligibility:

To qualify for the DBP credit, a customer must have at least 100 kW of electricity demand. DBP is not available to customers with Direct Access service, customers on Real-Time Pricing (RTP) agreements (such as RTP-2, RTP-2-1, etc.), customers with Hourly PX Pricing Options, or those enrolled in other similar programs offered by CAISO. Customers who have these pricing options already receive market-based hourly energy prices from their current rate. Participation in DBP is compatible with other SCE interruptible / curtailment programs, including the I-6, TOU-8-SOP-1, BIP, AP-1, TOU-PA-SOP-1, Optional Binding Mandatory Curtailment Program, ACCP, and Scheduled Load Reduction Program (SLRP).

If the above interruptible programs are activated, the terms of I-6, I-6-BIP, API, TOU-PA-SOP-1, and ACCP agreements take precedence. No credits for demand bidding will be paid during any period of operation that overlaps with an interruption event under those programs. However, if a customer participates in both SLRP and DBP, DBP will take priority, and no overlapping payments will be made.

This program is suited for large businesses and industrial customers who have the flexibility of reducing power that is not critical to their main operations or processes for four-hour time periods from 8 a.m. to 8 p.m.

Hours of the day when Curtailment Bids may be submitted:

Specific-duration events can be called for any weekday (excluding holidays) between 8 a.m. and 8 p.m. in the three time blocks listed below. Customers may choose to submit power reduction commitments for one or more of the available four-hour time blocks. However, a customer may not submit more than one bid for the same time block for any given DBP event. If a customer submits two bids for the same time block, both bids will be excluded from that DBP event.

Time Blocks	**Time Periods**
A	8 a.m.-12 p.m.
B	12 p.m.- 4 p.m.
C	4 p.m.- 8 p.m.

Customers must submit the same price and load reduction for each hour of a four-hour time block. If a customer accidentally submits more than one bid price for one four-hour time block, both bids will automatically be rejected.

Financial Opportunity:

Customers can submit bids at four price options taken from one of two pricing schedules (tiers) determined by CAISO / California Department of Water Resources (DWR). If the customer's bid price is accepted by CAISO / DWR, the customer receives a credit calculated by multiplying the bid price by the qualified kW reduction. The demand reduction must be at least 10% of the customer's average annual demand for the past 12 months and not less than 100 kW.

Price Tier A	**Bid Price (per kWh)**
Option 1	$0.10
Option 2	$0.30
Option 3	$0.50
Option 4	$0.70

Price Tier B	**Bid Price (per kWh)**
Option 1	$0.15
Option 2	$0.35
Option 3	$0.55
Option 4	$0.75

Submitting a Commitment to Reduce Power:

Customers submit power reduction bid commitments via the DBP website. Once a customer has received a signed DBP Agreement, a logon user ID and password are assigned for the DBP website, http:\\www.sceenergymanager.com. The website displays the time blocks, price tiers, and bid prices for DBP events.

Bids are submitted for a DBP event on the next eligible day, any weekday (excluding holidays) following the bid submission. DBP bids must be placed no later than 1 p.m., the day before an event. The CAISO/DWR accepts or rejects bids and notifies SCE. SCE updates the website, and customers may log on any time after 5 p.m. (but before the event begins) to see whether their bids are accepted for that particular event. The primary means by which bid acceptance is signaled is via the DBP website. If a customer logs on to the website once an event is in progress and can see the event under way, this indicates that customer's bid was accepted. If the customer can no longer see the event on the screen, this indicates that customer's bid was not accepted. At the time a customer signs the DBP Agreement, the customer may specify an e-mail or pager number that SCE will use at 5 p.m. on the day of bidding to notify customers whose bids were NOT accepted. This system is strictly voluntary and used as a backup only.

Future enhancements to the DBP website will include information about customer usage and baselines during an event; this information is expected to help customers monitor their usage to that they can receive the maximum payment.

How and When Customers Receive Credit:

In general, credits appear on customer bills within 30 to 90 days after the voluntary power reduction.

Determination of the Total kWh of Actual Reduction:

For SCE to determine how much load a customer actually reduced, SCE must know what the customer's usage would have been before the power reduction (which the DBP tariff refers to as the customer-specific energy baseline or CSEB). SCE will use the "10-Day Rolling Average Energy Usage" methodology to calculate a CSEB. The CSEB is determined on an hourly basis using the average of the energy usage for the same hour during the past 10 similar days (excluding days when the customer was paid to reduce power under another designated rate discount program or if the customer was subject to a rotating outage) prior to a DBP event. Then the CSEB or 10-day rolling average is compared to the actual kWh used for the same hour during the DBP event to determine whether the customer complied with the program and is eligible for a bill credit.

Frequency of Participation:

There is no limit to the number of DBP events. Participation in the program is voluntary.

Commitment Requirements to Reduce Power:

No penalties are charged and continued participation in the program is not jeopardized if a commitment to reduce load is submitted but not actually implemented, or if a commitment to participate is not submitted.

Contractual Requirements:

A DBP agreement is available through SCE representatives. In this agreement, the customer must designate which service accounts participate in the program and the average annual demand for these accounts, which is defined as the total number of kWh used during the previous 12 months divided by the total hours in the year.

c. Project Design / Technological Description

Types of Equipment Needed:

The customer must have interval metering capable of recording usage in one-hour intervals and internet access to bid and to receive notification of DBP events. Internet access is the only means of submitting commitments to reduce power. An interval meter is provided at no charge. To receive the meter requires a minimum of one year's participation in the program and full compliance with the minimum DBP bid requirements in at least 10 events. Failure to meet these criteria will result in the customer having to reimburse SCE for meter costs.

d. Suggestions for Enhanced Operation and Customer Acceptance

This program is moving toward a market-based pricing scenario as suggested for the I-6, OBMC, and BIP programs described above. By posting a price, customers have the option of participating depending on their own internal requirements. This program could offer prices based on the market value of the load reduction, which would result in a less restrictive pricing plan than the fixed choices currently offered. Allowing the customer to choose a bid price amounts to the same concept previously described as the "strike price," in which the customer establishes the price at which s/he is willing to take internal action to reduce load and effectively sell the unused energy into the market.

Experience around the country suggests that most customers do not object to mandatory curtailment for true system emergencies. Therefore, it is suggested, as a requirement for participating in the DBP program, customers are required to commit some level of mandatory load reduction for emergency situations. Mandatory reductions could be tied to Stage 3 system status, which in most cases would also be publicized in the media so customers would have an independent means for knowing why load reductions were called. As mentioned previously, the pricing structure will probably mean that loads would already have been shed prior to the emergency, so mandatory reductions may not have to be called into play.

5. Scheduled Load Reduction Program (SLRP)

a. Program Definition & Summary

SLRP offers qualifying SCE bundled service customers with a demand of at least 100 kW the opportunity to receive a bill credit for reducing power on certain weekdays during the summer season, June 1 through September 30 of each year. Specifically, SLRP allows customers to voluntarily commit to power reductions during pre-scheduled days and time periods. In return, SCE offers a bill credit for actual qualified kWh reductions.

b. Customer Delivery Methodology

Eligibility:

To qualify, the customer must have an energy demand of greater than 100 kW and be willing to commit to at least a 15% reduction in load from the customer’s maximum demand during the previous 12 months, which must not be less than 100 kW. This option is not available if a customer is enrolled in any of the following:
- Direct Access Service
- Hourly PX Pricing Option
- any RTP option
- OBMC Program
- CAISO Ancillary Services or Demand Relief Programs

Other rate discount programs compatible with SLRP are:
- I-6
- Base Interruptible Program
- TOU-8-SOP-I
- AP-1
- TOU-PA-SOP-I
- ACCP
- DBP

If a customer is currently participating in I-6, TOU-8-SOP-I, AP-I, or TOU-PA-SOP-I, the customer must fulfill their annual maximum interruption obligations under those programs before receiving bill credits for participation in SLRP. Also, if DBP and SLRP events occur simultaneously, customers do not receive payment for load reduction for the SLRP event but will receive payment for energy reduced for the DBP event.

Good Candidates for SLRP:

SLRP may benefit large businesses and industrial customers with the flexibility to reduce power for four-hour time periods between 8 a.m. and 8 p.m.(Monday through Friday). This program is also intended for customers who can shift operations to the off-peak period while curtailing load during one or all of the four-hour time periods of the SLRP program between the hours of 8 a.m. and 8 p.m.

Time periods for power reduction:

Customers may choose to submit power-reduction commitments for one or more of three available four-hour time periods:

Options	**Time Periods**
Option A	8 a.m.-12 p.m.
Option B	12 p.m.- 4 p.m.
Option C	4 p.m.- 8 p.m.

Participants must agree to shed a specific amount of load for each hour of the four-hour time period as specified in their SLRP agreements.

Customers may sign up for SLRP for a maximum of three days per week. However, customers may only sign up for the same time period on a maximum of two days. For example, if a customer wishes to participate in the program on Monday, Wednesday, and Friday of each week; the customer could only choose the 8 a.m. to 12 p.m. time period on two of those days.

Financial Incentive:

Participants receive a credit of $0.10 per kWh for qualified reductions. Incentives appear as bill credits, generally within 30-90 days after the customer voluntarily reduces power.

Determining actual power reduction:

To determine how much load was actually shed, SCE must know what the customer’s typical usage would have been prior to reducing power (i.e., the CSEB). SCE uses a 10-day rolling average energy usage methodology to calculate the CSEB. The CSEB is based on the average kW consumed for each hour in the period that corresponds to the customer’s pre-scheduled Power Reduction Time Period, during the preceding 10 days prior to a SLRP event (excluding days on which the customer was paid to reduce power under another SLRP or other designated rate discount program or if the customer was subject to a rotating outage). The CSEB or 10-day rolling average for each hour is compared to the actual number of kWh that the customer used during the same hour of the SLRP event to determine whether the customer complied with the program requirements.

Shifting load to On-peak Periods:

SCE monitors energy usage to ensure that customers do not shift load to the on-peak period (12 p.m. to 6 p.m.). Monitoring is accomplished by comparing the customer's average monthly on-peak usage from the previous year to the average on-peak usage in the current month. If it is determined that the customer shifted more than 15% of load to the on-peak period, the customer is not eligible for SLRP credits in that month. If the customer does not have 12 months of established interval data recorder (IDR) metered data, the customer's monthly on-peak usage will be compared to an average load profile. If the customer increases usage over the average load profile by more than 20%, the customer will not receive SLRP payments for that month.

Penalties:

No penalties are charged if a customer does not reduce power during a SLRP event. However, the customer will not receive payment for participating in a SLRP event unless the customer reduces power usage in accordance with SLRP program requirements during every hour of a SLRP event. SCE reserves the right to terminate a customer from the SLRP program if the customer fails to comply with any five scheduled SLRP events.

Contractual Requirements:

The customer must complete and sign a SLRP agreement. In this agreement the customer must specify amounts of load the customer agrees to reduce by hour, and the time periods (Option A, B, and/or C) during power usage which will be reduced.

Canceling or Altering Agreements:

Customers may terminate SLRP agreements during the annual 30-day window, November 1 through December 1. Termination of service under SLRP becomes effective on January 1 of the following year. SLRP commitments cannot be altered.

c. Project Design / Technological Description

Types of equipment:

The customer must have an installed, operational IDR capable of recording usage in hourly increments before participating in the program. The customer must also have established at least 10 weekdays of usage before service will be provided under the SLRP rate. An IDR is provided at no charge.

d. Suggestions for Enhanced Operation and Customer Acceptance

This program is specifically tailored to customers who must schedule load reduction well in advance of a controlled event. It is impossible for these customers to participate in dynamic, real-time marketplace transactions. Therefore, there is no practical way to modify this program so that it can be market based, as defined by this study.

B. Programs Based on the Utilization of New Technologies

1. Demand-Responsive Commercial Thermostat Pilot Program

a. Program Definition & Summary

SCE is implementing a turnkey demand-responsive commercial thermostat pilot program targeted at small commercial customers. The goal of this program is to test the viability of controlling load using internet technology and thermostats to affect heating, ventilation, and air conditioning (HVAC) use.

The pilot program is designed to include approximately 5,000 small commercial SCE customers, representing an estimated four megawatts (MW) in peak demand reduction, resulting in electricity and demand savings before the end of 2002. Participants in the program will receive the necessary technology (hardware and services) at no cost and a financial payment incentive (of up to $300) for continued program participation.

The main objective of this pilot program is to fulfill the statutory requirement of AB970 contained in Public Utilities code 399.15 (b) paragraphs 4, 5, and 6 to "equip commercial buildings with the capacity to automatically control thermostats…," "evaluate installation of local infrastructure," and provide "incentives for load control." This pilot program will accomplish these directives while simultaneously testing other assumptions of interest regarding:

- Consumer participation and behavior patterns in the program.
- Consumer satisfaction with newer interactive load control technologies.
- Responsiveness of small commercial customer load to price signals or system demand.
- Ability of such programs to deliver reliable and verifiable energy and demand savings.

The success of this program depends on the ability of the service provider to deliver the program services and equipment requested in the time frame desired and to conform to all contractual, administrative, and technical requirements.

b. Customer Delivery Methodology

The following is a general statement for the scope of work for the pilot program, with roles for all parties, objectives of the pilot program, procedures, and desired outcomes. Program evaluation is not included in this scope of work, but coordination with third-party evaluators is requested by SCE.

SCE's Role:

SCE will be the utility program administrator for this program, which includes both regulatory reporting and contract administration for program delivery. Specifically, SCE will:

- Define the overall scope of work based on program design guidelines.
- Fine-tune the program design and implementation.
- Competitively select service provider(s) to deliver program services and equipment.
- Act as contract administrator for program delivery.

- Collaboratively with the service provider, recruit customers for the program, including posting information on the utility-hosted internet site.
- Provide marketing assistance and facilitation to the contractor(s) who deliver the program.
- Conduct random site inspections of at least 10% of program participants to verify technology installation and program operation.
- Process and deliver incentive payments to customers.

SCE will work collaboratively with the service provider selected for this pilot program to ensure program success but will also enforce contract schedules and deliverables (based on the service provider's proposal), and enforce all contract terms and conditions in accordance with SCE's procurement policies.

Service Provider's Role:

The service provider selected for this pilot program is responsible for the technology to be implemented and will collaborate with SCE to solicit customers. The service provider will be directly involved with small business customers throughout the duration of the pilot program. At a minimum, the service provider will deliver:

- Connected programmable HVAC thermostats for 5,000 small commercial customers.
- Data services and software, as required for the duration of the pilot program.
- Software setup at utility site.
- Installation and maintenance services at customer sites.
- Customer training and education.
- System administration and tracking system.
- Communications services.
- Settlements and/or reporting of program activity.
- Cooperation with third-party evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002.

The service provider will coordinate with individual customers to arrange equipment installation and setup at customers' sites. The service provider will schedule and coordinate equipment installations, maintenance, repair; and, at the end of the pilot program, removal of all hardware and software.

Customer Eligibility:

The three distinct small commercial customer groups eligible for the pilot program are:

- Those with high average monthly summer consumption.
- Those with high consumption because of climate (geographically sectored).
- Those in small cities and rural areas.

SCE wishes to test the viability of the program for each of these customer groups.
Small commercial customers who are currently enrolled in other demand-response programs are excluded from participating in the pilot program, and pilot program participants will be precluded in the future from participating in both the pilot program and demand-response

programs offered by other state agencies or interruptible programs being considered in pending state regulatory filings.

The demand-responsive commercial thermostat pilot program requires that only the customer's thermostat be capable of internet interface, so the customer does not have to own or operate a personal computer to participate in the program.

Marketing and Promotion:

Information about the program is made available to target small commercial customers through the utility website and bill inserts. Community-based organizations and small business associations will also be involved in program marketing and outreach to the extent feasible. SCE will work with the service provider to contact and recruit interested customers.

No application from individual customers will be required for this program other than a signed affidavit in which the customer agrees to have the equipment installed at their site and signifies that s/he understand the terms and conditions of the pilot program. The service provider will have the authority to interact with the customer to make sure that each customer completes the necessary paperwork and understands the program and that the technology is installed.

Program information will also be posted on the website of the CPUC, including links or contact information at the utility where consumers and other interested parties may learn about the program or request more information.

c. Project Design / Technological Description

The preferred technologies eligible to be included in this program should be programmable HVAC (connected) thermostats with two-way internet connectivity. Technologies that simply allow third parties to interrupt load on a one-way basis will not be considered. At a minimum, the technology selected must do all of the following:

- Operate in accordance with all local, state, or federal codes for use with small commercial packaged HVAC systems in the geographic areas selected.
- Allow the customer some level of control (override, etc.) over their own HVAC equipment.
- Provide interactive information for customers to use in making consumption decisions (e.g., via the thermostat or a computer internet connection).
- Allow the remote administrator to verify actual operation of the individual device at the customer site, including duration and level of kW demand reduction.

The thermostats must be compatible in both form and function with existing HVAC systems for small businesses and must be "transparent" to the customer -- i.e., must allow traditional HVAC control when the demand-responsiveness function is not activated or operational.

Once equipment has been installed at the customer's site, the program can be activated by setting the thermostat to a preset default for a maximum time period to be determined at the outset of the program. Each interruption period will be considered an "event." A maximum number of events during an annual program period should also be determined at the beginning of the program and communicated to the customer.

A customer should have the ability to override the thermostat setting at any time during an event, subject to prespecified settings. The program operators may also wish to vary the thermostat settings and /or the numbers of hours over which each event occurs to test consumer tolerance and reactions to different operating procedures or schedules.

The hardware and software offered by the delivery service provider for this program should have the capability of periodically reporting thermostat settings and consumer behavior for payment settlement purposes. This information should also be made available to the program evaluator for estimating aggregate energy savings and peak demand reduction impacts.

Estimated Program Cost:

In general, customer installation for such equipment/programs are usually less than $500 per customer / thermostat. This cost includes installation labor. The internal costs associated with implementing the back-office operation associated with this project are not available.

d. Suggestions for Enhanced Operation and Customer Acceptance

Because this is a new program, it is not practical to implement suggested program enhancements at this time. However, a basic observation is that customers may be enticed to use the system if they are allowed to sell energy and capacity to the grid in a fashion similar to what has been described for some of the other programs previously discussed above. In effect, the web-based thermostat could become an enabling technology that might also support some of the programs already in place (modified as suggested in the report). This concept is also described in the new program design being proposed in the Residential and Small Commercial segment of this report called Customer Choice Load Management.

<u>2. Satellite-Based Direct Load Control (CANCEL-ERB)</u>

a. Program Definition & Summary

This program uses the existing SCE UltraNet Satellite system to make emergency reductions in non-essential large C&I electrical loads [Customer Approved Non-Critical Electric Loads (CANCEL)] which might allow SCE (and possibly the state) to maintain electricity service to all essential loads during capacity shortages, thereby eliminating Emergency Rotating Blackouts (ERBs). The system is capable of providing SCADA-like communications to remote terminals that could be located throughout California, not just in the SCE service area, which is an inherent feature of a satellite-based network.

The current approach to ERBs is to drop all critical <u>and</u> non-critical electrical loads on entire substation feeders. If ERBs last for 20 or more hours, as is projected to happen in the future, statewide industry losses could exceed $6.4 billion, and manufacturing losses could exceed $1.2 billion, representing a possible loss of approximately 135,000 jobs. Under these conditions, public safety could be endangered by neighborhood blackouts and failure of traffic signals to function.

The technology in this program is especially suited to providing the sophisticated communications and control necessary to manage relatively large C&I loads (in contrast to residential loads). This system makes it possible to drop only loads designated as CANCEL in an emergency while maintaining power for all critical or essential customer operations. The system would eliminate the negative impacts of ERBs on critical loads.

The initial proposal is to apply CANCEL-ERB only to the SCE system, and the costs shown here are for the program at SCE. However, the benefits of virtually eliminating ERBs for entire substation feeder loads and meeting spinning reserve requirements accrue to the entire state. Other major state utilities will be free to apply the CANCEL-ERB approach with their customers. The program will allow for an orderly introduction of more efficient combined-cycle gas generation, fuel cells, and other technologies and will improve grid control reliability at the state level.

It is proposed that SCE's UltraNet satellite system for emergency power control be expanded to include installation of satellite terminals at the customer level for near-instantaneous control of customer approved nonessential loads. This kind of emergency load control could be used to balance electricity system demand with available generation during emergencies. Non-critical electrical loads would be placed on separate circuits, which could be interrupted during emergencies when required by the ISO. These loads, selected by the customer, could also be monitored for energy consumption characteristics during normal operation and could thus be used by the customer to manage their energy consumption more accurately.

The general overall benefits of this system are:

- Benefit/Cost Ratio: ~10. Because information on customer non-critical loads is sparse, the actual load reduction achieved by this program may be as small as 2,000 MW. (If only 2,000 MW of load were available to be interrupted, the Benefit/Cost ratio would be ~7.)

- Environmental Impact: Provides 2,000 – 2,500 MW of emergency peak power demand capacity without any fuel consumption.

- California Jobs: More than 90% of the hardware for the proposed project will be manufactured in California.

- Metering Expense: Provides TOU metering for large C&I customers without requiring a change of meters.

- Improved Monitoring: Provides ability to monitor the effects of other conservation measures as a function of time of day compared to baseline consumption.

- Rapid Non-Critical Power Demand Verification: Verifies Non-Critical Electric Load demand reduction per customer and cumulative load reduction capability as installations proceed. Incentives can be based on verified load reduction using the rapid two-way communications capability of the network to any location in the state.

- Benefits Verifiable by all Parties: Provides power demand and energy conservation benefits verifiable by all parties. No hidden costs. All costs, including operations & maintenance costs during and after the project, have been clearly identified.

- Reserve Margin Benefits Accrue with each Installation: Entire project does not need to be completed before number and duration of critical rotating blackouts can be reduced.

- Generic Solution: Could be used to advantage by other states.

- Accurate Load Research Data Base: Provides the best tools developed to date for accurate, synchronized load data.

- Low Implementation Cost: Provides a measurable solution at a cost for the first two years equivalent to two to three days of state expenditures for spot-market energy purchases.

- First-time Non-Critical Load Profiling: Real-time monitoring of customer-selected non-critical loads allows a weekly non-critical load profile to be developed for each customer and for the power system. Currently, there is no information on the total non-critical load fluctuation for customers on a week-to-week basis. A matrix of the non-critical loads available to be dropped can be developed for the entire SCE network. This dynamic matrix of load profiles can be used to accurately determine how many customers are required to drop load during a power emergency at any time.

- The benefits of the CANCEL-ERB Application using SCE's UltraNet satellite accrue even when there is adequate planned generating capacity. Imbalances between on-line generation and load can occur during any outage of transmission lines or power generation, including outages resulting from causes such as lightning, earthquakes, or fires. The system developed by SCE will be able to respond more rapidly and reliably than other proposed options. This system is directly applicable to many load-related ancillary services required by CAISO.

- The proposed solution should not be considered a replacement for planned efficient fossil or renewable resource generation. It is simply an environmentally friendly alternative to conventional power system control.

b. Customer Delivery Methodology

This program would be offered on an incentive basis that would tie the value of load reduction directly to the amount of incentive the customer receives. Because the program would be based on accurately time-stamped, real-time data, a market-based compensation model could easily be developed.

c. Project Design / Technological Description

An advanced, low-cost satellite system developed by SCE and currently in use at 300 substations would be connected to unique, addressable monitoring and control devices to turn and non-critical electrical loads on and off within one second after a command is issued by the utility.

System Technical Summary:

UltraNet:

Patented architecture links multiple remote satellite terminals to a central hub that supports:

- SCADA
- Distribution Automation
- Pole-top Monitoring
- Weather / Hydrological Data Collection
- Ku Band System (with the highest rain fade margins of any satellite network)

The system uses very small flat-array antennas.

Hub Terminal:

Continuously collects data from all terminals and stores information until the SCADA master collects it. Direct access is available for priority commands. The hub also provides all network monitoring.

UltraNet Remote Terminal Earth Stations:

Remote terminal stations are self-contained, external units that perform all signal transmissions, up/down conversions, and signal processing. A compact radio frequency (RF) antenna transmits and receives all communications to and from the satellite. The outside unit requires only an RS-232 data cable and a direct-current (DC) power connection to the inside equipment. No RF is brought into the building, thus eliminating potential interference issues.

General Specifications:

Data Rate: 1.2 kbps (current), 9.6 kbps (planned)
Error rate: 1X 10-7 BER maximum
Fade Margin: Up to 16 decibels (dB)

Remote Earth Station:

Ports: Standard RS-232 selectable up to 9.6 kilobytes per second (kbps), which includes programmable protocols and optional interface and expansion capabilities.
Reprogramability: Over the air from hub to terminal or locally through the RS-232 interface
RF Power: 0.5 watts standard, 1 watt optional.

Hub Station:

Outdoor: Standard Ku-band transmit / receive 3.8 meter antenna plus transmit and receive equipment.
Outbound capacity: 0.6 kbps (9.6 kbps planned).
Inbound Capacity: 0.6 kbps each with 50 simultaneous remote earth stations.

d. Estimated System Performance (kW / kWh, etc.).

Within nine to 12 months (phase 1), it is estimated that 1,000 MW could be controlled using this satellite system. The benefits of controlling non-critical loads will accrue as each customer installation is completed. Within 18 to 24 months (phase 2), approximately 1,500-2,000 MW of industrial and commercial load would be controllable in this manner. Finally, within three years, approximately 2,000-2,500 MW of non-critical load could be available for emergency load management.

e. Estimated Program Cost

The cost for the first two phases is estimated to be $118 million over two years.

III. Residential / Small Commercial Load Management Programs

A. Programs Based on the Existing SCE Load Management System / Technology Base

1. Air Conditioning Cycling Program (Base) / Air Conditioning Cycling Program (Enhanced)

a. Program Definitions & Summary

The Base ACCP, which has been closed to most customers since April 1996, is reopened. This program offers qualifying customers a credit on their bills during summer months in return for allowing SCE to temporarily shut off their air conditioners without advance notice a limited number of times during the summer season. Customers allow SCE access to their air conditioning units to install a remotely controlled device.

The Enhanced ACCP offers qualifying customers a credit on their bills during summer months in return for agreeing to allow SCE to temporarily shut off their air conditioners without advance notice during the summer season. In comparison to the Base ACCP, the Enhanced program doubles credit amounts, and the potential number of times SCE may shut off the customer's air conditioning unit is unlimited during the summer season. Customers allow SCE access to their air conditioning units to install a remotely controlled device.

b. Customer Delivery Methodology

Program participants are compensated according to the following model. The program is operational each year from the first Sunday in June through the first Sunday in October. The Base Program limits the number of control 15 events per year of no more than six hours each.

Base Program
Cycling Percent = $/Ton/Day

Residential
50% = $0.05
67% = $0.10
100% = $0.18

GS-1/TOU-GS-1
30% = $0.014
40% = $0.042
50% = $0.07
100% = $0.20

GS-2/TOU-GS-2/ TOU-8
30% = $0.42
40% = $1.25
50% = $2.10
100% = $6.00

The Enhanced Program operates during the same time window as the Base Program. There is no limit to the number of control events under the Enhanced Program. Each event is limited to six hours per day.

Enhanced Program
Cycling Percent = $/Ton/Day

Residential
50% = $0.10
67% = $0.20
100% = $0.36

GS-1/TOU-GS-1
30% = $0.028
40% = $0.084
50% = $0.14
100% = $0.40

GS-2/TOU-GS-2/ TOU-8
30% = $0.84
40% = $2.50
50% = $4.20
100% = $12.00

c. Project Design / Technological Description

This system is a traditional radio-based, one-way, DLC system using the most desirable load management frequency of 154.46375 megahertz (MHz). The system has been expanded over the years to provide innovative dispatcher interface options. The main technological challenge facing the current program is its inability to broadcast the full slate of control messages needed to implement the currently available customer participation options (the various duty cycle options). This problem cannot be solved without additional capital investment in the current system. Specifically, the system needs to upgrade its control / data format to implement a more sophisticated customer address scheme. This is only one of several major features currently available in state-of-the-art, one-way, radio-based systems. Upgrading the current system to a modern control technology would enhance SCE's ability to offer additional customer participation options. Unfortunately, an upgrade will not solve the entire problem, because there are also two fundamental areas of concern associated with the radio transmitter system. First is the issue of time-sharing with adjacent power companies; currently, SCE must share airtime with both San Diego Gas and Electric (SDG&E) and Pacific Gas and Electric (PG&E). It is possible these utilities would relinquish their access to this frequency, because it is believed they are no longer utilizing their original systems, which shared the frequency. If this change can be negotiated, a three-fold increase of capability would immediately become available to SCE for additional broadcasting. The second improvement that can be made is associated with the transmitters themselves. The current system must cycle through at least three transmitter groups (effectively repeating each message three times), because of the relatively unstable transmitter oscillators that are a part of the old system that is currently in place. The system's available data throughput would at least triple if SCE upgraded these transmitters to state-of-the-art, solid-state transmitters specifically designed for simulcast service, which have the ability to transmit simultaneously with adjacent transmitters sharing the same frequency without causing destructive interference.

Making the above two physical changes and incorporating current enhancements such as Distributed Intelligence would address the current program's technical constraints. These changes would allow the current base infrastructure to support all of the elements of the current base ACCP (and implementation of the proposed Customer Choice Load Management system described later in this document). If these investments cannot be made, the only choice for SCE is to move to a different RF, which would most likely result in the purchasing of airtime from one of the existing paging systems in the area. There is nothing inherently wrong with this approach, which should be seriously considered before a decision is made about upgrading the existing system. Determining the most cost-effective choice should be fairly simple.

d. Estimated System Performance (kW / kWh, etc.)

Program load reduction estimates are based on the control of a certain tonnage of installed capacity. The potential load reduction is equal to the installed capacity, because the current control system only implements the 100% duty cycle. Therefore, the actual load reduction is directly equal the average diversified demand of the air conditioning unit.

The existing system could be significantly enhanced by creating geographically defined climate zones to distinguish the relatively mild coast climate from the relatively hot inland climate. This mix of mild and hot climates within the service area creates a high probability of "Free Riders" – customers whose air conditioning systems are either not running at all or is running at a very low duty cycle. In either case, these "Free Riders" dilute the overall load reduction performance of the system. If homogenous climate zones could be created, a more productive duty cycle / per kW demand reduction could be implemented across the system. This suggestion is not meant to imply that the current kW values used to evaluate the program are mathematically flawed, just that by creating these climate zones SCE could take into account the drastic variations in performance (load reduction) among customers. The new climate zones would effectively create separate load management systems throughout the service area. Each system would be dispatched according to system performance parameters consistent with its specific region. The current system works on a pay-per-control basis; system efficiency would increase significantly if only customers that could actually deliver load reduction were controlled when a capacity shortage developed. Customers close to the coast would not be controlled very often; and as a result, participation levels would probably adjust accordingly. Some climate zones might "underperform" to the extent that they would be disqualified from participation, at least from an economic dispatch perspective. Their participation would probably always be beneficial during system emergencies / statewide capacity shortages, which would most likely correspond to abnormal weather conditions that would result in even those customers having some load relief to contribute during a system generation capacity shortage.

An additional enhancement to help offset the drastic variations in duty cycle among the SCE customer base is the so-called “Smart” or “Adaptive” Duty Cycler. This software, which is written into the microprocessor of the load management switch, actually monitors the historic duty cycle of the air conditioning system and attempts to adjust the duty cycle by a percentage rather than giving a specific across-the-board command. An example is a command to reduce the duty cycle by 10% rather than going to a forced duty cycle, e.g., 50%. With an Adaptive Duty Cycler, the load control command would always generate a load reduction; this should be a significant improvement over conventional fixed-duty-cycle control. Where this technology has been deployed, increased load reduction per customer has been realized. The only disadvantage is the potential for serious customer comfort impacts. The Adaptive Duty Cycler cannot anticipate customer intervention before, during, or after control. By altering air conditioner system operation; customers could exacerbate their own discomfort well beyond what would normally result if they did not adjust the system’s operation. This issue needs to be tested. Most vendors offering the Adaptive Duty Cycler option have included default parameters to limit customer impact. These defaults need to be tested to determine their overall success in limiting customer comfort impacts without diluting the load reduction benefits possible from the Adaptive Duty Cycler concept.

e. Estimated Program Cost

The typical cost to implement a modern load control switch that would support the options necessary to fully implement the current program tariffs is approximately $175 per customer. This is for a very basic outside installation mounted at the air conditioning unit. No inside access is contemplated for this kind of installation. The load management head end or controller would have to be upgraded to implement the new control strategies as well as the new transmitter simulcast control system. The estimated cost to upgrade the existing controller system is approximately $50k. The cost to upgrade the transmitter system could easily exceed $25k per transmitter.

B. Programs Based on the Utilization of New Technologies and Concepts

1. Customer Choice Load Management

a. General Description

The primary intent of the proposed Customer Choice Load Management system is to allow customers, in this case the mass market (Residential & Small Commercial customers, who typically have single-phase service), to chose how to purchase electricity while providing the utility or ISO/ RTO an added source of “equivalent” generation capacity that can be used to improve system reliability. The new system can help reduce the need to purchase extremely high-priced spot market energy and capacity. At the same time, it would help improve system reliability by providing operational reserves and emergency load reduction.

Although the program as described below is primarily focused on the mass market, a modified version could be developed to meet C&I customer requirements. The primary difference would be the level of customer interaction with the utility during the system’s implementation. We focused on the mass market because many utilities already have a relatively large number of load reduction / relief programs focused on the C&I market. This program is specifically designed to add to or supplement any existing mass-market air conditioning cycling programs that may already be in place at a utility.

In general, this new load management program attempts to provide a mechanism for the mass market to participate in the spot-market purchase / sale of electricity while simultaneously offering the utility a load management system that can provide emergency load relief during capacity shortages. The system allows customers to react to spot market prices without the need for dedicated metering equipment. This feature was included to the system's design because of the general perception that automated meter reading (AMR) deployments are not cost effective. It is hoped by addressing this concern that we have enhanced the opportunity for deployment of this new program. The program was also designed to be absolutely cost effective in its most basic form. Many load management programs have been deployed around the country when the industry was in dire of load reduction; some of those programs were deployed primarily out of political necessity rather than good business judgment about a program's financial merit. The program proposed here includes an evaluation of financial merit so that it can withstand future economic challenges. This is the logical path because the deployment of an uneconomic load management system that must eventually be shut down once it is found not to be financially viable would exacerbate an already difficult utility cost structure, which would be an undesirable scenario in a competitive market.

Because we wanted the system to be "rock solid" financially, we analyzed in detail the use of customer incentives for customer solicitation. Historically, load management systems have utilized a fixed incentive structure. Although attractive to a large number of customers, it puts an unmanageable financial burden on the programs. As a result of this problem, almost all of the programs created in the aftermath of the oil embargo of the late 1970s have made major adjustments in their credit / participation payments to try to keep costs in line with the value the programs deliver to the utility and / or marketplace. In every case, no entirely new customer delivery mechanism has been developed that fundamentally eliminates the ongoing fixed credit structure. Some newer programs being implemented around the country today are attempting to address this issue with "pay-per-control" strategies. The payments in these strategies are still fixed and cannot automatically adapt to the true market value of a customer's load reduction contribution.

The Customer Choice Load Management program described below is an attempt to directly link customer compensation and the real-time market value of the customer's load reduction. This direct linkage will help ensure the financial merit of the load management system and has forced the development of a completely new customer delivery / incentive structure in combination with existing, tried and true load management technology. The program design is actually technology neutral. As an example and to demonstrate the program's financial viability, the most cost-effective technology available (conventional DLC) was chosen for the program's evaluation. Some technology options that can provide significant value-added customer benefits are also addressed.

b. Program Design

The Customer Choice Load Management program cost will not be cross-subsidized by customer classes outside the program or other non-participants. This strategy ensures that the program is fundamentally a good business decision for customers (participant and non-participant) and for the utility. Even though the example in this document is based primarily on the use of conventional DLC equipment, an internet-based thermostat would provide similar performance. The only difference, other than the obvious benefits and more predictable impacts of using a thermostat to control the air conditioning system, would be initial cost. It is assumed that the customer would have a choice between these two technology options and could in effect purchase the thermostat option if desired – paying the difference between the base technology (DLC in this example) and the thermostat option.

Two basic electricity system concerns cause all load management systems to be “dispatched” (in this context, “dispatched” means physically implemented, resulting in the actual control of connected load). These two attributes are system reliability and economics.

Historically, load management has been employed predominantly for economic reasons. The economic dispatch of load management is to avoid the purchase of high-cost energy on the spot market or to avoid running high-cost native generation [usually Combustion Turbines (CTs), which are the least costly generator to build but the most costly to operate]. Most load management systems have been cost justified on the basis of providing additional generation resources that are primarily used and valued by the utility for providing increased reserve margins or reliability. Because reserve margins are by definition for contingency situations, the actual incidence of dispatching the load management system to provide additional generation may, in practice, be rare depending on how often the utility experiences unforeseen electrical events that result in an unexpected generation deficit. During “critical capacity” conditions, the utility can implement its reserves (generation or load management) on an as-needed basis.

It is important to remember the value of using load management for reliability purposes is determined by comparing the cost of load management to the cost of providing reserves from another source, e.g., purchased capacity or building and owning additional generation. In other words, the value of load management for reliability is NOT determined by how often the system is dispatched. Some utilities have the perception that load management has little value because it has not been dispatched very often. How often the system is dispatched is simply a function of how often the system dispatcher needs generation reserves to maintain system stability and/or reliability. Utilities contemplating the deployment of a load management system must make it clearly understood that load management’s value is in relation to generation planning, because load management avoids the need for more costly generation that would have to be purchased to provide the same level of operating reserves / system reliability.

To understand how load management functions help ensure system reliability, it is necessary to understand reserves, which generally have two components:

1. Frequency-responsive spinning reserves are intended to provide additional system generation capacity within seconds of an event (contingency) that lowers system frequency to some predetermined level (e.g., 59.7 Hz). All frequency-responsive spinning reserves must be on line within 10 seconds of a contingency.

2. Supplemental reserves are required to provide their rated additional capacity within 10 minutes after a contingency, picking up where spinning reserves leave off and continuing until 30 minutes after the initial event.

Load management systems are ideally suited for providing supplemental reserves. The key technical issue is ensuring that load management systems can be dispatched rapidly enough to reduce load within the required 10-minute window. Most conventional load management systems can easily respond within this time frame.

It would be impractical to dispatch load management systems as they are currently designed within the 10-second time frame required for spinning reserves. However, if load management customer equipment or switches were designed to internally sense system frequency and respond accordingly, the systems could respond rapidly enough to provide spinning reserves. Frequency-sensing capacity could realistically be incorporated in the design of load management receivers. With this design change, the Customer Choice Load Management system could become the first with the capability to provide frequency- responsive spinning reserves.

The Customer Choice Load Management program has both economic and reliability components. The economic component primarily benefits the customer, and the reliability component benefits the utility by providing cost-effective system operating reserves (primarily supplemental reserves).

The economic component of the Customer Choice Load Management system is based on a "lite" version of the typical financial relationships that exist in options trading. It is necessary to understand not only the concept of "Strike Price" (explained in Section I above) but also the concept of a "Put" option to understand how customers can benefit from allowing their loads to be controlled. According to the Chicago Board Options Exchange (CBOE), options are standardized contracts that give the buyer the right but not the obligation to buy or sell a particular asset (electric energy in this case) at a fixed price (the strike price) for a specific period of time (until expiration). A "put" option normally represents the right to sell shares of underlying stock (in this case the right to sell a unit of electric energy).

Because the utility and the customer will both be in a profitable position as a result of deploying the load management system, the effective cost to the utility for these customer credits will always be zero or could even represent a profit over the actual cost of avoided purchased power. The profit margins during some dispatch scenarios will be used to offset program operating and other costs. The incentive for customers to participate in the Customer Choice Load Management Program will be based on two financial and service rewards:

- A regular (e.g., every two years), free air conditioning checkup. The retail value for this service is approximately $65, but the utility might be able to contract for delivery of this service at a lower rate.
- The customer's choice to sell capacity (currently limited to 1 kW for this example) into the energy market at a preselected sell ("strike") price. The utility can use the sale of this capacity to offset the purchase of energy on the spot market. Formal market research is needed to forecast the level of customer interest in this compensation model. (It is worth noting that, although there was significant doubt about the level of customer acceptance that

traditional load management programs would enjoy prior to their deployment, experience has shown there is a substantial customer group within the residential / small commercial market segment that is keenly interested in managing its own energy costs. In the Customer Choice Load Management program, the utility can build on the success of those original load management programs).

Whatever sell price the customer chooses, it will be equal to or less than the avoided costs of purchasing energy on the spot market. This insures that all transactions will be profitable for the utility. This financial relationship is important, because it ensures that the marketplace and not the utility's customer base are paying for the customer incentives. The only cost to the utility is the actual cost of the load management equipment, operations and maintenance, and the air conditioning service calls provided to program participants. Even the service call costs might be covered by the retained value that could accrue between the customer's sell price and the actual cost of purchased energy.

The utility can dispatch the system for a particular customer any time market prices match or exceed the customer's sell price for energy. This model is intended to insure that the customer is compensated each time the load management system is dispatched. A provision related to system reliability will also be added to the customer participation contract. This provision gives the utility the right to control any participant's load when system reliability is at risk. This will allow the utility to use the system to provide emergency equivalent generation capacity for reliability purposes, i.e., avoidance of rolling blackouts. It is assumed that during emergency dispatch conditions, customers would be compensated at their chosen sell prices even if the actual spot market price of energy were below that level. Otherwise, customer compensation would be calculated according to the standard contract terms. It is theoretically possible that a system emergency could occur outside of high price conditions. The utility needs to have a mechanism for compensating participants under these conditions.

Actual customer compensation is based on payment to the customer of a value that is less than or equal to the cost of purchasing the same amount of energy and capacity on the spot market. The total annual compensation a customer can expect is based on the number of hours during which load control is dispatched during the season; the customer receives compensation for each hour of control. Compensation is planned to vary as the spot market price of electricity changes. In this specific example, the payment price would only change by increments on a specific schedule. In other words, the compensation price remains the same as long as the spot market price remains within a given spread and then steps up (or down) to the next level as the spot market reaches the next identified range of prices.

An example of this program design might be as follows: A customer chooses a sell price of $100/MWh. Once the spot market energy prices reaches $100/MWh, the customer's compensation is a flat $0.10/ control hour until spot market energy prices reach $250/MWh. At that point, the customer's compensation will rise to $0.25/control hour, and so on as certain pre-specified price break points are reached. In an actual design, the changes could follow some predictable algorithm that would automatically adjust the compensation / retained value according to desired program financial goals and customer acceptance. It is important to note that this is only one example scenario for the purposes of explaining the basic concept of this program in this document. Many other “profit sharing” designs could be developed that might be even more attractive to the customer.

A typical “price duration” curve has been used to demonstrate how the financial model works. The forward price curve listed below is real but may not represent a particular market area; a forward price curve for the specific market of interest must be used when the program is actually deployed. These data represent a 10-year average, rounded to hours. For convenience, the table only shows the cumulative total number of hours at specific price breaks. This format was used to simplify the illustration. In actuality, prices would be forecasted for each hour in which there was a price change (a true forward price curve). The following example is for summer months only.

Price per hour	# Hours at or above that Price per Yr.
Option A: $100/MWh and higher	440
Option B: $150/MWh and higher	348
Option C: $250/MWh and higher	292
Option D: $500/MWh and higher	130
Option E: $1,000/MWh and higher	52

Because customer compensation is based on the sell price, the number of hours that the spot price of energy is at or above the sell price will equal the number of hours of control the customer’s load would be controlled. In the example year above, if a customer chooses a sell price of $100/MWh, the customer would experience a predicted 440 hours of load control per year.

Customer #1, Option A:

Customer Selected Sell Price:$100/MWh
Customer Impacts:

a. Number of control hours: 440 (the total number of hours that the price is expected to equal or exceed $100/MWh).
b. Compensation would be calculated as follows:

Customer Option	Sell Price	# Hours of Control / Yr.	$ Per year @ Sell Price	Total $ / Yr. of Customer Benefit

A	$100/MWh	440	(440-348) 92 (92X$.1) **$9.20**	($9.20+$8.40+$40.50 +$39.00+$52.00 =) **$149.10/Yr.** $0.34/Hr. of control
B	$150/MWh	348	(348-292) 56 (56X$.15) **$8.40**	($8.40+$40.50+$39.00 +$52.00=) **$139.90/Yr**. $0.40/Hr. of control
C	$250/MWh	292	(292-130) 162 (162X$.25) **$40.50**	($40.50+$39.00 +$52.00=) **$131.50/Yr**. $0.45/Hr. of control
D	$500/MWh	130	(130-52) 78 (78X$.50) **$39.00**	($39.00+$52.00=) **$91.00/Yr.** $0.71/Hr. of control
E	$1000/MWh	52	**$52.00**	**$52/Yr**. $1.00/Hr. of control

As can be seen by this chart, the option that requires the most control activity, Option A, provides the highest annual payment. This is only one example. The actual compensation could be set up to be lower if market research indicates sufficient customer participation could be elicited with lower numbers. Another compensation design could simply offer one sell price but include different kW contributions, e.g., 0.5 kW, 1 kW, and 1.5 kW. The intent of creating sell price or kW options is to give customers multiple participation options to match various comfort requirements. In these two examples, the sell price options vary the number of control hours whereas in the multiple kW option scenario, the customer can choose a lower (or higher) kW value to match economic rewards with comfort preferences (the lower the kW contribution, the smaller the comfort impacts). Other variations are also possible with different sell price break points combined with variable load reduction contributions. The fundamental concept remains the same – match customer compensation to the load reduction market value.

The cash flow to the utility, which could be used to offset the actual cost of installing and operating the program, is intended to come from the difference between the sell prices and actual spot market energy prices. If, for example, the customer has chosen a $100/MWh sell price and the actual spot market price is $140/MWh, the utility would accrue $40/MWh in net financial benefits. As these benefits accumulate, they can be used to offset the capital or operations and maintenance costs of the system. If the load management system cost will be considered an "expense," it is easier to simply trade these costs off against each other. It is important to note that this is only an example to demonstrate the concept. In an actual program design, the utility probably would not keep the entire difference between the customer's sell price and the market price. A more likely scenario would probably have the utility sharing this "profit" with the customer according to a ratio established based on results of market or other research.

An example of the positive cash flow to the utility is described below. This example assumes that the number of hours between each break point are linearly distributed. The total number of control events per price range was arbitrarily limited to 50.

For an Option A customer ($100/MWh Sell Price):

Spot Price	**#Control Hours (1)**	**Average Hrs./event (2)**	**Price Change per Event (2)**	**Net Profit/Yr. (4)**
$100-$150	92	1.84 Hr.	$1.00	$2.254
$150-$250	56	1.12 Hrs.	$2.00	$2.744
$250-$500	162	3.24Hrs.	$5.00	$19.845
$500-$1,000	78	1.56Hrs.	$10.00	$19.11
$1,000-$2,000	52	1.04Hrs.	$20.00	$13.2496
Total Profit per Customer A per Year				**$57.20**

1. The number of control hours is derived from the price-duration statistics.

2. The average number of hours per event is equal to the number of hours when energy is forecasted to be at that price divided by the number of events, which was arbitrarily set at 50. The $/MWh price change per event within that price range was assumed to be linear. For example, the price range ($100-150/MWh) is equal to 92 control hours/50 events = 1.84 Hrs/per event; for 50 events spread over a $50 price change, this corresponds to a price change of $1/per event. The second price range ($150-250/MWh) has an average number of control hours per event of 1.12. The price change per event was arbitrarily set at $2 / MWh.

3. The range of prices for the $1,000+ price range was arbitrarily set between $1,000 and $2,000.

4. Net profit is determined by multiplying the number of hours that the actual price is above the sell price. For example, the first load control takes place for the price spread of $100 - $150. The number of hours per event is 1.84. The net profit during the second control event is forecast to be 1.84 hours X (1.10 – 1.00) = $0.00184.

c. Customer Delivery

Delivery of the new Customer Choice Load Management Program will have to be simplified so that participants can understand its basic components. (For example, the references to options trading terminology used for explanatory purposes in this document should probably not be part of the program's general marketing strategy.) We assume that the delivery strategy will focus primarily on the issues that have made all load management programs popular: the opportunity for customers to reduce their electricity costs, and the positive environmental effects and cost savings of not building generation and / or transmission, and distribution facilities that can be avoided.

As mentioned previously, a key advantage of this program design is that the customer is rewarded each time the program is dispatched. This scenario creates the exact opposite relationship between the customer and its operation (control) as was true in old-style programs where the customer's hope was that s/he would never be controlled. There was no linkage between the program's operation and the customers' opportunity to save money. As a result, customers' satisfaction with the program was greatly influenced by the frequency and/or duration of load control events. With the new program design, customers will learn to associate control with a savings opportunity.

Opt-Out Options:

The new Customer Choice Load Management program will give each customer the option of choosing not to participate in the program's operation on any particular day. The technology exists in all modern DLC systems to disable control on a customer-specific basis. This option is critical to the long-term success of the program, because it will help eliminate the customers' perception that they do not have control over the program's impact on them. Advanced technology options such as web-based thermostats inherently allow customers to initiate overrides and document all changes. DLC requires an automated customer interface system, so that customers can enter their "opt-out" requests. Because a large portion of the population has not embraced the internet as an acceptable tool for this kind of transaction, it is anticipated that both an internet and a normal customer call center interface will need to be available. An automated voice response unit could help limit the impact of opt-out calls on call center staff.

Benefit Options:

The new program will also offer benefit tiers (described above as strike or sell price options). As customers become accustomed to load management and its comfort impacts, some program participants will likely choose to change their participation levels or schedules. For purposes of this document, we assume that the participation levels correspond to the sell prices described above and will be presented to customers in terms of annual savings opportunities derived from the forward price curves currently in effect. It will be necessary to communicate to customers, at least on an annual basis, what their opportunities are for all of the available schedules. For this document, Schedules are identified as A-D, with Schedule A corresponding to the Option A sell or strike price described above, and so on. History has shown that the so-called "forward curve" for the future price / duration of energy purchases can be very dynamic. Changing forecasts for prices need to be communicated to customers as often as possible so that the utility can manage customer expectations. Customer earnings per control will not change in relation to price changes, but the frequency with which the load management system is dispatched could change significantly from year to year, which directly affects customers' overall annual savings opportunities. We assume that program participants would receive price forecast information via means such as a dedicated website and direct mailings.

Comfort Impacts:

Another major difference between the new Customer Choice Load Management program and previous load management programs is the impact on customers. The new Customer Choice program is specifically designed to deliver 1 kW of load reduction from each customer regardless of temperature, time of day, or month of the year. This dynamic control strategy will contribute significantly to managing, predicting, and maintaining customer comfort impacts.

Traditional load management programs and air conditioner cycling programs are marketed and operated on a duty-cycle basis, i.e., the customer signs up for a maximum interruption period per unit time base, usually 30 minutes. For example, a 50% duty cycle choice means the customer selects a control strategy that interrupts their air conditioning system for 15 minutes of each half hour. The difficulty with this method of load control is that it has no “auto correct” mechanism for overcontrol. Overcontrol is defined as the customer giving up more cooling capacity (kWs) than the program has been rated for. When the actual temperature is above the normal high temperature for which the program is rated (its “name plate” rating, e.g., 1 kW @ 92º F), the program is actually delivering more load reduction than its “name plate” value; a temperature of 98º F may deliver 1.5 kW at the same duty cycle. Overcontrol may seem like an advantage to the utility, which is receiving more than it is paying for. However, overcontrol can have a profoundly negative impact on customer comfort, because the extra kWs delivered to the utility equate to a cooling shortage for the customer. The more kWs shed, the greater the customer’s discomfort. The Customer Choice Load Management program can significantly improve the predictability of customer comfort impacts, which has been one of the greatest challenges that traditional load management programs have encountered, by maintaining a steady 1-kW load reduction regardless of weather and time-of-day conditions.

Another way to understand how traditional load management programs have run afoul of customer comfort preferences is that most of these programs are rated in terms of how much load reduction they can deliver. This rating is determined by measuring the load reduction that can be delivered for one hour (e.g., 4-5 PM) at one temperature (e.g., 92 degrees) in one month (e.g., August). This value becomes the program’s “name plate” rating; e.g., using the example above, the program can deliver 250 MWs. However, the actual load reduction will vary widely depending on the time of day, actual temperature, and month of the year. As load reduction varies, so does customer comfort.

It is important to note that most, if not all, contemporary load management systems are capable of implementing the new control strategy proposed for the Customer Choice program if the software that manages the system is modified appropriately. The Load Control Receiver (LCR) does not need to be modified if it is of recent vintage.

Customer comfort impacts could also be managed with increasing accuracy by aggressive marketing of the web-based thermostat option. As this technology is deployed, a close correlation will develop between load reduction and thermostat-based control methods and their resulting temperature changes, which will allow the customer to know, in advance, what temperature impacts are likely to be during a control event. As load research is performed and customer comfort data are retrieved from individual thermostats, customer comfort impact predictions and load reductions can begin to be matched very accurately, permitting the utility to closely manage customer expectations. This is one of the major benefits of deploying this technology – the accurate prediction of impacts on a customer-specific basis. For conventional DLC, load reduction is a statistically based, average value delivered from the entire population of participants. Although the utility can depend on the load reduction through its understanding of the characteristics of this diversified load, some customers provide more load reduction than others and therefore suffer more comfort impacts. This situation is inherent to conventional DLC systems.

The Adaptive Duty Cycler control algorithm described earlier in this document is an attempt to help mitigate this inherent limitation of conventional DLC. Use of this algorithm to date has resulted in increased load reduction by decreasing the number of “free riders” (customers who don’t actually contribute load reduction). As noted above, because this algorithm is somewhat dependent on knowledge of the historical run patterns of the air conditioning units to which it is applied, it is vulnerable to unanticipated customer intervention. This could exacerbate the customer comfort impacts (even though the load reduction it delivers might be significantly superior to that provided by conventional duty cycling methods.) Although the adaptive duty cycling concept has been part of DLC product designs for many years, it is just now starting to be deployed in significant numbers. Thus, the concept needs to be closely evaluated, as implemented by each vendor, to determine its effect on load reduction and customer comfort.

Air Conditioning Checkup:

A very important part of the new Customer Choice Load Management program is the regular air conditioning system checkup. This preventative maintenance program has two primary purposes: 1) it is an incentive for customer participation, and 2) it avoids what has been a major reason for failure of one-way DLC programs – disconnection of the equipment involved, which often happens during routine maintenance or service calls.

It is anticipated this benefit will be a major tool for soliciting customer participation. Although it is not a cash credit, it offers the customer a service of value, which the utility may well be able to contract to provide for less than the market cost. The utility could administer the air conditioner inspection directly or could offer vouchers that would allow the customer to select from a list of contractors certified by the utility as qualified to perform the service.

The utility and customer both benefit from an air conditioning system that is in good condition, providing optimum comfort and load reduction. In addition, the regular checkups insure that the equipment is appropriately connected to provide load reduction under the terms of the program.

Some load management technologies have two-way designs, which might permit the utility to offer less frequent air conditioning system checkups. However, two-way systems are not foolproof. Web-based thermostat options include both one-way and two-way designs. One-way options would still require regular onsite checkups, but the two-way design might be able to detect some forms of equipment disconnection. These two technology choices should be evaluated for their respective vulnerability to unauthorized disconnections.

In general, the failure rate of conventional DLC equipment is very low. The relative maturity of the products and their long history of deployment for this application are both reasons for their reliable performance.

d. Technology and Load Reduction

Technology Options

Direct Load Control (DLC):

The Customer Choice Load Management program is technology neutral. The only requirement for program success is the delivery of 1 kW of load reduction to the electricity grid when the customer's selected participation level is reached. The choice of DLC as the base technology is intended to demonstrate that a control system that does not require real-time customer intervention could be deployed in a cost-effective manner. This technology is intended to provide a basic mechanism for the mass market to participate in a power-sharing / selling service. Historically, the mass market has been excluded from these types of programs, because it was assumed the technology that would be required to permit mass-market customers to participate would be prohibitively expensive. Systems have been designed that require installation of customer "gateways," which are intelligent home automation systems that react to real-time information provided from an external communications infrastructure. These systems involve establishing a local area network (LAN) to provide the communications and control (of the air conditioning system, etc.) necessary for customer participation in the program.

The architecture of a DLC system is the inverse of gateway systems. DLC systems have a master station / head end that is centrally located rather than distributed to each customer, and no real-time interaction is required. The only communications with the customer are for selecting or changing the customer's level of participation. The utility can spread the cost of the single DLC master station over all program participants; and the DLC receiver is relatively inexpensive, which makes this a very low-cost method of implementing customer responses to the dynamic price changes of the electricity market.

Although DLC technology is not the most glamorous technology available, it was chosen as the base technology for this example so that the program would have the most positive benefit / cost analysis possible. This technology should allow mass-market customers who do not want to invest in sophisticated technology to participate cost effectively in the market.

The specifications for a DLC system were described in *A Case Study Review of Technical and Technology Issues for Transition of a Utility Load Management Program to Provide System Reliability Services in Restructured Electricity Markets* (Weller 2001) and will not be repeated here.

To use a new or existing very high frequency (VHF) load management system for the Customer Choice program, some fundamental technological enhancements are necessary. The first is the deployment of a new protocol that will allow for targeted control of the various load groups. A very powerful, hierarchical, customer address scheme will be needed which allows each customer to be individually controlled or grouped with other control groups. Regional / geographic grouping will also be needed to take advantage of transmission and distribution (T&D) efficiency improvements. A second major change involves deployment of new solid-state radio transmitters that can encode the new protocol described above as well as implementation of simulcast broadcasting. The simulcast capability will at least triple the amount of information that can be delivered with this system in contrast to what is possible with traditional designs. The combination of these changes will increase the data throughput, so that it can easily support the new program. Without these changes, the utility will have to move away from any existing load management technology and build a completely new system or lease airtime from available public paging systems. Even though those systems are generally available and offer some advantages over conventional VHF systems, it is preferable to rely on an internally owned system. Another major advantage of the current frequency band (VHF) is that it permits the utility to use the least expensive DLC receiver option. More expensive (900-MHz) DLC receivers can cost 50 to 100% more than conventional VHF equipment.

Web-Based Thermostat Control Technologies:

Several web-based thermostat control technologies could be employed to enhance customer participation in the Customer Choice Load Management program. Some of these systems are one way; others offer a two-way communications option. The two-way option should be seriously considered. It permits the utility to monitor the performance of the customer's air conditioning unit, which will be beneficial in determining the customer's actual load reduction as well as maintenance issues that develop for each unit. All of the web-based thermostat solutions offer an option for programming via the internet. The benefit of using the internet is that the interface can be more user friendly method than the interfaces of on-site programmable thermostats, which can be as difficult to program as Video Cassette Recorders. The web interface should be self explanatory and intuitive so that it will not require detailed user instructions. Web-based thermostats are also solid-state thermostats that automatically deliver energy savings to the customer. These high-tech thermostats provide both a more accurate temperature setting and eliminate excessive temperature swings (hysteresis) typically found with low-cost, electromechanical thermostats that are usually part of original air conditioner installations.

An example of a web-based thermostat solution is given below to demonstrate the architecture of this type of system.

Carrier ComfortChoice two-way web-based thermostat:

The Carrier ComfortChoice program programmable thermostat is customer enabled using a web interface package provided by Silicon Energy or at the thermostat itself. The thermostat is a fully programmable Carrier EMi thermostat that uses the SkyTel two-way paging infrastructure two-way communication interface. An alternate interface system uses a combination of one-way paging and standard telephone -- provided in this example is by emWare's Power Save. The system diagram for the emWare solution is shown below in Figure 1. An alternative to the two-way SkyTel solution is needed because the two-way portion of that network is still under construction and therefore has limited availability.

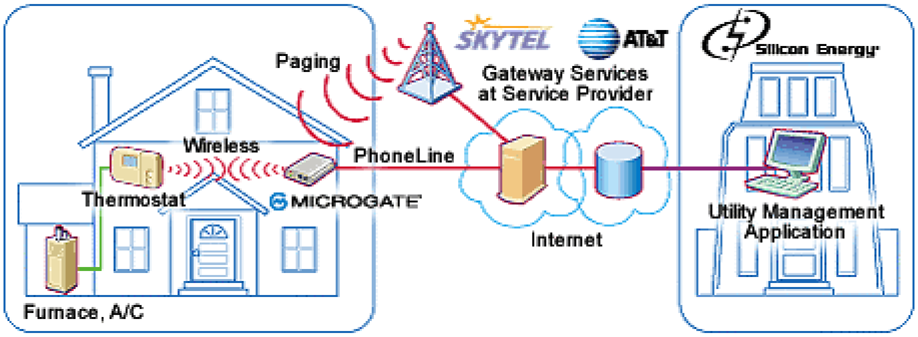

Figure 1 - Power Save System (emWare)

A two-way interface provides information about thermostat set points, and more specifically, whether a customer has overridden a control event. ComfortChoice uses the override feedback to determine how much load reduction is available rather than monitoring actual load reduction itself. Load research determines predicted system performance, and override data are used to "de-rate" the system's performance on any particular day. This innovative approach to performance monitoring goes a long way toward customer performance verification but does not eliminate the fact that each customer's load reduction will vary. The use of a two-way system needs to be closely evaluated to determine whether the improved monitoring it provides justifies the increased cost over a one-way web-based thermostat solution.

The physical installation of the EMi thermostat in a two-way SkyTel implementation includes installation of an external "controller box" near the air handler / circulating fan (the box controls the actual operation of the air conditioning system as well as the two-way SkyTel RF interface).

The physical installation of the emWare solution involves the installation of a MicroGate, which handles the interface with the two wide-area networks (customer-shared telephone and one-way paging network), as well as, the creation of a two-way RF LAN for communicating with the EMi thermostat. The creation of this LAN offers the opportunity to include future applications such as AMR and water heater control. The temperature setback command is broadcast to the MicroGate, which relays that information via the RF LAN to the EMi thermostat. The telephone interface is non-intrusive, and the customer is not interrupted.

General Notes:

- The thermostat is controlled by either a temperature setback or duty cycle.
- A "non-override" option is provided.
- Tamper Detection is handled by the transmission of a "heartbeat" back to the utility once a week. Device status reports are also available.
- The thermostat activity data are stored for seven days. These data typically include parameters such as cooling / heating run time per hour and number of starts.
- SkyTel restore services to their transmitters within four days; current average is two days. SkyTel claims 99.9% availability, which translates to 8.76 hours of downtime per year.

Both technology options are intended to be deployed without the use of AMR systems. An AMR system would be ideal for the implementation of an RTP program where the customer's benefit is based on the exact amount of load reduction the customer provides when energy prices are high. Deployment of AMR has, however, been slow because utilities have had difficulty quantifying the strategic and operational benefits that are derived from the system. The concrete benefits of AMR (fewer meter readers, greater accuracy of readings) generally do not, by themselves, justify the cost of deployment. Therefore, we designed the Customer Choice program so that it did not depend on an AMR system. However, an AMR system would address most of the inaccuracies associated with the DLC system that we describe. In other words, AMR complements DLC. An AMR system would immediately allow customer-specific performance monitoring as well as monitoring of the performance of the load management equipment (the latter function requires a specific type of AMR system).

Load Reduction Delivery:

The Customer Choice program is designed to deliver 1 kW of load reduction from each customer (on average) during system emergencies and when the market price for electricity matches the sell price selected by each program participant. In the early days of the program, traditional load research techniques will be used to verify load reductions. It is suggested that the utility build an empirically based "Time / Temperature" matrix that should, over time, predict with increasing accuracy the required air conditioning control actions needed to deliver the desired 1 kW of load reduction. The "Time / Temperature" matrix would correlate air conditioning duty cycle with time of day, temperature, and month of the year for each hour of the load management "season." A complete year's worth of data could be developed to provide emergency load relief information outside of the load management season. Generally, the load management season will probably correspond to the months of the year during which load reduction is available. Using the "Time / Temperature" matrix, the utility could dispatch the proper duty cycle of control that delivers the desired 1 kW of load reduction. For the Customer Choice program, real-time, geographically specific outside air temperature must be available to adjust the duty cycle so that over- and under-control can be avoided during each specific hour.

If interval-based AMR equipment were available, there would be no need to create a statistically based load performance model. However, because AMR equipment is not available in most areas of the U.S. at this time, the two-way thermostat system is an alternative that offers some customer-specific, more or less real-time information about air conditioning system performance. Even though the thermostat records air conditioner run time (rather than energy use), this information can help the utility calculate the load reduction achieved from control activities and will also help the utility monitor the general performance of the air conditioning system.

Load management for West Coast utilities poses unique problems that are generally not an issue in other service areas. These problems stem from the climate: on the coast, summer weather is very comfortable, but the climate a few miles inland is much hotter. The time-temperature matrix described above is therefore necessary to address differences in climate zones throughout the utility service area. Each climate zone should have relatively homogeneous weather characteristics. This zoning of customers is absolutely necessary for this program to succeed. For customer comfort, load control of air conditioning systems must be dispatched according to actual local conditions, not a system average, which would be too hot for the coast and too cold inland. Zoning is also imperative for cost-effective customer compensation; if the weather in a particular zone means that little or no load reduction can be achieved in that zone, it is not sensible from an economic point of view to control the air conditioning systems of customers in that zone. Only climate zones where predicted load reduction is sufficient would be able to participate in each load reduction event (which, from the customer's perspective, is a sales opportunity). Thus, Customer Choice load management will actually function as though there are multiple load management systems within the utility service territory; although, this complexity will be invisible to any individual customer.

e. Financial Benefits

General Benefit / Cost Analysis:

Based on cost-benefit data for the example outlined in this document, the program would definitely be cost effective. The annual contribution or retained value delivered from the Option A customer is projected to be $57.20/ year. Because the installation cost for a conventional one-way DLC receiver is approximately $175 (including hardware, installation labor, and marketing / sales costs), that cost would be recovered in a little more than three years (3 x $57.20 = $171.60). Because the retained value also recurs over the life of the program, the Present Value of each of these customer contributions, over a 20-year period, is substantial, as shown below:

<u>Annual Customer Contribution Summary (See Appendix)</u>

Customer Option A	$57.20
Customer Option B	$54.46
Customer Option C	$51.71
Customer Option D	$31.87
Customer Option E	$12.76

<u>Present Value of Cash Flow (20 years, 7%) (See Appendix)</u>

Option A	$605.98
Option B	$576.95
Option C	$547.82
Option D	$337.63
Option E	$135.18

This summary shows that all options except E, more than cover the cost of installation and most likely also the operations and maintenance associated with installation. As long as the utility can tailor this installation as an asset for reliability purposes, the program should have a very low net cost.

For an annual air conditioner checkup and a general operations and maintenance, expenses are summarized as follows:
Present Value of Annual Air Conditioner Checkup (worst case) and Administrative Cost = $582.67 ($50/Yr. air conditioner Checkup Cost plus $5/Yr. General operations and maintenance).

Present Value of Cost Per Customer = $757.67, includes:

- $175/customer installation cost
- $50/yr. air conditioning tune-up cost
- $5/yr. general operations and maintenance

Comparing the present value of the cost per customer ($757.67) to the present value delivered by an Option A customer ($605.98), we see that an Option A customer almost covers their costs simply from the retained value portion of the program. This scenario does not include benefits for providing added system operating reserves or increased overall system reliability, nor does it take into account the societal benefits of reduced energy generation, which are the primary benefits traditionally used to justify load management programs. Once these traditional benefits are added to the "retained value" benefits just described, the overall cost effectiveness of this load management program design should be very significant.

The general discussion presented here is not a comprehensive benefit / cost analysis; it is offered to give insight into some of the present worth of investments in the proposed load management program. A more complete analysis would include some industry-standard economic assessment model such as DSManager. However,it is difficult to reflect all of the benefits mentioned above in models like DSManager, so it is prudent to consider them separately. Another significant benefit that will be discussed below involves targeted transmission and distribution impacts, which could significantly increase the value of installations that capture these benefits.

Even though the financial value of the ancillary services described below is dynamic in nature, economic values must be established in order to maximize the benefits from deployment. It is assumed that the cost to operate the load management program will be insignificant with respect to the value it provides in the form of load relief during system emergencies / disturbances. That is, it is highly likely that customer-selected prices at which to sell their load reduction to the system (strike prices) will be less than or equal to spot-market energy prices in case of an emergency. However, if a less expensively ancillary service can be provided elsewhere, the less expensive option should be purchased.

Ancillary Services:

Load management programs can, if suitably modified, provide other ancillary services, such as load following, voltage control, various forms of reserves, etc. The benefits of using existing load management programs to provide these services is analyzed in an earlier report (Weller 2001).

Transmission & Distribution Benefits:

The basic premise for using load management to provide a T&D system benefit is that the program could be targeted at T&D construction projects which are being built primarily for reliability purposes. These projects are sometimes classified as "Contingency" projects, because their primary purpose is to see the system through unusual loads or unexpected system outages. They are typically associated with substations and transmission lines and are almost by definition not profitable investments, because they provide capacity that is only used in emergencies and therefore does not materially affect the utility's ability to increase sales and / or revenues.

An example of a contingency project would be increasing the capacity of substation transformers, which are often sized so that, if one transformer fails, the remaining transformer can pick up the load and maintain service while the failed unit is being repaired. The margin between the capacity of the transformer and its emergency burden is determined by planning standards that have been derived over many years of designing and managing the T&D system. At some point, however, the load on a substation will grow to the point that it exceeds the ability of the remaining transformer(s) to provide back-up if one transformer fails. At this point, T&D planners must increase the capacity of the substation transformer system – unless the utility has another option for compensating for lost transformer capacity. Load Management installations targeted at customers being served from a substation that can no longer provide its own emergency back-up capacity could be used to reduce demand on that substation in case of a transformer outage. With demand reduced, the remaining transformer(s) could continue serving the remaining load on the substation. This is an ideal application for load management, because it defers unprofitable T&D investments. This use of load management can also help extend the life of transformers by reducing the frequency and duration of over-loading.

Load management may or may not be able to match the costs of new T&D. However, T&D engineering departments have worked diligently to reduce the cost of adding capacity to the T&D system – and have succeeded, so that an additional 10.5 MVA of substation power transformer capacity that could have cost more than $1,000,000 in the past now costs only $650,000. This translates to $62 / kW of installed capacity, a very low cost in comparison to the $175 / kW of implementing load management, which does not include operations and maintenance and incentives. Considering this cost comparison for the example cited, , it is obvious that load management would only result in a financial advantage, if it is deployed first for its generation benefit, and secondarily, for its T&D benefits.

Examples of Load Management Applications to Defer T&D Improvements.

Commercial applications of load management can defer T&D projects. For example, load management could have an immediate impact in a downtown area served by "network service" that has for many years been on the list for a capacity addition but has barely missed being included in each year's T&D budget. The addition would be very costly and would not generate much new revenue because of the relatively low growth rate in the area. Use of load management to defer this capacity addition for even a few years would have a significant positive impact on the utility's construction budget. Considering the relatively slow load growth in the area in question, use of load management could actually defer construction until the facilities naturally needed replacement because of age or deterioration. This application of load management would require the utility to focus on commercial customers and require the development of a C&I version of the Customer Choice Load Management program.

A typical residential application of load management could be in the "old core" area of a city that is primarily served by a very old four-kilovolt (kV) distribution system. The old circuits may be pushing the limits of their transformer ratings and are beginning to be upgraded to 12-kV systems. If there were a substantial air conditioner load in that area, load management would be an attractive option.

Load management could also be marketed in a new and developing suburban service area adjacent to a large metropolitan city. These suburbs could be growing from 10 to 20% per year with mostly new construction, which would be ideal for load management and web-based thermostat applications. The additional annual distribution capacity that would be required to serve load growth in this area could be as much as 30 MW / year, which could be avoided through load management.

Close coordination between load management programs and a utility’s T&D planning group could take advantage of dual benefit opportunities. However, it appears the cost of targeting T&D applications for load management would only be justified when there is a generation benefit available to combine with the load management investment. Because the Customer Choice Load Management program has been designed to automatically accommodate a T&D need, the program should perform for both system needs, as required by electrical service conditions, as long as the customers don’t feel “over controlled” by both the generation and T&D applications. (It would be ideal from the customer perspective if T&D system load reduction requirements were simultaneous with economic dispatch for generation). The actual T&D benefits that can be attributed to the load management program would have to be determined on a case-by-case basis.

IV. Next Steps

We recommend a team or task force be created at the state and / or federal level to continue development of the Customer Choice Load Management program proposed in this document. The task force could elaborate the program design to the point where a pilot or demonstration project could be undertaken to validate the program's performance, actual costs, and customer acceptance.

We also recommend testing the suggested modifications to existing SCE programs. For existing SCE programs, modifications that do not require tariff changes should be tested first. This is important, because some of the concepts associated with the Customer Choice Load Management program can also be tested, e.g., modification of duty cycle as a function of temperature, climate zones, etc.

We recommend that an audience be found at the state and / or federal regulatory level for the fundamental concepts associated with the Customer Choice Load Management program. The inclusion of regulatory stakeholders at the beginning of development of a load management program is critical, especially in the California market where utilities are struggling to determine their roles in the deployment of such systems. If an audience could be assembled that included the power purchase staff of the DWR, we could specifically address the economics of delivering cost-effective ancillary services to the California market using load management in contrast to traditional generation resources. The context should be statewide, because any utility can benefit from the program.

References

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Appendix

A. Customer Choice Load Management

1. Customer Compensation & Utility Profit Spreadsheets

$100 - $150 / MWh

Price Range for 50 event prices	Event#	Price	# hours/event	Customer Compensation	Net Profit to Utility
$100-$150 (92 hours of purchase)	1	$0.100	1.84	$0.18400	$0.00000
	2	$0.101	1.84	$0.18400	$0.00184
	3	$0.102	1.84	$0.18400	$0.00368
	4	$0.103	1.84	$0.18400	$0.00552
	5	$0.104	1.84	$0.18400	$0.00736
	6	$0.105	1.84	$0.18400	$0.00920
	7	$0.106	1.84	$0.18400	$0.01104
	8	$0.107	1.84	$0.18400	$0.01288
	9	$0.108	1.84	$0.18400	$0.01472
	10	$0.109	1.84	$0.18400	$0.01656
	11	$0.110	1.84	$0.18400	$0.01840
	12	$0.111	1.84	$0.18400	$0.02024
	13	$0.112	1.84	$0.18400	$0.02208
	14	$0.113	1.84	$0.18400	$0.02392
	15	$0.114	1.84	$0.18400	$0.02576
	16	$0.115	1.84	$0.18400	$0.02760
	17	$0.116	1.84	$0.18400	$0.02944
	18	$0.117	1.84	$0.18400	$0.03128
	19	$0.118	1.84	$0.18400	$0.03312
	20	$0.119	1.84	$0.18400	$0.03496
	21	$0.120	1.84	$0.18400	$0.03680
	22	$0.121	1.84	$0.18400	$0.03864
	23	$0.122	1.84	$0.18400	$0.04048
	24	$0.123	1.84	$0.18400	$0.04232
	25	$0.124	1.84	$0.18400	$0.04416
	26	$0.125	1.84	$0.18400	$0.04600
	27	$0.126	1.84	$0.18400	$0.04784
	28	$0.127	1.84	$0.18400	$0.04968
	29	$0.128	1.84	$0.18400	$0.05152
	30	$0.129	1.84	$0.18400	$0.05336
	31	$0.130	1.84	$0.18400	$0.05520
	32	$0.131	1.84	$0.18400	$0.05704
	33	$0.132	1.84	$0.18400	$0.05888
	34	$0.133	1.84	$0.18400	$0.06072
	35	$0.134	1.84	$0.18400	$0.06256
	36	$0.135	1.84	$0.18400	$0.06440
	37	$0.136	1.84	$0.18400	$0.06624
	38	$0.137	1.84	$0.18400	$0.06808
	39	$0.138	1.84	$0.18400	$0.06992
	40	$0.139	1.84	$0.18400	$0.07176
	41	$0.140	1.84	$0.18400	$0.07360
	42	$0.141	1.84	$0.18400	$0.07544
	43	$0.142	1.84	$0.18400	$0.07728
	44	$0.143	1.84	$0.18400	$0.07912
	45	$0.144	1.84	$0.18400	$0.08096
	46	$0.145	1.84	$0.18400	$0.08280
	47	$0.146	1.84	$0.18400	$0.08464
	48	$0.147	1.84	$0.18400	$0.08648
	49	$0.148	1.84	$0.18400	$0.08832
	50	$0.149	1.84	$0.18400	$0.09016
Per Customer Compensation				**$9.20000**	
Net Profit to Utility Per Customer					**$2.25400**

$150 - $250 / MWh

Price Range for 50 event prices	Event#	Price	# hours/event	Customer Compensation	Net Profit to Utility
$150-$250 (56 hours of purchase)	1	$0.150	1.12	$0.16800	$0.00000
	2	$0.152	1.12	$0.16800	$0.00224
	3	$0.154	1.12	$0.16800	$0.00448
	4	$0.156	1.12	$0.16800	$0.00672
	5	$0.158	1.12	$0.16800	$0.00896
	6	$0.160	1.12	$0.16800	$0.01120
	7	$0.162	1.12	$0.16800	$0.01344
	8	$0.164	1.12	$0.16800	$0.01568
	9	$0.166	1.12	$0.16800	$0.01792
	10	$0.168	1.12	$0.16800	$0.02016
	11	$0.170	1.12	$0.16800	$0.02240
	12	$0.172	1.12	$0.16800	$0.02464
	13	$0.174	1.12	$0.16800	$0.02688
	14	$0.176	1.12	$0.16800	$0.02912
	15	$0.178	1.12	$0.16800	$0.03136
	16	$0.180	1.12	$0.16800	$0.03360
	17	$0.182	1.12	$0.16800	$0.03584
	18	$0.184	1.12	$0.16800	$0.03808
	19	$0.186	1.12	$0.16800	$0.04032
	20	$0.188	1.12	$0.16800	$0.04256
	21	$0.190	1.12	$0.16800	$0.04480
	22	$0.192	1.12	$0.16800	$0.04704
	23	$0.194	1.12	$0.16800	$0.04928
	24	$0.196	1.12	$0.16800	$0.05152
	25	$0.198	1.12	$0.16800	$0.05376
	26	$0.200	1.12	$0.16800	$0.05600
	27	$0.202	1.12	$0.16800	$0.05824
	28	$0.204	1.12	$0.16800	$0.06048
	29	$0.206	1.12	$0.16800	$0.06272
	30	$0.208	1.12	$0.16800	$0.06496
	31	$0.210	1.12	$0.16800	$0.06720
	32	$0.212	1.12	$0.16800	$0.06944
	33	$0.214	1.12	$0.16800	$0.07168
	34	$0.216	1.12	$0.16800	$0.07392
	35	$0.218	1.12	$0.16800	$0.07616
	36	$0.220	1.12	$0.16800	$0.07840
	37	$0.222	1.12	$0.16800	$0.08064
	38	$0.224	1.12	$0.16800	$0.08288
	39	$0.226	1.12	$0.16800	$0.08512
	40	$0.228	1.12	$0.16800	$0.08736
	41	$0.230	1.12	$0.16800	$0.08960
	42	$0.232	1.12	$0.16800	$0.09184
	43	$0.234	1.12	$0.16800	$0.09408
	44	$0.236	1.12	$0.16800	$0.09632
	45	$0.238	1.12	$0.16800	$0.09856
	46	$0.240	1.12	$0.16800	$0.10080
	47	$0.242	1.12	$0.16800	$0.10304
	48	$0.244	1.12	$0.16800	$0.10528
	49	$0.246	1.12	$0.16800	$0.10752
	50	$0.248	1.12	$0.16800	$0.10976
Per Customer Compensation				**$8.40000**	
Net Profit to Utility Per Customer					**$2.74400**

$250 - $500 / MWh

Price Range	Event#	Price	# hours/event	Customer Compensation	Net Profit to Utility
$250-$500 (162 hours of purchase)	1	$0.250	3.24	$0.81000	$0.00000
	2	$0.255	3.24	$0.81000	$0.01620
	3	$0.260	3.24	$0.81000	$0.03240
	4	$0.265	3.24	$0.81000	$0.04860
	5	$0.270	3.24	$0.81000	$0.06480
	6	$0.275	3.24	$0.81000	$0.08100
	7	$0.280	3.24	$0.81000	$0.09720
	8	$0.285	3.24	$0.81000	$0.11340
	9	$0.290	3.24	$0.81000	$0.12960
	10	$0.295	3.24	$0.81000	$0.14580
	11	$0.300	3.24	$0.81000	$0.16200
	12	$0.305	3.24	$0.81000	$0.17820
	13	$0.310	3.24	$0.81000	$0.19440
	14	$0.315	3.24	$0.81000	$0.21060
	15	$0.320	3.24	$0.81000	$0.22680
	16	$0.325	3.24	$0.81000	$0.24300
	17	$0.330	3.24	$0.81000	$0.25920
	18	$0.335	3.24	$0.81000	$0.27540
	19	$0.340	3.24	$0.81000	$0.29160
	20	$0.345	3.24	$0.81000	$0.30780
	21	$0.350	3.24	$0.81000	$0.32400
	22	$0.355	3.24	$0.81000	$0.34020
	23	$0.360	3.24	$0.81000	$0.35640
	24	$0.365	3.24	$0.81000	$0.37260
	25	$0.370	3.24	$0.81000	$0.38880
	26	$0.375	3.24	$0.81000	$0.40500
	27	$0.380	3.24	$0.81000	$0.42120
	28	$0.385	3.24	$0.81000	$0.43740
	29	$0.390	3.24	$0.81000	$0.45360
	30	$0.395	3.24	$0.81000	$0.46980
	31	$0.400	3.24	$0.81000	$0.48600
	32	$0.405	3.24	$0.81000	$0.50220
	33	$0.410	3.24	$0.81000	$0.51840
	34	$0.415	3.24	$0.81000	$0.53460
	35	$0.420	3.24	$0.81000	$0.55080
	36	$0.425	3.24	$0.81000	$0.56700
	37	$0.430	3.24	$0.81000	$0.58320
	38	$0.435	3.24	$0.81000	$0.59940
	39	$0.440	3.24	$0.81000	$0.61560
	40	$0.445	3.24	$0.81000	$0.63180
	41	$0.450	3.24	$0.81000	$0.64800
	42	$0.455	3.24	$0.81000	$0.66420
	43	$0.460	3.24	$0.81000	$0.68040
	44	$0.465	3.24	$0.81000	$0.69660
	45	$0.470	3.24	$0.81000	$0.71280
	46	$0.475	3.24	$0.81000	$0.72900
	47	$0.480	3.24	$0.81000	$0.74520
	48	$0.485	3.24	$0.81000	$0.76140
	49	$0.490	3.24	$0.81000	$0.77760
	50	$0.495	3.24	$0.81000	$0.79380
Per Customer Compensation				**$40.50000**	
Net Profit to Utility Per Customer					**$19.84500**

$500 - $1,000 / MWh

Price Range	Event #	Price	# hours/event	Customer Compensation	Net Profit to Utility
$500-$1000	1	$0.500	1.56	$0.78000	$0.00000
	2	$0.510	1.56	$0.78000	$0.01560
	3	$0.520	1.56	$0.78000	$0.03120
	4	$0.530	1.56	$0.78000	$0.04680
	5	$0.540	1.56	$0.78000	$0.06240
	6	$0.550	1.56	$0.78000	$0.07800
	7	$0.560	1.56	$0.78000	$0.09360
	8	$0.570	1.56	$0.78000	$0.10920
	9	$0.580	1.56	$0.78000	$0.12480
	10	$0.590	1.56	$0.78000	$0.14040
	11	$0.600	1.56	$0.78000	$0.15600
	12	$0.610	1.56	$0.78000	$0.17160
	13	$0.620	1.56	$0.78000	$0.18720
	14	$0.630	1.56	$0.78000	$0.20280
	15	$0.640	1.56	$0.78000	$0.21840
	16	$0.650	1.56	$0.78000	$0.23400
	17	$0.660	1.56	$0.78000	$0.24960
	18	$0.670	1.56	$0.78000	$0.26520
	19	$0.680	1.56	$0.78000	$0.28080
	20	$0.690	1.56	$0.78000	$0.29640
	21	$0.700	1.56	$0.78000	$0.31200
	22	$0.710	1.56	$0.78000	$0.32760
	23	$0.720	1.56	$0.78000	$0.34320
	24	$0.730	1.56	$0.78000	$0.35880
	25	$0.740	1.56	$0.78000	$0.37440
	26	$0.750	1.56	$0.78000	$0.39000
	27	$0.760	1.56	$0.78000	$0.40560
	28	$0.770	1.56	$0.78000	$0.42120
	29	$0.780	1.56	$0.78000	$0.43680
	30	$0.790	1.56	$0.78000	$0.45240
	31	$0.800	1.56	$0.78000	$0.46800
	32	$0.810	1.56	$0.78000	$0.48360
	33	$0.820	1.56	$0.78000	$0.49920
	34	$0.830	1.56	$0.78000	$0.51480
	35	$0.840	1.56	$0.78000	$0.53040
	36	$0.850	1.56	$0.78000	$0.54600
	37	$0.860	1.56	$0.78000	$0.56160
	38	$0.870	1.56	$0.78000	$0.57720
	39	$0.880	1.56	$0.78000	$0.59280
	40	$0.890	1.56	$0.78000	$0.60840
	41	$0.900	1.56	$0.78000	$0.62400
	42	$0.910	1.56	$0.78000	$0.63960
	43	$0.920	1.56	$0.78000	$0.65520
	44	$0.930	1.56	$0.78000	$0.67080
	45	$0.940	1.56	$0.78000	$0.68640
	46	$0.950	1.56	$0.78000	$0.70200
	47	$0.960	1.56	$0.78000	$0.71760
	48	$0.970	1.56	$0.78000	$0.73320
	49	$0.980	1.56	$0.78000	$0.74880
	50	$0.990	1.56	$0.78000	$0.76440
Per Customer Compensation				**$39.00000**	
Net Profit to Utility Per Customer					**$19.11000**

$1,000 - $2,000 / MWh

Price Range	Event #	Price	# hours/event	Customer Compensation	Net Profit to Utility
$1000-$2000	1	$1.000	1.04	$1.04000	$0.00000
	2	$1.020	1.04	$1.04000	$0.02080
	3	$1.030	1.04	$1.04000	$0.03120
	4	$1.040	1.04	$1.04000	$0.04160
	5	$1.050	1.04	$1.04000	$0.05200
	6	$1.060	1.04	$1.04000	$0.06240
	7	$1.070	1.04	$1.04000	$0.07280
	8	$1.080	1.04	$1.04000	$0.08320
	9	$1.090	1.04	$1.04000	$0.09360
	10	$1.100	1.04	$1.04000	$0.10400
	11	$1.110	1.04	$1.04000	$0.11440
	12	$1.120	1.04	$1.04000	$0.12480
	13	$1.130	1.04	$1.04000	$0.13520
	14	$1.140	1.04	$1.04000	$0.14560
	15	$1.150	1.04	$1.04000	$0.15600
	16	$1.160	1.04	$1.04000	$0.16640
	17	$1.170	1.04	$1.04000	$0.17680
	18	$1.180	1.04	$1.04000	$0.18720
	19	$1.190	1.04	$1.04000	$0.19760
	20	$1.200	1.04	$1.04000	$0.20800
	21	$1.210	1.04	$1.04000	$0.21840
	22	$1.220	1.04	$1.04000	$0.22880
	23	$1.230	1.04	$1.04000	$0.23920
	24	$1.240	1.04	$1.04000	$0.24960
	25	$1.250	1.04	$1.04000	$0.26000
	26	$1.260	1.04	$1.04000	$0.27040
	27	$1.270	1.04	$1.04000	$0.28080
	28	$1.280	1.04	$1.04000	$0.29120
	29	$1.290	1.04	$1.04000	$0.30160
	30	$1.300	1.04	$1.04000	$0.31200
	31	$1.310	1.04	$1.04000	$0.32240
	32	$1.320	1.04	$1.04000	$0.33280
	33	$1.330	1.04	$1.04000	$0.34320
	34	$1.340	1.04	$1.04000	$0.35360
	35	$1.350	1.04	$1.04000	$0.36400
	36	$1.360	1.04	$1.04000	$0.37440
	37	$1.370	1.04	$1.04000	$0.38480
	38	$1.380	1.04	$1.04000	$0.39520
	39	$1.390	1.04	$1.04000	$0.40560
	40	$1.400	1.04	$1.04000	$0.41600
	41	$1.410	1.04	$1.04000	$0.42640
	42	$1.420	1.04	$1.04000	$0.43680
	43	$1.430	1.04	$1.04000	$0.44720
	44	$1.440	1.04	$1.04000	$0.45760
	45	$1.450	1.04	$1.04000	$0.46800
	46	$1.460	1.04	$1.04000	$0.47840
	47	$1.470	1.04	$1.04000	$0.48880
	48	$1.480	1.04	$1.04000	$0.49920
	49	$1.490	1.04	$1.04000	$0.50960
	50	$1.500	1.04	$1.04000	$0.52000
Per Customer Compensation				**$52.00000**	
Net Profit to Utility Per Customer					**$13.24960**

B. Customer Compensation & Utility Profit

Total Profit Per Customer/Yr.	
$100-150	$2.2540
$150-250	$2.7440
$250-500	$19.8450
$500-1000	$19.1100
$1000-2000	$13.2496
Customer Option A	$57.20
Customer Option B	$54.46
Customer Option C	$51.71
Customer Option D	$31.87
Customer Option E	$12.76
Present Value of Cash Flow (20 years)	
Option A	$605.98
Option B	$576.95
Option C	$547.82
Option D	$337.63
Option E	$135.18
Present Value of Annual Air Cond. Checkup & Administrative Cost ($50/Yr. air conditioner Checkup Cost plus $5/Yr. General O&M)	$582.67
Present Value of Cost Per Customer	$757.67

Annual Customer Compensation per Price Segment	
$100-150	$9.20000
$150-250	$8.40000
$250-500	$40.50000
$500-1000	$39.00000
$1,000-2,000	$52.00000
Annual Total Customer Compensation	
Option A	$149.10000
Option B	$139.90000
Option C	$131.50000
Option D	$91.00000
Option E	$52.00000