DISTRIBUTED ENERGY RESOURCE (DER) IMPLEMENTATION: TESTING IMPLEMENTATION OF A DEMAND-RESPONSE PROGRAM WITHIN A SMALL BUSINESS POPULATION

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
San Francisco Community Power
M. Cubed
Energy and Environmental Economics, Inc.

November 2010
CEC-500-2010-014
Prepared By:
San Francisco Community Power/M. Cubed
Steven J. Moss
James Fine, PhD
San Francisco, CA
Energy and Environmental Economics, Inc.
Snuffer Price
Eric Cutter
San Francisco, CA
Contract No. 500-03-009

Prepared For:
California Energy Commission
Public Interest Energy Research (PIER) Program

Steve Ghadiri
Contract Manager

Linda Kelly
Program Area Team Lead

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Melissa Jones
Executive Director

DISCLAIMER
This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.
Acknowledgements

The project team wishes to acknowledge a number of key individuals without whose assistance this research would not have been a success.

California Energy Commission: Linda Kelly and David Michel.
Lawrence Berkeley Laboratories: Mary Ann Piette.

Please cite this report as follows:
Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission) conducts public interest research, development, and demonstration (RD&D) projects to benefit the electricity and natural gas ratepayers in California. The Energy Commission awards up to $62 million annually in electricity-related RD&D, and up to $12 million annually for natural gas RD&D.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Building End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Environmentally Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration

Distributed Energy Resource (DER) Implementation: Testing Implementation of a Demand-Response Program Within a Small Business Population is the final report for the project (Contract Number 500-03-009) conducted by M. Cubed/San Francisco Community Power, and Energy and Environmental Economics, Inc. for the Energy Commission. The information from this project contributes to PIER’s RD&D program area.

For more information on the PIER Program, please visit the Energy Commission’s website at www.energy.ca.gov/pier or contact the Energy Commission at (916) 654-4878.
# Table of Contents

PREFACE .........................................................................................................................iv  
ABSTRACT .......................................................................................................................ix  
EXECUTIVE SUMMARY .................................................................................................. 1  
1.0 Introduction ................................................................................................................ 7  
   1.1. Project Objectives ............................................................................................... 8  
   1.2. Report Organization .......................................................................................... 8  
2.0 Project Description ..................................................................................................... 9  
   2.1. DR Enrollment ................................................................................................... 12  
   2.2. Demand Response Results ............................................................................... 17  
   2.3. DR Results Interpretation ............................................................................... 26  
   2.4. Potential Biases in DR Findings ........................................................................ 27  
3.0 Cost-Benefit Analysis/Least Cost Curve of Installed DER ....................................... 37  
   3.1. Demand Response Benefit/Cost Analysis ......................................................... 39  
   3.2. Benefits of DR Programs ............................................................................... 39  
4.0 Barriers to Implementation ....................................................................................... 45  
5.0 Key Findings and Recommendations ...................................................................... 49  
   5.1 Community-Based Organizations Can Provide an Effective Approach to Encourage Cost-Effective DR Adoption ................................................................. 50
List of Tables

Table 1. Load reductions segmented by all participants, those that reduced, and those that increased relative to the baseline. ................................................................. 4
Table 2. Active hours for different DR programs ........................................................... 11
Table 3. Demand response enrollees faced significant delays related to meter installation and billing system updates ................................................................. 13
Table 4. Participating meters can be nominated to curtail for different periods ............ 15
Table 5. Initially estimated load reductions for individual sectors ............................... 16
Table 6. Curtailment activity ....................................................................................... 19
Table 7. Summary of curtailment and exceedance cohorts ......................................... 20
Table 8. Summary of hour-specific loads for five curtailment call days and 26 customers ........................................................................................................... 22
Table 9. Questions addressed by the various cost tests .............................................. 38
Table 10. Benefits and costs of various perspectives .................................................. 38
Table 11. Demand response value ............................................................................. 40
Table 12. Demand response value of CBP and DBP DR programs, with T&D benefits 41
Table 13. Cost-benefit analysis of summer 2007 curtailment days ............................. 44
# Table of Figures

Figure 1. Changes in electricity use during the 165 customer days for four-hour curtailment periods on July 3 and 5, and August 29, 30 and 31. ............................... 2
Figure 2. Minimum, maximum, and average performance by customer ............................ 3
Figure 3. California electricity consumption by customer class ........................................ 9
Figure 4. Wait times from application date to participation eligibility among 245 enrolled facilities. ................................................................................................................... 13
Figure 5. Wait times from application date to participation eligibility among 26 facilities that participated in 2007 Energy Alerts. ........................................ 14
Figure 6. Hourly net performance by day ........................................................................... 18
Figure 7. Mean, minimum, and maximum curtailment hours for each month. .................... 19
Figure 8. Histogram of 4-hour load curtailments and increases for 119 customer-days. 21
Figure 9. Histogram of 4-hour load curtailments and increases for 119 customer-days as percentage of baseline................................................................. 22
Figure 10. Excellent performance by an office building during July curtailment calls. .... 23
Figure 11. Excellent performance by an office building during August curtailment calls. 24
Figure 12. Moderate performance by a school during August curtailment calls. ............. 24
Figure 13. Mixed performance by a religious organization during July curtailment calls. 25
Figure 14. Mixed performance by a religious organization during August curtailment calls ......................................................................................................................... 26
Figure 15. Temperature pattern for days prior to curtailment calls on July 3 and 5, 2007. ........................................................................................................... 29
Figure 16. Temperature pattern for curtailment and prior days on August 29, 30, and 31. ......................................................................................................................... 30
Figure 17. August 29 curtailment call trends for 18 customer-days.................................... 32
Figure 18. August 30 curtailment call trends for 18 customer-days.................................. 33
Figure 19. August 31 curtailment call trends for 18 customer-days.................................. 34
Figure 20. Sequence of response by hour for August 29 through August 31 for 17 customer-days. ................................................................................................................ 35
Figure 21. Demand response program benefits ranked by 66 participants with bars showing standard deviations (with survey question referenced by number). ............ 46
Figure 22. Institutional preferences for DR program administration (within responses). 50
Figure 23. Institutional preferences for DR program administration (within responses). 50
Abstract

As California’s electric power industry continues to evolve, the use of “distributed energy resources”, such as energy efficiency, demand-response, and distributed generation, has emerged as a significant and growing tool in balancing regional supply and demand, managing peak power needs, increasing reliability, reducing ratepayer and utility costs, and inducing other societal benefits. This study supplements an in-depth examination of the actual impacts of intensive, targeted application of a variety of distributed energy resources measures on two distribution feeder lines located in San Francisco, California. In particular, this report provides an analysis of the benefits, costs, effectiveness, and challenges associated with implementing a demand-response program among commercial class customers located in five San Francisco Bay Area counties.

Keywords: Commercial customers, curtailment, distributed energy resources, energy efficiency, demand response, distributed generation
Executive Summary

This project is an extension of a larger, multi-year research effort that examined whether a combination of “distributed energy resources” – distributed generation, energy efficiency, and demand response – can beneficially smoothen the load usage and improve power quality at the distribution feeder level; estimated the benefits and costs of a diverse array of actually implemented distributed energy resources from the perspective of the utility, customers, and society; and evaluated the “real world” challenges to distributed energy resources adoption by a diverse set of energy consumers, including those in the public and private sectors.

This project element extended and narrowed the original research questions to focus on a unique demand-response pilot initiative implemented within a population of small (that is, less than 200 kilowatts of peak demand) commercial class ratepayers. In particular, the extension project investigated whether small electricity users will effectively participate in demand response programs without the use of enabling devices; examined the benefits and costs of an actually implemented demand response program within this customer class; and evaluated the practical challenges to demand response adoption by commercial customers. This customer class is responsible for more than one-third of statewide electricity use and is considered “hard-to-reach” by policy makers and utilities.

The research project team consisted of San Francisco Community Power, a community-based nonprofit organization specializing in implementing demand management programs, and M. Cubed, a consulting firm with expertise in public policy analysis and resource economics. The team successfully advocated for a pilot demand response program focusing on the study population as part of a California Public Utility Commission proceeding;¹ recruited 245 small- and medium-sized commercial energy users, with collectively 379 meters, into the demand response program;² and examined the results associated with the 28 customers who were fully processed (for example, had advanced meters installed and associated billing software activated) by Pacific Gas and Electric Company in time to participate in the program during the summer of 2007.

Demand response participants’ responses to curtailment calls were estimated by comparing the expected energy use patterns with consumption levels as determined by tariff during the periods in which the participants were asked to lower their demand (for example, the baseline was calculated as the average of the three highest energy use days among the 10 prior weekdays, with no weather adjustments).

---

¹ This activity was not funded by the California Energy Commission.
² In general, each commercial energy user represents one facility. However, some customers enrolled facilities that had multiple meters in the program.
Will Small- and Medium-Sized Electricity Users Effectively Participate in Demand Response Programs Without Enabling Devices?

Demand response participants ranged in size and diversity from a small deli to a modest-sized college campus. Participants were called upon to curtail on five days, spanning July 3 to August 31, for four-hour periods.

Collectively the participants reduced their load by an average of 4.9 percent across all curtailment call hours. However, use of this average masks the fact that the customers exhibited a split distribution of responses, in which during most curtailment periods the great majority of customers reduced their electricity use in response to a call while during some periods a minority of customers increased their use. In particular, and as reflected in Figure 1, during 81 percent of customers-days collective load was lower than the calculated baseline. However, on 19 percent of customer-days collective load exceeded the calculated baseline.

![Curtailment By Day and Customer: 81% Curtailed, 19% Exceeded](image)

**Figure 1. Changes in electricity use during the 165 customer days for four-hour curtailment periods on July 3 and 5, and August 29, 30 and 31.**

*Source: M. Cubed/ Energy and Environmental Economics, Inc.*

Note that the non-weather-corrected approach to determining the baseline used in this analysis may result in an underestimate of participants’ response levels. For example, a recent Lawrence Berkeley Laboratory report found that the approach used herein resulted in the lowest estimated level of demand response of seven methods examined.
Setting aside potential baseline estimation bias, if there were particular customers on either side of the decrease/increase divide, overall curtailment performance could be improved by dropping those customers who increased their electricity use. Unfortunately, as shown in Figure 2, the same customers appear on both sides of this divide on different days, making the remedy more challenging. Specific meters within a given customer’s facilities do show consistent use trends, providing for some ability to improve outcomes by eliminating individual meters from the program. Likewise, additional outreach to participating customers to encourage better performance may prove to be an effective strategy.

![Graph showing Mix, Max, and Average Hour Performancy by Customer](image)

**Figure 2. Minimum, maximum, and average performance by customer**

Source: M. Cubed/ Energy and Environmental Economics, Inc.

As indicated in Table 1, 81 percent of the combined load, a total of 84,576 kWh, dropped by 9.2 percent, a reduction of 7,794 kWh as compared with the baseline. This reduction is less than the 11 percent decrease found in the earlier analyses, which was based on a different calculation that relies on a statistical regression method and focused on a much smaller participant population; but is somewhat higher than the approximately 9 percent reduction that has previously been found for the residential class in other studies. However, 19 percent of combined load, a total of 31,404 kWh, exceeded the calculated curtailment period baseline by 6.6 percent, or 2,083 kWh.
Table 1. Load reductions segmented by all participants, those that reduced, and those that increased relative to the baseline.

<table>
<thead>
<tr>
<th>Sample Population</th>
<th>Aggregate Load (kWh)</th>
<th>Load Change During Curtailment Period (kWh)</th>
<th>Percentage Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Customers</td>
<td>115,924</td>
<td>-5,709</td>
<td>-4.9</td>
</tr>
<tr>
<td>Customers that Achieved Curtailment</td>
<td>84,547</td>
<td>-7,792</td>
<td>-9.2</td>
</tr>
<tr>
<td>Customers that Exceeded Baseline</td>
<td>31,376</td>
<td>+2,083</td>
<td>+6.6</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

These data strongly suggest that small customers can participate effectively in demand response programs. However, individual customers may not perform as expected, particularly at a given meter level. This factor is what prompts the need to appropriately lump together groups of customers as a way of spreading risks, but, more important, points to the need to quickly eliminate non-performing customers or meters, or, better yet, to screen them out before they are enrolled in the program.

In addition, the baseline, though simple and transparent to calculate, omits what temperature effects could have been on the load and may not accurately measure actual reductions relative to what a customer would have demanded during the curtailment period. Other possible reasons for the estimated behavior include the possibility that demand response payments, or the absence of penalties, may not be high enough to effectively induce participants to consistently curtail. For example, the value to the customer of continuing full operations outweighed the incentives to do otherwise, and/or these energy users may not have the capacity (for example, personnel) to reduce their electricity use when called upon.

Under the pilot program participants were protected against the assessment of penalties for nonperformance, which eliminated a key motivating reason to comply. In that respect the results are encouraging; they suggest that the modest incentives offered, without any disincentives, were sufficient to induce notable load reductions during more than four-fifths of the customer-days studied.

What Are the Benefits and Costs of a Demand-Response Program Focusing on Commercial Customers?
Excluding meter costs, from a societal perspective program benefits were positive. This result is noteworthy given that preliminary analyses of demand response programs oriented toward larger electricity users (for example, greater than 200 kW) indicate break-even benefit-cost ratios without including meter costs. However, the program did not yield net benefits from the utility’s perspective, even when meter and installation costs are excluded. This is not surprising given that the program was called upon only five times, in part because of delays in installing meters at participant sites. If the program had been active during all four summer months, and experienced twice as many calling events for program engagement³, it would likely yield net benefits from all perspectives. Likewise, the benefit estimates exclude possible long-term payback associated with customers having increased data access, which could induce them to improve their energy management-related behavior.

Survey data indicates that while participants viewed obtaining absolute cost savings as a key program benefit, they equally valued “doing the right thing.” In particular, participants identified contributing to grid reliability, and reducing greenhouse gas and polluting air emissions, as a motivating factor in their participation in the program.

**What Are the “Real World” Challenges to Adoption of Demand Response by Commercial Customers?**

Key barriers to effective demand response implementation within the commercial class include the following:

- **Energy users’ reluctance to adopt measures with which they are not immediately familiar.** This disinclination arises from many small businesses’ lack of time to consider new technologies or behaviors, lack of trust in vendors, and lack of sophistication about energy issues. For example, of the energy users who ultimately agreed to enroll in the demand response program, 82 percent said that they spent no time on energy management, with only 6 percent having a dedicated energy manager. In this situation it’s easier to say “no” than to take the time to learn about something new, even when it may result in noticeable cost savings.⁴

- **Lack of sufficient incentives for behavioral changes.** In cases where the energy user does not directly pay their electricity bill, or when a public-sector agency’s bills are paid centrally, and as a result program benefits would not come back to the specific facility, there may be little motivation to adopt demand response.⁵ Likewise, if multiple individuals are involved in approving program enrollment, an energetic internal champion is needed to marshal the necessary paperwork through the process. A number of energy users who ultimately enrolled in the program cited the

---

³ Program is engaged when participants are signaled to cut their electricity usage
difficulty of gaining management’s attention to the issue as a key barrier to their participation.

- **Lack of information about energy consumption patterns.** The customer population examined in this study generally did not have advanced utility meters before enrolling in the demand response program and, as a result, did not know how much electricity they demanded at peak. Without this information the benefits from participating in a demand response, or energy efficiency, program was substantially unknown, or at least uncertain.

- **Negative previous experience with an energy management program.** Some energy users had previous negative experiences with demand response programs, including the imposition of complex paperwork and the risk that they’d be penalized if they didn’t perform as expected. These ratepayers were loath to engage in another discussion about enrolling in a demand response program.

In working with commercial customers, the project team found that it’s best if a vendor or utility starts at a sufficiently high level on a businesses’ organizational chart, preferably the owner, manager, or vice-president. Similarly it is useful to package the multitude of programs that may be offered by municipal agencies and the local utility for the customer. This approach provides the greatest chance that at least some of the measures will be adopted, reduces the risk that “stranded opportunities” will be created, and results in the most cost-effective delivery of services. Likewise, from a customer’s perspective, it may not be important to distinguish between energy efficiency and demand response programs or between what entity is offering the program – though the study participants expressed a strong preference for working with a nonprofit organization – so much as to obtain a single set of money-saving opportunities, regardless of what they’re called.
1.0 Introduction

California regulators and investor-owned utilities (IOUs) are increasingly looking to demand-response programs to cost-effectively reduce peak loads during particularly high-demand periods (e.g., summer months); as a way to avoid forced outages; and to reduce reliance on especially polluting resources. Likewise, policy makers and others are encouraging IOUs and the California Independent System Operator (California ISO) to incorporate demand-response programs at meaningful levels into integrated resource planning, as a way to avoid the need to construct expensive new generation, transmission, and distribution facilities. For example, the California Public Utilities Commission has established a goal of achieving a 5% peak load reduction for the state’s investor-owned utilities.

Although industrial and large agricultural customers have actively participated in demand response programs since the 2001 energy crises – and in “interruptible” and other similar programs before that—to date residential and commercial class customers have been largely unable to enroll in demand response tariffs, mostly due to the assumption that these customer groups would not be cost-effective candidates for program inclusion. In particular, it has been considered cost-prohibitive to provide the advanced meters necessary for smaller customers to effectively participate in demand response programs. The exception to this includes San Diego Gas & Electric Company’s (SDG&E)’s demand response program, for which customers with peak demands as low as 20 kilowatts (kW) are eligible, and the statewide Demand-Bidding Program (DBP), which allows “chain” stores with at least one location with peak demands in excess of 200 kW to enroll their other facilities with less than 200 kW into the program.

As part of its original research, in 2004 SF Power obtained a California Public Utility Commission (CPUC) order to enable small- and medium-sized energy users located on a distribution feeder line in San Francisco to receive a free interval meter if they enrolled in the Demand Reserve Partnership (DRP). Based on preliminary project results, SF Power obtained another CPUC order in March 2006 to extend this pilot program to commercial class energy users located in Alameda, San Francisco, and San Mateo.

---

6 The oldest and most polluting generating assets are placed in service last, in some cases only when demand is highest during a few days or weeks in the summer. By reducing peak demand on those days, the state can avoid scheduling these resources, with concomitant air quality benefits.
7 This situation will of course change as advanced meters are installed by PG&E, Southern California Edison, and San Diego Gas & Electric.
8 Some aggregators active in PG&E’s service territory may be willing to enroll less than 200 kW customers in available DR programs by paying for meter installation; however, the extent of this practice, as well as its penetration level, is unknown.
9 Revisions to Rate Schedule E-DBP – Demand-Bidding Program to Facilitate Implementation of the San Francisco Pilot Program.
counties. In November 2006, the CPUC ordered an expansion of the pilot program to Contra Costa and Santa Clara counties, as well as a larger version of a pallet jack load shifting initiative that was piloted in the initial study.

The results of the 2004 feeder-specific demand response activity were reported in the earlier report. In summary, the project team found that while the aggregate load impact was small, the six commercial customers who participated in the initial pilot demand response program reduced their loads when called upon by approximately 11 percent. This research expands on the initial pilot analysis to examine adoption of a demand response program by commercial class (i.e., less than 200 kW) energy users located in Alameda, Contra Costa, San Francisco, San Mateo, and Santa Clara counties. Study results are based on survey and customer-level meter data, particularly as compared with baseline load patterns.

1.1. Project Objectives

This project element addresses the following research questions:

What are the benefits and costs of commercial class customer participation in a DR program from the perspective of the utility, the customers, and society?

What are the “real world” challenges to DR adoption by commercial customers?

1.2. Report Organization

Section 1 provides brief project introduction. Section 2 contains a detailed project description, including the study population’s characteristics, and the process for monitoring and measuring the results of the implemented measures. Section 3 presents DR impacts and a cost-benefit analysis. Section 4 indentifies key barriers to DR implementation. Section 5 presents key findings and recommendations.

10 In 2007 the DRP was closed, and the Capacity Bidding Program took its place.
11 The expanded load-shifting initiative was unsuccessful, mostly due to the large marketing costs associated with identifying older-model battery-powered pallet jacks that could effectively use external timers. A more effective load-shifting initiative would allow the timers to be applied to a wider range of battery-based equipment, including potentially scissor lifts and golf carts.
2.0 Project Description

As indicated in Figure 3, the commercial class is responsible for more than one-third of peak statewide energy consumption. Over the next five years commercial peak energy demand is expected to increase by 28%, with the class growing faster than any other customer group except residential.

![California Electricity Consumption by Customer Class](image)

**Figure 3. California electricity consumption by customer class**

Source: M. Cubed/ Energy and Environmental Economics, Inc.

During the study period the following DR programs were available to energy users:

- Business Energy Coalition program (BEC) focuses on energy users with more than 1 megawatt (MW) of load and the ability to make a minimum curtailment commitment of 200 kilowatts (kW) per year. BEC doesn’t impose penalties for non-performance, and performance is evaluated based on the aggregated group’s overall reductions rather than an individual facility’s. Program incentives include a $50 per kW of curtailable monthly payment; a free advanced interval meter; year-round access to Web-based energy monitoring software; and public relations efforts on behalf of participants. Curtailment events are limited to five hours per event, with no more than five events per month. Events are triggered by Stage One alerts, California Independent System Operator forecasts, and PG&E localized emergencies.

- Capacity Bidding Program (CBP) replaced the Demand Reserves Partnership (see below) in the spring of 2007 but retained many of its features. CBP payments and penalties are determined by comparing actual reductions at the individual meter level during curtailment periods against a tariff-mandated baseline analysis and nominated (i.e., aggregator-promised) load reductions. Baseline consumption estimates are determined by the three days with the highest aggregate load during the ten days prior to a curtailment call, with the simple average of the load over
these days calculated for each hour. Based on this analysis the hourly ratio of actual curtailments to nominated curtailments is calculated, which in the tariff is called the “Delivered Capacity Ratio” (DCR). Full payments based on the nominated load are made if a customer achieves a Delivered Capacity Ratio of 0.9 or greater. If the DCR ratio is between 0.75 and 0.9, payments are reduced by 50 percent. No payments or penalties are accrued for ratios between 0.5 and 0.75 (i.e., no monetary gains or penalties are realized from curtailment other than the avoided cost of delivered energy). For Delivered Capacity Ratios between 0 and 0.5, the aggregator is assessed a penalty equal to the payment rate multiplied by 0.5 minus the Delivered Capacity Ratio (which will be less than 0.5). Customers who did not reduce their use at all trigger a penalty equal to 50 percent of the payment that would have been rendered had the energy user lowered their use by their nominated amount. That is, customers that increased their load or reduced by less than 50 percent of their nominated load induce a penalty determined by the degree of the curtailment shortfall.

Critical peak pricing (CPP) provides a discounted rate year-round with per kW charges increasing by a factor of five during Energy Alert periods.

Demand Bidding Program (DBP) enables customers with at least one facility with a peak demand greater than 200 kW to receive a free meter for the less than 200 kW facilities they enroll. DBP participants nominate the amount of load they’re willing to curtail a day ahead of an Energy Alert day through PG&E’s Web-based interactive program.

Demand Reserves Partnership (DRP) targeted energy users with more than 200 kW of peak electricity use. Under the DRP two types of payments were made:

Fee Type I – participation fee during the summer in exchange for commitments to participate;

Fee Type II – performance tied to the actual amount of demand reduced during a curtailment call. Similar to the CBP, penalties were imposed if the actual curtailment-period response was less than 95% of the contracted amount.

The program season extended from June 1 to September 30. During these months participants could be called to curtail between the hours of 11 a.m. and 7 p.m. Monday

12 The CBP analysis is based on the total load for all sites included in the aggregated group. However, the analysis used herein relied on the three highest days for each site/facility. This study approach is commonly used by independent system operators.

13 Customers that have higher loads than their baseline pay a penalty; but the tariff suggests that the penalty is capped at 50 percent of the payment for achieving the nominated curtailment. This payment schedule poses asymmetrical risks to aggregators as compared with the utility. That is, the aggregator is not rewarded for exceeding its nominated load at the same level as the penalty imposed for not meeting the promised reduction. Likewise, for small customers with unknown load profiles or abilities to curtail, it encourages a risk-averse approach to nominations.
through Friday, excluding holidays. As indicated in Table 1, participation was limited to no more than 24 hours in a given month. In most cases, curtailment notifications were issued between 2 and 3 p.m. for curtailments being requested between the hours of 11 a.m. to 5 p.m. the next day.\textsuperscript{14}

Table 2. Active hours for different DR programs.

<table>
<thead>
<tr>
<th>Program</th>
<th>Max Hours per Day</th>
<th>Max Events per Month</th>
<th>Max Hours Per Year</th>
<th>Incentives</th>
</tr>
</thead>
<tbody>
<tr>
<td>Business Energy Coalition</td>
<td>5</td>
<td>5</td>
<td>100</td>
<td>$50/kW</td>
</tr>
<tr>
<td>Demand Bidding Program</td>
<td>4</td>
<td>10</td>
<td>160</td>
<td>$0.50/kW day ahead</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$0.60/kW day-of</td>
</tr>
<tr>
<td>Demand Reserves Partnership/ Capacity Bidding Program</td>
<td>8</td>
<td>4</td>
<td>128</td>
<td>$3.71 - $21.57 day ahead</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>$4.27 - 24.81 day-of</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Two key data sources were used to examine customer-specific DR impacts:

1. \textit{Customer real-time meter data}. 15-minute interval data was obtained through PG&E’s meter data Web interface. The data analyzed in this report cover five four-hour curtailments for 33 meters, a total of 165 customer meter-hours.

2. \textit{Survey data}. SF Power developed and fielded a survey among DR participants, with a focus on obtaining insights into the energy users’ characteristics and motivations for enrolling in the program. Between late-March and early October 2007 160 survey instruments were distributed, with 71 completed and returned, a 44 percent response rate. The distribution of businesses represented in the 71 surveys is shown in Figure 2.

\textsuperscript{14} Demand Response aggregators, including EnerNoc and EnergyConnect, typically require a participant to be able to reduce at least 50 kW to enroll in their programs, and install controls to enable customers to automatically manage their electricity use.
2.1. DR Enrollment

Several steps were necessary to fully enroll potential participants in the CBP program to the point in which they could be called upon to reduce their loads:

*Identify plausible candidates.* The project team did not have access to utility data that would help determine what businesses might be the best candidates for the program (e.g., energy users with more than 100 but less than 200 kW of peak demand). As a result, lead lists had to be developed based on theories related to the electricity consumption pattern and flexibility of a given sector, and their likely willingness to temporarily reduce their load. The search engine Google was used to identify candidates that fit into five main industry sectors that seemed promising based on previous work: schools and nonprofits, municipalities, green-certified businesses, property management firms, and warehouses. Over time these categories were expanded to include lodging facilities, automobile dealerships, retail stores, and industrial operations. Leads were also generated through attendance at events (e.g., sustainability conferences and workshops); networking with colleagues in the “green” field, as well as with other DR providers; and sending email blasts.

*Obtain necessary paperwork.* To enroll participants had to complete and submit hard-copies of the following documents: a signed agreement with SF Power; a PG&E add/delete form; and copies of their PG&E bills. Because the add/delete forms include PG&E’s mailing address, and the utility required “wet” signatures, the paperwork was frequently posted to the utility, rather than to SF Power, which required constant tracking to ensure materials had been received and properly processed.

*Install meters.* Once a facility submitted all of the necessary paperwork, if they already had a qualified meter PG&E reprogrammed and verified that it functioned properly. If they didn’t have an advanced meter one was installed. Once the installation or verification was complete, PG&E’s billing department entered the meter into the appropriate billing system. Many facilities with functioning advanced meters were prevented from participating in the program because of billing system delays. Table 2 and Figures 2 and 3 show the range of times an enrolled facility had to wait to be activated into the program.\(^{15}\) It took at least six months for a given participant to negotiate this process, with an average wait time of roughly a year and a half.\(^ {16}\)

*Nominate load.* Nominations are made up to five days before the close of the month for the following month (e.g. by May 25 for June participation). As indicated in Table 3, individual meter loads can be nominated to curtail for up to four hours, six, or eight

\(^{15}\) In addition to the PG&E-related delays, it can take up to four weeks for SF Power to process applications. In early 2007 CBP program administration was transferred from APX to PG&E, which may have caused some of the delays.

\(^{16}\) As of October 1, most participants had yet to be processed, with the average wait time likely to reach two years.
hours. Most meters were nominated to participate in the full eight hours, though none were actually asked to reduce their use for that long.

Notify participants of Energy Alert Days. SF Community Power notified customers of Energy Alert events the business afternoon before the curtailment was to take place. Automated notices were sent to all account contacts by email, recorded voice message and fax. A staff member then placed personal phone calls to each account’s primary contact to ensure that they received the notices.

Table 3. Demand response enrollees faced significant delays related to meter installation and billing system updates.

<table>
<thead>
<tr>
<th>Wait Times for Facilities Ineligible to Participate as of October 1, 2007</th>
<th>Wait Times for Facilities That Participated in Summer 2007 Energy Alerts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Wait to be Fully Processed</td>
<td>9 months</td>
</tr>
<tr>
<td></td>
<td>11 months</td>
</tr>
<tr>
<td>Longest Wait Time</td>
<td>18 months</td>
</tr>
<tr>
<td></td>
<td>15 months</td>
</tr>
<tr>
<td>Shortest Wait Time</td>
<td>n/a</td>
</tr>
<tr>
<td></td>
<td>6 months</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Figure 4. Wait times from application date to participation eligibility among 245 enrolled facilities.

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Figure 5. Wait times from application date to participation eligibility among 26 facilities that participated in 2007 Energy Alerts.
Source: M. Cubed/ Energy and Environmental Economics, Inc.
Table 4. Participating meters can be nominated to curtail for different periods.

<table>
<thead>
<tr>
<th>Nomination duration</th>
<th>Commitment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-4</td>
<td>Meters nominated for this duration commit to curtailing for at least four hours, though they may be called upon to curtail for as little as one hour.</td>
</tr>
<tr>
<td>2-6</td>
<td>Meters nominated for this duration commit to curtailing for at least six hours, though they may be called upon for as little as two hours.</td>
</tr>
<tr>
<td>4-8</td>
<td>Meters nominated for this duration commit to curtailing for at least four hours, though they may be called upon for as little as four hours.</td>
</tr>
</tbody>
</table>

Source: M. Cubedl/ Energy and Environmental Economics, Inc.

It was difficult for SF Power – and almost impossible for individual customers – to determine what amount of load reduction to nominate for a given participating meter. In most cases the participant’s peak load was unknown, since they hadn’t previously had an advanced meter, or, if they did, peak load information was unavailable; and, of course, it was unknown how much they would actually reduce when called upon. Likewise, in cases where a facility had multiple meters, neither the customer nor SF Power knew exactly what electricity uses were associated with a particular meter.

SF Power estimated individual customer load nominations by multiplying the average daily kWh use, as indicated on their utility bill, by one percent (0.01). The resulting estimated kW was then roundly adjusted based on the devices the energy user said they were willing to curtail. For example, air conditioning (AC) loads can contribute up to half a facility’s energy use; if a customer was willing to substantially reduce their kW curtailment estimate was doubled. Table 4 shows the expected amount of facility-specific load nominated for the demand response program by sector as of October 1, 2007.17

17 The continued existence of T12s, ironically nominated for use in a DR program, illustrates small businesses unwillingness to accept all offered energy-savings rebates.
Table 5. Initially estimated load reductions for individual sectors.

<table>
<thead>
<tr>
<th>Industry Sector</th>
<th>Loads to reduce</th>
<th>Number of Facilities</th>
<th>Number of Meters</th>
<th>Total Estimated Load Reduction (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Auto dealerships</td>
<td>Lights: indoor; Lights: Outdoor; HVAC; Refrigerators; Office Electronics; Pallet jack charging; Conveyers; Baking or Production lines, Other</td>
<td>11</td>
<td>14</td>
<td>55.5</td>
</tr>
<tr>
<td>Banks</td>
<td>Lights: indoor; Appliances; Office Electronics, Refrigerators</td>
<td>5</td>
<td>5</td>
<td>11.55</td>
</tr>
<tr>
<td>Municipal Facilities</td>
<td>Lights: indoor; HVAC; Appliances; Office Electronics; Lights: Other</td>
<td>58</td>
<td>70</td>
<td>398.25</td>
</tr>
<tr>
<td>Community Centers</td>
<td>Lights: indoor; Lights: Outdoor; Lights: Other; Appliances; Office Electronics; Pallet jack charging; Conveyers; Other</td>
<td>7</td>
<td>7</td>
<td>69</td>
</tr>
<tr>
<td>Grocery Stores</td>
<td>Lights: indoor; Refrigerators; Appliances; Lights: Warehouse; Lights: indoor; HVAC; Office Electronics; Pallet jack charging; Lights: Other</td>
<td>11</td>
<td>21</td>
<td>52.75</td>
</tr>
<tr>
<td>Hotels</td>
<td>Lights: indoor; Office Electronics; Refrigerators; Other; Lights: Other, HVAC; Elevators, Appliances</td>
<td>17</td>
<td>22</td>
<td>289.5</td>
</tr>
<tr>
<td>Industrial Facilities</td>
<td>Lights: indoor; HVAC; Office Electronics; Other</td>
<td>4</td>
<td>6</td>
<td>80.5</td>
</tr>
<tr>
<td>Office Buildings</td>
<td>Lights: indoor; Lights: Outdoor; Appliances; Office Electronics; Other, HVAC, Elevators, Pallet jack charging</td>
<td>12</td>
<td>20</td>
<td>292.85</td>
</tr>
<tr>
<td>Other</td>
<td>Lights: indoor; Lights: Outdoor; HVAC; Elevators; Lights: Other, Appliances, Pallet jack charging</td>
<td>5</td>
<td>11</td>
<td>37.75</td>
</tr>
<tr>
<td>Printers</td>
<td>Lights: indoor; Lights: Outdoor; HVAC; Office Electronics</td>
<td>2</td>
<td>3</td>
<td>12.5</td>
</tr>
<tr>
<td>Property Management Firms</td>
<td>Lights: indoor; HVAC; Elevators; Office Electronics; Other</td>
<td>20</td>
<td>56</td>
<td>313.55</td>
</tr>
<tr>
<td>---------------------------</td>
<td>-------------------------------------------------</td>
<td>-----</td>
<td>-----</td>
<td>--------</td>
</tr>
<tr>
<td>Recreation Facility</td>
<td>Lights: indoor; HVAC; Office Electronics; Refrigerators</td>
<td>3</td>
<td>4</td>
<td>26</td>
</tr>
<tr>
<td>Religious Centers</td>
<td>Lights: indoor; Lights: Outdoor; Refrigerators; Other; Baking or Production lines; Appliances, Office Electronics</td>
<td>8</td>
<td>11</td>
<td>14.88</td>
</tr>
<tr>
<td>Restaurants</td>
<td>Lights: indoor; Refrigerators, HVAC; Office electronics</td>
<td>9</td>
<td>11</td>
<td>22.79</td>
</tr>
<tr>
<td>Retail Stores</td>
<td>Lights: indoor; Lights: Outdoor; HVAC; Office Electronics; Lights: indoor; Refrigerators; Lights: Other</td>
<td>13</td>
<td>18</td>
<td>52</td>
</tr>
<tr>
<td>Schools &amp; Colleges</td>
<td>Lights: indoor; HVAC; Appliances; Office Electronics; Refrigerators; Lights: Other</td>
<td>18</td>
<td>31</td>
<td>266.85</td>
</tr>
<tr>
<td>Senior Centers</td>
<td>Lights: indoor; Lights: Outdoor; Appliances; Office Electronics, HVAC</td>
<td>3</td>
<td>13</td>
<td>34</td>
</tr>
<tr>
<td>Storage Facilities</td>
<td>Lights: indoor; HVAC; Office Electronics; Refrigerators, Appliances</td>
<td>9</td>
<td>11</td>
<td>13</td>
</tr>
<tr>
<td>Warehouses</td>
<td>Lights: indoor; Lights: outdoor; HVAC; Office Electronics; Refrigerators; Pallet jack charging; Conveyers; Lights: Other; Conveyers; Baking or Production lines</td>
<td>30</td>
<td>42</td>
<td>141.75</td>
</tr>
<tr>
<td><strong>TOTALS:</strong></td>
<td></td>
<td>245</td>
<td>376</td>
<td>2184.97</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

### 2.2. Demand Response Results

Figures 6 and 7, as well as Tables 5 and 6, display summary performance data. On some event days and in some hours aggregate reductions exceeded 0.5 megawatts (MW). However, on the other extreme, in one hour on August 30 the group showed a small increase in electricity use. Likewise, as indicated in Figure 7, while the mean reduction in July and August was notably positive, there was a significant range in minimum and
maximum load reductions during a given point in time. This variability would need to be addressed if this group of customers is to effectively participate in a DR program over time.

Figure 6. Hourly net performance by day.

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Figure 7. Mean, minimum, and maximum curtailment hours for each month.
Source: M. Cubed/ Energy and Environmental Economics, Inc.

Table 6. Curtailment activity.

| Total Number of Customer Curtailment-Days (i.e., customer-days) | 165% |
| Number of Customer-Days on Which Net Reductions Occurred | 139% |
| Percent of Customer-Days on Which Net Reductions Occurred | 75% |

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Table 6 shows the total number of customer-days, which consists of the number of meters (33) multiplied by curtailment days (5), for a total of 165. This reflects the “bucket” of potentially curtable load.

As indicated in the table, the aggregate group reduced its load by 4,870 kW, or 4.9 percent, in response to curtailment calls. Use of this average masks the fact that on most customer-days aggregate load noticeably fell in response to the calls: during 81 percent of customers-days aggregate load was lower than the calculated baseline. However, on 19 percent of the customer-days aggregate load exceeded the calculated baseline.
Table 7. Summary of curtailment and exceedance cohorts.

<table>
<thead>
<tr>
<th>Cohort</th>
<th>Aggregate Load (kWh)</th>
<th>Load Change During Curtailment Period (kWh)</th>
<th>Percentage Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Customers</td>
<td>115,924</td>
<td>5,709</td>
<td>-4.9</td>
</tr>
<tr>
<td>Customers That Achieved Curtailment</td>
<td>84,547</td>
<td>-7,792</td>
<td>-9.2</td>
</tr>
<tr>
<td>Customers That Exceeded Baseline</td>
<td>31,376</td>
<td>+2,083</td>
<td>+6.6</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Table 7 shows that 81 percent of the time the aggregate load effectively curtailed by an average of 9.2 percent, and that during the remaining periods, 19 percent of the time, aggregate load exceeded the baseline by 2,083 kW, a 6.6 percent increase.
Figure 8. Histogram of 4-hour load curtailments and increases for 119 customer-days.
Source: M. Cubed/ Energy and Environmental Economics, Inc.

Figure 9 further illustrates the bifurcated nature of the group’s response by showing the number of customer-days in a series of bins that are 50 kW-wide (except for the edge bins) and range in value from -705 kW to +150 kW. The mode of the distribution of curtailment results is the bin with customer-days ranging in value from -1 to -50 kW: more customer-days fell into this range than any other, and most of the other results were close to this bin range.¹⁸

¹⁸ One customer showed a 100 percent reduction in load, and another a 111 percent increase.
Individual hours were also examined to understand call responses. Summaries for each of the five curtailment call days are provided in Table 8.

Table 8. Summary of hour-specific loads for five curtailment call days and 26 customers.

<table>
<thead>
<tr>
<th>Calendar Day</th>
<th>3-Jul</th>
<th>5-Jul</th>
<th>29-Aug</th>
<th>30-Aug</th>
<th>31-Aug</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Hours</td>
<td>112</td>
<td>112</td>
<td>112</td>
<td>112</td>
<td>112</td>
</tr>
<tr>
<td>Mean Change</td>
<td>(15.7)</td>
<td>(8.6)</td>
<td>(2.1)</td>
<td>(3.0)</td>
<td>(21.7)</td>
</tr>
<tr>
<td>St Dev</td>
<td>35.6</td>
<td>29.3</td>
<td>37.2</td>
<td>34.9</td>
<td>38.7</td>
</tr>
<tr>
<td>Mean Curtailment</td>
<td>(18.2)</td>
<td>(14.7)</td>
<td>(15.3)</td>
<td>(17.4)</td>
<td>(26.2)</td>
</tr>
<tr>
<td>Mean Exceedance</td>
<td>2.3</td>
<td>9.0</td>
<td>24.7</td>
<td>20.1</td>
<td>5.0</td>
</tr>
</tbody>
</table>
By most measures, August 29 and 30 were the two worst performing days, with absolute reductions occurring in only 67 percent and 62 percent of hours, compared to 88 percent, 74 percent, and 86 percent for July 3, July 5 and August 31. Notably, peak San Francisco temperatures on August 29 and 30 were the highest among prior days, suggesting that there may be a temperature bias in the baseline calculation. For the August curtailment calls the baseline is relatively low because the prior 10 days were cool, and HVAC load was likely lower than during the hot weather experienced during the curtailment calls. Though temperature correlates positively with load, other factors might have influenced performance.

Figures 10 through 15 provide illustrative examples of excellent, mixed and poor curtailment performances for selected customer types. Figure 10 and 11 show how a (greater than 200 kW peak load) office building successfully curtailed in July and August, and how load was reduced during hours before and after the four-hour curtailment call period.

![Figure 10. Excellent performance by an office building during July curtailment calls.](image_url)

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Figure 11. Excellent performance by an office building during August curtailment calls.

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Figure 12 shows moderate performance by a school during the August curtailment call. Also shown is how load reduction performance improved on successive days. A potential pitfall is revealed for August 30 during the hours ending at 9 and 10 p.m., when load was considerably higher than the baseline, though this may simply reflect new activity (e.g., a cleaning crew) in the building.

Figure 12. Moderate performance by a school during August curtailment calls.

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Figures 13 and 14 show the mixed performance of a religious organization. The excellent performance in July was not repeated in August. The poor August performance reflects that early in the call period curtailment was achieved, but baseline load is exceeded in the later hours, most likely because programs at the site were initiated. This mixed performance suggests that some customers may not be well-suited to curtail for a full four-hour period.

Figure 13. Mixed performance by a religious organization during July curtailment calls.
Source: M. Cubed/ Energy and Environmental Economics, Inc.
2.3. DR Results Interpretation

As described in Section 3.2, 81 percent of customer-days achieved curtailment during DR calls, representing 73 percent of the aggregate load studied and reflecting average reductions of 9.2 percent. On 19 percent of customer-days, aggregate load was 6.6 percent above the cohort’s baseline. The combined effect of these decreases and increases on the 115.924 kW of aggregate load was a net reduction of 5,709, or 4.9 percent.

Ten customers were responsible for the 25 best performances during the four-hour curtailments. Among the top 10 performers were two schools and two religious organizations, which achieved large reductions in both magnitude and proportion relative to the baseline. No retailers made the top 10 list. It’s difficult, however, to develop generalizations about the performance of industry sectors because their occurrence rates are not significantly greater than their representation in the sample population. As a result, it is not possible to claim that certain types of organizations were more adept at curtailing electricity demand than others. That said, it’s notable that half of the largest magnitude reductions were associated with office buildings and/or property management firms, an outcome that suggests that office buildings have a significant potential to participate effectively in DR programs.

The top performer – a car dealership – had zero load reported for the curtailment period, suggesting a 100 percent curtailment. However, this customer had access to back-up
generation, which it may have employed in response to the curtailment calls, so it was not included among the customer-days reported in the report’s tables and figures.

A number of factors may impede a customer’s ability to curtail load, including lack of dedicated staff time or expertise, such as an onsite energy manager, or an inability to adjust HVAC systems, refrigerators, lights, and other electrical equipment. However, one of the poorest performing customers, a small college, does have a dedicated energy manager. In such cases, poor curtailment performance might be ameliorated with focused outreach to the manager on the day of the curtailment call and/or prior to it to prepare for a more effective response.

2.4. Potential Biases in DR Findings

The baseline should reflect the unperturbed load profile that would have occurred absent an intervention; in this case the curtailment event. There is no single best approach to developing a baseline. The basic idea is simple – to establish the amount of energy that a group of customers would have used absent the intervention – but its quantification is fraught with uncertainties and ultimately requires subjective decisions. For example, it is no more compelling to develop a baseline using the average of the three highest loads among 10 prior weekdays than the average of the two highest loads from the prior two months, or even prior two years.

Any baseline determination method will contain inherently arbitrary elements. A few guiding principles can be usefully applied to evaluate a proposed method:

Be easy to implement. A method is undesirable if it requires extensive training or is time-consuming to apply. 19

Be accurate. Under- or overestimating a program’s kW savings leads to an under- or overstatement of a program’s demand response value.

Be transparent, so as to facilitate third-party review and validation. A black-box approach is undesirable because it invites skepticism, thereby potentially diminishing a demand response program’s acceptance by various stakeholders (e.g., ratepayers, utilities and regulators).

Be applied consistently for all customers.

19. When choosing a method for evaluating individual customer demand response, employing a simple approach is a high priority, since both customers and program administrators are expected to make use of the method. In the case of program evaluation, however, ease of implementation is less critical, as it’s conducted by those familiar with analytical techniques. At the same time, a complex method requiring substantial time and money for expert analysis is undesirable, and, if it differs from the tariff-mandated method, may be less useful to policy makers.
Be designed so as not to favor either the utility or the customer (i.e., be neutral).

Common methods of estimating baseline energy use include:

Prior-days averaging techniques, which compare the load profile on an event day to the average profile over multiple days prior to the event (i.e., the tariff-mandated approach). The average non-event profile may at times be adjusted to match the actual loads in the morning before the event hours.

Weather-matching techniques, which compare the load profile on one or more event days to the average profile over non-event days with similar weather characteristics.

Regression-based load comparison, which entail estimating customer-specific hourly load regressions that incorporate the effects of time, weather and event variables.20

Econometric demand models based on a system of electricity demand equations, typically derived from utility-maximization behavior of electricity consumers.

Several potential weaknesses are likely to be present in any approach to calculating a baseline or establishing graduated payment/penalty schedules. For example, for many industry sectors, load correlates with temperature. However, the baseline calculation method used by PG&E does not take temperature into consideration. As a result, for example, if the 10-week days prior to a curtailment call were relatively cool, the resulting baseline would be biased, since it would be more difficult for customers to “beat their baseline.” Conversely, if temperatures on a curtailment day are lower than the three days used to calculate the baseline, reductions during curtailment periods should be “easier” because the baseline would be biased upward relative to the curtailment call day. In this vein, a recent Ernest Orlando Lawrence Berkeley National Laboratory (LBNL) analysis found that the CBP-required baseline method frequently resulted in estimates of load increases on the hottest curtailment days.21

Figures 10 and 11 show the temperature peaks for San Francisco on curtailment and prior days for July and August. Though program participants were located throughout the Bay Area, and San Francisco peak temperature may not be a strong predictor of regional temperature peaks, it is interesting to note that July temperatures for the baseline days did not vary dramatically from the July curtailment call days. August, however, is a different story: the first two curtailment call days, August 29 and 30, were


by far the two hottest days during the period of interest. The average 24-hour peak temperature for the San Francisco Station in the prior 14 days was 73.6 degrees F, whereas the curtailment call peaks were 83, 84 and 75, respectively, for August 29, 30 and 31.22 As a result, for August payments, the baseline may be lower than is reasonable, since it doesn’t reflect the warmer conditions experienced during curtailment call days.

![Figure 15. Temperature pattern for days prior to curtailment calls on July 3 and 5, 2007.](image)

Source: M. Cubed/ Energy and Environmental Economics, Inc.

The LBNL analysis found that the accuracy of baseline models could be improved substantially if a morning adjustment factor were applied for weather-sensitive commercial and industrial buildings. However, the report also found that for customers with highly variable loads no baseline model produced satisfactory results.

---

22 The LBNL study found the lowest level of load reductions during a similar heat wave that occurred in late July 2006.
Figure 16. Temperature pattern for curtailment and prior days on August 29, 30, and 31.

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Setting aside baseline issues, other factors that may cause a participant to fail to meet their nominated curtailment include the following:

- The nominated load was too ambitious.
- The customer might have been able to achieve the nominated load but failed to act swiftly or completely, possibly because of “participant fatigue” setting in after multiple call days.
- There were errors in measurement, recording, reporting or analysis, incorrectly indicating a false failure to fully curtail.

Only 29 of the 165 customer-days had four-hour load curtailments that were more than one percent above their baselines. Sorting by aggregate load performance over the four-hour curtailment period, schools, colleges, and community centers had eight of the ten worst performances in terms of proportional load increase. When sorting by magnitude of load growth, office buildings join the list of worst performers. The poor performance of some public and pseudo-public spaces is surprising because they are also well represented amongst the best performers.

Looking in finer detail at the individual hours, however, 139 of the 560 customer-hours, 25 percent, had loads that were higher than their baselines. The proportion of unsuccessful hours is much higher than unsuccessful four-hour periods; in many cases large reductions during some hours made up for large increases in others.
It is informative to explore the extent to which curtailment improved during the four-hour period. Figures 12A, B, C, and D show the evolution of load reductions during the three August calls for 18 customer-days. Visually, there is no clear trend toward improving or degrading curtailment during the four-hour period. On August 29 only three customer-days showed a downward trend during the period, with five trending upwards; several customers flirted with their baseline. Whereas only one achieved later hour curtailment after exceeding its baseline in early hours on August 30, more customers had just the opposite result of achieving curtailment in the early hours only to exceed the baseline later in the day.

On August 30 most customer-days showed gradual upward trends. Likewise, most customers either achieved reductions for all hours of the period or did not, rather than improving or degrading significantly over time. Only one customer achieved early period curtailment only to exceed its baseline later in the day.

Compared with the prior two days, August 31 was a dramatic success. Only one customer failed to achieve curtailment; most curtailed for all curtailment hours.
Figure 17. August 29 curtailment call trends for 18 customer-days.

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Figure 18. August 30 curtailment call trends for 18 customer-days.

Source: M. Cubed/ Energy and Environmental Economics, Inc.
Finally, the three August curtailment call responses are examined in sequence in Figure 20. The figure shows that five customers didn’t respond on the first two days – suggesting that either they may have missed the alert, or the person responsible for implementing the reductions was otherwise engaged – but then achieved curtailment on the third day. Several customers had gradual downward trends through the three-day period, but more had loads that remained rather flat.
The fact that under no circumstances would a participant be penalized may have played a role in their behavior. Without the prospect of a penalty, and given that effectively reducing load requires some work on the part of a facility’s staff, it would be simple to ignore the curtailment call. From that perspective it may be surprising that the group performed as well as it did.
3.0 Cost-Benefit Analysis/Least Cost Curve of Installed DER

Having estimated the energy use changes associated with the DR program, the team calculated the benefits of those impacts and compared them to the costs necessary to achieve them. The benefit-cost (B/C) approach used to evaluate the DR program provides an assessment from three different perspectives – DR customer, utility, and society – resulting in a deeper and more balanced economic evaluation than any single viewpoint.

Specifically, costs and benefits were evaluated from the perspective of the three “cost tests” defined in the California Standard Practice Manual that are widely used to analyze distributed energy resource programs, as follows:23

- **Participant Cost Test.** Measures the quantifiable costs and benefits to the customer from implementing DR. Participant costs include purchase and installation costs, less any incentive or rebate received from the utility or other party. Benefits are the participants’ bill savings due to reduced energy consumption, as well as any direct payments.

- **Utility Cost Test (UCT).** Measures DR’s net impact on the utility’s revenue requirement. Utility costs include those related to direct installation costs incurred by the utility and any third-party program implementer (e.g., SF Power), incentives and rebates, administration, overhead, and marketing. Benefits are the utility’s avoided cost of purchasing or generating energy.

- **Total Resource Cost Test (TRC).** Measures DR’s cost and benefits as a resource option based on the total cost of the measure, including participant and utility/third-party costs. Costs include those incurred by both the participant to purchase, install and maintain DR; and by the utility and third-party to market and administer the program. Incentives and rebates are excluded as they are not a resource cost; instead, they are transfers from the utility to the customer. That is, a rebate increases the utility’s cost and decreases the participant’s cost by the same amount, with a net effect of zero.

A common misperception is that there is a single best perspective for evaluating DR costs and benefits. While each test provides accurate results, employing all three sets of findings together describe who benefits and who pays, and what incentives may be

---

23. Note that although the authors reference the perspectives in the California Standard Practice Manual, the cost-benefit analysis applied herein is different from the cost-effectiveness analysis conducted on California efficiency programs, which typically assume a “static” and unchanging set of benefits (referred to as “avoided costs”). Because DR implementation is intended to change not only the quantity of energy used, but also the reliability and quality of that energy, DR will not deliver a single fixed benefit level.
needed for specific stakeholders to benefit from DR adoption. The key questions answered by each cost test are shown in Table 9.

Table 9. Questions addressed by the various cost tests

<table>
<thead>
<tr>
<th>Cost Test</th>
<th>Questions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Participant Cost Test</td>
<td>- Does DR result in net savings to the customer?</td>
</tr>
<tr>
<td></td>
<td>- Is the customer likely to participate in a DR program?</td>
</tr>
<tr>
<td>Program Administrator Cost Test (PAC)</td>
<td>- Does DR result in net savings to the utility or program administrator?</td>
</tr>
<tr>
<td></td>
<td>- What is the net impact on the utility’s revenue requirement?</td>
</tr>
<tr>
<td>Total Resources Cost Test (TRC)</td>
<td>- Does the DR program result in net savings to the service territory or region as a whole (regardless of who pays the costs and who receives the benefits)?</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Table 10 lists the specific benefit and cost components that are attributed to each cost test perspective.

Table 10. Benefits and costs of various perspectives.

<table>
<thead>
<tr>
<th>Tests and Perspective</th>
<th>DR Costs</th>
<th>DR Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td>Participant Cost Test</td>
<td>Equipment and installation costs</td>
<td>Incentive payments</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Energy sales and/or bill savings</td>
</tr>
<tr>
<td>Program Administrator Cost Test (PAC)</td>
<td>Incentive payments Direct Equipment and installation costs Administration and overhead costs</td>
<td>Energy savings Avoided energy use and emissions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avoided power production, transmission, and distribution</td>
</tr>
<tr>
<td>Total Resources Cost Test (TRC)</td>
<td>Equipment and installation costs Administration and overhead costs</td>
<td>Avoided Energy use and emissions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avoided power production, transmission, and distribution savings</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Avoided blackout and brownouts System reliability</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.
3.1. Demand Response Benefit/Cost Analysis

It is difficult to monetize benefits and costs associated with DR. This analysis relies on the CPUC avoided costs used to evaluate the benefits of EE programs for the California IOU’s. These are the best available estimates of DR value. However, the avoided costs for energy efficiency do not capture several important benefits provided by DR measures, including⁴:

- **Capacity Value.** Depending on the characteristics of the DR program, DR reduces capacity costs corresponding to planning and operating reserves, as well as emergency response/outage reduction.
- **Consumer Surplus Value.** Mandatory and voluntary DR programs will result in a gain in welfare and a transfer from producers to consumers.
- **Option Value.** DR resources available for dispatch in a volatile energy market provide a positive option value.
- **Value of Flexibility in Expansion Planning.** DR programs that can be developed and implemented in a short time period (“capacity in a hurry”), within an overall resource planning and procurement paradigm can provide additional benefits over long lead-time capacity investments.
- **Portfolio Hedge Value.** The incremental value of having more dispatchable demand resources and reduced forward purchase requirements within an overall resource portfolio.
- **Value of Lost Load.** The value attributable to demand response programs that are capable of preventing or capping unserved energy beyond the level required by reliability targets.

3.2. Benefits of DR Programs

The primary benefits of demand response programs are on-peak, immediate energy savings and improved system reliability. DR programs reduce the risks to utilities, customers, and society of tight supply/demand balances, high prices, and, in worst-case scenarios, involuntary outages.

DR program benefits from the UCT and TRC perspectives consist of energy-related cost savings, statistically estimated based on market prices; and reliability benefits. The value of the energy saved by DR programs depends on how reliably the program can deliver load reductions in a given time period. That is, the number of hours a day and the number of days in a year that a utility can call on a curtailable load program will determine the program’s value. The more a program can be reliably called upon during

---

²⁴ The shortcomings of the avoided cost estimates for energy efficiency are documented in *Phase 1 Results: Establish the Value of Demand Response*, Orans et al, Demand Response Research Center Research Opportunity Notice, Lawrence Berkeley National Laboratory.
times of tight supply, the more utility planners can use it to avoid purchasing high cost electricity and the higher the program value to the utility and society.

The $/kW and average $/MWh value of the CBP program can be seen in Table 11. These values are based on the hours during which curtailable load can be dispatched relative to the market prices forecasted for those hours. As shown in the table, the $/kW price rises as the number of available hours increases, reflecting the value of the additional program availability. However, the average $/MWh value decreases as the number of available hours increases, reflecting the spread of program benefits across more hours.

Table 11. Demand response value.

<table>
<thead>
<tr>
<th>Program</th>
<th>Availability</th>
<th>$/kW Value</th>
<th>Average $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Bidding Program</td>
<td>Max Hours per Day: 4</td>
<td>$26.59</td>
<td>$221.57</td>
</tr>
<tr>
<td></td>
<td>Max Events per Month: 10</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Max Hours per Year: 120</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Reserves Partnership/Capacity Bidding Program</td>
<td>Max Hours per Day: 8</td>
<td>$38.90</td>
<td>$255.94</td>
</tr>
<tr>
<td></td>
<td>Max Events per Month: 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Max Hours per Year: 152</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

These program benefits are based on market price forecasts. DR programs, while not necessarily designed to do so, could also provide the benefit of deferring or eliminating the need for future transmission and distribution (T&D) upgrades. T&D systems are built to serve lower peak load, so a DR program capable of reducing load during peak hours could reduce the amount of T&D capacity needed in a given service area.

In order to examine the program’s potential value with respect to T&D benefits, the $/kW capacity and average $/MWh program values were recalculated to include T&D benefits. The recalculated program benefits are illustrated in Table 12.

25. Market prices are based on CPUC avoided costs adopted in April 7, 2005, Decision (Rulemaking 04-04-025)

26. The T&D benefits are also part of the adopted CPUC avoided costs used for energy efficiency.
Table 12. Demand response value of CBP and DBP DR programs, with T&D benefits.

<table>
<thead>
<tr>
<th>Program</th>
<th>Availability</th>
<th>$/kW Value</th>
<th>Average $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Bidding Program</td>
<td>Max Hours per Day: 4</td>
<td>$37.62</td>
<td>$313.46</td>
</tr>
<tr>
<td></td>
<td>Max Events per Month: 10</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Max Hours per Year: 120</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Reserves Partnership/Capacity Bidding Program</td>
<td>Max Hours per Day: 8</td>
<td>$71.16</td>
<td>$468.13</td>
</tr>
<tr>
<td></td>
<td>Max Events per Month: 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Max Hours per Year: 152</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.

To calculate the overall monetary value of the DR test program from the UCT and TRC perspectives, the value of the curtailed energy is combined with the program’s estimated demand reductions.

For comparison purposes the estimated cost to commercial customers of a forced outage is assumed to be $68.20 per kWh unserved;\(^\text{27}\) a small business with 3 kW of demand could lose an estimated $613.80 as a result of a three-hour outage. This is significantly higher than voluntary participants are willing to accept to curtail a portion of their load.

From the participants’ perspective, DR benefits include payments or incentives received for participating in the program; beneficial behavioral changes that arise from the energy management “conditioning” induced by program participation;\(^\text{28}\) and enhancements in area reliability with the concomitant reduction in the risk of forced outages.

For the summer 2007 DR program, individual customers incurred no direct costs associated with equipment or installation, nor did they risk the assessment of penalties for failure to meet their nominated load reduction. SF Power accepted the risks, and ratepayers paid for the administrative and marketing expenses associated with enrolling participants. As a result, it is most appropriate to analyze program costs and benefits from the perspective of SF Power, the program administrator, as shown in Table 13.


\(^\text{28}\) Several DR participants on the feeder reported that, after a few curtailments calls, they permanently changed the way they used electricity, resulting in ongoing energy savings.
Key benefit and cost elements include the following:29

- **Administration and Overhead:** Between January 1 and September 30, 2007, a total of $310,606 was spent marketing the program and enrolling customers. However, the full benefits from these expenditures, as measured by curtailment call reductions, were not realized during the study period since in most cases enrolled customers had not been fully activated into the program.30 For the purposes of the cost-benefit analysis, the authors assigned 5 percent of marketing and administrative costs to the cohort of customers analyzed in this report because only about half of the 28 customers’ August curtailment results are included in this study, and these customers represent roughly 11 percent of the facilities enrolled through the marketing efforts.

- **Equipment:** The cost for a fully loaded meter, including the meter itself, installation and maintenance is $2,700. The total cost for the 34 meters was $91,800, reflecting an annual cost of $10,357 when amortized over 12 years at a 5 percent rate.

- **Avoided Energy Use Benefits:** The program administrator made payments to program participants totaling $4,850, but one customer who received a $60 payment was not included in this analysis, leaving a net payment of $4,790. In addition, program participants realized a quantifiable financial benefit of avoided electricity costs. This benefit was estimated using the gross curtailment of 7,792 kWh, rather than net of 5,709 kWh, because it seems unreasonable to assign the DR program costs associated with customers’ failure to reduce their load relative to their baseline, given that it is highly unlikely that the efforts of program administrators led customers to increase their load.

- **Avoided marginal damage from emissions:** The reductions in electricity use results in avoided power generation and, concurrently, avoided polluting air and greenhouse gas emissions. To calculate this benefit, marginal damages obtained from the U.S. Environmental Protection Agency were multiplied by the estimated avoided emissions for carbon dioxide (CO₂), particulate matter (PM₁₀) and nitrogen oxides (NOₓ). Left out of the calculation are avoided marginal damages from emissions of carbon monoxide, sulfur dioxide, fine particulate matter (PM₂.₅) and volatile organic compounds. Given the pollutant damages omitted, the estimate of avoided damage is conservatively low despite its

29. DR can lead to permanent EE savings. In general, energy management implementation can serve to “jump-start” interest in a continuing improvement process. Once businesses have been effectively engaged, they are more likely to proactively request assistance with resource management issues. For example, after working with San Francisco businesses on energy issues for several years, SF Power began to receive assistance requests related to water conservation and solid waste disposal.

30. See Section 2.1: DR Enrollment.
presentation as a range based on high, low and mid range values for marginal
damage costs and emissions rates.

- **Avoided investments in power production, transmission and distribution capacity:** Avoided electricity demand is assumed to have a 1 percent probability of avoiding costs associated with infrastructure investments for enhanced production, transmission and distribution capacity. Avoided costs per kW were drawn from the analyses summarized in Table 12.

- **Avoided brownouts or blackouts:** As with avoided electricity infrastructure investments, there is value associated with the avoidance of blackouts or brownouts. The estimate of this value is based on the assumption that each kW not used has a $68 value if it avoided blackouts or brownouts, and that there is between a 0.001% and 0.1% probability that the peak demand curtailment achieved by this program contributed to the avoidance of a blackout or brownout.

Taken together, net program benefits range from -$10,563 to -$2,482 (i.e., negative benefits), with the outcome dependent on several key assumptions related to the proper treatment of avoided infrastructure costs, avoided outages, and the assignment and amortization of equipment costs. If meter costs are excluded net benefits become solidly positive from a total resources cost perspective, ranging for a low of $1,325 to a high of more than $6,362. This result is particularly noteworthy given that preliminary analysis of DR programs catering to larger electricity users (i.e., >200 kW) indicate break-even benefit-cost ratios without including meter costs.
Table 13. Cost-benefit analysis of summer 2007 curtailment days.

<table>
<thead>
<tr>
<th></th>
<th>Worst</th>
<th>Mid</th>
<th>Best</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Societal Perspective, Without Equipment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sum of Benefits</td>
<td>$3,336</td>
<td>$3,795</td>
<td>$7,858</td>
</tr>
<tr>
<td>Sum of Costs</td>
<td>$2,011</td>
<td>$1,752</td>
<td>$1,496</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>1.66</td>
<td>2.17</td>
<td>5.25</td>
</tr>
<tr>
<td><strong>Program Administrator Perspective, Without Equipment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sum of Benefits</td>
<td>$3,292</td>
<td>$3,352</td>
<td>$3,427</td>
</tr>
<tr>
<td>Sum of Costs</td>
<td>$6,801</td>
<td>$6,542</td>
<td>$6,286</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>.48</td>
<td>.51</td>
<td>.55</td>
</tr>
<tr>
<td><strong>Societal Perspective, With Equipment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sum of Benefits</td>
<td>$3,296</td>
<td>$3,795</td>
<td>$7,858</td>
</tr>
<tr>
<td>Sum of Costs</td>
<td>$13,900</td>
<td>$12,110</td>
<td>$10,340</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>.24</td>
<td>.31</td>
<td>.76</td>
</tr>
<tr>
<td><strong>Program Administrator Perspective, With Equipment</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sum of Benefits</td>
<td>$3,292</td>
<td>$3,352</td>
<td>$3,427</td>
</tr>
<tr>
<td>Sum of Costs</td>
<td>$18,690</td>
<td>$16,900</td>
<td>$15,130</td>
</tr>
<tr>
<td>B/C Ratio</td>
<td>.18</td>
<td>.20</td>
<td>.23</td>
</tr>
</tbody>
</table>

Source: M. Cubed/ Energy and Environmental Economics, Inc.
4.0 Barriers to Implementation

With some notable exceptions, SF Power initially encountered either a lack of interest or outright hostility from businesses it contacted to enroll in the program. It took multiple contacts to convince many of the facilities to even consider program participation. Beyond this generally negative recruitment environment – which notably improved over the three years leading up to the summer study period, as environmental concerns spurred by threats of global climate change increased – project team members identified a number of barriers to small- and medium-sized commercial customer DR participation. The most obvious of these is, as discussed in Section 1, the lack of suitable DR tariffs or incentive programs for this population of energy users; at the time the original research was initiated there were essentially no DR programs available for independent commercial ratepayers with less than 200 kW of demand. As discussed, SF Power was able to obtain a CPUC ruling allowing less than 200 kW peak demand facilities located in five counties with access to the DRP/CBP.

Even with the availability of a DR program, the majority of the energy users who completed the enrollment process were not able to actually participate in the program during the study period because their meters were not installed or billing changes were not completed. If these delays continue they could seriously impair the program’s ability to effectively function.

A key barrier to attracting customers to the program is the difficulty of quickly and effectively communicating important program characteristics (i.e., transaction and information costs). In addition, in many cases once an energy user expressed interest in the program, it was hard to get management’s attention to sign the paperwork; this was particularly true for municipalities. And occasionally there was push-back from employees about reducing their electricity use.

Some prospective participants indicated that they had been previously been approached by PG&E or an aggregator, but ultimately chose not to enroll because they were concerned about the possibilities of facing penalties, or were put-off by burdensome paperwork requirements. In many cases this concern was ultimately addressed by clearly and repeatedly stating that in no case would the participant be exposed to penalties; and by minimizing the amount of curtailment initially expected from them.

Figure 21 shows the survey results related to participants’ stated motivation for enrolling in the program. As indicated in the figure, the top reasons were: right thing to do, save energy, climate, peak load, and grid reliability.
Figure 21. Demand response program benefits ranked by 66 participants with bars showing standard deviations (with survey question referenced by number).

Source: M. Cubed/ Energy and Environmental Economics, Inc.

All told, based on almost four years of experience working with commercial class customers, potential and actual DR participants could be characterized as follows:

- **Environmentally conscious early adopters.** These energy users are regularly searching for cost-effective, environmentally friendly ways to reduce their utility bill, and are open – sometimes eager – to exploring new ideas. Over the four-year period in which the project was developed, there was a steady increase in the number of energy-users who expressed the desire to “go green,” most likely as a result of increased media attention to the issue.

- **Environmentally conscious poseurs.** These ratepayers, who include quasi-public or heavily regulated facilities, are similar to environmentally conscious early adopters but are primarily motivated by obtaining positive media attention and good community relations for their efforts. As a result, they tend to be less willing to adopt expensive or experimental energy management strategies than the early adopters and tend to require considerable “hand-holding” through the negotiation of sometimes complex and usually slow bureaucratic processes. They are particularly wary of large capital investments that do not pay off quickly.
• *Suspicious, penny-pinching, adopters:* These facilities are wary of any kind of significant investment, or even spending time on energy issues. They do, however, want to reduce their electricity costs: every penny saved goes straight to the bottom line. They are willing to pilot new technology – as long as they don’t have to pay much, if anything, to do so.

• *Knife’s-edge adopters.* These facilities, which are typically public sector, are either highly motivated to adopt DR measures or not motivated at all, mostly as a result of their institutional characteristics or whether or not a higher authority is encouraging them to do so. This is particularly the case if budget policies do not allow an individual facility to capture the monetary benefits of program participation. While many cities and counties are eager to participate in environmentally attractive energy management programs, some municipal energy users declined to participate in *any* DR program, in part because they had little institutional motivation to do so.

• *Modestly motivated managers.* These facilities, which include large, multiple tenant buildings, are broadly interested in reducing their electricity costs, and have a mild desire to explore sustainable energy use practices. However, they are risk-adverse and are unlikely to adopt anything but very basic energy management strategies (e.g., lighting retrofits and sensors)

• *High reliability ratepayers.* These facilities are most concerned with ensuring 100 percent reliability. However, they are broadly interested in reducing their electricity costs in an environmentally benign way, particularly if they are in a competitive sector.

• *Non-Adopters.* Aside from facilities that have limited abilities to participate in DR programs (e.g., high reliability ratepayers), these energy users primarily consist of warehouses and wholesalers who virtually refused to even engage in a discussion about proffered programs. In some cases attempts were made to conduct follow-up conversations with non-adopters, to further explore their attitudes, but these attempts were firmly rebuffed by managers or owners who “didn’t have time to waste.”

The project team found that there were little behavioral differences between owner- or tenant-occupied facilities, but a key factor was the accessibility of the decision-maker. With a few exceptions, the ability to communicate directly with the individual responsible for energy-related decisions provided the best chance that DR would be adopted, though in most cases comprehensive information about the proposed intervention and its consequences was required before a facility would proceed further with it.

Publicly owned facilities tended to be more complex to negotiate, particularly since there were more “doorkeepers,” making it difficult to gain access to the decision maker. As previously discussed, these facilities tend to have “knife’s edge” decision-making
processes with regards to adopting energy management measures. That is, they tended
to either readily adopt them, or be unwilling to adopt them at all, based on the facility
manager’s attitudes and overall government policies. Once the “adopters” were
identified through persistent, mostly “cold” calls, the length and complexity of the
interpreters were introduced in an attempt to achieve a successful outcome. enrollment
process varied among municipalities, with some requiring formal approval from a
number of different departments or even the legislative body. That said, given the
collectively large loads frequently available at cities and counties – including water
pumping and HVAC – even with recruitment challenges they make for good prospects.

Facilities at which the decision-maker spoke English as a second language were also
difficult to work with, and on several occasion Mandarin and Cantonese.
5.0 Key Findings and Recommendations

Successful DR programs focusing on commercial customers would seem to require six primary elements:

- A tariff, or set of incentives, which effectively induce energy users to both enroll in the program and undertake the necessary short-term reductions when called upon. In this respect the asymmetrical nature of the CBP’s payment and penalty scheme may inappropriately reduce incentives to participate in the program.

- A consistent, persistent, and informed outreach effort. Without a focused marketing effort it is unlikely that small- and medium-sized businesses will voluntarily adopt DR measures.

- A simple, non-threatening enrollment process (e.g., no lengthy forms with extensive “legalese”).

- A population of energy users who are willing and able to temporarily reduce their electricity use (e.g., some flexibility in their energy use; the labor or technology necessary to respond to calls). The research project similarly demonstrated that multiple experienced-based education efforts may be needed to fine-tune effective participation.

- Sufficient time to recruit participants and fully enroll them in the program – including meter and billing activation – prior to their receiving their first curtailment call, including, if possible, time to conduct trial calls. In this respect the length of time it takes from enrollment to activation needs to be substantially shortened if the program is going to be successful.

- Presentation material specifically tailored to the energy user’s characteristics and circumstances. Similar to the curtailment education process, these materials may need to be developed in an iterative fashion, as experience provides greater knowledge about the energy consumption practices of participating customers at the meter level.

- Program administrators should have flexibility and multiple options for suggesting the most appropriate baseline calculation method to be employed to determine DR-induced responses. Alternatively, suitable adjustments to the existing baseline calculation should be made (e.g., a morning adjustment factor). Given that the population of energy users studied herein hasn’t been subjected to much, if any, inquiries into appropriate baseline estimation methods, care should be taken in adopting a baseline estimation technique should DR programs ultimately be made more broadly available.
5.1. Community-Based Organizations Can Provide an Effective Approach to Encourage Cost-Effective DR Adoption

The survey data indicates energy users prefer working with nonprofit organizations, as shown in Figure 23.

![Bar chart showing institutional preferences for DR program administration](image)

**Figure 23. Institutional preferences for DR program administration (within responses).**

Source: M. Cubed/ Energy and Environmental Economics, Inc.

Community-based organizations (CBO), such as SF Power, can provide a number of benefits to DR recruitment and implementation efforts through:

- Persistent and sustained customer contact. This is particularly the case if the CBO is able to garner funding from several different sources to pursue complimentary projects over an extended time period.
- Knowledge of individual customer characteristics and needs.
- A knowledgeable staff that can match national, state, utility, and local DR programs to the customer base.
Glossary of Terms

BEC – Business Energy Coalition program (demand response program)
CBL – customer baseline load
CCSF – City & County of San Francisco
CHP – combined heat and power
CPUC – California Public Utilities Commission
DBP – Demand-Bidding Program
DER – distributed energy resources
DG – distributed generation
DR – demand response
DRP – Demand Reserves Partnership program (demand response program)
E3 – Energy & Environmental Economics, Inc.
EE – energy efficiency
IOU – Investor-owned utilities
kW – kilowatt
kWh – kilowatt-hour
M³ – M.Cubed
MW – megawatt
NPV – Net-Present-Value
NTG – Net-to-Gross ratio
PAC – program administrator cost
PCT – participant cost test
Produce Mart – San Francisco Wholesale Produce Market
PV – photovoltaic
RD&D – research, development and demonstration
SEP – Southeast Wastewater Treatment Plant
SFE – San Francisco Department of the Environment
SFPUC – San Francisco Public Utilities Commission
SFUSD – San Francisco Unified School District
SLG – single-line-to-ground
T&D – transmission and distribution
TAC – technical advisory committee
TOU – time of use
TRC – total resource cost