Final Report

2008 Process Evaluation of California Statewide Aggregator Demand Response Programs

Prepared For:

CALIFORNIA ENERGY COMMISSION

CALIFORNIA PUBLIC UTILITIES COMMISSION

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SOUTHERN CALIFORNIA EDISON

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EVALUATION OVERVIEW

This process evaluation is Volume 3 of a three-part project focused on aggregator-driven demand response programs operating in California in 2008. Volume 1 presents the results from an ex post and ex ante impact evaluation focused on estimating the load impacts.[1] Volume 2 presents the results from a baseline analysis study.[2]

This evaluation investigated three demand response programs operating in the territories of California's electric investor-owned utilities (IOUs): Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

The three demand response programs include:

- **Capacity Bidding Program (CBP) –** a statewide program operating in the territories of all three IOUs
- **Aggregator Managed Portfolio (AMP)** – offered by PG&E
- **Demand Response Resource Contracts (DRC)** – offered by SCE

While CBP is a statewide program, some components and processes vary between the IOUs. The evaluation focuses on the experiences of the utilities, aggregation firms, and customers involved in the programs during Program Year 2008.

This project included process and impact evaluation activities designed to assess how effectively the programs have been administered and to develop information on customer awareness of and response to the programs. This volume presents the results of the process evaluation work, which included:

- Developing a logic model and program theory for the portfolio of aggregation programs
- Conducting in-depth interviews with program staff and representatives from aggregation firms

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1 Christensen Associates Energy Consulting, LLC. *2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs. Volume 1: Ex Post and Ex Ante Report*. May 1, 2009.

2 Christensen Associates Energy Consulting, LLC. *2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs. Volume 2: Baseline Analysis of AMP Aggregator Demand Response Program.* May 1, 2009.

- ➡ Fielding participant phone surveys
- ➡ Conducting surveys with a sub-set of consistent and inconsistent load providers.

This evaluation was performed under the guidance of the Demand Response Measurement and Evaluation Committee, consisting of representatives from each of the three electric IOUs, the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC).

DATA COLLECTION AND SURVEY SAMPLE DESIGN

This process evaluation included in-depth interviews with representatives of each of the five programs reviewed: AMP, DRC, and CBP contacts at each of the three participating IOUs. In addition, we conducted two sets of surveys with participants. The first survey comprised a statistically valid sample of over 200 participants and covered a range of process issues, including: communication and interaction with the program; expectations from participation; overall satisfaction with various components of the programs; and future demand response intentions. The second survey was a qualitative conversation with a subset of participants that had been previously categorized as *consistent* or *inconsistent* responders, based upon the load impact analysis completed by the impact evaluation team.[3]

KEY FINDINGS

The following are the key findings from this current process evaluation.

- ➡ **Program processes had become more streamlined and routine in 2008**. Staff at all three utilities reported improvements to their program processes in 2008. Most often, these involved efforts to streamline and facilitate enrollment. Many program processes that were new or under development in 2007 had become routine in 2008. Contacts from aggregation firms and from the three utilities reported developing solid working relationships with each other. These factors made the 2008 program year a positive experience for everyone involved.
- ➡ **The value and expertise of the aggregation firms has become apparent to utility staff.** Utility contacts expressed appreciation for the work of the aggregation firms and their perceived ability to identify and recruit a variety of customers for demand response curtailment; utility contacts also described becoming more aware of the specific benefits of working with aggregators.

  Utility contacts were optimistic that aggregation firms were tapping into customers who had not already participated in demand response programs. This belief was confirmed

[3] For a more extensive description of the methodology and sampling strategy, see Appendix A.

during the participant surveys, in which over 75% of contacts reported that their organization had not previously participated in demand response programs.

Both utility contacts and those from aggregation firms reported that account representatives had been reluctant advocates for aggregation demand response programs. However, while over half of participants surveyed reported they had first heard of the program from their aggregator, 25% reported hearing of the program first from their account representative, indicating that account representatives are marketing the program.

➡ **Aggregators enroll participants in a specific program by considering the price paid per curtailed kW and the level of risk**. Aggregators participating in multiple programs consider payment levels and risk in deciding between the CBP and AMP or DRC. Aggregators enrolled in only one program have no choice when nominating load for the month. However, aggregators enrolled in multiple programs in one service territory must decide between programs. Aggregation contacts report enrolling customers and nominating load based on the price paid for capacity and the potential for risk if the customer fails to meet curtailment goals. Other contacts sought to benefit from particular features of the CBP, or used the program as a reserve for load they were considering adding to their DRC or AMP contract. Because of these comments, we expect that, as aggregators begin to exceed their contractual obligations associated with DRC and AMP, they will increasingly place excess capacity into the CBP.

➡ **Participants reported no major problems with their 2008 program experience.** Only about a quarter of the contacts reported having questions that had to be resolved prior to enrollment, of this group, the most common concern centered on penalties and program flexibility. In general participants reported:

- The notification strategy worked well for their organization.
- Payment amounts met or exceeded their expectations.
- The payments were received within the timeframe they expected.
- They intended to participate in the 2009 program.

➡ **We found few discernable differences between participants characterized as *consistent* and *inconsistent* responders**. The post-event survey results revealed no discernible differences in how consistent and inconsistent responders answered questions related to their setting load reduction goals, their experience of event notifications, the actions they typically took to curtail, their methods for tracking demand response performance, and their communications with aggregators

The results of the participant survey indicate that having a specific curtailment plan was related to the effectiveness of demand response activities. Consistent responders were significantly more likely to report possessing a specific action plan than inconsistent responders.

➡ **Enabling technology is installed to facilitate participation, but most participants continue to rely on manual curtailment activities**. When asked what type of action they took in response to the curtailment request, most participants reported manually shutting down equipment. This was followed, somewhat distantly, by manually launching an automatic curtailment system or program.

A majority of participant contacts reported not having an EMS system installed prior to enrollment, and few reported installing one after enrolling in the aggregator's demand response program. In general, participant contacts who reported that they or their aggregator had installed equipment to enable participation could only vaguely describe the type of equipment – most mentioned metering equipment or consumption monitoring equipment.

There is some indication that participants enrolled in SCE's DRC program have more equipment installed – particularly sub-meter, PIB, and communication equipment. These participants were significantly more likely to report that their aggregators had installed technologies in their facilities when compared to other programs.

➡ **Participants report taking actions in response to curtailment requests, but many contacts believe their participation is optional**. Almost all participants that received a notification request reported taking action to reduce their energy use. The most common action was to manually shut down equipment. However, more than three-quarters believed that their response to the curtailment request was optional. We found no difference between programs or utility territory, indicating a widespread perception among participants that they do not necessarily have to curtail when called. It is not clear whether this is communicated to them by their aggregator, or if the aggregators are unaware of this perception.

➡ **Few participants are turning to backup generation to assist in curtailment.** While almost 40% of participant contacts reported having access to back up generation, only 5% ultimately reported that they used this equipment to comply with curtailment requests.

➡ **The diffuse and opaque nature of the aggregated load providers and their relationships with their aggregators creates challenges in obtaining information and characterizing participants**. We were able to interview 10 of the 11 active aggregators, but experienced difficulty obtaining the customer contact information required to launch the customer survey. Several aggregation firms were unresponsive to requests for customer contact information, while others were quick to provide this information. In some cases, utility staff had to compile lists from paper enrollment files. Regardless of the source of contact information, it remained quite difficult to link a specific contact to a service agreement (SA ID) as reported in the data files provided to the impact evaluation.

- Since SA ID numbers do not necessarily map to one meter or badge number, or even one location, the process evaluation contact lists had to be linked to organizations as they appear in the utility customer information system. This listing may or may not match the organization name as reported by the aggregator, and thus, for about 40% of cases, we were unable to link the contact name to a specific event.
- Additionally, since the actual curtailment goals are established in agreements between aggregators and their customer load providers, the impact analysis can only assess if a response occurs, not whether or not participants are consistently or inconsistently meeting their demand response goals.

➡ **The post-event surveys were too distant from curtailment events to permit in-depth assessment with contacts**. We used the results of the impact team's load impact coefficient analysis to classify participants into categories of consistency. This strategy did not allow for an in-depth understanding of the differences between *consistent* and *inconsistent* responders, particularly since interviews followed curtailment events by six months or more. A post-event survey conducted immediately after a demand response event would be more likely to yield detailed responses, but could fail to identify meaningful differences between consistent and inconsistent responders because:

- Curtailment goals could be so low that they fail to emerge in post-event analyses of performance.
- Participants may not have a clear sense of their demand response performance relative to their load reduction commitments.

CONCLUSIONS AND RECOMMENDATIONS

In light of the findings from this process evaluation, we make the following conclusions and recommendations:

➡ ***Conclusion 1:* Opportunities for simplifying the eligibility and enrollment process should be explored**. All three utilities require the Add/Delete form for the CBP, which they developed collaboratively when they agreed to hire APX and use the same enrollment form. AMP also requires an Add/Delete form in order to formally enroll a participant. However, in some cases, an SA template, a Customer Information Standardized Request form (CISR) or a Third Party Authorization (TPA) may also be required. Contacts from utilities and aggregation firms both noted the difficulties associated with the CISR and wondered if this form could be replaced. Only DRC does not require an Add/Delete form, instead relying on the CISR alone.

The enrollment forms serve two major purposes: (1) they ensure that the customer is qualified to participate in the aggregator's demand response program; and (2) they ensure that the customer is aware of and agreeing to participate in the program. It may be possible to design a form that fulfills both purposes. The CISR contains no specific reference to demand response program enrollment, but can be used to determine eligibility, while the Add/Delete form clearly indicates that the customer is enrolling in a demand response program with an aggregation firm, regardless of eligibility.

> ***Recommendation A:*** Consider enabling eligibility verification of a given SA ID or customer on-line through a log-in feature

> ***Recommendation B:*** Consider replacing the CISR with a form designed specifically for aggregation demand response activities, and/or merging the CISR and Add/Delete into a single form

➡ ***Conclusion 2:*** **The APX interface caused problems for aggregators with numerous enrolled meters**. In 2008 the interface required aggregators to re-load their entire nomination list every month by dragging and dropping each SA ID into the web-based form. Providing access to prior month's lists or defaulting to the last nomination list could simplify and speed up the process for aggregators, who could then focus only on making specific, relevant changes.

> ***Recommendation:*** Encourage APX to improve the nomination interface by creating a nomination process that defaults to the prior month.

➡ ***Conclusion 3:*** **Ways of speeding up the settlement process should be explored**. Staff from all programs described a somewhat complicated process of receiving, verifying, and confirming meter data prior to releasing it to aggregators. Obtaining settlement-quality meter data generally requires the involvement of multiple people or departments and can take time. While staff reported getting this information out to aggregators within 60 days, this could result in statements being delivered to participants up to 90 days after an event. Aggregators noted that the timeframe for settlements and payments was problematic, with more than half of them saying it could take months to receive payment.

> ***Recommendation A:*** Compare the initial meter data with the final settlement-quality meter data. If the difference between the two data sets is nominal, consider developing a *true-up* process, whereby initial curtailment is calculated and adjusted if necessary in the next program month to address any difference between the initial calculation and the SQMD.

> ***Recommendation B:*** Consider assigning all participants to calendar billing to avoid settlement delays caused by meters scheduled to be read late in the month.

➡ ***Conclusion 4:* Demand response program options should be streamlined and the features of each clarified on utility websites.** Documenting the program listings on the utility websites confirmed comments from aggregator contacts that numerous demand response programs are listed on utility websites. Given the large number of demand response programs listed on utility websites, it is difficult for many customers (and aggregators) to gauge eligibility and determine which program is most appropriate.

> ***Recommendation:*** Consider allowing customers to enter their account or SA ID information to obtain a list of demand response programs for which they are eligible.

➡ ***Conclusion 5:* Aggregators can be helped in marketing demand response programs by translating the triggers into meaningful social and individual benefits**. Aggregators struggled to explain the trigger and/or likelihood of events to potential CBP participants. The official *heat-rate* trigger is difficult for aggregators to explain or predict. Few aggregators reported they were able to predict the likelihood of curtailment events, particularly for the CBP. Post-event survey respondents indicated that knowing the reason behind the demand response event could help them enlist the cooperation of others by helping them communicate about the event to large groups of students, staff, or customers.

Participants believe they are curtailing because of grid-reliability issues. When asked if they knew why they had been asked to curtail in 2008, almost half reported they believed they were responding to grid-reliability issues, including a subset specifically mentioning they were asked to curtail to avoid brownouts and rolling blackouts.

Demand response programs often appeal to participants for both social and individual benefits, and both are important motivators for participation. Improved understanding of when and why curtailment events are called could help aggregators recruit customers and help customers understand why they are being called to curtail.

> ***Recommendation:*** Consider clarifying or refining the reasons for demand response with both social and individual benefits to make it easier for aggregators to communicate to their customers the circumstances under which curtailment events are likely.

➡ ***Conclusion 6:* Many organizations appear poised to undertake a variety of energy efficiency upgrades and/or consider all options of reducing their peak demand, including investments in permanent demand reduction**. All participant contacts were asked if they were considering installing additional equipment or technologies that might allow for additional demand response during events. Twenty-three percent reported considering additional equipment. When asked to describe the equipment, contacts described a variety of equipment, including efficiency upgrades (such as efficient lighting and HVAC upgrades) and solar panels that might reduce the organization's overall demand, but would be unlikely to help them drop additional load during a curtailment event. The frequency of the solar panel response is notable because the net metering that generally accompanies solar panel installation would disqualify an organization from participating in any of the aggregator-driven demand response programs as currently structured.

> ***Recommendation A:*** Explore the possibility of including participants with solar net metering.
>
> ***Recommendation B:*** Identify strategies for linking participants with energy efficiency programs, as many of these organizations are committed to doing everything possible to reduce their energy use.

1 INTRODUCTION

This process evaluation is Volume 3 of a three-part project focused on aggregator-driven demand response programs operating in California in 2008. Volume 1 presents the results from an ex post and ex ante impact evaluation focused on estimating the load impacts.[4] Volume 2 presents the results from a baseline analysis study.[5]

SCOPE OF THE EVALUATION

This evaluation investigated three demand response programs operating in the territories of California's electric investor-owned utilities (IOUs): Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The evaluation focuses on the experiences of the utilities, aggregation firms, and customers involved in the programs during Program Year 2008.

The three demand response programs include:

- ➡ **Capacity Bidding Program (CBP) –** a statewide program operating in the territories of all three IOUs
- ➡ **Aggregator Managed Portfolio (AMP)** – offered by PG&E
- ➡ **Demand Response Resource Contracts (DRC)** – offered by SCE

While CBP is a statewide program, some components and processes vary between the IOUs.

PROGRAMS EVALUATED

Capacity Bidding Program

The Capacity Bidding Program (CBP) is a statewide price-responsive program developed to succeed the California Power Authority's Demand Reserves Partnership program that ended in 2006. The CBP is a tariff program that provides specific payments to nonresidential customers who volunteer to reduce their energy use (load or capacity) by a specific amount for each month

4 Christensen Associates Energy Consulting, LLC. *2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs. Volume 1: Ex Post and Ex Ante Report*. May 1, 2009.

5 Christensen Associates Energy Consulting, LLC. *2008 Load Impact Evaluation of California Statewide Aggregator Demand Response Programs. Volume 2: Baseline Analysis of AMP Aggregator Demand Response Program.* May 1, 2009.

of the CBP season (May through October). The CBP first was implemented in 2007.

Bilateral Contract Programs

Following direction from the CPUC, PG&E and SCE each issued an RFP to establish bilateral agreements for additional demand-response resources. In May 2007, the Commission approved five such demand-response agreements between PG&E and third-party aggregators. These contracts became the Aggregator Managed Portfolio (AMP). The CPUC approved one such agreement for SCE in early 2007. SCE proposed eight additional aggregator contracts in October 2007; in March 2008, the CPUC approved four of them. These contracts became the Demand Resource Contracts (DRC) program.

Aggregator Managed Portfolio (AMP)

PG&E's Aggregator Managed Portfolio (AMP) allows aggregators to negotiate agreements with PG&E to deliver a specified amount of demand response for a price established in the contract. As negotiated bilateral contracts, the terms (both the level of demand-response capacity promised and the price paid for it) between PG&E and each aggregator can vary.

Demand Resource Contracts (DRC) Program

SCE's Demand Resource Contracts (DRC) program procures demand response capacity through aggregators responsible for marketing the opportunity, identifying and enrolling eligible customers, notifying those customers of curtailment events, and reconciling payments for customers who curtail their energy use during events. The DRC program is guided by contracts negotiated between each aggregator and SCE. As in the AMP program, the terms (both the level of demand-response capacity promised and the price paid for it) between SCE and each aggregator can vary.

Logic Model and Program Theory

Prior to beginning any of the data-collection work, the evaluation team developed a program logic model for the statewide CBP from both the utility and aggregator perspectives (Figure 1.1 and Figure 1.2, respectively). These two components implement the program to meet their own goals and objectives. Ultimately, we reviewed these logic models and revised them to reflect the broader logic inherent in the aggregator-driven program model.

We found that, while the programs vary slightly in *process* (requiring different forms, payment amounts that vary by tariff or contract terms, whether or not the settlement occurs in-house or is calculated by the third-party vendor, APX), they do not vary significantly in theory or logic: all five programs rely upon aggregators to identify and recruit customers capable of reducing their energy use when requested by the utility in exchange for payment.

Figure 1.1: Logic Model – Utility Perspective Aggregator-Driven Demand Response Programs

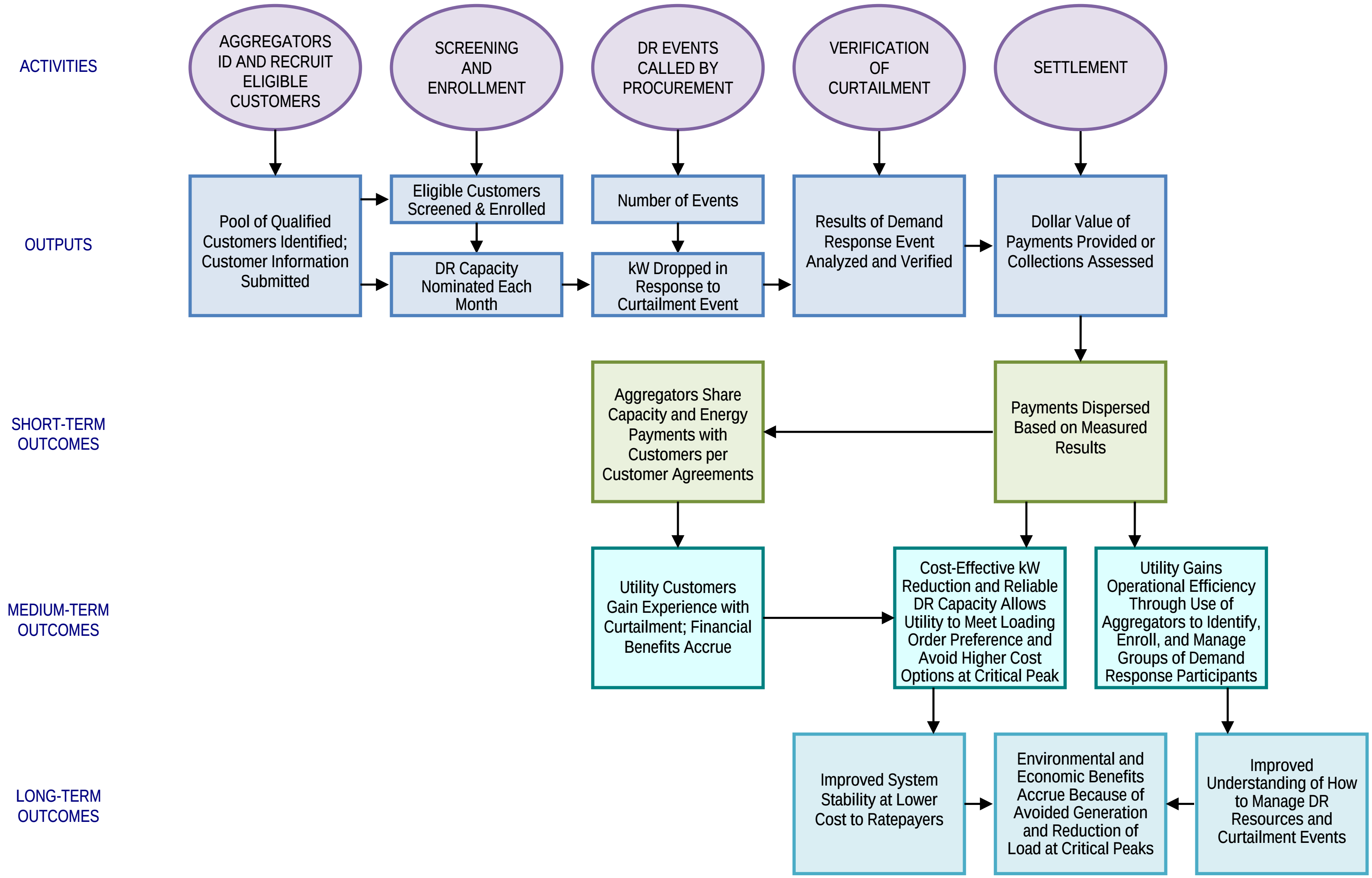
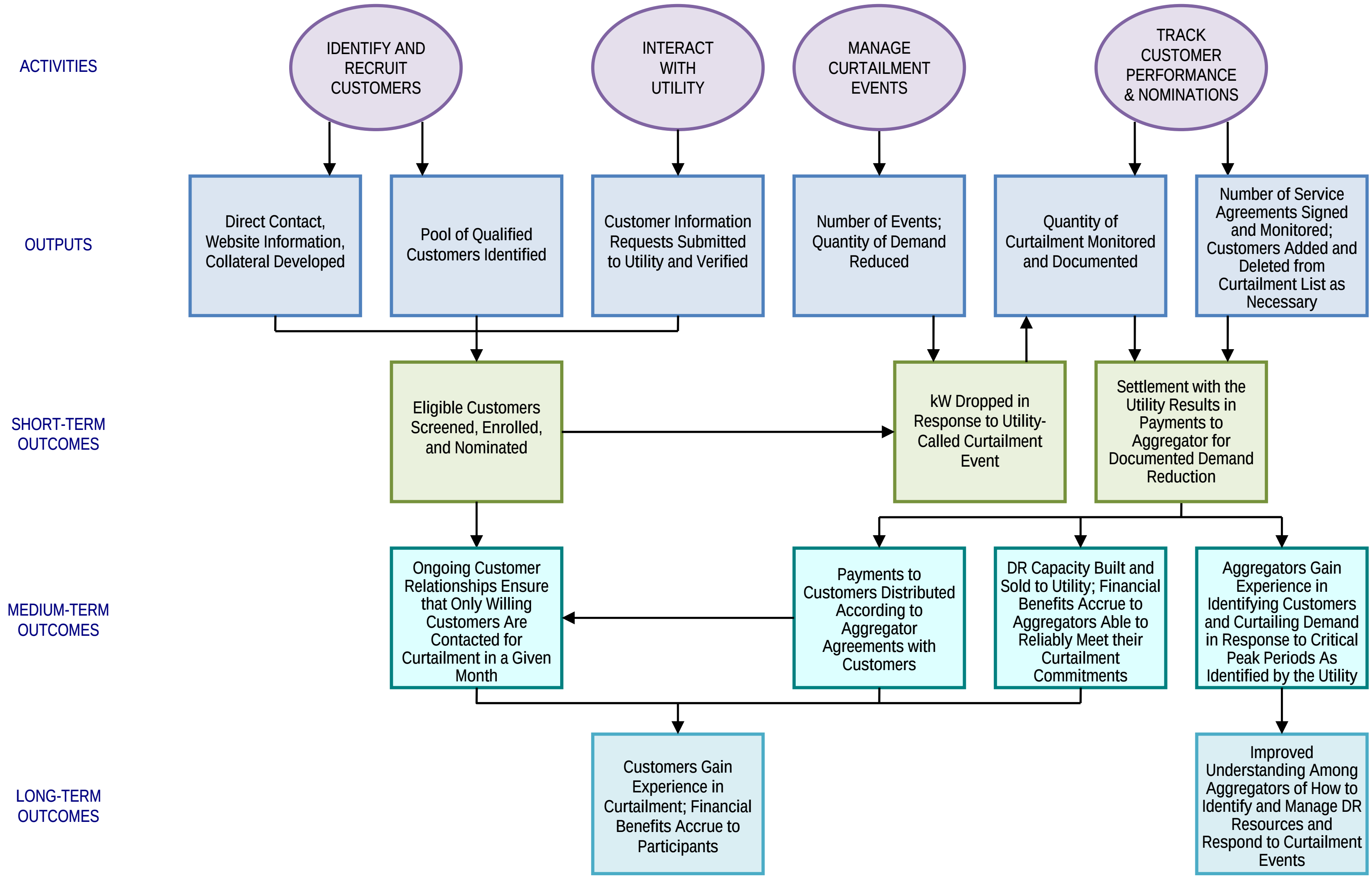


Figure 1.2: Logic Model – Aggregator Perspective Aggregator-Driven Demand Response Programs



The most significant variation occurs in SCE's DRC program and involves a technical assessment analysis that results in a *reasonableness* review of the curtailment as nominated by DRC aggregators, and allows SCE to adjust the contract payments accordingly. This is discussed in more detail in Chapter 2. DRC is also the only program operating year-round. However, both of these components affect the process of implementing the program, not the underlying logic.

Program Theory

Program Theory from the Utility Perspective

The utility program theory (Figure 1.1) assumes that by recruiting aggregators to organize and coordinate the demand response activities of groups of customers, the California utilities will gain access to a previously unknown pool of qualified customers. Screening and enrollment activities conducted by the utilities will ensure aggregator-identified customers are enrolled in demand response programs.

Utility procurement departments will call demand response events when needed. Verification activities will ensure the utility pays only for demand response that actually occurs during events. Aggregators will then distribute capacity and energy payments with their enrolled customers, as outlined in agreements previously executed with each customer.

These program activities will result in a reliable response to curtailment events. The actual level of demand response that occurs will be analyzed and verified, and financial payments will be made or penalties assessed per the payment terms established by tariff (for CBP) or by contract (AMP and DRC). Implementation of the aggregator-driven demand response programs will augment existing demand response resources and will result in California utilities: meeting loading order preference; avoiding high-cost purchases during periods of critical peak; and improving system stability.

It is also expected that the utility, aggregators, and customers will gain experience with demand response. Utility experiences will result in improved operational efficiency and understanding of how to manage demand response resources and to call events. Aggregators will gain experience in enrolling and managing groups of customers. Customers will gain experience with actual curtailment. Financial benefits will accrue to aggregators and customers for successful demand response. Finally, economic and environmental benefits will accrue from avoided generation and reduction of load during periods of critical peak.

Program Theory from the Aggregator Perspective

Aggregators identify potentially qualified customers (Figure 1.2) and recruit them to CBP, AMP, or DRC, depending upon a variety of factors, including: the program in which the aggregator is enrolled, the price paid per curtailed kW, and the level of risk perceived by the aggregator with a given customer.[6] Through interaction with the customer's utility, aggregators are able to screen, enroll, and consolidate a quantity of demand response capacity. In the case of AMP and DRC, the quantity of demand response capacity should match the amount they have committed to nominate. Aggregators manage this demand response capacity through ongoing interaction with a data exchange website (for CBP) and through other tracking activities.

Aggregators will shed capacity as promised during a utility-called demand response event. The utilities will analyze and verify the results of these events and aggregators will receive payments from the utility according to existing agreements for documented curtailment. Aggregators will distribute these payments to customers according to agreements previously executed with each customer. Through communication, payments, and curtailment assistance, aggregators will build and maintain on-going customer relationships that help them manage customer expectations and avoid conflicts over requests to drop load. Customers will gain experience with curtailment activities, and also realize financial benefits from demand response and their relationship with an aggregator.

Aggregators will gain experience in identifying customers and managing curtailment activities during an event, and will become better able to build and sell demand response capacity to the utility. Aggregators will profit from this activity and build larger and more reliable portfolios of demand response. Aggregators will develop a better understanding of how to identify and manage demand response resources, and will respond successfully to future curtailment events.

METHODOLOGY AND POPULATIONS

This process evaluation included in-depth interviews with representatives of each of the five programs reviewed: AMP, DRC, and CBP contacts at each of the three participating IOUs. In addition, we conducted two sets of surveys with participants. The first survey comprised a statistically valid sample of over 200 participants and covered a range of process issues, including: communication and interaction with the program; expectations from participation; overall satisfaction with various components of the survey; and future demand response intentions. The second survey was a qualitative conversation with a subset of participants that had been previously categorized as *consistent* or *inconsistent* responders, based upon the load impact analysis completed by the impact evaluation team.

For a more extensive description of the methodology and sampling strategy, see Appendix A.

6 Assuming that when they have choice, aggregators are most likely to enroll customers into the program that offers the best price per kW curtailed with the least amount of risk. For example, if an aggregator is skeptical that a customer will meet the load curtailment targets established, that aggregator would likely enroll the customer in the program where underperformance will cost the least.

THIS REPORT

Following this introduction are five chapters. Chapter 2 presents a fuller description of each of the programs, and incorporates information and lessons learned from the in-depth interviews with staff contacts. Chapter 3 describes the experience and opinions of enrolled aggregators. Chapter 4 presents the results of the general participant survey, and Chapter 5 presents the findings from the smaller post-event survey. Finally, we offer conclusions and recommendations in Chapter 6.

2 PROGRAM DESCRIPTIONS

This chapter presents a brief description of each program and the experiences of the program staff.

DEMAND RESPONSE PROGRAM PORTFOLIOS

The California IOUs offer a variety of programs covering all aspects of demand response. Each utility offers a portfolio of demand response programs that includes both reliability and price-responsive programs. In some cases, a program will offer a specific rate to a customer willing to interrupt or reduce demand during a system emergency (e.g., the Base Interruptible Program or Critical Peak Pricing). In other cases, a customer will sell their capacity through a bid to the utility (e.g., the Demand Bidding Program).

Reliability programs are called when the system is at risk because of high-demand, instability, or because of transmission and distribution constraints. These programs include direct load control, large customer emergency and capacity programs, and voluntary interruptible or curtailable rate schedules. Reliability programs do not necessarily compensate enrolled customers for the load they drop during a called event. This is particularly true when the program provides ongoing benefits to participating customers through lower rates in exchange for potential or occasional requests to drop load.

Price-responsive programs, on the other hand, pay a specific, established price for demand response capacity and may include penalties for nonperformance. These programs tend to be called when prices or demand are particularly high, thus serving as a hedge against volatility in the wholesale power markets. Many utility representatives do not regard the capacity nominated through price-responsive demand response programs as a firm resource, but rather as a strategy for improving the overall efficiency of electricity markets.[7]

The characteristics of each program are not necessarily obvious to potential participants, or even participating aggregators. As is demonstrated in Table 2.1, each of the utilities offers multiple pricing and bidding programs.

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7 Hopper, Nicole, Charles Goldman, Ranjit Bhharvirkar, and Dan Engel. *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. See: *http://eetd.lbl.gov/EA/EMP/reports/62754-revised.pdf*.

Table 2.1: Utility-Based Demand Response Options

PG&E	SCE	SDG&E
PeakChoice Program	Agricultural and Pumping Interruptible Program	Base Interruptible Program
Base Interruptible Program	Automated Demand Response	Capacity Bidding Program
Capacity Bidding Program	Time of Use Base Interruptible Program	CleanGen
Critical Peak Pricing	Large Power Interruptible Program	Critical Peak Pricing
Demand Bidding Program	Capacity Bidding Program	Critical Peak Pricing – Emergency
Optional Binding Mandatory Curtailment Plan	Critical Peak Pricing	Peak Generation
Pilot Optional Binding Mandatory Curtailment Plan	Demand Bidding Program	
Smart AC™	Optional Binding Mandatory Curtailment Program	
	Summer Discount Plan	

Note: These represent demand response program options listed on utility websites as of March 31, 2009.

Aggregator-Driven Programs

This evaluation focused on the three programs that rely on curtailment service providers to aggregate eligible, but usually not-yet-participating, customers and to coordinate their curtailment activities when activated by the utility. These aggregators are a diverse group of energy service firms operating in California, with headquarters throughout the nation. The three aggregator-driven programs reviewed here are the statewide Capacity Bidding Program (CBP), PG&E's Aggregator Managed Portfolio (AMP), and SCE's Demand Resource Contracts (DRC) program.

All three of the programs are price-responsive. That is, in response to a notice from the utilities, aggregators ask customers to curtail their energy use in exchange for a payment established prior to the notice. The most distinguishing difference between the programs is the mechanisms through which prices are established for nominated capacity and curtailed energy.

For the CBP, price-per-unit of nominated capacity and curtailed energy is established by tariff. That is, unlike programs with bilateral agreements, all participating aggregators receive the same capacity credit payment per kilowatt-hour they nominate. These prices vary depending on the type of product selected (day-of, or day-ahead) and the length of the curtailment promised in hours-per-day (4, 6, or 8 hours). Participants may adjust their nominations each month, including their day-of/day-ahead choices and event duration. CBP aggregators earn energy payments based on the level of delivered energy relative to nominated capacity for any month in which there is an event.

For the AMP and DRC program, the price paid to aggregators per unit of nominated capacity and curtailed energy is set in bilateral contracts negotiated between aggregation firms and the utilities (PG&E and SCE, respectively).

While differing in the mechanisms through which prices are set, the three programs have many similar and important components. (Table 2.2) Other differences include whether or not the nominations and settlement calculations are managed by the utility (in the case of AMP and DRC) or through APX (in the case of CBP) and how penalties are assessed. SCE's DRC is the only program operating year-round.

Table 2.2: Major Program Components: Summary Table

COMPONENT	CBP	AMP	DRC
Utilities Offering	Statewide (All)	PG&E	SCE
Prices Established By	Tariff[1]	Contract	Contract
Trigger	Called by procurement, guided by the heat rate of the generation portfolio	Called by procurement at utility discretion	Called by procurement at utility discretion
Aggregator Only	No In 2008 customers could participate directly[2]	Yes	Yes
Collateral Required	SCE, SDG&E only	Yes	Yes
Monthly Nomination	Yes	Yes	Yes
Capacity Payments	Yes	Yes	Yes
Energy Payments	Yes	Yes	Yes
Penalties	Yes (For delivery of less than 50% of nominated load)	Yes (For delivery of less than 50% of contracted load)[3]	Yes[4]
Who Calculates Settlement	APX with utility input	Utility	Utility
Baseline Calculation Method	3 in 10	3 in 10	3 in 10
Eligible Customers	Over 20 kW: must have an IDR	Size not specified: must have IDR meter and Internet access	Size not specified: must have IDR meter and Internet access
Season	May-October	May-October	Year-round (usually called in the summer)

1 CBP tariff contains language noting that curtailment events may be triggered when generating resources reach a resource dispatch equivalence of 15,000 btu/kWh heat rate or as system conditions warrant (including high temperatures, supply constraints, system emergencies).

2 Only SCE had directly enrolled customers in 2008; there were fewer than five.

3 Penalties do not apply to test events.

4 Aggregators that fail to deliver promised load reduction during a DRC event are charged $4,000 for the first MW of missed load reduction and $1,000 for each additional MW of missed load reduction. However, these penalties are not necessarily based on the amount of capacity specified in the DRC contract, because SCE has developed a process whereby they test and adjust the expectations and associated payments based on the capacity actually demonstrated in a test event.

THE CAPACITY BIDDING PROGRAM

The CBP is a statewide, voluntary demand response program that offers customers incentives for reducing energy consumption upon request. This price-responsive program was developed in 2006 to succeed the California Power Authority's (Power Authority) Demand Reserves Partnership program. As noted above, CBP is a tariff-driven program that provides specific payments to nonresidential customers that volunteer to reduce their energy use by a pre-specified amount during the CBP season (May-October). CBP was first implemented in 2007.

Trigger

The earlier Power Authority program had operated with a firm *strike price*, or *trigger* whereby the program could be called whenever the market price for power reached a certain threshold. With the program's migration to the utilities, the trigger was changed. Currently, the utilities can initiate the CBP whenever the *electric resource generation facilities reach or exceed a heat rate of 15,000 BTU/kWh.* Theoretically, using a generation heat-rate threshold means the demand response program would be triggered when utilities must rely on dirtier, less efficient generation resources. Each utility's internal energy procurement group monitors its unique generation-portfolio efficiency and decides when to call the program. Thus, the trigger reflects the generation portfolio efficiency of each utility. The utilities consider this proprietary information and will not share it with third parties. According to program contacts, the generation heat rates cannot be completely transparent without a risk of gaming by other load-serving entities or independent power producers that regularly sell power to the California IOUs.

The CBP contacts at all three utilities reported that procurement departments track the generation heat rate and call events. While the heat-rate trigger is established in the program guidelines, it is viewed as more of a principle than a rule, since the program can be called whenever the utility forecasts that resources may not be adequate. According to CBP staff contacts, this *soft trigger* can occasionally create communication challenges for program staff because it is hard to explain and is based on confidential information.

Marketing

The three utilities conduct almost no marketing of the CBP. Instead, the utilities rely on curtailment service providers to market the program to potential participants. These aggregators are responsible for contacting and enrolling customers, identifying demand response capacity, aggregating the load represented by these customers, and selling this resource to the utility via monthly nominations of demand response capacity.

CBP staff members at each of the IOUs interact primarily with the aggregation firms, not the participating end-user customers. However, the utilities do offer limited direct CBP marketing activities, including flyers or website information, combined with information presented directly to account executives.

- ➡ **SCE** holds periodic meetings for aggregators and account executives. The utility also gathers its account executives each year to inform them about the its energy efficiency and demand response program portfolio. There are opportunities during this meeting to answer questions and make presentations about existing programs and any changes for the current program year.
- ➡ **PG&E** relies on information posted on its website and on aggregators' efforts to inform and recruit new customers.
- ➡ **SDG&E** posts information and program brochures on its website.

Staff at all three utilities report occasionally interacting with end-use customers who call to check on the legitimacy of the aggregation firm, ask questions about the settlement process or payment stream, or to get help resolving an issue with their aggregator.

Other Features

As noted above, aggregators sell their portfolio of demand response capability to the utilities per the terms of the CBP tariff. The terms of curtailment commitment represented by each customer and the payment terms established between the aggregator and customer are not known to the utility. As established in the tariff, the utilities pay aggregators 20% more per enrolled kW than they pay their directly-enrolled customers. This additional charge compensates aggregators for their efforts to recruit customer load providers, for managing the notification and curtailment activities, and, in some cases, for absorbing the risk of potential penalties for underperformance when a demand response event is called.

By the end of 2008, the CBP had been implemented for two years. At all utilities, customers are enrolled through their Service Account numbers (SA ID) and participation can be measured in the number of service accounts nominated. Each customer has a unique customer number; however, customers may have multiple service accounts if they have multiple locations, or even multiple meters at the same location.

Nomination and Settlement

A distinguishing feature of the CBP (when compared to the AMP or DRC) is the program's dynamic nomination process. This means an aggregator can vary the level of load nominated each month, based on the load profile of individual customers. Each of the IOUs has contracted with the same third-party, web-based service provider – APX – to manage the nomination and settlement process for the CBP. Each aggregator manages their nominations through the APX system. Each utility's data is separate, so an aggregator participating statewide has three passwords and could have three upload tasks each month.

When the procurement department at an IOU decides to call an event, they contact APX. APX sends a signal to the aggregators, identifying the CBP option and product to be called. The CBP operates two options (*day-of* or *day-ahead*) and three products (durations of *1-4 hours*, *2-6 hours*, and *4-8 hours*). This means the CBP offers more flexibility than the bilateral programs, but requires that aggregators specify both the product and the duration for each SA ID during each month's nomination. Once an event is called, aggregators inform customers and launch their respective curtailment activities at the required interval.

At the end of any month in which an event was called, the IOUs work with APX to track observed performance and calculate credits based on observed load reductions. This information is sent to the aggregators in the form of a settlement payment or penalty notice. The utilities provide settlement information to the aggregation firms no later than 60 days after the event month has ended. Aggregators distribute payments to individual customers.

CBP staff at all IOUs must interact with APX frequently (particularly during the CBP season) and less frequently with the California Independent System Operator (CAISO). CBP staff at each of the IOUs also participates in regular conference calls with their counterparts at the other utilities. These conference calls provide an opportunity for CBP staff statewide to coordinate activities, discuss emerging issues or lessons learned, and identify opportunities to improve coordination or communication with APX. Utility staff informs CAISO whenever a demand response program is called. In addition, CBP staff from all three IOUs meets at least annually to discuss: lessons learned; pending changes or upgrades to the program or APX systems; and, more recently, progress in the state's Market Redesign and Technology Upgrade (MRTU) effort.[8]

In 2008, each of the CBP options (day-of and day-ahead portfolios) was called by all three utilities at least once (Table 2.3).

Table 2.3: Number of 2008 CBP Events by Utility

UTILITY: OPTION	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	TOTAL
PG&E: Day-Of	1	—	—	—	—	1
PG&E: Day-Ahead	—	—	1 (Test)	—	—	1
SCE: Day-Of	—	—	—	—	2	2
SCE: Day-Ahead	—	5	8	4	3	20
SDG&E: Day-Of	—	—	—	—	2	2
SDG&E: Day-Ahead	—	2	—	—	—	2

8 This effort is focused on ensuring that power suppliers have fair and open access to the transmission system within the ISO control area, resulting in the delivery of the least-cost electricity to consumers. Features are likely to include a day-ahead market for energy, an integrated forward market, and locational pricing. For more information, see the CAISO website: *www.caiso.com*.

SCE's day-ahead option was activated far more than were the other utilities'. The actual number of portfolios (represented by *option*, *duration*, and *aggregator*) activated during an event can vary, making it difficult to say whether or not every CBP customer enrolled in a given month would have experienced each event.

The utility-specific experiences as described to us by contacts at each of the three IOUs are presented below.

Utility-Specific Experiences: CBP at Pacific Gas & Electric

Enrollment and Nomination

In order to be enrolled as an aggregator at PG&E, a firm needs to complete the aggregator enrollment form provided on the utility's CBP page on the PG&E website. PG&E does not require a collateral deposit from enrolled aggregators.[9] In 2008, there were 12 aggregators enrolled in the program, but only six were active, in that they had nominated load for the 2008 program. According to program contacts, this is likely because of the time required to identify, recruit, and enroll participants: aggregators who enrolled late in the 2008 season or those without existing customers in California may have recruited customers too late to participate in 2008.

Aggregators use the *Notice to Add or Delete Customers Participating in the Capacity Bidding Program* (Add/Delete form) to add or delete SAs from their portfolios. PG&E program staff confirms eligibility by checking that customers are on an eligible rate schedule (are not a wholesale customer, on standby rates, or net-metered) and that they have an interval data recorder (IDR). In PG&E territory, any meter with over 200 kW peak demand is eligible for a free IDR. [10] New IDR meters for locations with less than 200 kW peak demand are installed at aggregator or customer expense.[11]

Once a customer is determined to be eligible, an aggregator can enroll load by nominating SA numbers of the customer. An accepted customer is placed in the APX system and is eligible for CBP nominations. The CBP season officially runs May through October, but since there are no payments for May or October at PG&E, the season is effectively June through September.

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9 This is listed under *aggregators* on the PG&E website.

10 This is defined in Electric Schedule E-CBP tariff as bundled service customers with a maximum demand of 200 kW or greater for three consecutive months in the past 12 billing months.

11 An exception to this policy applies to the small- and medium-sized commercial customers enrolled through the San Francisco Community Power Small Customer Aggregation Pilot Program. PG&E provides interval meters and communication equipment at no cost to these participants.

In 2008, customers were allowed to enroll directly in PG&E's CBP program; however, none had done so as of December 2008. In 2009, customers will not be allowed to enroll directly in the CBP.

Events, Settlements, and Payments

In 2008, PG&E called two events: one day-of and one day-ahead event (Table 2.3). The day-ahead event was a test event and the day-of event was an actual called event. According to program contacts, response to the events was about 75% to 80% of nominated capacity, but neither event occurred during extremely hot weather.

When an event is called, metering agents hired by APX collect the interval data. PG&E also is involved in collecting the interval-meter data in its territory because of the prevalence of radio frequency meters.[12] From the end of each operating month, PG&E has 60 days to settle with the aggregators. PG&E's system does not verify the curtailment until a monthly re-cycle date occurs (similar to a billing cycle).

PG&E requires settlement-quality meter data (SQMD) before validating the results and reconciling the event with CAISO energy prices for that day. Reconciled event data are sent to APX. APX is directed to release the information to aggregators, who are then able to log into the system and see each customer's load usage and data. The baseline usage is calculated as an aggregate baseline; customer-specific baseline data is not reported. Program staff expects aggregators to have other methods of tracking individual customer performance during curtailment.

The original 2009-11 filing indicated PG&E was considering options or entities other than APX to provide settlement services. However, staff reported that the invoicing and payment processes have gone smoothly, and the utility plans to continue to contract with APX in 2009. In addition, they noted that APX provides other valuable services, including managing trades with direct-access customers at the CAISO.[13]

[12] Only PG&E can collect radio frequency meter data.

[13] Direct access customers enrolled in demand response programs must schedule a power delivery to the sponsoring utility equal to the amount of their curtailment. Since these customers are not bundled or delivery customers of the regulated utility, their curtailment activities would not materially benefit the sponsoring utility system without a corresponding delivery of power.

Utility Specific Experiences: CBP at Southern California Edison

Enrollment and Nomination

To enroll in CBP at SCE, an aggregator must complete a CBP *Aggregator Agreement* and a CBP *Credit Application*. Staff ensures the agreement and credit application are signed, validated, and acknowledged. They scan the documents and send them to the corporate credit department for approval. The approval process ranges from a few weeks to a few months. Aggregators must provide a deposit of at least $4,000 before SCE will list them as an aggregator on the SCE website. As aggregators commit to or nominate more demand response capacity, they must deposit additional funds per the *CBP Deposit Requirements* table posted on the CBP page of SCE.com.[14] According to program contacts, waiting for aggregators' required deposits can stall the process. Once the application and credit deposit have been received, an aggregator is listed on the website and can begin recruiting and enrolling customers.

A *Customer Information Standardized Request* (CISR) form and an Add/Delete form must be submitted for each customer an aggregator seeks to add to its portfolio. The CISR form authorizes the utility to release customer information to the aggregator. Each CISR must be signed, and have the correct SA numbers and addresses of service. In addition, the customer name listed on the CISR must match that listed in SCE's customer information system. Generally, the customer information system name matches the name listed on the bill. Occasionally, the names do not match and SCE returns the CISR form to the aggregator.[15]

The Add/Delete form often is submitted after the CISR. According to staff, aggregators will submit a CISR as a strategy to investigate the eligibility of the account. The CISR will reveal whether or not an account qualifies and is a viable candidate (e.g., that the customer is on a qualifying rate schedule or has an appropriate peak load). In these cases, an aggregator will submit an Add/Delete form only when they know they want to nominate a given customer. Aggregators are required to send in the Add/Delete form with the customer's original signature. CBP staff report new aggregators occasionally are surprised by this requirement and may fail to send in the original form.

Upon enrollment in the CBP, the customer's billing cycle is changed to calendar billing so that their meter is read on the first of each month.[16]

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14 The CBP deposit requirements range from $4,000 for aggregated load under 400 kW to $100,000 for aggregated load between 7,501 and 10,000 kW.

15 A further complication of the CISR-S form is that it requires applicants to indicate a specific expiration date. It is possible that the CISR-S could expire long before the program is over and the aggregator or customer has left the program.

16 Calendar billing is helpful to aggregators because all load providers (or participating meters) are read early in the month. Without calendar billing, obtaining settlement-quality meter data can take longer, as aggregators must wait for those with billing dates later in the month to cycle through the system.

Meter Funding

All three IOUs require CBP-enrolled customers to have an eligible IDR meter. In SCE territory, service accounts over 200 kW should already have a valid meter, so this becomes an issue only for smaller customers. During 2007 and 2008, SCE enabled hundreds of smaller customers to enroll in CBP through a special meter funding program that allowed customers with meters as small as 50 kW to obtain an IDR meter at no charge.[17] Funding for this effort was exhausted at the end of 2008.

Events, Settlement, and Payment

In 2008, SCE had called twenty day-ahead events and two day-of events. The number of aggregators and portfolios called varied somewhat by event, as did the hours called.[18] Staff report that the responses to called events were “seamless” and that the staff had received no complaints about notification. According to CBP staff at SCE all participating aggregators met their requirements for the year. However, penalties were levied against one aggregator for two months for failing to deliver the minimum required load reduction.

By the end of 2008, SCE had streamlined the internal data entry process for the CBP by enabling export directly to the APX system. This change allows staff to enter customer information only once. CBP staff would like to be able to see the load curtailment information at the service account level and are working with APX to produce this report.

APX processes the settlement calculations for the CBP and sends the information to SCE staff for verification. Once verified and agreed upon, aggregators are invited to log into the APX website to view the final event performance details. According to CBP staff, the calculation and settlement processes through APX were improved in 2008, in response to a few problems with calculations that occurred in 2007. The CBP tariff allows SCE 60 days from the close of the event month to settle with CBP aggregators. Staff reported no delays in this process and said they have been able to meet this deadline every month.

Utility Specific Experiences: CBP at San Diego Gas & Electric

Enrollment and Nomination

CBP staff at SDG&E report the 2008 program processes for the CBP were more streamlined and efficient than they were in 2007, which was the first year of the program. During 2007, CBP

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17 DRC enrollees were not eligible for meters through this program.

18 For more detail on actual program event dates and hours, see *Volume I* of this report: *Ex Post and Ex Ante Report*.

staff established the contract, procedures, reporting, and settlement processes at APX, and finalized the content and format of the input screens.

SDG&E relies on APX to manage much of the tracking and invoicing processes for the CBP. Since APX essentially manages the program processes for SDG&E, program staff focuses on enrolling customers and new aggregators, verifying information, and managing customer performance data.

SDG&E requires potential aggregators to submit a *Third Party Authorization* form (TPA), which is similar to the CISR-S.[19] When a third party requests information about a customer's energy use, the customer is required to sign the TPA releasing this information.[20] SDG&E also requires an Add/Delete form. SDG&E staff uses the information to verify that the customer has an IDR meter and meets the 20-kW threshold, and therefore qualifies to participate in the program. Like the other IOUs, SDG&E is installing IDR meters on-site for every large customer. In 2007, the CBP had to compete with SDG&E's meter group for attention within the utility, which occasionally delayed the pace of meter installation. In 2008, this was less of a problem because the pace of new enrollments slowed and SDG&E gave CBP meter installation priority.

SDG&E also contracts with the individual customers of participating aggregators. The contract does not set participation terms, but notifies customers that SDG&E could require them to pay a penalty that might accrue if an aggregation firm defaults on its obligations to the utility. Since aggregators often focus on enrolling customers for the next event month, these contracts occasionally are overlooked. For this reason, SDG&E does not have such a contract for every customer.

Once a customer is enrolled, SDG&E uploads that information to the APX interface. As is the case at the other utilities, the APX database is a critical part of the program – this is where aggregators log in and nominate customer load.

SDG&E program staff focuses on meeting the needs of participating aggregators and ensuring the program works for them. Staff views aggregators as the customers for this program and does not discuss aggregators or specific contract terms with utility customers.

There were no end-use customers enrolled directly in the CBP in San Diego in 2008.

Events, Settlements, and Payments

In 2008, SDG&E called one day-of and one day-ahead event. After an event, SDG&E forwards the meter data to APX, so APX can calculate performance relative to baseline and assess the

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19 These forms were developed in 1999 in preparation for deregulation; they were not developed for the CBP.

20 The TPA is identical to the CISR-S.

performance of aggregated load compared to nominated load. Settlements are calculated by APX for every month of the CBP program year, including months in which no events are called. Under their agreement with SDG&E, APX earns additional payments for preparing invoices. The invoices are forwarded to CBP staff for review and, ultimately, to the accounts payable department. Delays in processing by SDG&E staff occasionally have slowed payments to aggregators.

BILATERAL CONTRACT PROGRAMS

Following the heat storms that gripped California in the summer of 2006, the CPUC directed PG&E and SCE to issue requests for proposals to purchase additional demand response resources through bilateral contracts, and then to seek approval for those contracts from the Commission in early 2007. [21]

At PG&E, these contracts were the basis of the Aggregator Managed Portfolio (AMP) program. The AMP allows aggregators to enter into bilateral contracts with PG&E to deliver a specified amount of demand response for a price established in the contract. As negotiated bilateral contracts, the terms (both the level of demand response capacity promised and the price paid for it) between PG&E and each aggregator may vary.

At SCE, the activities associated with these contracts became the Demand Resource Contracts (DRC) program, offered by SCE to procure demand response capacity through aggregators responsible for marketing the opportunity, identifying and enrolling eligible customers, notifying those customers of curtailment events, and reconciling payments for customers who curtail their energy use during events. The contracts are negotiated between each aggregator and SCE, as are the terms: the amount of load curtailment contracted, the price paid for each nominated megawatt, the price paid for energy reduction, and the duration and notification terms.

Both programs operate with capacity incentives and energy incentives. Capacity incentives are based on the promise to reduce load during called events. Aggregators and their load providers receive capacity payments, even if no event is called. However, if an event is called and the promised load curtailment does not materialize, aggregators may have to forgo capacity payments or may be penalized. Depending upon the specifics of their agreements with customers, aggregators may pass these penalties on to their load providers. The utilities pay incentives only for measured energy savings that occur during an event.

[21] Decision 06-11-049.

PG&E's Aggregator Managed Portfolio (AMP) Program

Program History and Evolution

In early 2007, PG&E responded to the CPUC's request by filing an application requesting approval of bilateral contracts with five aggregation firms. The CPUC approved these contracts in the spring of 2007 and PG&E launched the AMP program. Originally treated as a procurement program, AMP steadily grew as the processes, paperwork, and settlement strategies were implemented and streamlined. As the program evolved and became a standardized demand response offering, staff shifted their focus from procurement to operations.

AMP expects aggregators to deliver turnkey, demand response services directly to PG&E customers. AMP was developed after and is similar to the CBP. For instance, customers enrolled by aggregators are combined to form a portfolio capable of delivering demand reduction as requested by PG&E. The primary difference between the CBP and AMP is that the aggregation firms enrolled in AMP have committed to provide a set level of demand reduction capacity each month of the summer season for several years. These commitments and associated obligations are documented in contracts prepared and executed by the aggregators and PG&E.

Role of Contracts

Since the commitment levels are established in the contracts and aggregators must meet them, AMP staff focuses on contract management. The terms of the contracts differ by aggregator and milestones are designed to help them achieve their long-term commitment. Aggregators contract directly with each load provider (end-use customer) to establish an appropriate commitment level. PG&E does not know the details of this commitment and, therefore, the specific source of the megawatts expected to be curtailed.

For 2009-2011, the commitment level established in the contract can be adjusted upward or downward if requested by February 1st of each year. AMP also provides information used to forecast load for the CAISO. AMP staff asks each aggregator to forecast the demand response load they anticipate nominating each month during the season. Staff report this demand response forecast to the ISO. The payments, as established in the contract, are not adjusted based on these forecasts.

A collateral deposit is required and is based on each aggregator's commitment level for the year. The exact amount is calculated, aggregators are informed, and a letter of credit or collateral payment is due by April 1st.

Communication

AMP staff members report communicating frequently with contracted aggregators, particularly during the program season. This communication generally focuses on verifying eligibility and resolving discrepancies between spreadsheets and databases. AMP is in the process of developing an on-line enrollment process that is expected to accelerate this process and avoid simple errors associated with data entry or conflicting databases. PG&E is designing the new system to link directly to its customer information system, and will require aggregators to provide an account identification number, as well as a service account and meter badge number.

The new system will continue to provide aggregators with a summary spreadsheet, as well as automatic emails noting the number of service accounts and the activity associated with them. The summary information will be bundled into a spreadsheet and sent to aggregators via PG&E's secure file transfer system. Staff expects these improvements to increase accuracy and confidence, and reduce double- or triple-checking of customer data.

Marketing

AMP relies on the aggregators' sales force to contact and enroll customers in the program. PG&E includes demand response programs in account executive training efforts, which include webinars and meetings designed to inform them about AMP. According to program staff, it is difficult for account representatives[22] to include specifics about AMP in their demand response presentations because they do not always know what aggregators are offering customers – particularly the specific price paid and other ancillary services or new equipment included. Additionally, account representatives cannot promote one aggregator over another; instead they provide a list of all five aggregators to potential participants and let the customer decide which aggregator fits their needs.

Enrollment and Nomination

To enroll customers, AMP provides aggregators an SA template to populate and upload to PG&E's file transfer site. Aggregators maintain their own database of enrolled customers. They use this information to enter the badge number or meter number on the SA and submit it by midnight on the first of each month.

AMP program staff reviews each submitted SA template in order to verify the eligibility of the customer. To be eligible, customers cannot be enrolled in another demand response program[23] and must have an IDR meter. The peak capacity load (in kW) is also noted. While there is no restriction on kW size, customers under 200 kW are unlikely to have the required IDR meter. Within three working days, AMP staff notifies the aggregator if the customer is eligible to participate in the program; they explain any reasons for ineligibility. AMP staff provide a

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[22] At PG&E, account representatives are called Service and Sales Representatives.

[23] Other than the Optional Binding Mandatory Curtailment Plan (OBMC) and the Pilot Optional Binding Mandatory Curtailment Plan (POBMC). In OBMC a utility customer can be exempted from rotating outages by agreeing to reduce the load on the entire circuit serving a facility. In POBMC, up to 10 PG&E customers participate in a load management program that uses real-time demand to adjust the program baseline.

spreadsheet to aggregators showing which SAs are eligible and which are ineligible. In some cases, ineligibility problems are eventually resolved—in other cases, the SA must be excluded from the program.

Following this verification effort, the aggregator must submit a signed, original Add/Delete form by the 15th of each month in order to make a customer eligible for nomination.[24]

Events, Settlements, and Payments

In 2008, PG&E called five AMP events. All but one of them (a day-of event in May) were test events. One day-ahead test event was called in August) and five day-of test events were called (one each in May, July and August, and two in September). The one non-test day-ahead event was called in May. All five AMP aggregators were called simultaneously for only two of the events. According to program contacts, PG&E did not necessarily get the load expected from all aggregators. Staff heard a variety of explanations for this, including unprepared customers, overly optimistic demand response estimates, and lower critical peaks in 2008 than in 2007, due to milder weather and a slowing economy.

AMP events are triggered at PG&E's discretion, typically when threshold energy prices specified in the contracts are met, or when local constraints or system emergencies threaten reliability. These events most commonly occur during very high price periods, often associated with capacity shortfalls due to hot weather.

Events are called by PG&E's procurement department, based on the strike price for an aggregator and the expected price of power for a given period. Since the prices established in the aggregator contracts are relatively high, these demand response resources are called only when the price of power is high.

Only one of the five AMP aggregation contracts is for day-ahead curtailment. The remaining four provide curtailment on the day of an event, with only 30 minutes' notice required. Day-of curtailment contracts require aggregators to have a relatively systematic and automated process for communicating the imminent curtailment event to their customer load providers.

The program can call two test events per season. Staff reports using these events to determine whether or not aggregators are able to provide the demand response curtailment resource to which they have committed. Test events are treated like official events and include a standard notification process. If an aggregator fails to deliver the committed megawatts, it can request a re-test. In this case, payment is based on the better of the two events. No penalties are levied for test events, even if an aggregator delivers less than 50% of the committed load.

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24 While the contracts stipulate the information must be at PG&E by the 15th, AMP staff reports having some flexibility to accommodate delays in paperwork delivery and/or other minor coordination problems, and have occasionally given aggregators an extra day or two to submit paperwork.

Settlement and Payment

The standard period for all AMP payments is two calendar months. Aggregators are expected to submit an invoice to PG&E monthly for payment obligations incurred during the preceding two months. Working with PG&E's electric settlements group, the AMP Program Manager verifies payments or penalties as appropriate for load reduction delivered by aggregators.

Payment processes depend upon whether or not a demand response event was called during the month. If no event is called, PG&E pays the *Option Premium Payment*, as calculated by multiplying the *Commitment Level* (in megawatts) by the *Option Premium Price* (as established in the contract). If an event is called, payments are based on actual performance of the aggregated load relative to the aggregated baseline during demand response events. For this capacity, PG&E pays an *Adjusted Hourly Option Premium Payment* calculated by applying an *hourly delivered capacity ratio*.

The hourly delivered capacity ratio is calculated after the performance relative to the baseline is established. The capacity ratio determines whether or not the aggregator earns full payment, partial payment, no payment, or is assessed a penalty. Aggregators also can earn a demand response energy price payment for kilowatt-hour reductions that occur because of demand response activities during an event.

SCE's Demand Resource Contracts (DRC) Program

Program History and Evolution

SCE responded to the CPUC's 2006 request to pursue bilateral arrangements for additional demand response by proposing contract agreements with aggregation firms; one of these agreements was approved by the CPUC in May 2007. SCE proposed eight additional aggregator contracts in October 2007; CPUC found four of these to be cost-effective and approved them in March 2008. These contracts became the DRC program. The CPUC noted SCE could submit additional contracts in its application for 2009-2011 demand response programs.

Like AMP, DRC allows SCE to engage aggregators in demand response contracts through which they agree to provide a certain amount of curtailment when requested by SCE. Customers of aggregation firms agree to reduce their energy use when contacted by aggregators prior to a DRC event. Aggregators enroll customers directly and establish agreements with customers independent of SCE. These agreements allow aggregators to recruit a portfolio of SCE customers able to shed load on short notice.

DRC's program manager and operations team handle regulatory and administrative issues, oversee program processes, and address questions from aggregators or account representatives.[25,26]Aggregation firms are required to pass a business economic feasibility test before approval. This is to confirm they have the resources to meet their contractual obligations.

Meters and Equipment

The DRC Policy and Procedure Manual notes that the DRC program targets aggregators of smaller customers with IDR meters that use from 50 kW to 200 kW monthly. These are usually commercial customers with monthly loads of at least 50 kW. Accounts with monthly loads greater than 200 kW should already have IDR meters installed.[27]

Since IDR meters are considered SCE property and are available exclusively for utility use, aggregators are allowed to connect a KYZ/PIB interface to monitor customer performance during curtailment events. Aggregators can nominate customers without a PIB, but if they do, they will not be able to see the performance data prior to settlement calculations and statements. While CPUC rules require SCE to bill customers for any cost involved in replacing the IDR, adding a PIB, or both, SCE can charge and credit an aggregated customer from the aggregator's account, resulting in no-net cost to a customer.[28] SCE will install a new IDR meter and PIB for $950, or just a PIB for $500. DRC staff has received few requests for meters, but many for PIB equipment

Marketing

Aggregation firms market their own demand response programs to SCE customers and specify the terms of participation for enrolled customers, including the expected load reduction, payments, and penalties. SCE does not market the program directly. It lists the program on its website under the Demand Response Program menu; staff is considering adding an FAQ page. Indirect marketing can occur through SCE's account representatives, who occasionally are invited to attend meetings with a customer and an aggregator. According to staff, the SCE representative will attend only if the customer invites them. This can avoid the appearance that SCE advocates for a particular aggregation firm.

DRC program staff report needing to communicate with account executives about the program, to help them understand that the program is legitimate and that aggregators are not trying to steal their customers. The reps have long-term relationships with their customers and can become

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25 *Demand Resource Contracts Program Policy and Procedures Manual,* pages 101-4.

26 At SCE, account representatives are called Business Customer Division (BCD) Representatives

27 As described in the CBP section detailing the program experience at SCE, in 2007 and 2008, SCE operated a special meter funding program that allowed customers with meters as low as 50 kW to obtain an IDR at no charge. Funding for this effort was exhausted at the end of 2008.

28 *Demand Resource Contracts Program Policy and Procedures Manual*, pages 101-7.

protective when third-party vendors approach their customers offering ancillary services. The slow pace of regulatory decisions and the resulting uncertainty also can affect the enthusiasm of account reps, some of whom may be reluctant or unable to explain programs that have not yet obtained Commission approval.

Enrollment and Nomination

Aggregators are required to submit a customer's CISR form prior to receiving SCE billing data. Once the CISR is submitted, it is verified. This is the point at which errors in the CISR (address or name discrepancies, or other issues) usually emerge. Any errors in the CISR must be resolved before the customer is verified and becomes eligible to be included in an aggregator's enrollment.

Once customers are verified, the aggregator submits a nomination list at least five days before the beginning of the next operational month. Aggregators can nominate any number of their customers.

Events, Settlements, and Payment

The decision to call an event rests with SCE's power trading group. In dispatching the demand response resource, they call the aggregators directly without informing DRC staff. SCE called day-of DRC resources only once in the summer of 2008, but in November, a transmission problem in San Diego affected the CAISO and triggered a day-of curtailment event. [29] Eighteen day-ahead events were called in 2008. [30] Staff reports these events were operationally smooth and dispatched in accordance with the contracts.[31] While SCE did not get the load expected, the effect was mitigated by the adjustments via the technical potential assessments.

Settlement Calculations and Payment

SCE measures the performance of aggregated customers during an event, calculates the load impact, and forwards the meter data to the aggregator. The aggregator uses this information to assess whether or not the customer has met its curtailment obligation.

SCE calculates all DRC settlements in-house. The time required to do so depends on when the last meter is read. IDR meters do not necessarily communicate remotely, thus some meters must be read manually. Since it can take up to 45 days for the last meter to be read and the settlement

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[29] Excluding a test event on March 25, 2008.

[30] Including a test event on July 9, 2008.

[31] No events included all four aggregation firms. Only one day-of event included three. The rest of the events involved only one or two aggregators.

cannot be calculated until then, statements may not be available to aggregators for a month or more. Staff reports no major concerns or problems with this process.[32]

There are two basic paths for invoicing. In operating months in which no events are called, the payment is straightforward and based on the capacity reservation payment in the contract, as modified (if necessary) by the technical potential assessments. If there is an event, aggregators are paid on measured performance for both delivered capacity and associated energy savings. Payments are sent to the DRC aggregator; no payments or charges are sent to a customer directly from SCE.

Assessing Technical Potential

Aggregators are penalized $4,000 for the first megawatt of missed load reduction and $1,000 for each additional megawatt of missed load reduction. Since penalties accrue with even one megawatt of missed load reduction, SCE developed a process for assessing the technical potential for the group of service accounts nominated each month by each aggregator. The DRC purchase agreements require aggregators to submit a written statement assessing the estimated kW demand reduction available for each service account within their aggregated group after providing a list of those customers for each operating month. Aggregators make this assessment by considering their customers' total demand, seasonality factors, individual curtailment plans, the level of automatic curtailment, the presence of enabling technologies, prior experience with demand response, and past performance. DRC staff reviews this technical potential assessment and evaluates portfolios.

The assessment document is checked for reasonableness through an iterative process of validation and discussion until it is approved. DRC staff believes the process of developing the technical potential document helps aggregators identify and account for aspects likely to affect their customers' load reduction capacity. These variables include the seasonality of the load or the reliability of automated curtailment systems. Developing this assessment takes time; DRC staff reports holding frequent phone meetings and occasional in-person meetings with aggregators in order to discuss emerging issues, new customer enrollment, or the technical potential analyses.

According to DRC staff, the technical potential reports are a tool for identifying the actual load likely to be available, were an event to be called. They consider the documents tools to help DRC be prudent with ratepayer money and to avoid punishing aggregators for the length of time required to find eligible customers, close the sale, and enable the capacity. Test events were used

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32 DRC, like the other programs, relies on a 3-in-10 baseline, calculated for the aggregated portfolio. At the end of 2008, several aggregation firms were arguing for a customer-specific baseline, rather than an aggregated baseline. Reviewing the considerations of the different baseline calculation strategies is beyond the scope of the process evaluation tasks.

to create a baseline for the performance of each aggregated portfolio. The results helped identify areas where the aggregator was weak. In some cases, aggregators were unaware of these weaknesses. When test results come in noticeably below the level indicated by the technical potential, staff will re-review the assumptions and capacity in a given portfolio.

For months in which no event is called, if the technical potential assessment is less than the capacity contained in the contract, the delivered capacity payment is adjusted downward to equal the technical potential times the capacity credit rate. However, if the technical potential assessment is greater than the contracted capacity, the delivered capacity payment is not increased.

For months in which an event is called, the capacity payment calculation is based on the *measured* performance of the aggregated portfolio, not the technical potential assessment. However, any difference between measured performance and the technical potential assessment is taken into account in reasonableness reviews of future technical potential assessments.

The process of assessing and reviewing the technical potential associated with each aggregated portfolio is not an explicit part of the DRC contracts, but current aggregators have agreed to the approach, including any reductions in expected load impacts and corresponding settlement payments resulting from a technical potential assessment lower than the contracted capacity. SCE expects to amend the existing agreements to include this process for the 2009-11 program.

LESSONS LEARNED

During our interviews, program staff at each of the programs articulated lessons learned from their experience with the aggregator-driven programs.

Respect for Aggregators

Contacts described becoming more aware of the specific benefits of working with aggregators. For example, unlike a regulated utility, aggregation firms are able to tailor services and payments to the needs of a specific customer. Contacts were optimistic that aggregation firms were tapping into customers who had not already participated in demand response programs, rather than simply moving customers from one program to another.

Program contacts expressed appreciation for the work of the aggregation firms and their perceived ability to identify and recruit a variety of customers for demand response curtailment. This appreciation was expressed in a variety of ways, including:

➡ **Increased understanding of the length of time required to develop and build the demand response resource:** Aggregators must identify, enroll, nominate, and season each load provider in order to develop the demand response capacity fully. Each step takes time to navigate, regardless of the milestones or commitments in the contracts. This understanding led to the development of the technical potential assessment process in

DRC and to frequent meetings focused on identifying and overcoming barriers in other programs.

- ➡ **Seeing aggregators as active and effective marketers able to identify and enroll customers new to demand response**
- ➡ **Increased reliance on aggregators to sell the demand response products, recruit customers, and enroll many megawatts of curtailable load**
- ➡ **Expecting that aggregators will suggest improvements and help the utility meet its demand response goals**
- ➡ **Recognizing that establishing good relationships with staff at aggregation firms is critical to managing these programs effectively**

Utility-Process Barriers

Contacts articulated a variety of challenges for aggregators related to interacting with the utility bureaucracy. These challenges could result from paperwork or credit requirements, database idiosyncrasies, or regulatory or legal processes.

Contacts described challenges for aggregators just *"to get past the welcoming stage – to where they know the processes, required forms, and steps to validate customers."* Every utility does these things a bit differently and program contacts occasionally hear complaints about this from aggregators. Navigating the internal process requirements can slow customer recruitment and enrollment, particularly early in the relationship.

Staff at all three utilities reported improvements to their CBP processes in 2008. Most often, these focused on streamlining and facilitating enrollment. However, program staff also noted processes had simply become more routine and smoother in 2008.

Staff contacts acknowledged needing to document that the customer has agreed to participate, but reported seeking other, simpler processes for doing this. Contacts mentioned the need to eliminate or combine forms and to improve electronic processes. All three IOUs require the Add/Delete form, which they developed collaboratively when they agreed to hire APX and use the same enrollment form. However, in some cases, an SA template, a CISR, or a TPA is also required. Contacts wondered whether some of these forms were extraneous, or if part of the enrollment process could occur through the customer's on-line account. Suggestions in this vein included combining the CISR and Add/Delete into one form, or enabling eligibility verification through a login feature, instead of the CISR.

Role of Account Representatives

Aggregation firms represent a challenge for account representatives at all three utilities. In some cases, this could reflect confusion about whether or not aggregator-driven demand response capacity will count toward year-end demand response goals established for account executives.

SCE

This is particularly the case at SCE, where the account representatives operate with specific goals for each program. When a customer enrolls in SCE's CBP via an aggregator, program staff inform the account executive so they can answer the customer's questions and know their account's participation status. CBP staff at SCE report that aggregators have complained about a lack of account representative support for the program. DRC staff note they have spent time with account representatives confirming that DRC is a legitimate program and assuring them that the aggregators are not stealing customers by seeking to enroll them in the demand response effort.

SDG&E

SDG&E staff reported that the account executives are not directly involved in promoting the CBP, but they occasionally approach staff with questions about the program. SDG&E's salaried account executives are not incentivized to promote program participation.

PG&E

A PG&E AMP contact noted that it is difficult for account executives to talk about AMP with customers, since the terms and payment schemes are unknown and can reflect size, risk, or other factors important to the aggregator. AMP staff also have heard occasional complaints from aggregators about lack of support from account executives. PG&E CBP staff notes that account executives were assumed to have a role in encouraging CBP participation, but the challenges in measuring the kW load drop of an aggregated customer created difficulties for account executives wanting to document the demand response enrollment. Demand response goals were established for PG&E account executives in 2007, but not in 2008.

All Utilities

Contacts at all three utilities report meeting with account executives at least once a year to encourage them to support the aggregator-driven programs and to answer questions about how these programs work. One contact expects that as the number of aggregation firms increases and the sales and marketing efforts expand accordingly, aggregators are likely to reach an increasingly diverse group of customers, including smaller ones that do not have account executives.

SUMMARY

All five programs operate with a similar long-term goal: use the expertise and marketing skills of curtailment service providers to identify, enroll, and aggregate groups of customers able to drop load when requested. The specific processes through which customer information is received, verified, and nominated varies by utility and program, but the overarching purposes are identical: ensure that customers are qualified and have agreed to participate.

A few structural differences drive major internal program processes. These include the method through which prices are set and triggers established, and the role of APX in curtailment event management and settlement for the CBP. DRC is unique in its year-round operation and in requiring a technical potential assessment of each aggregator that offers a reasonableness review of aggregator-estimated curtailment capacity.

When asked about program implementation and marketing, program staffs focused almost exclusively on their relationships with aggregation firms, since they have only an arms-length relationship with the aggregator-enrolled customers. The opacity of the communication and payment terms established between the customer and aggregator is part of the design of the program, but it does make it difficult for staff to comment directly on customers' participation experiences.

Staff contacts at all utilities reported developing solid working relationships with the aggregation firms operating in their service territories. In several cases, staff described overcoming communication and process challenges in previous program years. This made 2008 a better experience for everyone involved.

Staff from all programs described a somewhat complicated process of receiving, verifying, and confirming meter data prior to releasing it to aggregators. Obtaining settlement-quality meter data generally requires the involvement of multiple people or departments and can take time. While staff reported getting this information out to aggregators within 60 days, this could result in statements being delivered to participants up to 90 days after an event.

3 AGGREGATOR EXPERIENCES

This chapter presents the results from interviews with participating aggregators.

POPULATION AND SAMPLE

We obtained lists of aggregators from utility contacts and utility websites. As of December 2008, the combined list identified 16 unique aggregator organizations that were listed with at least one of the five programs.[33] Two of the 16 aggregators were listed and active in all five programs. Five of the 16 aggregators were truly inactive because they had not nominated load for any of the five programs during the 2008 season. All of the inactive firms were registered with the CBP, since AMP and DRC are contract-driven and thus not optional. The remaining nine aggregators registered for and/or participated in at least one combination of programs. Therefore, there were 11 active aggregators.

We interviewed contacts at 14 of the 16 aggregators registered with any of the five programs. We also interviewed 4 of the 5 inactive aggregators and 10 of the 11 active aggregators. [34] Of the 14 aggregators we interviewed, all but one reported that they intended to participate in the 2009 season. Table 3.1 shows the interview disposition data. It is important to note that a number of aggregators enrolled in each program overlap and thus the interviews are not additive.

Table 3.1: Aggregator Interview Disposition

UTILITY AND PROGRAM		LIST	ACTIVE INTERVIEWED	INACTIVE INTERVIEWED	TOTAL INTERVIEWED
PG&E	**CBP**	12	6 of 6	4 of 6	10
	AMP	5	5 of 5	NA	5
SCE	**CBP**	13	6 of 7	6 of 6	12
	DRC	4	4 of 4	NA	4
SDG&E	**CBP**	7	4 of 5	2 of 2	6
All Programs		**16**	**10 of 11**	**4 of 5**	**14**

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33 We did not include any self-aggregating customers. Large customers were allowed to act as their own aggregator for the 2008 season, but few did.

34 Inactive aggregator contacts experienced a shorter interview because they could not discuss program-specific experiences in 2008. Instead, we asked them about their reasons for nonparticipation in 2008, any marketing experiences they may have had, and their intention to participate in the future. One of the ten active aggregators broke off the interview midway through. This partially-complete interview is counted here.

Participation took many forms. For example, an aggregator could be active in AMP and DRC, but inactive in the CBP – having registered for the program in anticipation of needing CBP for load beyond that required by their contract, but then not using it in 2008. Or, an aggregator could have registered for the CBP in all three territories, but nominated load in just one or two of them. In both of these cases, the aggregator would be considered active in one territory but inactive in another.

Figure 3.1 illustrates the distribution of the 16 *registered* aggregators among the three programs (CBP, AMP, and DRC). Figure 3.2 illustrates the distribution of the 11 *active* aggregators among the three programs.

Figure 3.1: Distribution of the 16 *Registered* Aggregators

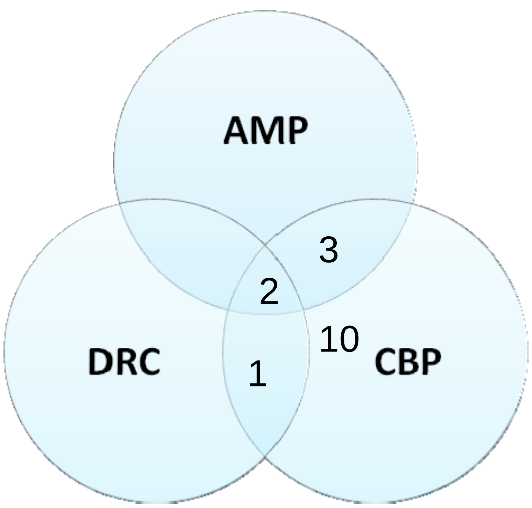
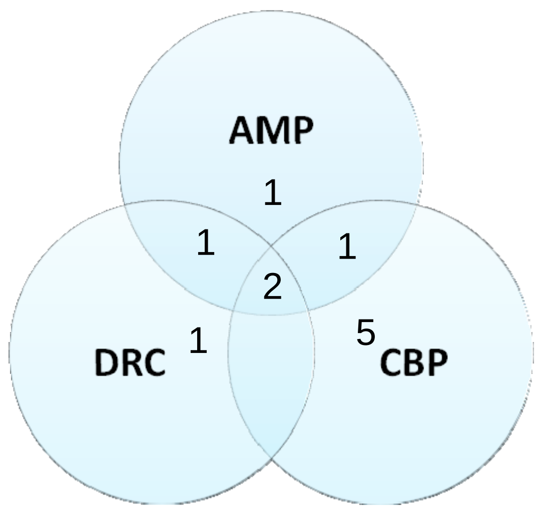


Figure 3.2: Distribution of the 11 *Active* Aggregators



In 2008 all of the listed aggregators were registered for CBP (Figure 3.1).[35] Among those also registered for the bilateral contract programs (AMP and DRC), two participated in both.

Figure 3.2 illustrates the distribution of active aggregation activity. While all of the active aggregators were registered for CBP, only eight of the 11 nominated load for any of the CBP programs in 2008. Three of the 11 nominated load only through their bilateral contracts.

35 In part this is because SDG&E does not have a bilateral contract program. Thus, any aggregator wanting to enroll demand response capacity in San Diego would have to register with the CBP.

Aggregator Characteristics

Branding

Just over half of the active aggregators we spoke with (6 of 10) reported marketing the program under a different name or including the program under an existing aggregator brand. These names included *Clean Energy Network – CA*, *PowerPay*, *Share the Power*, *Peak Days On-Call*, *Clean Green California*, and *Energy Alert*. In several cases, the programs represented California versions of programs packaged and offered to customers elsewhere. The remaining four aggregators reported using the tariff name or the program name as assigned by the utility. In one case, an aggregator contact reported that using the utility tariff name and paperwork made the program terms more transparent to load providers. Aggregators actively participating in competing programs within the same utility territory did not report branding their CBP and non-CBP efforts differently.

Staffing

We asked the ten active aggregators about the level of staffing required for them to implement the program(s) in California. The answers ranged from one to 50, but most (7 of 10) reported requiring fewer than 10 people. Because of the differing sizes and structures of the aggregation firms, these numbers are not necessarily a true count of the total of staff required. One contact reported that the entire organization was involved in delivering the program, while another excluded subcontractors, and still another excluded staff at a remote operations center. Aggregators that offered the program only to existing customers in California and those for whom demand response had not been their primary business reported the smallest staff requirements.

We also asked aggregators to describe the primary categories of activities of their staff. The most common categories were sales and marketing and technical services, each reported by seven of the ten active aggregators we spoke with. The three aggregators reporting no sales and marketing staff also said they approached existing customers only. Four of the ten active aggregators reported having staff dedicated to customer service. Five of the ten reported having staff focused on utility program requirements, such as nomination activities and settlement calculations.

Most of the aggregators registered for the programs in 2008 had experience providing demand response resources in other markets. Seven of the ten active aggregators reported working in other jurisdictions to deliver resources. [36] Two of the four inactive aggregators we spoke with reported working in other demand response markets.

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[36] For example, the New York Independent System Operator (NYISO) or PJM Interconnection.

Six of the ten active aggregators reported participating in more than one program in California (CBP, DRC, and AMP). We asked these aggregators to discuss how they assigned providers to a program. Only three of the seven were active in competing programs within one utility territory (e.g., nominating load to both the CBP and AMP, or the CBP and DRC). In cases where an aggregator participated in only one program per service territory, they had no choice about where to place the nomination.

One aggregator described nominating load to the program that was most lucrative for the firm. Another described enrolling customers first in the CBP because the features of that program (attractive meter rebates in SCE territory or benefiting from requirements that CBP customers be placed on monthly billing) were a way to resolve structural problems in the contract program, such as lack of meters or billing delays. In this case, participant load providers would be enrolled first in the CBP and then transferred to DRC. Another contact described the CBP as a "holding pond" for load they were considering adding to their contract, or would add if there was room.

Primary Business Focus

Aggregator firms are diverse in size and focus. Registered firms included Load Serving Entities (LSEs) providing demand-response services to their existing power customers, firms whose primary focus is profiting from demand-response payments available throughout the nation, and vendors who profit from the sale of proprietary technologies.

Aggregators' business plans and market approaches often are reflected in their differing relationship to enabling technologies. Firms tend to encourage the installation of technologies likely to meet their unique needs for visibility, monitoring, communication, and control. Several operate with centrally-managed network operations or communication centers that control participating providers' load and monitored performance. All aggregators, even the six that incorporate enabling technologies into their business plan, reported that they did not pressure customers to purchase any particular product. However, three aggregators reported requiring participants to install monitoring and/or visibility equipment that allows for either automated curtailment (typically through an Energy Management System [EMS] program) or near real-time monitoring.

- *"We have our own line of proprietary products, but our approach is consultative. If we have an energy engineer visiting a site and they find a possibility of introducing improvements, or if enabling technology is required, we will offer that. But, our goal is to evolve the relationship with our customers to be a true partner…. Early conversations focused on demand response might evolve into an offer of additional technologies or products. The process builds on itself and helps us manage customer satisfaction."*
- *"We typically know what type of controls our customers have. We can provide them with options on how to automate. We don't push any product or manufacturer's equipment over another… but if they want us to, we can specify and install this equipment."*

- *"We install a metering application for all customers that allows them to see their performance during events and monitor scenarios in near real time. This is a requirement for our customers. In this way, enabling technologies are addressed with every customer – but, we will help them identify other technologies, especially if automation or control will bring value to them."*

Aggregators clearly approach enabling technologies differently. While some valued the control and visibility highly, others reported focusing on demand-response activities only and leaving the technology out of the conversation.

These differences emerged again when aggregators were asked about how they approached managing curtailment events among their customers in 2008. We asked active aggregators to estimate the portion of their customers that relied on automatic demand-response activities, which required them to take no action other than allowing communication or control software to curtail load as planned. Contacts estimated a portion ranging from zero to 100% of their nominated load, as shown in Table 3.2.

Table 3.2: Portion of Load Automatically Curtailed

PORTION AUTOMATICALLY CURTAILED	NUMBER REPORTING (N=9)
0%	2
25% to 50%	2
50% to 75%	2
75% to 100%	3

Customer Recruitment

In 2008, recruiting new customers was challenging, particularly for aggregators engaged in unsolicited marketing activities. Aggregators operate without access to load or meter data, rate class, or other important indicators of energy use and likely eligibility prior to contacting a customer. Industry type and size are indicators of potential eligibility, but these factors do not map perfectly to qualifying meters. Two contacts estimated the portion of customers that ultimately qualify to those contacted: one said 10% and the other 5%.

We asked aggregators specifically about how they identified and recruited eligible customers in 2008. Aggregators approaching new customers faced more difficulties than those approaching customers with whom they had an existing relationship. Among aggregator firms with active recruitment and sales activities, contacts described using a variety of basic prospecting tactics to identify potential load providers. A typical scenario involved a phone call or visit by an aggregator representative seeking someone able to answer basic questions about proxy indicators of potential eligibility, including: revenue, number of employees, square footage, size of energy bill, SIC code, or rate class. Aggregators engaged in unsolicited marketing activities reported that proxy indicators often were the only way to identify a potential provider because customers rarely knew their peak demand by meter.

Once aggregators identified a prospect, they presented the program details. We asked aggregators to describe what, if any, concerns their customers had about the program in the marketing phase. According to active aggregators, when first contacted, customers might be confused by the terminology or program opportunity, or believe it sounded too good to be true.

- *"It's interpreted as 'free money'…. We have to get past that. If we can, then we are able to explain why it is happening. That it's not really free money, that there is an economic reason for it."*
- *"I've heard people say it's too good to be true, but mainly in their understanding of the capacity payments. People think [the capacity payments] are weird. We explain that it's like a utility insurance policy."*

Once aggregators explained the parameters of the curtailment program, customer concerns often shifted toward fear about the effect of curtailment on their business, including the number and duration of events. Customers might worry that they did not have any load to shed or that shedding load would materially affect their operations. In some cases, these worries extended to concerns about getting the operations staff to follow through on the curtailment instructions.

- *"The most common concerns involved fear about the number of times they will be called to curtail, and if the effort will be worth the money."*
- *"They want to know the maximum curtailment parameters. They are concerned about the maximum time they might be curtailed."*

Customers also were concerned about underperformance. Underperformance could net them less revenue or, even more problematic, trigger penalties. [37] Customers must determine for themselves the value proposition for curtailment events. This can be challenging. According to aggregator contacts, when considering the program opportunity, customers generally try to estimate and weigh the expected income and possible loss. For the 2008 aggregator-driven programs, customers had to do this without being able to predict the circumstances that would cause an event. These programs are price-driven. The CBP operates with a trigger tied to the efficiency of generation alternatives (a *heat rate*). This trigger is not necessarily tied to a publicly-available indicator, like temperature or the wholesale market price. The bilateral

[37] This concern emerged specifically in discussing the participation of direct-access customers, who are required to pay for the power they already have contracted to receive. For direct-access customers, power delivery must be rescheduled to the IOU, instead of the customer, to match curtailed load.

programs (AMP and DRC) are triggered based upon the price established between the aggregator and the utility in their contract. This price is not publically available.

Finally, several contacts mentioned that potential participants have been suspicious about the aggregator's role or relationship with the utility. This suspicion is framed two ways: a customer with a poor relationship with their utility might be wary of utility-supported activities; or, conversely, a customer that trusted its utility might need to verify the details with an account representative before agreeing to enroll.

Aggregators reported overcoming these concerns by:

- ➡ **Providing clear and accurate information** about curtailment opportunities and examples of similar firms' success
- ➡ **Tapping into environmental consciousness** among California businesses, which could lead them to consider participating for reasons other than simple economic value
- ➡ **Testing or demonstrating load-drop opportunities** and starting with the smallest-commitment/least-impact approaches to build confidence.

Enrollment

Paperwork and collateral requirements varied by utility and program and there was no single form for enrolling customers in aggregator programs in 2008. Table 3.3 describes these various forms.

Table 3.3: Program Requirements

UTILITY	PROGRAM	FORMS REQUIRED PRIOR TO NOMINATION	DEPOSIT OR LETTER OF CREDIT REQUIRED
PG&E	**AMP**	SA Template is used to receive customer information and verify eligibility. Add/Delete form requires wet signature and actually enrolls customer.	Yes
	CBP	Add/Delete form is required.	No
SCE	**DRC**	CISR is required for each name as listed in the CIS.	Yes
	CBP	CISR is required for each name as listed in the CIS. Add/Delete form is submitted prior to nomination. Wet signature is required on Add/Delete form.	Yes
SDG&E	**CBP**	TPA is required to get information on a customer's energy usage. Add/Delete form is required to enroll.	Yes

Complaints emerged about the language and format of the CISR. The CISR form was created ten years ago, during California's experiment with electricity deregulation, and includes language designed to protect customers from new load-serving entities recruiting large customers and selling themselves as an alternative to the regulated utility. This form is now being used to authorize the utility to release customer information. The top of the CISR states: "This is a legally binding contract – read it carefully." The *Release of Account Information* section indicates that a representative of the potential customer must sign that they are authorized to execute the document and financially bind the customer.

- *"If there is interest, we ask them to sign a CISR or TPA. Once we have this, we can request data…. That's when we find out if the meters are truly qualifying or not, if the load is high enough, what their consumption or demand pattern is, and if there is potential for demand response."*
- *"Most customers don't know their peak load on a given day…. The way to get the meter data is a CISR form. The problem with the CISR form is that it looks like you are applying for a mortgage and using your first-born child as collateral. And we are just investigating whether the customer is eligible or not."*
- *"Edison requires a CISR and PG&E doesn't. This is an important difference because of the language on the CISR and because the CISR has an expiration date on it that the customer fills in…. They may hedge and fill in a date that's only a year out. Then, we have to go get another one."*
- *"The CISR has a lot of legalese and can be a roadblock for us. Instead, we'll try to get interval load data another way first. We try to avoid it until the very end, because it looks like a contract and customers will ask that their legal departments review it first."*

PG&E requires an Add/Delete form to enroll customers in both AMP and the CBP, but also requires a Service Agreement (SA) Template to verify eligibility for AMP. At SCE, a CISR is required for each name as listed in the customer information system, but only the CBP requires an Add/Delete form. SDG&E uses a Third Party Authorization (TPA) form to release information about energy and demand history, but requires an Add/Delete form to enroll a customer in the CBP. The TPA is a simplified version of the CISR form, but contains the same language declaring that the form is a legally binding contract.

Aggregators complaining about the CISR questioned whether the legal language was necessary, given the increasing availability of this information through the Internet, particularly for existing IDR customers that already have access to their usage history and interval data via a simple log-in. Aggregators said that the legal language intimidated some customers and caused delays when contacts decided they did not have the authorization to enter into a legal contract. In discussing the CISR, aggregators noted that the form was being used only to grant them access to meter data and peak-load patterns, but customers became suspicious when faced with language about a "legally binding" document.

- *"There must be a better way than faxing these documents and requiring wet signatures. All you need is to have a customer log in to the utility website…. Can't they just add us as an authorized partner?"*

Aggregators seeking to have a Pulse Interface Box (PIB) installed to capture the IDR data for a newly enrolled customer must submit a Meter Pulse Authorization form (MPA). Aggregator complaints about this form were less about the form itself than about the timing. The form must be filled out *after* the customer is enrolled, which requires the aggregator to return to the customer for an additional signature after all of the other paperwork is complete.

Nominating Load

The process for nominating customer load varies by program. Aggregators nominating load to one of the bilateral programs must submit a spreadsheet to AMP or DRC staff by the 15th of each month. Both programs accept enrollment forms year-round, but only SCE's DRC can be called between October and May. Since submitted spreadsheets become the nominated load for each aggregator, the accuracy and completeness of each submittal are important. Aggregators report monitoring the content of these spreadsheets for meters or customers inadvertently dropped or deemed ineligible. For example, a customer may need to wait for an IDR meter or un-enroll from another demand-response program before they are eligible. As those things occur (e.g., the meter is installed, the customer leaves the other program), the customer will become eligible and can be nominated.

For the CBP, participating aggregators at all three IOUs nominate their load through the APX website interface. APX managed the nominations and notification for the prior CPA program, and thus was considered a logical entity to manage the same processes for CBP. While most aggregators expressed satisfaction with their interactions with APX, aggregators with numerous SA IDs to nominate each month complained about the lack of scalability. The APX process requires that each SA ID be re-nominated through a drag-and-drop web interface. The nomination screen is wiped clean every month, so each meter must be re-entered every month. Suggestions for improving this focused on making it easier to manage large numbers of nominated meters, so that nominations for a given month can be saved or that each month defaults to the previous list, allowing the aggregator to focus only on changes to the preceding month.

Estimating Demand Response Potential among New Customers

An important part of assessing and nominating load is estimating a customer's capacity to reduce their energy use. We asked aggregators to describe how they typically approach this task. Aggregators may start by obtaining usage data through submitted enrollment forms (CISR, TPA, and Add/Delete) or through utility web-based services for large customers (*InterAct* at PG&E, *EnergyManager*® at SCE, and *kWickview* at SDG&E) that provide access to 15-minute historical consumption data and demand information. Once the data are obtained, aggregators review the information or discuss options with customers.

- *"We look at the [demand] curves; they speak volumes. You can make accurate decisions based on the graphs. [Without the graphs] we have to do a walk-through, preliminary audit. This analysis is completed and reported back to the customer. We'll discuss measures and receive customer comments about the measures based on their understanding of their business requirements."*
- *"Initially, we just use rule-of-thumb calculations. We let them dictate what they think they can do and then review that number for reasonableness. We do mandatory tests."*
- *"We look at their loads and have been able to do some DR audits, at least for a sample of them…. This lets us look at all their loads. We try to calculate each load, determine a pattern, and try to predict what could happen. We have to attribute kW for each load we might curtail in a given store."*
- *"As you start doing more and more nominations, you get more information and a sense for what's possible. The first one was extraordinarily complex; we did not necessarily know which devices were attached to which meter – and you have to nominate a meter."*

Demand data are not always available ahead of time. Only customers with IDR meters can log into the utility web-based services, and not all of these will necessarily provide access to an aggregator. Small customers or those with no prior experience with demand response may require aggregators to invest more time in auditing their operations or rely on educated guesses.

Aggregators reported using a variety of strategies to estimate demand-response potential. Many employed multiple strategies and selected the most appropriate one, based on a customer's size, the level of risk to the aggregator, or the quality of existing information. The most common approaches to estimating demand-response potential include:

➡ **Testing customers' demand-response capability** (reported by seven aggregators) – two of these aggregators reported that this would occur only occasionally, or if requested by a potential provider.

➡ **Relying on educated guesses or rules of thumb** (reported by five aggregators) to estimate the demand response potential at a given customer site. In these instances, aggregators review the data they receive, study the load shape and peak demand, or ask about prior experience in other demand-response programs.

➡ **Undertaking an engineering review** (reported by four aggregators), ranging from a desk audit to a walk-through audit, or a more extensive on-site analysis. When a more technical audit occurs, it may include an extensive analysis of existing equipment, the need for additional EMS or controls equipment, or an effort to attribute kW to specific loads (for example the portion of a customer's load attributable to lighting or motors).

- ➡ **Relying on a PIB to provide accurate interval data** (reported by two aggregators) and inform curtailment plans .
- ➡ **Letting customers determine the level of curtailment they are willing to commit to.** While only three aggregators specifically noted letting the customer determine what they will do, the negotiation process described by others also recognized the value of having customers start conservatively and have a positive demand-response experience. Customers able to successfully meet their demand-response obligations may choose to do more in the future.

One aggregator expressed a desire for more funding for sub-metering, (perhaps through a TA/TI-type program). By installing a current transformer (CT) type sub-meter on each load considered for curtailment, this aggregator expects to gain a deeper understanding of how the loads are interacting and connected to the EMS. Communication problems with the EMS or load that is not connected can mean that a portion of load expected for curtailment is not available.

2008 Event Triggers

Only two aggregators reported that they tracked the factors likely to lead to curtailment events in California. A third aggregator noted that patterns in temperature and ISO peaks indicate when an event is likely. One of the two that tracked factors reported using statistical tools to analyze and predict the likelihood of events, but also noted that the most obvious metric is the actual load in the California system at the ISO website. The other reported tracking weather conditions in PG&E territory, but not being able to track factors likely to lead to curtailment in SCE territory:

- *"SCE has been all over the map…. In August, there were eight events. On at least four of those days, we had no idea why – it wasn't hot, there were no load emergencies. This was hard on us and hard on our customers. They'd like to know they did it for a good reason. It gets hard to justify and get continued cooperation…. SCE could not give us a good reason because of proprietary day-ahead forecasting. In a third of the cases, the ex post pricing at the ISO wasn't close to the price where our load would have been cost-effective. I don't know why they picked on these day-ahead contracts so much."*

Seven other aggregators reported being unable to track triggering events in California. Comments about this typically mentioned the *heat rate* trigger associated with the CBP and the fact that the bilateral programs are triggered at utility discretion.

- *"Sometimes it's mysterious. Extreme weather may occur, and [the program] is not triggered. Sometimes it seems random. Even the way it's described… this 'heat rate' thing. It's impossible to communicate to customers."*
- *"We track factors on the East Coast, but in CBP it's 15,000 BTU/kWh. I don't know how to calculate that kind of stuff…. I basically track the weather."*

- *"It's triggered by the heat rate. We don't have any way to track that. We don't have any ability to predict what might happen in 2009."*

Timeliness of Payments and Settlements

Six of the ten active aggregators mentioned delays in the utility payment and settlement process.[38] A seventh contact reported no problems with the timeframe within which their firm received the capacity payments, but noted that this firm had experienced no actual called events and thus had no energy calculation settlements or payments in 2008. Two other contacts reported working directly with APX to understand the settlement calculations. Both of these contacts came from firms with fewer than ten customers enrolled.[39]

Aggregators complained about the timeframe within which payments and settlements occurred at all three utilities. It is common for aggregators to pay their customers only after receiving payment from the utility and this approach can create long delays in payments to load providers. Several aggregators noted that SCE had a well designed, easy-to-read settlement document, but that the data were not readily available. One contact described receiving the settlement data 45 to 60 days after the end of the event month. If the payments were net-30, or if there were corrections, the settlement and payment process easily could stretch to three or four months. Another reported during an interview with us in early February 2009 that his organization had not received payments yet for September or October 2008.

Those commenting on the difference between the utilities on this aspect noted that PG&E used a less polished format, but began the settlement process within a few weeks, abbreviating the entire process.

- *"It took Edison a long time to send payments on invoices last year. This was a problem for us because we receive payments and then pay out to our customers. Some invoices were outstanding for four to six months. The bright side is that by the end of the summer, things were moving more quickly."*
- *"Payments were not within the time period we expected. At one utility, there was a three-month lag. We pressure the utilities to get those payments on time…. We have to pay our customers on a timely basis. At San Diego, it's probably an understaffing issue."*
- *"For Edison, it takes a long time to get a settlement. PG&E isn't as snazzy, but much quicker – [AMP settlement data are]provided within two weeks. I look at the raw data,*

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38 Only nine of the ten aggregators answered questions about settlements and payments. The ten completes included one partial complete.

39 The number of unique customers nominated does not necessarily correlate to the number of meters enrolled.

do the whole data processing and send them what I think I should be invoicing, and they confirm it or correct it. It takes a lot longer for SCE."

In general, comments about the timeliness of settlements centered on the bilateral contract programs, not the CBP. However, there were complaints from one CBP-only aggregator and two aggregators that participate in multiple programs mentioned CBP-only territories in their comments. CBP settlements are managed through APX, which could explain why aggregators were less likely to attribute CBP delays to the utility.

In discussing the delays in payments, several aggregators discussed waiting for settlement-quality meter data (SQMD). One contact described her perception that the raw data and the settlement data were extremely close. In some cases, aggregators would be able to see this because of the presence of PIB monitoring equipment or through electronic access to a customer's IDR data. This contact believed that launching the settlement process with the raw data, but with an opportunity to reconcile or adjust payments in subsequent months (if necessary), could speed up the payment process.

Ultimately, these delays could affect the success of the demand-response effort broadly by disconnecting the payment and the activity.

Program Competition

While not asked directly about how they interacted with competing programs at the utilities, three contacts spontaneously mentioned barriers resulting from the other demand-response programs offered by the California IOUs. As illustrated in Table 2.1, each of the utilities offers a suite of demand-response programs, occasionally with overlapping target customers and similar descriptions.

- *"There are too many competing programs out there. The utility has its own demand response programs. PG&E has so many it's hard to keep track of them all."*
- *"The competition with the utilities is a problem. There are so many options for demand response, it's overwhelming. I'm not sitting down with you with a menu of eight different programs with different terms. We make it simple for our customers."*
- *"It's difficult in California because we also compete with the utilities. Normally, we'd be more industrial focused, but in California our industrial adoption is lower than elsewhere because we compete with BIP. BIP is attractive and virtually all the industrial customers are signed up. This program is very low risk – it's rarely, if ever, called – and pays more than we can pay them. BIP does come with a performance penalty, but it hasn't been called in three years."*

SUMMARY & FINDINGS

Aggregators reported many lessons learned in the 2008 program season. These lessons included improvements in marketing and messaging, an improved understanding of utility processes, and better knowledge of their customers' capacity for demand-response performance.

Our interviews with aggregators and subsequent analysis of these documents revealed:

- **Aggregators represent a variety of business models and approaches to demand response.** These differences often reflect the variety of experiences firms have had in the market and whether they have products to sell in addition to aggregation services.
- **Aggregators reported challenges selling and marketing the programs, particularly to new customers**. In some cases, it took months to make contact, answer questions, complete paperwork, enroll customers, and estimate and nominate load.
- **Paperwork and collateral requirements for the 2008 programs varied by utility**. There was no single form or process and the requirements could be applied differently in different territories. Aggregators noted the differences, but were not overly concerned or surprised by them. Many of these firms operate in multiple demand response markets and are accustomed to navigating nomination processes. However, there were multiple complaints about the CISR form. The form is a binding contract and contains legal language. In some cases, this intimidated customers and delayed the enrollment process, because prospects believed they needed to obtain a legal review of the document.
- **Several aggregators noted difficulties with collateral requirements**. We did not ask contacts directly about the collateral requirements; however, three contacts expressed frustration with them.[40] One specifically advocated that uniform creditworthiness standards for the CBP be established for the three utilities and that those standards be discussed openly so that one utility cannot interpret the requirements more stringently than another.
- **Aggregators noted that the timeframe for settlements and payments was problematic**, with more than half of them saying it could take months to receive payment.
- **Aggregators do not distinguish between the programs in how they market the demand response opportunity to customers or estimate the demand response potential at a given site**.

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40 Collateral requirements involve deposits or letters of credit, as required by the utilities. For programs that have them, aggregators are required to provide collateral to the utility before being authorized to enroll customers and nominate load. The terms of these requirements vary in both structure and amount between the five programs.

- ➡ **The APX interface caused problems for some aggregators**. The processes for the CBP are, in many cases, remnants of the previous CPA program, which was designed for individual customers to nominate their own load. Aggregators with numerous enrolled meters complained of the APX interface that required them to re-load their entire nomination list every month by dragging and dropping each SA ID into the web-based form.
- ➡ **Several aggregators stated that there were too many competing demand response programs in California and that having to compete with the utility's own programs was particularly challenging**.
- ➡ **Aggregators struggled to explain the trigger and/or likelihood of events to potential participants**. The official heat-rate trigger is difficult for aggregators to explain or predict. Few aggregators reported they were able to predict the likelihood of curtailment events, particularly for the CBP.

In general, aggregators nominated load to the program that was most lucrative for the firm, or to benefit from certain program features (such as monthly billing). Aggregators participating in multiple programs often described the CBP as a reserve for load they were considering adding to their contract, or would add if there was room. As aggregators begin to exceed their contractual obligations associated with DRC and AMP, we expect that they will increasingly place excess capacity into the CBP.

4 PARTICIPANT EXPERIENCES

This chapter presents the results from surveys with 270 participants of the 2008 aggregator demand response programs: the CBP at PG&E, SCE, and SDG&E; AMP at PG&E; and DRC at SCE.

METHODOLOGY

The participant surveys were designed to explore several key issues associated with the aggregator programs, including: communication, administration, program expectations, customer satisfaction, program awareness, and future intentions.

As described more fully in Appendix A, we stratified our population by four main characteristics in order to ensure that we surveyed an appropriate number of contacts in each of the four groups. Specifically, we sought to compare responses by:

- **Utility service territory:** We assigned each organization to the appropriate utility territory as indicated by their presence on a specific aggregator customer list or because of their presence in one of the utility-generated lists used by the impact team. In some cases, we found organizations that participated in more than one territory. These were assigned a *multi-utility* status.
- **Program:** We assigned each organization to the appropriate program as indicated by the lists provided by aggregators, or because of their presence in one of the utility -generated lists used by the impact team.
- **Load size:** We divided our population into small and large load customers, based on a cut-off of 500 kW of maximum summer hourly demand.
- **Consistency of curtailment responses:** We used performance data as provided by the impact evaluation team to assign *consistent* or *inconsistent* responder status to each of the unique customers identified in the general survey population list. For any contact associated with multiple SA ID, the process evaluation team assigned consistency status based upon how a majority of SA ID were found to have performed.

The evaluation plan assumed the cooperation of all aggregation firms in providing contact information to enable surveys of their load providing customers in California. Regrettably, despite months of communication, several aggregation firms remained unresponsive or uncooperative to requests for participant contact information. Since the representativeness and usefulness of the results depended on including participants from all aggregation firms, utility staff at all three IOUs combed through program enrollment forms for contact information for four of the eleven aggregation firms (See Appendix A for more information on list development).

The unique customer contact list ultimately developed by the process evaluation team was merged with the curtailment response categories and load-size data by matching customer names from the impact data files. Sixty-two percent of the unique contact names were successfully matched with these data. We were not able to link the contact name from the unique contact list to the impact evaluation files for 38% of the list. This 38% is characterized below as being of unknown size and consistency.

The participant survey was conducted by telephone interview from Abt SRBI's call center using trained, professional survey managers and interviewers. The survey was fielded from April 24 to May 11, 2009, during normal Pacific Standard Time business hours in order to reach as many contacts as possible. A total of 246 surveys were completed. To counteract non-response bias, a minimum of five attempts per telephone number was made to complete the surveys. The average length of the survey was less than 12 minutes, including the screening questions. The cooperation rate was 96%.[41] The Table 4.1 presents a summary of the final disposition.

Table 4.1: Summary of Participant Survey Disposition

DISPOSITION		TOTAL*
Completed		246
Refused	Hard Refusal	10
	Soft Refusals	1
List Errors	Wrong Number/Person	2
	Fax/Modem/Line Problems	4
	Disconnected Number	17
	No Longer with Company	17
No Contact Made	Away for Duration	2
	Other Barrier	3
Not Screened	Call Back: Appointment or Unspecified	119
	Over Quota for Segment	116
Screened Out	Not Qualified	7
Not Dialed	Cell Phone, Duplicate, Quota Met	57

41 Cooperation rate is the proportion of eligible respondents actually contacted who agree to participate in a research study. The cooperation rate can be impacted by the length of the interview, the subject matter, and the type of person being interviewed.

DISPOSITION	TOTAL*
TOTAL LIST	**600**

* The total includes 14 from the post-event survey as the quota for each group is met; the original list contained 586 contacts.

The data from this survey were combined, where appropriate, with data from the 24 participants interviewed as part of the post-event survey. Questions unique to the post-event survey are discussed in Chapter 5. Questions identical to the participant survey are combined and reported here, for a final sample of 270. Table 4.2 displays the final sample characteristics as distributed among the four comparison groups.

Table 4.2: Participant Sample by Major Group Identify

BY UTILITY TERRITORY		
UTILITY	WEIGHTED COUNT	WEIGHTED PERCENT
PG&E	190	71%
SCE	54	20%
SDG&E	22	8%
Multi-Utility	4	1%
TOTAL	**270**	**100%**
BY PROGRAM PARTICIPATION		
PROGRAM	WEIGHTED COUNT	WEIGHTED PERCENT
CBP	131	49%
AMP	90	33%
DRC	45	17%
Multi-Utility Programs	4	1%
TOTAL	**270**	**100%**
BY CONSISTENT/INCONSISTENT STATUS		
STATUS	WEIGHTED COUNT	WEIGHTED PERCENT
Consistent Responders	97	36%
Inconsistent Responders	70	26%
Unknown	103	38%
TOTAL	**270**	**100%**
BY SIZE		
SIZE	WEIGHTED COUNT	WEIGHTED PERCENT
Small (<500 Max KW)	77	29%

BY UTILITY TERRITORY		
UTILITY	WEIGHTED COUNT	WEIGHTED PERCENT
Large (500 Max KW or greater)	90	33%
Unknown	103	38%
TOTAL	**270**	**100%**

The disposition and sample description is described fully in Appendix A.

Guidelines for Reading this Chapter

The reader should keep in mind the following methodological points when reading this chapter:

- All data from the participant survey were analyzed consistently using four categorical schemas in order to identify any discernable difference in responses among groups defined above.
- In the analysis presented below, we report only overall frequencies unless notable significant differences between any of the groups were observed among categories.
- For each categorical scheme, we applied appropriate statistical tests, such as Chi Square (denoted by χ^2), as well as other nonparametric test methods for finding significant differences among groups.
- All tests were run for all variables in a consistent sequence: first, by including all cases; next, by excluding the multi-utility participants; and finally, by excluding both the multi-utility participants and the participants of San Francisco Community Power (SF Power). It was necessary to test for significance with and without multi-utility customers because of the small number of cases in this category.[42] Conversely, it was necessary to test for significance with and without SF Power participants because of this aggregator's overwhelming representation in PG&E's CBP (representing 88% of all unique participants) and the generally smaller load size of these customers relative to other aggregator participants.
- For the initial analysis, any response of "don't know" and/or a refusal to answer was treated as missing data. For some questions, we determined that *don't know* was an important and/or insightful answer and recalculated the frequencies to include these responses. For most questions, however, this is not the case.

[42] Groups with very small numbers can cause violations of the assumptions in many statistical tests.

- Due to our treatment of *don't know* and refusals, as well as a survey structure that probes some issues more deeply for a subset of customers, the number of total responses (the *n*) may vary between tables.
- The responses to approximately 32 topics discussed in the post-event survey were pulled from the larger data set and analyzed as part of the more qualitatively-focused, post-event survey discussion in Chapter 5.
- For tables that show responses to questions that allowed multiple responses or coded open-end responses, column percents represent the percentage of all the respondents who were asked this question. The percent total (not shown) may be greater than 100% because respondents could have provided more than one response.
- All reported figures are based on weighted frequencies and percentages, unless otherwise noted.

Participant Profile

Participant organizations span a wide range of business activities (Table 4.3). The most commonly reported types of industrial activities reported were manufacturing (22%) and food processing (7%). Retail, lodging, warehouse, and office buildings were the most frequently reported commercial activities. Thirteen percent of the participants reported their facilities were government-owned, including 27 water and wastewater facilities.

Table 4.3: Primary Activities in the Building

PRIMARY ACTIVITY	WEIGHTED COUNT	WEIGHTED PERCENT (N=270)
Manufacturing	58	21%
Public (government)*	35	13%
Retail	25	9%
Office	24	9%
Lodging	21	8%
Service (other than food service or retail sales)	19	7%
Food Processing	18	7%
Warehouse and Storage	17	6%
Education	14	5%
Food Sales	10	4%
Food Service	10	4%
Health Care	7	3%

PRIMARY ACTIVITY	WEIGHTED COUNT	WEIGHTED PERCENT (N=270)
Worship	5	2%
Other	4	2%
No Response	1	0%
WEIGHTED TOTAL	**270**	**100%**

* Includes 27 water utilities.

More than half of respondents (51%) reported that industrial equipment is the largest source of electricity consumption (Table 4.4). Twenty-two percent reported air conditioning consumes the most electricity. These end-uses were followed in frequency by responses of lighting, refrigeration, and water pumping.

Table 4.4: Largest Electricity Consumption Source

EQUIPMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=270)
Industrial Equipment	139	51%
Air Conditioning	58	22%
Lighting	40	15%
Refrigeration	12	4%
Water Pumping	6	2%
Other	8	3%
Don't Know	7	3%
WEIGHTED TOTAL	**270**	**100%**

Prior Participation and Number of Locations

Most contacts reported their organizations had not previously participated in demand response programs (Table 4.5).

Table 4.5: Prior Participation in Demand Response

PRIOR PARTICIPANT	WEIGHTED COUNT	WEIGHTED PERCENT (N=269)
Yes	59	22%
No	206	76%

PRIOR PARTICIPANT	WEIGHTED COUNT	WEIGHTED PERCENT (N=269)
Don't Know	4	2%
WEIGHTED TOTAL	**269**	**100%**

Smaller customers (those with maximum summer demand less than 500 kW[43]) were more likely to report being first-time demand response program participants (χ^2, $p < 0.05$).[44] However, this difference disappears when the customers of SF Power are excluded from the analysis, likely because many SF Power customers are small load first-time participants. We found no other correlation between customer size and previous participation in demand response programs.

The 59 contacts reporting their organization had previously participated in demand response programs were asked for how many years their organizations had participated. Thirty-five were able to report the number of years. A majority (26) reported they had less than five years of prior experience, three reported six to nine years of experience, and five reported more than ten years of previous experience with demand response (Table 4.6).

Table 4.6: Years of Prior Demand Response Participation

YEARS OF PARTICIPATION	WEIGHTED COUNT	WEIGHTED PERCENT (N=35)
1 to 2 Years	13	37%
3 to 5 Years	13	37%
6 to 9 Years	3	9%
More than 10 Years	6	17%
WEIGHTED TOTAL	**35**	**100%**

As illustrated in Table 4.7, a majority of the participants (74%) are single-site.

43 PG&E categorizes customers above 200kW as "large." The distribution of participant kW indicated a median split at 516kW. Without evidence that customers above a specific size are fundamentally different than customers below that line we chose a value near the median.

44 The maximum hourly demand for the summer period is a typical criterion for classifying customers by load size.

Table 4.7: Number of Locations Participating in 2008

NUMBER OF PARTICIPANT LOCATIONS	WEIGHTED COUNT	WEIGHTED PERCENT (N=250)
1 Location	186	74%
2 to 5 Locations	45	18%
6 to 9 Locations	8	3%
10 or More Locations	11	5%
WEIGHTED TOTAL	**250**	**100%**

Program Awareness and Reasons for Participation

Forty-one percent of contacts reported they first learned of the program when approached by their aggregator (Table 4.8). Ten percent reported they already had an existing relationship with their aggregator. Hearing of the program from a utility account representative was another common response (25%), while others learned of the program via utility website, email, or bill insert.

Table 4.8: Source of Initial Program Awareness

SOURCE	WEIGHTED COUNT	WEIGHTED PERCENT (N=233)
Aggregator	96	41%
Utility Account Representative	59	25%
Existing Relationship with Aggregator	23	10%
Utility Website, Email, Bill Insert	19	8%
Corporate Directive	14	6%
Trade Association	8	3%
Other	14	6%
WEIGHTED TOTAL	**233**	**100%**

We asked contacts to rate several potentially important reasons for participation (using a one-to-five scale where "1" means *not at all important* and "5" means *very important*). Participants considered that most of the suggested reasons were important (Table 4.9). Three reasons stood out as most important: receiving financial benefit (84% percent gave this reason a "4" or a "5"); being viewed as a good corporate citizen (81%); and helping the utility avoid outages (79%).

Table 4.9: Reasons for Program Participation

REASON	1 Not at All Important	2	3	4	5 Very Important
Receive Financial Benefit or Bill Savings (n=266)	3%	2%	11%	21%	63%
Help the Utilities Avoid Outages (n=266)	2%	4%	15%	22%	57%
Be Viewed As a Good Corporate Citizen (n=268)	3%	3%	13%	25%	56%
Avoid Rolling Blackouts (n=268)	1%	6%	16%	22%	55%
Help Improve Electric System Reliability (n=266)	4%	4%	18%	28%	46%

Note: weighted percentages.

Seventy-two contacts offered additional reasons for participating. The most common reason, given by 47 contacts (65% of the 72), was to augment corporate green initiatives and demonstrate an overall concern for the environment. Seven contacts (9%) mentioned the flexibility of the program and/or that no penalty was assessed.

Decision-Making

Twenty-six percent (or 66 participants) reported having questions or concerns that needed to be resolved before their organizations could decide to enroll in the program (Table 4.10).

Table 4.10: Concerns Prior to Enrollment (Multiple Responses Allowed)

CONCERN	WEIGHTED COUNT	WEIGHTED PERCENT (N=66)
Penalty / Program Flexibility	17	25%
Frequency / Timing / Duration of Events	12	17%
Obligation / Contracts / Legal	10	15%
Notification Method / Timing	8	13%
Impact on Business	7	11%
Baseline Calculation	4	7%
Payments, Incentives	4	7%
How Energy Use Is Monitored	3	5%
Legitimacy of Program/Aggregator	3	4%
Equipment Installation	3	4%

Note: The weighted percent column gives the proportion of all respondents who were asked this question. The weighted percent total is greater than 100% because multiple responses were allowed from each respondent.

Overall, participants' concerns pertained to potential risks to their businesses and how the program worked. Many concerns overlapped, as contacts discussed both the possibility of payments and the likelihood of penalties. The most frequently cited issues (mentioned by 17, or 25% of those reporting issues) concerned the likelihood of penalties and understanding any flexibility they had in opting not to respond.

- *"We were concerned about penalties that might be imposed for underperformance or non-performance and the flexibility to opt out of curtailment."*
- *"We had concerns about how payments would be handled, how we would be notified of an event, what, if any, penalties would be imposed for underperformance or nonperformance and the flexibility of the process through which we could lower the curtailment amount that we committed to."*
- *"I wanted to help, but did not want to shut down every time, because sometimes I need the power… under the program, if I did use power at that time, I would be penalized."*

Participants also commonly reported concerns related to the frequency, timing, and/or duration of demand response events (mentioned by 12 contacts).

- *"I wanted to know when curtailment events would be likely to occur. The aggregator assured me they could work around our production schedule on the weekends."*
- *"We wanted to know how much load we would be expected to shed. We were more interested in the frequency than the duration."*

Participants also reported concerns associated with contractual and legal obligations, the methods that would be used to notify them of events, how their performance would be calculated, and how payments would be calculated and dispersed.

Those reporting that they had questions or concerns that needed to be resolved before their organization could commit were asked to whom they turned for answers. Of the 66 that reported seeking clarification from another source, the most common response (mentioned by 44, or 66%) was that the customer turned to the aggregator for information. (Table 4.11). This was followed by seeking information from their utility account representative (reported by 13).

Table 4.11: To Whom Participants Turned for Information (Multiple Responses Allowed)

ENTITY	WEIGHTED COUNT	WEIGHTED PERCENT (N=66)
Aggregator	44	66%
Utility Account Representative	13	20%
Utility Website	1	2%
Other Website	1	1%

Other	2	3%
Resource Within Company	4	6%
Non-Response	1	1%
Don't Know	5	8%

Note: The weighted percent column represents the percentage of all the respondents who were asked this question. The weighted percent total is greater than 100% because multiple responses were allowed from each respondent.

Contacts reporting questions or concerns prior to their enrollment were asked how long it took for them to get the information they required. A majority (77%) reported they received sufficient information within two weeks (Table 4.12).

Table 4.12: Time Required to Obtain Adequate Information

TIME REQUIRED	WEIGHTED COUNT	WEIGHTED PERCENT (N=63)
Less than 1 Week	17	27%
1 to 2 Weeks	32	50%
3 to 4 Weeks	6	10%
One Month up to Two Months	5	8%
Two Months or More	3	5%
WEIGHTED TOTAL	**63**	**100%**

Very few surveyed participants reported having difficulties with the enrollment process. The ten (4% of 250) that reported difficulties said they encountered: failed equipment (2); general delays (2); miscommunication (1); disqualification (1); and other business-related issues (3), such as having a concern about how much control aggregators would have on the electricity meter, or about internal communications. Many of these participants (6 out of 7 who reported valid responses) reported needing two months or more to resolve their difficulties.

Technologies

Forty percent of surveyed participants reported their facilities had an energy management or building control system prior to their enrollment with their aggregator (Table 4.13).

Table 4.13: Portion Reporting Prior EMS or Control System

PRIOR ENERGY MANAGEMENT SYSTEMS	WEIGHTED COUNT	WEIGHTED PERCENT (N=262)
Yes	105	40%
No	156	60%

PRIOR ENERGY MANAGEMENT SYSTEMS	WEIGHTED COUNT	WEIGHTED PERCENT (N=262)
WEIGHTED TOTAL	**262**	**100%**

Fifteen percent of participant contacts (40 of 267) reported installing new equipment in order to participate in the aggregator's demand response program and were able to describe it. The most common type of equipment installed was meter-based equipment that made it easier to monitor demand or allowed real-time consumption monitoring (Table 4.14). This was followed by miscellaneous internal equipment, and upgraded EMS systems that improved control and/or assisted in overall energy management.

Table 4.14: Participant-Installed Equipment (Multiple Responses Allowed)

EQUIPMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=40)
Meter-Based Equipment or Sub-Meter	24	61%
Miscellaneous Internal Equipment	7	18%
Upgraded EMS	4	10%
Software	4	9%
Communication Devise	2	6%
Other	1	3%

Note: Multiple responses allowed; percentages will total to more than 100%.

Forty-two percent (88 of 96 contacts) reported that their aggregators had installed new technologies in their facilities, typically after their enrollment (Table 4.15).

Table 4.15: Aggregator Installed Technology

NEW TECHNOLOGY INSTALLED	AMP (N=83)	CBP (N=113)	DRC (N=42)	TOTAL (N=238)
Yes	27%	36%	88%	**42%**
No	73%	64%	12%	**58%**
WEIGHTED TOTAL	**100%**	**100%**	**100%**	**100%**

Note: Weighted percentages.

Respondents participating in SCE's DRC program were significantly more likely to report that their aggregators had installed technologies in their facilities compared with participants from other programs (χ^2, $p < 0.05$). Eighty-eight percent of DRC respondents said their aggregators installed some type of technology, compared to 27% of the PG&E AMP respondents and 36% of CBP respondents. This difference remained significant even after excluding SF Power.

There are several potential explanations for this difference. First, in 2008, SCE installed IDR meters and PIB boxes for less than half the cost of similar installations at PG&E ($950 at SCE for both, as opposed to $2,700 for an IDR-only at PG&E). Second, SCE offered a path through which smaller commercial customers (down to 50 kW) could obtain an IDR meter for free.[45] Finally, DRC operates with a technical potential assessment process (more fully described in Chapter 2) that requires aggregators to demonstrate exactly how much capacity will be available and assesses performance penalties after the first missed megawatt – which may increase the desire by DRC aggregators to accurately assess and manage their nominated capacity.

Table 4.16 summarizes the type of equipment that the respondents reported their aggregators had installed, by program. In general, it was difficult for participant contacts to precisely describe the equipment installed. Thus the categories in Table 4.16 should not be viewed as an accurate description of what was ultimately installed. Rather, these categories reflect how participants *describe* what was installed.

Table 4.16: Type of Equipment Installed by Aggregator (Multiple Responses Allowed)

EQUIPMENT	AMP (N=22)	CBP (N=41)	DRC (N=36)	TOTAL (N=99)
Meter Equipment	55%	**85%***	56%	**68%**
Monitoring Hardware/Software	**50%***	20%	**43%***	**35%**
Sub-Meter or PIB	10%	19%	**39%***	**24%**
Communication Equipment	10%	5%	19%	**11%**
Equipment Control	0%	14%	5%	**8%**

Note: Weighted percentages. Multiple responses allowed; percentages will total to more than 100%.

* Differs significantly by program (χ^2, $p < 0.05$).

The percentages in Table 4.16 represent the percentage of respondents who reported that the given equipment was installed by the aggregator. For example, of all the participants who reported their aggregator installed new technology (99), 68% said their aggregator installed meter equipment.

Installations of meter equipment, monitoring hardware and software, and a sub-meter or PIB system were the most common responses. Meter equipment was more commonly installed at CBP customers' facilities (85%), as compared with AMP (55%) and DRC (56%) customers' (χ^2,

45 PG&E provided IDR meters at no charge to the customers of SF Power, as directed by the CPUC.

$p < 0.05$). On the other hand, installation of hardware and software for monitoring was more commonly reported by AMP and DRC customers than by CBP customers (χ^2, $p < 0.05$). Installation of a sub-meter or PIB was reported most frequently by DRC customers (39%; χ^2, $p < 0.05$).

Whenever contacts described equipment added to a meter, or metering equipment attached to existing loads, we counted this as separate from more general reports of "metering equipment." Responses we coded as *sub-metering and PIB* equipment typically included descriptions such as:

- *"Some kind of metering device."*
- *"Energy pulse modulation unit."*
- *"Metering equipment for the meters."*
- *"New digital pulse meters to measure usage real-time."*
- *"I don't know what it was, but it was a way to collect energy usage data and get it back to them… I don't know the name."*

Of those reporting their aggregators had installed new technology, 19% reported that a utility rebate or incentive offset the cost of the new technology (Table 4.17). We found no difference in this result by utility or program.

Table 4.17: Technology Incentive Received

RECEIVED INCENTIVE	WEIGHTED COUNT	WEIGHTED PERCENT (N=95)
Yes	18	19%
No	77	81%
WEIGHTED TOTAL	**95**	**100%**

All participant contacts were asked if they were considering installing additional equipment or technologies that might allow for additional demand response during events. Twenty-three percent reported considering additional equipment. Contacts described a variety of equipment, including efficiency upgrades (such as efficient lighting and HVAC upgrades) and solar panels that might reduce the organization's overall demand, but would be unlikely to help them drop additional load during a curtailment event. The frequency of the solar panel response is notable because the net metering that generally accompanies solar panel installation would disqualify an organization from participating in any of the aggregator demand response programs as currently structured.

Table 4.18: Potential Future Equipment (Coded Open-Ended Responses)

EQUIPMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=62)
Efficiency Upgrades	27	44%
Solar Panels	11	18%
Controls	7	11%
Automated System	6	9%
Advanced Meters	6	9%
Load Monitoring System	3	5%
On-Demand Compressor	3	5%
WEIGHTED TOTAL	**62**	**101%**

Note: Rounding and weighting causes the total to equal more than 100% and increases the count by one.

Event Notification

Ninety percent of participant contacts reported receiving a notice to curtail because of an event or test event in 2008. The 10% reporting that they had not received event notification could have been from organizations enrolled later in the summer or excluded from nomination for some reason. Contacts could also be mistaken (Table 4.19).

Table 4.19: Portion Receiving Notification in 2008

RECEIVED NOTIFICATION	AMP (N=87)	CBP (N=124)	DRC (N=44)	TOTAL (N=255)
Yes	98%	81%	93%	90%
No	2%	19%	7%	10%
WEIGHTED TOTAL	**100%**	**100%**	**100%**	**100%**

Participants enrolled in the CBP were significantly less likely to report they had received notification compared to participants enrolled in other programs (χ^2, $p < 0.05$). Almost all AMP participant contacts (98%) and 93% of DRC contacts reported receiving notification for an event or test event in 2008, compared to 83% of CBP participants.[46] The proportion of the SDG&E CBP respondents reporting they received notification was lower than that for the respondents in other utilities' CBP.

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46 Significance persists with or without the SF Power contacts.

Contacts were asked to estimate the number of events for which they were requested to curtail their energy use. Almost sixty percent reported being called to curtail one or two times in 2008 (Table 4.20). AMP and DRC contacts reported more frequent notification than did CBP respondents (χ^2, $p < 0.05$); within CBP participants, SCE customers reported significantly more notifications as compared with customers of PG&E and SDG&E (χ^2, $p < 0.05$). This is consistent with the number of actual events as described in Table 2.3.

Table 4.20: Number of Curtailment Events

NUMBER OF TIMES CALLED	AMP (N=78)	CBP (N=85)	DRC (N=34)	TOTAL (N=197)
1 to 2 Times	52%	73%	47%	**59%**
3 to 4 Times	35%	17%	44%	**28%**
5 to 9 Times	8%	8%	3%	**7%**
More than 10 Times	5%	2%	6%	**4%**
WEIGHTED TOTAL	**100%**	**100%**	**100%**	**100%**

Seventy-two percent of participant contacts that had received an event notification reported receiving notification via two or more methods. The most common method was email, followed by phone, fax, and page (Table 4.21). Other responses included receiving text messages to their cell phones.

Table 4.21: Method of Notification (Multiple Responses Allowed)

METHOD	WEIGHTED COUNT	WEIGHTED PERCENT (N=230)
Email	205	89%
Phone	176	76%
Fax	18	8%
Pager	10	4%
Other	6	3%

Note: The percentage represents the percent of all the respondents who were asked this question. The column percent totals more than 100% because multiple responses were allowed.

In order to understand how the notification process might differ for organizations participating with more than one location, we asked the 50 multi-site respondents how their other sites are notified, and by whom. More than half of the multi-site respondents (56%) reported that central staff notify other locations (Table 4.22). Almost one-third (30%) reported that the aggregator notifies each site. A small number reported that their other locations are remotely controlled and therefore no notification is necessary.

Table 4.22: Event Notification of Other Company Locations

PERSON RESPONSIBLE	WEIGHTED COUNT	WEIGHTED PERCENT (N=50)
Central Staff Notifies Each Site	28	56%
Aggregator Notifies Each Site	15	30%
No Notice Is Required, It's All Automatic	4	8%
Other	2	4%
Don't Know	1	2%
WEIGHTED TOTAL	**50**	**100%**

A majority of the respondents (63%) reported being contacted multiple times about a single event in 2008 (Table 4.23).

Table 4.23: Contacted Multiple Times per Event

MULTIPLE CONTACTS	WEIGHTED COUNT	WEIGHTED PERCENT (N=214)
Yes	134	63%
No	63	29%
Don't Know	17	8%
WEIGHTED TOTAL	**214**	**100%**

Virtually all participant contacts (97%) reported that the notification strategy they experienced in 2008 worked well for their organization (Table 4.24). The few contacts that mentioned problems with notification described lacking a backup contact, being confused by the content of the notice, or having insufficient time to prepare for the event.

Table 4.24: Notification Approach Worked for Participant

NOTIFICATION WORKED	WEIGHTED COUNT	WEIGHTED PERCENT (N=212)
Yes	206	97%
No	6	3%
WEIGHTED TOTAL	**212**	**100%**

The participants reporting they had received at least one event notification in 2008 were asked to describe potential improvements to the notification process. Only 30 of 214 (14%) offered suggestions for improvement (Table 4.25). Earlier notification was the most common suggestion (given by 17). This was followed by: contacting additional/alternative contacts when the primary contact person is unavailable; phone calls in addition to email; ceasing additional notification calls once the aggregator has received confirmation; and considering time-zone issues, if the recipient is located in other time zones.

Table 4.25: Potential Improvements to Notification (Multiple Responses Allowed)

SUGGESTION	WEIGHTED COUNT (N=30)
Earlier Notification	17
Backup Contact Information Available	4
Notification By Phone Not Only Email	4
Not Too Many Calls After Confirmation	3
Call In Appropriate Time Zone	2
Additional Email Notification	2

In order to better understand why participants might appear to have failed to respond to an event and why some events failed to produce the nominated capacity, we asked participants if they perceived that responding to an event was ever optional in 2008. Surprisingly, more than three-quarters believed that their response to the curtailment request was optional (Table 4.26). We found no difference between programs or utility territory, indicating a widespread perception among participants that they do not necessarily have to curtail when called. It is not clear whether this is communicated to them by their aggregator, or if the aggregators are unaware of this perception.

Table 4.26: Response to 2008 Request Optional

IS RESPONSE OPTIONAL	WEIGHTED COUNT	WEIGHTED PERCENT (N=209)
Yes	159	76%
No	50	24%
WEIGHTED TOTAL	**209**	**100%**

Of the 249 participants asked if they had developed a specific plan to direct their curtailment activities after receiving an event notification, 85% reported having such a plan (Table 4.27). With SF Power participants included, CBP respondents were significantly less likely to have a plan (78% reporting) when compared with AMP (92%) and DRC (93%) participants (χ^2, $p < 0.05$). The differences between the programs are not significant when SF Power customers are excluded, indicating that many of the CBP respondents without curtailment plans are enrolled in SF Power's program.[47]

Table 4.27: Existence of Specific Curtailment Plan

CURTAILMENT PLAN IN PLACE	WEIGHTED COUNT	WEIGHTED PERCENT (N=249)
Yes	212	85%
No	36	15%
WEIGHTED TOTAL	**249**	**100%**

Having a specific curtailment plan was also related to the effectiveness of demand response activities. Consistent responders were significantly more likely to report possessing a specific action plan (96%) when compared with inconsistent responders (73%; χ^2, $p < 0.05$).

RESPONSE, CURTAILMENT & PAYMENT

Response to Curtailment Events

Ninety-seven percent of participants reported taking action in response to the event notification (Table 4.28); among the 212 contacts answering this question, we observed a significant difference in how consistent and inconsistent participants responded (χ^2, $p < 0.05$). All consistent responders reported taking action in response to an event notification, while 10% of the inconsistent responders reported that they did not take action. It is important to note that this means 90% of inconsistent responders did report taking action, but for whatever reason (lack of automation, lack of load to curtail, competing business demands, or variable performance between sites) their performance as reported in the impact evaluation data files indicated that their overall response was inconsistent.

Table 4.28: Action Taken in Response to Notification

ACTION TAKEN	WEIGHTED COUNT	WEIGHTED PERCENT (N=212)
Yes	205	97%
No	7	3%
WEIGHTED TOTAL	**212**	**100%**

[47] As noted earlier, SF Power enrolled hundreds of small businesses in PG&E territory, many of whom rely entirely on manually shutting down equipment. Since SF Power customers are, on average, smaller than the other participants, we checked each statistical analysis to see if these customers are driving an observed difference.

We asked the seven reporting they had not taken action why they had not (Table 4.29).

Table 4.29: Why No Action Taken

REASON	COUNT (N=7)
Not Required to Act	3
Production Schedule / Other Business Requirements	2
No Action Is Required, It's Automatic	1
Building Operations Prohibited Action	1

When asked what type of action they took in response to the curtailment request, most of the 205 contacts who reported taking action reported they manually shut down equipment. This was followed, somewhat distantly, by manually launching an automatic curtailment system or program (Table 4.30).

Table 4.30: Action Taken (Multiple Responses Allowed)

ACTION	WEIGHTED COUNT	WEIGHTED PERCENT (N=205)
Manual Equipment Shut Down	172	84%
Manual Launch of Automatic Curtailment	50	24%
No Action Required, Automatically Launched	8	4%
Switch To Back-Up Generation	8	4%
Other	10	5%

Note: The percentage represents percent of all the respondents who were asked of this question. The column percent totals more than 100% because multiple responses were allowed.

Participant contacts described the type of equipment curtailed during events in 2008. Lowering lighting levels was the most common response followed by increasing set points on air conditioning equipment and shutting down motors or other industrial processes (Table 4.31).

Table 4.31: Equipment Curtailed (Multiple Responses Allowed)

TYPE OF EQUIPMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=172)
Lighting	122	71%
Air Conditioning	92	54%
Motors	81	47%
Industrial Process	67	39%

TYPE OF EQUIPMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=172)
Refrigeration or Freezer	15	8%
Elevators	4	2%
Compressor	4	2%
Computer Equipment	4	2%
Water Pump	4	2%

Note: Percent mentioning will total more than 100 because multiple responses were allowed.

Contacts from organizations with more than one enrolled location were asked if the activities were identical at each of their participating locations. Forty-nine participant contacts answered this question, with most (74%) reporting that the curtailment activities were the same at all locations. Thirteen (26%) reported that the activities differed among locations. Of those that described different activities at different locations, six primarily referred to the different types of equipment each location – noting that one facility had more cold storage or refrigeration equipment, or that other locations had a different strategy for pumping wastewater. Only one of the thirteen respondents described specific differences in activity; he noted that at some water treatment facilities the equipment needed to be shut down manually.

We also asked if their ability to meet demand response load reduction goals varied from location to location (Table 4.32).

Table 4.32: Did Demand Response Results Vary by Location

RESULTS VARIED BY LOCATION	WEIGHTED COUNT	WEIGHTED PERCENT (N=49)
Yes	31	62%
No	14	28%
Don't Know	4	10%
WEIGHTED TOTAL	**49**	**100%**

Of the 31 reporting their demand response results varied by location, 16 mentioned some type of variability in load or equipment available to curtail. Generally, these comments revolved around the size of the connected load (more pumps, a larger building, or older equipment). Ten described more aggressive curtailment activities occurring at different sites, or sites that simply did not curtail. Three contacts specifically reported that they could not curtail at all sites equally because of business concerns or customer demand for their product.

Backup Generation

The research team sought to identify if demand response participants typically had access to backup generation (Table 4.33) and, if so, were they using this generation to help them comply with curtailment requests (Table 4.34).

Table 4.33: Access Backup Generation

ACCESS TO BACKUP GENERATOR	WEIGHTED COUNT	WEIGHTED PERCENT (N=222)
Yes	86	39%
No	136	62%
WEIGHTED TOTAL	**222**	**100%**

Table 4.34: Use of Backup Generation

GENERATOR USED TO RESPOND	WEIGHTED COUNT	WEIGHTED PERCENT (N=86)
Yes	10	11%
No	75	88%
Don't Know	1	1%
WEIGHTED TOTAL	**86**	**100%**

While almost 40% of participant contacts reported having access to back up generation, only 5% of the 222 participants answering questions about backup generation ultimately reported that they used this equipment to comply with curtailment requests.

CURTAILMENT EXPERIENCE

This subsection presents the answers to several questions about the results and effects of curtailing at each participant organization. We sought to understand participants' perspectives about the extent to which they believed they had met their demand response goals (Table 4.35).

Table 4.35: Perceptions of Meeting Demand Response Goals

ABLE TO REDUCE THE ENERGY USE ...	WEIGHTED COUNT	WEIGHTED PERCENT (N=205)
More than Expected	52	25%
About What Was Expected	100	49%
Less than Expected	33	16%

ABLE TO REDUCE THE ENERGY USE …	WEIGHTED COUNT	WEIGHTED PERCENT (N=205)
Don't Know	16	8%
Experienced No Change In Usage	4	2%
WEIGHTED TOTAL	205	100%

Participant contacts were then asked if they had experienced any negative effects as a result of their curtailment activities. The most common response, experienced by 23% of 205 curtailing participants, was that curtailment activities had negative effects on employee or tenant comfort (Table 4.36). Of the four respondents reporting other negative effects from their curtailment activities, one reported having computer screens shut down unexpectedly, one reported that fish in a koi pond over-heated, one noted that lighting levels were too low, and the fourth experienced minor flooding in a canal.

Table 4.36: Negative Effects Resulting from Curtailment

EXPERIENCING NEGATIVE EFFECTS ON…	WEIGHTED COUNT	WEIGHTED PERCENT
Employee or tenant comfort (N=205)	47	23%
Productivity (N=204)	37	18%
Overall operations (N=205)	27	13%
Customer comfort (N=205)	20	10%
Sales (N=203)	6	3%
Other (N=205)	4	2%

Note: Percentages show the proportion of the respondents who mentioned each negative effect of all the respondents who provided valid responses.

SETTLEMENT AND PAYMENT

Seventy-seven percent of participant contacts reported that they had received payment for participating in the program with their aggregator in 2008. (Table 4.37)

Table 4.37: Payments Received for 2008 Participation

PARTICIPANTS RECEIVING PAYMENT IN 2008	WEIGHTED COUNT	WEIGHTED PERCENT (N=269)
Yes	207	77%
No	41	15%
Don't Know	21	8%

PARTICIPANTS RECEIVING PAYMENT IN 2008	WEIGHTED COUNT	WEIGHTED PERCENT (N=269)
WEIGHTED TOTAL	**269**	**100%**

CBP participant contacts were significantly less likely to report that they had received payment for their 2008 participation than the participants of AMP or DRC (χ^2, $p < 0.05$) . Approximately 25% of CBP contacts reported they had not received payment for their participation in 2008, compared to 6% and 13% of AMP and DRC contacts, respectively. The statistical significance remained regardless of whether or not the customers of SF Power were included.

Those reporting that they had received payment for their 2008 program participation were asked if the payments met, exceeded or fell short of their expectations. Eighty-four percent of contacts answering this question reported that payment amounts met or exceeded their expectations (Table 4.38). Those reporting that the amounts fell short were asked to elaborate. Of the 23 contacts that offered comments, the most common response (provided by 12) was that they had expected to earn more money for their participation. Six (including one that had already reported expecting to earn more) noted that they had underperformed during events and thus earned lower payments. One of these contacts reported having an uncooperative general manager who failed to curtail when requested. Three participants noted that there were fewer events than expected and three participants reported issues associated with how their curtailment was calculated.

Table 4.38: Perceptions of Payment Amounts

PAYMENTS	YES	WEIGHTED PERCENT (N=192)
Exceeded Expectations	37	19%
Meet Expectations	123	64%
Fell Short Of Expectations	32	17%
WEIGHTED TOTAL	**192**	**100%**

Most participants (88%) reported their organization received the payments within the timeframes they expected (Table 4.39). Of the 21 reporting that the payment timeframe did not meet their expectations, 19 reported it was slower than expected and, of those 19, 9 reported the payments were months later than expected (in some cases up to six months). Comments in this vein are somewhat consistent with the delays characterized by aggregators in Chapter 3 and include:

- *"We shut the power off in July and August and got the money in November."*
- *"They were about four months late, but the aggregator did keep in communication with us."*

- *"They are aggregated month-to-month over six months and we are paid a total sum at the end. Generally, it's been timely, but I think that when there has been a delay, it's because the utility has delayed payments to the aggregator."*

Table 4.39: Timeframe of Payments

PAYMENTS RECEIVED WITHIN THE TIMEFRAME EXPECTED	WEIGHTED COUNT	WEIGHTED PERCENT (N=182)
Yes	161	88%
No	21	12%
WEIGHTED TOTAL	**182**	**100%**

SATISFACTION

Satisfaction with Program Experiences

We found few differences in the responses to satisfaction questions based on status or program. For a few questions, we found a statistically significant difference between consistent and inconsistent responders, and for one question we found a difference based on the program. When these emerge, they are discussed with the related question in the section below.

We sought to understand how important it was for participants to know the reason for the demand response event (using a one-to-five scale where "1" means *not at all important* and "5" means *very important*). Half of the participants reported that it was important or very important (a "4" or a "5") that they know the reason for the curtailment request. However, the responses are notable for the lack of clear majority (Table 4.40).

Table 4.40: Importance of Knowing Reason for Curtailment Request

RESPONSE	1 Not at All Important	2	3	4	5 Very Important	TOTAL
Weighted Count	45	21	59	51	72	**248**
Weighted Percent	18%	8%	24%	21%	29%	**100%**

Inconsistent responders rated the importance of knowing reasons for a curtailment request significantly higher than consistent responders.[48] However, when SF Power customers are excluded, the difference is no longer significant.

Participants were asked if they knew why they had been asked to curtail in 2008. Almost half reported they believed they were responding to grid reliability issues, with a subset specifically mentioning avoiding brownouts and rolling blackouts (Table 4.41).

Table 4.41: Perceived Reason for Curtailment (Multiple Responses Allowed)

REASON	NUMBER	PERCENT (N=214)
Grid Reliability Issues*	131	48%
Temperature or Weather-Related Demand	62	29%
High Price of Power to Utility	36	17%
Vague Comments / General Conservation	24	11%
Environmental Concerns	24	11%
Don't Know	15	7%

* Includes avoiding brownouts or rolling blackouts, protecting the grid and easing grid strain. Twenty-nine contacts specifically reported they had been asked to curtail to avoid brownouts or rolling blackouts.

Program Expectations

Instead of a standard set of satisfaction questions, we used a scale of agreement to ask about specific indicators of satisfaction. Asking participants to rate their level of agreement with a concrete statement is more straightforward than interpreting participant satisfaction with a broad program component. Satisfaction questions can be troublesome because the ratings are almost always high, but we don't necessarily know why people are satisfied, or what aspect they are thinking about when they give their answers. Given these considerations, we asked participants to tell us how strongly they agreed with a given statement, such as: "*I had enough time to prepare for curtailment*." By asking the extent to which they agree or disagree that a program aspects worked for them, we can say with confidence contacts are referring to a specific aspect of enrollment, or notification, or timing.

Table 4.42 presents the results of these agreement questions on a one-to-five scale, where "1" equals strong disagreement and "5" equals strong agreement.

48 Significance determined by using the Mann-Whitney U, a non-parametric test used to analyze ordinal variables comparing two groups.

Table 4.42: Agreement with Indicators of Satisfaction

ASPECT STATEMENT	1 Strongly Disagree	2	3	4	5 Strongly Agree
INDICATORS OF MOTIVATION					
***It's important to do our part to save energy in times of peak demand*. (N=269)**	0%	0%	3%	18%	79%
***Participating in this program helps the environment*. (N=269)**	1%	2%	9%	23%	65%
***Participating in this program helps us save money*. (N=269)**	1%	5%	15%	17%	62%
ASPECTS OF PROGRAM PROCESS					
***Notification of demand response events was clear*. (N=253)**	1%	1%	5%	21%	72%
***The sign up process was easy*. (N=262)**	0%	2%	11%	25%	62%
***I had enough time to prepare for demand response events*. (N=249)**	0%	4%	11%	26%	59%
EVENT EXPECTATIONS					
***The number of demand response events was what I expected*. (N=262)**	6%	10%	22%	23%	39%

Among the three indicators of motivation, virtually all participants agreed (by reporting a “4” or a “5”) with the statement “It’s important to do our part to save energy in times of peak demand;” fewer agreed that the aggregator programs helped the environment or saved them money. Agreement with the statements about program processes was also strong, with more than 85% of participants agreeing that the notification of events was clear, that the sign-up process was easy, and that they had enough time to prepare for curtailment.

The lowest level of agreement occurred with the statement “*The number of demand response events was what I expected*,” to which 16% disagreed. Of those who disagreed, only four were enrolled in an SCE program. In follow-up questioning, 36 of 39 participants commenting on their disagreement explained they had expected to be notified about *more* events for which they would be required to respond.

CBP participants were more likely than AMP and DRC participants to indicate that the number of events did not meet their expectations (Table 4.43).[49] As noted previously, SCE called its CBP and DRC day-ahead portfolios numerous times, while PG&E and SDG&E called each CBP

49 We gauged statistical significance using the nonparametric Kruskal-Wallis test for three or more independent samples.

portfolio (day-ahead and day-of) only once, and AMP was called five times. Thus, it is likely that CBP participants in both PG&E and SDG&E territory would have expected to be called more. The lack of events might represent a diminished opportunity to profit from curtailment; however, participants could have also been pleased to be called so rarely.

Table 4.43: Number of Events Met Expectations by Program and Responder Consistency

PROXY SATISFACTION MEASURE FOR NUMBER OF EVENTS		1 Strongly Disagree	2	3	4	5 Strongly Agree
***The number of demand response events was what I expected*. (N=262)**		6%	10%	22%	23%	39%
Comparison by Program (p<0.05) *	**DRC**	0%	2%	25%	17%	56%
	AMP	0%	5%	22%	29%	44%
	CBP	11%	17%	21%	20%	31%
Comparison by Response Status (p<0.05) **	**Consistent Responder**	0%	9%	25%	25%	41%
	Inconsistent Responder	11%	18%	18%	27%	26%

* Kruskal Wallis test, a nonparametric test used to analyze ordinal data comparing more than two groups.

** Mann-Whitney U, a nonparametric test used to analyze ordinal data comparing two groups.

Inconsistent responders agreed at significantly lower rates than consistent responders with two statements: "*I had enough time to prepare for DR events*" and "*The number of DR events was what I expected*."[50] (Table 4.43 provides the responses of these two groups for "number of DR events".) Perhaps inconsistent responders would have had a better response to events had they had additional time to prepare.

For any response of "2" or "1", we asked contacts why they disagreed with that aspect. Note that no participants disagreed with the statement "*It's important to do our part to save energy in times of peak demand.*"

➡ ***"Participating in the demand response program helps the environment."*** Of the eight participants disagreeing with the statement, seven reported failing to understand how their curtailment would help the environment. In some cases, contacts noted that this was because of failure to perform on their part, and in other cases, due to skepticism of these claims or suspicion that the environmental benefits are limited.

50 We gauged statistical significance using the nonparametric Mann Whitney U test for two independent samples.

- ***"Participating in this program helps save us money."*** Of the 18 participants disagreeing with the statement, 17 commented on their disagreement. Four contacts reported nominal or no savings, while four reported that participating in the program actually cost their organizations (one because of costs associated with on-demand meter reading, three because of disruption and the associated impact on production). Two contacts noted that they had experienced no events. Other participant's comments about financial benefits or the lack thereof were nuanced and reflected their specific experiences and expectations:
  - *"To date, the [aggregator] program is not what we were told it would be. We signed up in 2007 and were not allowed to participate or were not eligible in 2007 because they lost the paperwork."*
  - *"We couldn't participate as much as I wanted to because of a 1988 lawsuit. An older woman fell and broke her hip because of the lowered lighting."*
  - *"The money is insignificant… the rebates are small and the events are short."*
  - *"It doesn't save us money—it makes us money."*
- ***"Notification of demand response events was clear."*** Of the six participants that disagreed, four said this was because they had actually received no notifications, and two reported experiencing confusion around the time frame and schedule of events.
  - *"The notification was not made clear to us; we didn't know when the event was going to happen."*
  - *"We had difficulty understanding their request and the timeframe for the event."*
- ***"The sign up process was easy."*** Of the six participants that disagreed, two reported it took longer than expected, two reported confusion with program details, and two reported difficulties in communicating or negotiating with their aggregator.
- ***"I had enough time to prepare for demand response events."*** While ten participants disagreed with the statement, only six articulated reasons for disagreeing. Five reported needing more time to prepare for events. One noted only that they were not prepared for the first event.
- ***"The number of demand response events was what I expected."*** Thirty-six of the 39 respondents disagreeing with this statement explained they had expected more events.

Another indicator of overall satisfaction is whether or not participants encourage others to sign up for the program or otherwise spread the word to other organizations. These counts are typically low, but can indicate future word-of-mouth program growth. About one-third of the participants reported they had spoken to other companies or other locations within their own company about participating in the program (Table 4.44).

Table 4.44: Participants Encouraging Others

SPOKEN TO OTHER LOCATIONS OR COMPANIES	WEIGHTED COUNT	WEIGHED PERCENT (N=247)
Yes	90	36%
No	157	64%
WEIGHTED TOTAL	**247**	**100%**

Future intentions are another indicator of overall satisfaction, since one would expect that truly dissatisfied participants would remove themselves from the program. Judging by intentions, the responses indicate strong overall satisfaction with the program experience, as 94% of participant contacts reported that they intended to participate in the 2009 program (Table 4.45).

Table 4.45: Expectations for Future Participation

EXPECT TO PARTICIPATE IN 2009	WEIGHTED COUNT	WEIGHTED PERCENT (N=261)
Yes	246	94%
No	15	6%
WEIGHTED TOTAL	**261**	**100%**

Of the 15 participants reporting they would not be participating in 2009, five reported this was due to negative financial effects resulting from participation. Two each reported that they: were not qualified; did not experience enough events; had experienced difficulty scheduling curtailment; or had a strained relationship with their aggregator.

Suggestions for Improvement

All participant contacts were asked if they had any suggestions for how to improve the program. Eighty-four offered suggestions for improvement (Table 4.46). The most frequently offered suggestions were requests for more advanced notification and requests for more information or better communication about program activities and demand response generally.

Table 4.46: Suggestions for Program Improvement (Multiple Responses Allowed)

AREAS FOR IMPROVEMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=84)
Advance Notification of Events	18	22%
Communication/Information in General	17	21%
Performance Feedback	13	15%
More Technical Support	13	15%

AREAS FOR IMPROVEMENT	WEIGHTED COUNT	WEIGHTED PERCENT (N=84)
Improving Baseline Calculation	5	6%
Greater Incentives	5	6%
More Events	4	5%
Internal Issues / Business Consideration	4	4%
Solar	4	4%
Notification Method	2	2%
Time Zone Issues	2	2%
Prompt Payment	2	2%

Typical requests for more advanced notice included:

- *"We'd like a longer notification period, as far out as possible. I do understand that this is often difficult."*
- *"More time to prepare is needed; we need more information to educate our tenants."*
- *"We'd like a two-day warning"*

Typical requests for improved communication in general included:

- *"My biggest suggestion would be for the aggregator to provide more accurate and consistent response in terms of customer service. They have a hard time calling us back or getting back in touch with us. The demand response notification they have mastered."*
- *"We need better communication between events and also during the year."*

However, there were also requests for more information or communication from the utility in this category. These comments included requests like:

- *"Simplify the whole process: it's hard to understand the rate process and thus the need for the aggregator."*
- *"Provide more advertising for demand response programs."*
- *"We need to have more public awareness. There is a need to make the public aware of the program – all of our customers asked about the signage."*

These suggestions were closely followed in frequency by requests for more technical support and improved feedback on performance. All of the top four suggestions are interrelated and involve providing more information on all aspects of curtailment: when it will be required; how the program works and the role of the aggregators; more information on actual loads and technical strategies; and better feedback on performance. These aspects all lead to more informed and prepared participants.

In some cases, the comments reflected a lack of understanding of how the program worked within the constraints of the utility system. For example:

- *"We'd like more notice time… like a couple of days in advance. I'd also like them to come up with alternative ways to save energy, such as using solar panels or backup generators."*
- *"I'd like three or four months after enrollment before the program starts."*

However, other requests reflected the need for certainty, or at least better information.

- *"I'd like a guarantee that events would not be called on consecutive days."*
- *"We need clear documentation or better explanation of the financial benefits of participating."*
- *"It would be good to have better forecasting of possible events that would trigger a demand response day – either from the utility or the aggregator."*

The two categories most likely to contain requests that are actually within the aggregator's purview are requests for more technical support and improved feedback on performance. The 14 requests for more technical support reflected requests for "more investigation into load demands," or "better labeling for equipment that needs to be shut down," or "someone to come out and identify the big users of electricity here."

Similarly, requests for improved feedback on event performance include requests for more rapid information from aggregators on how the customer did during an event, invoices or checks that itemized performance by facility, and general requests for feedback. In some cases, these comments were consistent with aggregator reports that delays in obtaining settlement quality meter data and issues around the baseline calculation process may affect customer satisfaction. Aggregators may be reluctant to provide a quick report of performance compared to baseline if the aggregated group failed to deliver the demand resource as expected. If customers were to possess an estimate of their performance, they could use that to estimate the payment they will receive. If this payment amount is reduced through the aggregated baseline calculation, it could affect customer satisfaction even more than by delayed accounting. Requests for more detailed performance feedback included comments like:

- *"Update me on our usage and our participation so I can know how much we are curtailing."*
- *"The aggregator's website should have my current power usage, my baseline demand, and my targeted reduction level."*

- *"We need feedback. You don't know if you met your committed number until after the program. Did we meet that number? How much did we miss it by? We need to make adjustments."*
- *"We need better follow up regarding results and remuneration."*

SUMMARY AND FINDINGS

Summary

We found few significant differences between how the different groups of participants answered most questions. The most notable differences occurred between programs when participants discussed the number of events and whether or not they had been paid for their participation in 2008.

- ➡ **CBP participant contacts were significantly less likely to report that they had received payment for their 2008 participation** than the participants of AMP or DRC.
- ➡ **Participants enrolled in CBP were significantly less likely to report they had received notification** compared to participants enrolled in other programs.

These factors could be interrelated, and may reflect the relatively low use of the CBP in both PG&E and SDG&E territories. The only CBP portfolio called more than three times was SCE's day-ahead portfolio, called 18 times.

Other areas of significant difference include:

- ➡ **DRC participants program were more likely to report that their aggregators had installed technologies in their facilities** compared with other programs. Eighty-eight percent of DRC respondents said their aggregators installed some type of technology, compared to 27% of the PG&E AMP respondents and 36% of CBP respondents.
- ➡ **Having a specific curtailment plan was also related to the effectiveness of demand response activities**. Consistent responders were significantly more likely to report possessing a specific action plan when compared with inconsistent responders.

Findings

- ➡ **Aggregators appear to be engaging new participants**. Aggregators appear to be recruiting organizations that had not previously participated in demand response programs. While about half of the participants we surveyed reported they had first heard of the program from their aggregator – either through direct marketing or because of a previous relationship with the aggregator – 25% reported hearing of the program from their account representative. A majority reported not having an EMS system installed prior to enrollment.

➡ **Participants are satisfied with the major components of the program**. Only about a quarter of the contacts reported having questions that had to be resolved prior to enrollment; of this group, the most common concern centered on penalties and program flexibility. In general, participants reported:

- They intended to participate in the 2009 program.
- Payment amounts met or exceeded their expectations.
- The notification strategy worked well for their organization.
- The payments were received within the timeframe they expected.

➡ **Participants are interested in using less energy overall; many are considering equipment upgrades and installation that could reduce demand response capacity**. When asked to describe potential future equipment under consideration for future installation, participants described a variety of equipment, including efficiency upgrades and solar panels. This equipment will likely reduce the organization's overall demand, but would be unlikely to help them drop additional load during a curtailment event. The frequency of the solar panel response is notable because the net metering that generally accompanies solar panel installation would disqualify an organization from participating in any of the aggregator-driven demand response programs as currently structured.

➡ **Participants report taking actions in response to curtailment requests, but many contacts believe their participation is optional**. Almost all participants that received a notification request reported taking action to reduce their energy use. The most common action was to manually shut down equipment. However, more than three-quarters believed that their response to the curtailment request was optional. We found no difference between programs or utility territory, indicating a widespread perception among participants that they do not necessarily have to curtail when called. It is not clear whether this is communicated to them by their aggregator or if the aggregators are unaware of this perception.

➡ **Few participants are turning to backup generation to assist in curtailment**. While almost half of participants reported having access to back up generation, only 5% of the 222 participants answering questions about backup generation ultimately reported that they used this equipment to comply with curtailment requests.

➡ **Participants believe they are curtailing because of grid reliability issues**. Almost half reported they believed they were responding to grid reliability issues, including a large subset specifically mentioning that they were being asked to curtail to help avoid brownouts and rolling blackouts.

5 POST-EVENT SURVEY RESULTS

The goal of the post-event customer survey was to more fully understand the experience of participants who reduced their energy use when requested to do so by their aggregator in 2008. Specifically, we sought to conduct interviews with a sample of customers in each program, based on whether during analysis conducted as part of impact evaluation activities they were found to have consistently or inconsistently responded to events.

POPULATION AND SAMPLE

The post-event surveys were designed to allow an interviewer to probe more fully into the actions taken or not taken during actual events in 2008. As described in Appendix A, the process evaluation team used performance data as provided by the impact evaluation team to assign *consistent* or *inconsistent* responder status to each of the unique customers identified in the general survey population list. For any contact associated with multiple SA ID, the process evaluation team assigned consistency status based upon how a majority of SA ID were found to have performed. Finally, prior to the general customer survey, the research team extracted 52 customer names from the larger sampling frame (described more fully in Appendix A) for the post-event survey. The contact names were divided between *consistent* and i*nconsistent* responders.

The team completed interviews with 24 participants during April and May 2009. Each interview took approximately 30 minutes to complete. We were able to complete more interviews with consistent responders than with inconsistent responders. Table 5.1 displays the final sample.

Table 5.1: Post-Event Sample (N=24)

UTILITY/PROGRAM		CONSISTENT RESPONDERS	INCONSISTENT RESPONDERS
PG&E	**CBP***	5	3
	AMP	2	1
SCE	**CBP**	3	1
	DRC	3	2
SDG&E	**CBP**	2	1
Multi-Utility (SDG&E/SCE)		1	0
TOTAL		**16**	**8**

* Includes a sub sample of SF Power customers

SUMMARY

Overall, this strategy for assessing the difference between consistent and inconsistent responders did not produce the level of detail we had sought in terms of understanding exactly what participants did when called to curtail and their experience of the event. We were unable to link a specific contact with a specific event in a meaningful way and were forced to rely on participant memories of events that could have occurred more than six months previously.

In general, we found few differences in the characteristics of consistent and inconsistent responders and how they experienced the program. The overall findings are presented below, followed by a more detailed presentation of the survey data and frequencies.

FINDINGS

The post-event survey revealed that consistent responders more frequently reported reducing industrial processes in response to event notification and engaging in communication with their aggregators more often than did inconsistent responders. We found no differences in how consistent and inconsistent responders answered questions related to setting load reduction goals, their experience of event notifications, and their methods for tracking demand response performance.

Participants rarely reported keeping records of their curtailment activities, instead relying almost exclusively on information from aggregators to assess their curtailment accomplishments.

The majority of participants were satisfied with the demand response event notification process. About one-quarter of participants reported that the total number of demand response calls was less than expected. Most reported receiving three or fewer curtailment requests.

In developing their curtailment strategies, participants typically began by identifying the equipment with the highest energy use and then developing strategies to either turn off or adjust this equipment when called to curtail. Shutting off or adjusting set points on air conditioning equipment was the most commonly reported curtailment activity. Reducing lighting levels and requests to staff or students to reduce their use of electricity were the next most common. Industrial customers typically shut down or reduced process-line operations. These findings are consistent with the general participant survey. Participants with multiple locations enrolled implemented strategies to shift load among different locations to meet load reduction goals.

Participants required few staff to implement their curtailment activities; the majority reported having one to three staff directly involved in coordinating demand response events. All contacts reported that they communicated internally about events, with about half notifying their entire staff.

While only a few contacts reported it was important to be informed of the reason for the curtailment event, most assumed that they knew the reasons for their 2008 events. Communicating the reason behind the demand response event could help participants needing to enlist the cooperation of others – including those that try to communicate the event to large groups of students, staff, or customers. There are indications that participants may be attempting to forecast demand response events in advance of notification from their aggregators by monitoring utility information.

SURVEY RESULTS

Almost 40% of the contacts for the post-event survey were from manufacturing organizations (9 of 24). Other contacts were from government entities (4), retail establishments (3), warehouse and storage facilities (3), educational facilities (2), service industries (2), and lodging facilities (1).

Most participants (17 of 24, or 71%) reported their organizations participated by curtailing at only one location. The remainder reported participating via more than one location, including two contacts from organizations that had enrolled more than 20 locations (Table 5.2).

Table 5.2: Number of Locations Participating in 2008

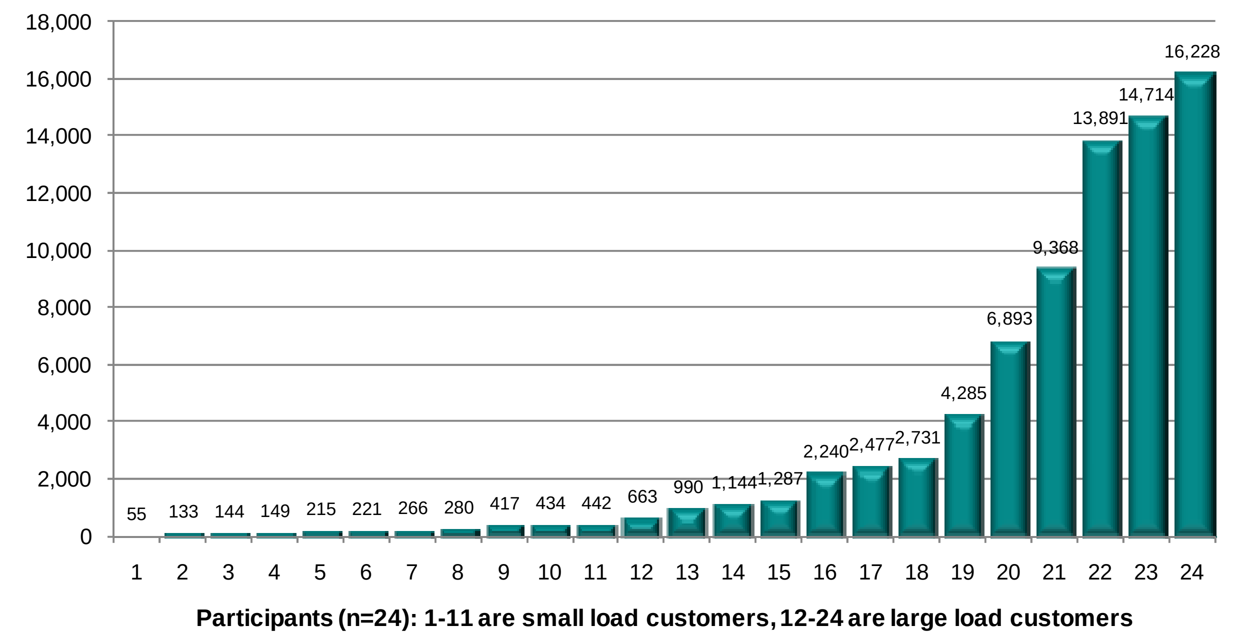
NUMBER OF LOCATIONS	CONSISTENT RESPONDERS (N=16)	INCONSISTENT RESPONDERS (N=8)	TOTAL (N=24)
One	10	7	17
2 to 10	2	1	3
20 to 100	2	0	2
More than 100	2	0	2

Participants represented organizations of many different sizes. Summing the maximum hourly demand from the impact evaluation data files reveals organizations with load sizes ranging from 55 kW to 16,228 kW. [51] The number of service agreement identifications (SA ID) did not necessarily correlate with participant load size. For example, of the five participants with the largest load sizes, two (both college campuses) had only one SA ID. Figure 5.1 displays the distribution of load sizes for the 24 participant organizations.

Ten participants were able to provide an estimate of the portion of their operating costs represented by electricity costs. Three contacts reported that electricity costs comprised greater than 10% of their operating costs. These included a wastewater treatment plant (10%), an industrial equipment repair company (30%), and a cement manufacturer (50%). The remaining contacts reported electricity costs ranging from less than 1% to 9% of operating costs.

51 The maximum hourly demand for the summer period is a typical criterion for classifying customers by load size.

Figure 5.1: Distribution of Participant Load Size – Maximum Hourly Demand in kW



Demand Response Goals and Strategies

One contact from an inconsistently responsive organization had no recollection of being called to participate in a 2008 demand response event. Therefore, questions regarding demand response notifications and curtailment activities were not asked of this participant.

Of the 23 participants able to speak about their 2008 curtailment activities, 21 reported being familiar with the process used to set the demand response goals and strategies for their organizations. Contacts described a variety of strategies for setting and meeting curtailment goals. For example, three participants reported having a specific staff or team responsible for managing energy at their organizations and two emphasized the importance of setting conservative goals that could be achieved easily.

Many contacts described identifying the equipment with the highest energy use and then developing strategies to either turn off or adjust this equipment when called to curtail. According to one such contact:

- *"The biggest consumers of electricity within our warehouse are the 30 AC units used to run a 300,000 square foot warehouse. So we turn down AC units and that is more than enough to cover our curtailment."*

Contacts also discussed the business considerations that informed planning for demand response events. In some cases, they considered the likely payment, given the potential impact to their businesses. According to one such contact:

- *"We decided that with the number of times [demand response events] were likely to occur, it made sense to shut almost everything down."*

Access to back-up generation was a consideration in determining load reduction capacities for two participants. One of these (a contact from a water treatment plant) reasoned that the entire plant could be shut down during demand response events, because of the plant's access to back-up generation.

In some cases, participants developed strategies for shifting load among different locations to meet an overall organizational target. One contact described using an EMS to rotate curtailment activities among a subset of 200 retail stores. This contact explained that when customers complain about curtailment activities at one location, additional curtailment is shifted to other stores.

Participants were asked what equipment was shut down and/or adjusted in response to event notification. Shutting off or adjusting set points on air conditioning equipment was the most common activity. Reducing lighting levels and reducing industrial processes were the next most common activities.

Consistent responders more frequently reported reducing industrial processes when asked to curtail than did inconsistent responders. Almost half (7 of 16) of consistent responders and about one-quarter (2 of 7) of inconsistent responders reported reducing industrial processes (Table 5.3).

Table 5.3: Equipment Shut Down or Adjusted (Multiple Responses Allowed)

EQUIPMENT AFFECTED / ADJUSTMENT PROCEDURES	CONSISTENT RESPONDERS (N=16)	INCONSISTENT RESPONDERS (N=7)	TOTAL (N=23)
Air Conditioning and/or Chillers	6	5	11
Lighting	5	4	9
Industrial Processes	7	2	9
Notify Staff and/or Students to Reduce Electricity Usage	2	2	4
Shut Down Entire Facility	2	1	3
Motors and/or Pumps	1	0	1
Fans	1	0	1
Anti-Sweat Controls	1	0	1
Refrigeration Compressors	1	0	1
Saunas	0	1	1

Method, Timeframe, and Frequency of Notifications

The 23 participant contacts able to describe their 2008 curtailment activities were asked about all aspects of the notification process. Eighteen of the 23 (78%) reported receiving three or fewer calls to reduce their energy use. The four customers who reported the greatest number of calls were participants in SCE's CBP program (Table 5.4).

Table 5.4: Frequency of Event Notification

NUMBER OF EVENT NOTIFICATION CALLS	CONSISTENT RESPONDERS (N=16)	INCONSISTENT RESPONDERS (N=7)	TOTAL (N=23)
1	6	1	**7**
2	5	2	**7**
3	1	3	**4**
5 to 10	3	0	**3**
11 to 15	1	1	**2**

Six contacts reported that the total number of demand response calls was less than expected. According to a participant who reported receiving three demand response calls:

- *"I expected about twice as many [events] as we had."*

Twenty-two participant contacts were able to describe the method(s) used to notify them of demand response events (Table 5.5). All reported being notified by email. Nineteen of these 22 were additionally notified by phone. Cell phone calls, text messages, and faxes were also used in combination with email and/or phone notification.

Table 5.5: Notification Methods (Multiple Responses Allowed)

METHOD	CONSISTENT RESPONDERS (N=15)	INCONSISTENT RESPONDERS (N=7)	TOTAL (N=22)
Email	15	7	22
Phone and/or Automated Voicemail	14	5	19
Cell Phone	3	2	5
Text Message	0	1	1
Fax	1	0	1

Two contacts, both of whom reported receiving curtailment notifications through multiple modes of communication, believed the amount of notification was excessive. According to one of these contacts:

- *"We were notified by email and by phone at the office and treatment plant, and through cell phones… they notified the heck out of us."*

While two participants reported the amount of notification was excessive, all twenty-three reported that the notification method(s) worked well for their organizations.

All 23 contacts were asked how, if at all, the process could be improved for their organizations. Three contacts articulated improvements. Two noted that earlier notification would help their organization; the third contact reported having to adjust internal processes to the West Coast time zone.

The descriptions offered by some participants indicated that they attempt to forecast demand response events in advance of notification from their aggregators. For example, a participant who coordinates demand response activities for 300 participating stores monitors utility information to gauge the likelihood impending demand response events. When utility indicators suggest an event is likely, this participant informs participating store managers in advance of the prospective event.

Internal Communication and Coordination

Participant contacts were asked about the number of staff responsible for coordinating curtailment activities. The responses ranged from one to eight. The majority of participants (15 out of 23) reported between one and three staff (Table 5.6).

Table 5.6: Number of Staff Involved

NUMBER OF STAFF	CONSISTENT RESPONDERS (N=16)	INCONSISTENT RESPONDERS (N=7)	TOTAL (N=23)
1 to 3	10	5	**15**
4 to 6	6	1	**7**
7 to 9	0	1	**1**

All participants reported communicating internally about the events when they occurred. Approximately half (11 of 23) notified their entire staffs. Comments from these participants suggest that communicating about participation in demand response activities to large numbers of individuals can be difficult. For example, a participant from a large college campus reported:

- *"There are announcements that we participate in demand response, but the majority of the time, most of the campus doesn't know what is happening."*

The contact further noted that these communication challenges result in less curtailment activity among students, faculty, and staff, thus reducing the load reduction amount for the campus.

Comments from retail participants also indicate that communicating about demand response participation with customers can be challenging. For example, the three retailers interviewed all reported placing placards to inform their customers of the store's participation in demand response activities. One of these three reported that, prior to placement of placards, some customers assumed there to be a problem with the store's refrigeration system, because lights in refrigerated cases had been turned off. However, another contact reported that the placards heightened customers' attention to curtailment activities, resulting in an increased number of customer complaints. As a result, this participant discontinued the use of placards.

Demand Response Performance

Of the 23 participants who recalled participating in 2008 curtailment activities, 3 reported that their organizations kept records of called events and of their responses to them, 4 reported not knowing if records were kept, and 16 reported that their organizations had not kept records. However, all 23 reported reviewing information provided by aggregators to track their demand response performance. Three of these 23 reported combining the aggregator-provided data with additional sources of information to better track performance. Of the three, one reported relying on tracking information provided by corporate offices, one reported using *kWickview* (a tool on the SDG&E website that enables customers to review demand performance in real-time), and a third reported that as a transmission customer he has access to meters that display energy demand information.

Initially, 18 out of these 23 participants reported that they had been able to reduce energy use to commitment levels. However, when asked if they had been able to reduce energy use to the levels they had committed to for *each* demand response event, 4 of these 18 reported that they had not.

Regarding their inability to reduce energy use to the levels they had committed to for each event, one among these four noted that the ability to achieve goals depends upon the individual actions of numerous staff, which vary for each event. In addition, this participant reported not having available load to curtail during an event called on a relatively cool day, because the participant's HVAC equipment was already running at a reduced level. A second among these four reported having not met goals for one demand response event as the respondent's company had been unable to reduce operations because of other business considerations.

Finally, two of the four contacts reported that, while their organizations had initially not been able to meet curtailment goals, eventually they were able to meet their goals consistently. One reported having achieved consistency through increased experience with implementing curtailment activities and the other by negotiating with the aggregator to adjust curtailment goals to a more readily-achievable level.

Notably, all four of the participants able to meet their curtailment goals for only some events were categorized as consistent responders.[52] Among the fourteen participants who reported meeting their curtailment goals for every event, three were identified as inconsistent responders. These discrepancies suggest that:

- ➡ Participants may not have a clear sense of their demand response performance relative to their load reduction commitments;
- ➡ Curtailment goals established might be so low that they failed to emerge in the regression analysis developed by the impact team to analyze the load impact coefficient; or
- ➡ It is difficult to use available data to consistently and accurately assess participant organizations' overall demand response performance.

We asked contacts to describe the number of times they were called to curtail in 2008. Of the seven participants who reported being called only once to reduce their energy use, six reported being able to reduce energy use to the level they had committed to for that event. Of the sixteen participants who reported being called for more than one event, ten reported meeting their curtailment goals for every event, four reported that they did not know, and two reported that they had not been able to meet curtailment goals for every event.

One participant, called three times to curtail in 2008, reported failing to meet curtailment goals in every case. This respondent reported not knowing why his organization was unable to achieve demand response goals.

Two participants, both identified as consistent responders, reported organizational tensions between commitments to energy efficiency and curtailment capacity. According to one of these participants:

- *"We are always trimming back [our energy use] so it's hard to free up more for demand response."*

According to the second participant:

- *"Our baseline was low so we didn't profit a lot from shutdowns because we were already doing a lot of [energy efficiency] each day."*

Several participants offered descriptions of their curtailment activities that indicate an in-depth understanding of demand response and how their performance will be measured. For example, one contact reported initiating curtailment activities at least twenty minutes prior to the start of

52 Recall that the *consistent* and *inconsistent* responder categories emerged from the impact evaluation analysis and represent a categorization scheme developed by the process evaluation team to assign an overall performance criterion to each organization.

an event and continuing those activities for at least twenty minutes after events have ended. According to this participant:

- *"This approach ensures accurate readings at the fifteen-minute data points before and after demand response events."*

Only three (of 23) participants reported experiencing negative effects as a result of their curtailment activities. As noted previously, one retailer reported confusion among customers before he began using placards to announce curtailment activities and a second retailer reported increased complaints from customers when placards were used. A third participant reported difficulties ensuring that others would cooperate: he described tenants who were unwilling or unable to reduce their energy use during demand response events.

One participant reported no negative effects as a result of curtailment, but noted the absence of negative effects is contingent upon the short duration of events. According to this respondent:

- *"What's important to us is the duration of events. Six-hour events are tough. In three-hour events you can run your refrigeration temperatures up and not hurt anything, but with four- to six-hour events you can't."*

Of the 19 participants responding to a question about whether it was important for them to know the reason(s) for demand response events, four reported it was important and two reported that it was somewhat important. Participants reported that having this information allows them to communicate the reason(s) for curtailment to other staff, students, and/or customers, potentially increasing cooperation.

Of the 16 participants reporting that they knew the reason(s) for demand response events (Table 5.7), the most common suspected reasons were "grid reliability issues" and "temperature or weather related demand."

Table 5.7: Participant-Provided Reasons for Curtailment Events (Multiple Responses Allowed)

REASON FOR CURTAILMENT	CONSISTENT RESPONDERS (N=11)	INCONSISTENT RESPONDERS (N=5)	TOTAL (N=16)
Grid Reliability Issues	4	4	**8**
Temperature or Weather-Related Demand	5	1	**6**
Fire	1	1	**2**
Test	2	0	**2**

Communication with the Aggregator

Nineteen contacts reported that they communicated with their aggregator following their enrollment in the program. Nine of the 19 participants reported either weekly or bi-weekly communication with the aggregator, four reported quarterly communication, three reported communicating one to three times, two reported daily communications, and one could not describe the frequency.

Consistent responders were more likely to report communication with aggregators than were inconsistent responders. Eighty-one percent of consistent responders (14 of 16) reported communicating with their aggregator following their enrollment in the program, compared to 63% of inconsistent responders (5 of 8).

Of the nineteen contacts reporting they communicated with their aggregator following their enrollment in the program, 18 were able to articulate the discussion topics (Table 5.8). These topics most frequently focused on general administrative issues (including general check-ins, payment issues, and validating load amounts), followed by discussions about load reduction goals (including participants' failure to meet load reduction goals and/or changes to participants' load reduction commitment).

Table 5.8: Topics Discussed with Aggregator (Multiple Responses Allowed)

COMMUNICATION TOPIC	CONSISTENT RESPONDERS (N=13)	INCONSISTENT RESPONDERS (N=5)	TOTAL (N=18)
Administrative	12	3	**15**
Demand Response Goals	2	2	**4**
Meter Connections	2	1	**3**
Adding Demand Response Locations	2	0	**2**

Overall Experience with the Program

Twenty two participants were able to answer questions regarding the elements of the program that worked best for their organizations. Most commonly, participants reported that the notification process worked best (5 out of 22 cases), followed by the ease of program participation and payments received (Table 5.9).

Table 5.9: What Worked Best About the Program (Multiple Responses Allowed)

ASPECT	CONSISTENT RESPONDERS (N=14)	INCONSISTENT RESPONDERS (N=8)	TOTAL (N=22)
Notification Process	3	2	**5**
Sign-Up / Participation Was Easy	2	2	**4**
Payment for Participation	3	1	**4**
Saving Energy	3	1	**4**
Aggregator Know-How	2	1	**3**
Increased Awareness of Energy Use	2	0	**2**
Being Viewed as a Good Corporate Citizen	2	0	**2**
Number of Events	1	0	**1**
Ability to Aggregate a Small Load	1	0	**1**

6 CONCLUSIONS AND RECOMMENDATIONS

All five programs operate with a similar long-term goal: use the expertise and marketing skills of curtailment service providers to identify, enroll, and aggregate groups of customers able to drop load when requested. The specific process through which customer information is received, verified, and nominated varies by utility and program, but the overarching purposes are identical: ensure that customers are qualified and have agreed to participate. Consistent with this common purpose, aggregators do not distinguish between the programs in how they market the demand response opportunity to potential participants, estimate the demand response potential at a given site, or notify load providers of curtailment events.

The structural and process differences between the programs result in some different requirements and experiences for enrolled aggregators. These include:

➡ **Different enrollment paperwork and collateral (deposit) requirements** between utilities and/or programs.

➡ **An extended program season for DRC aggregators**, who must consider the seasonality of their load providers in order to meet their nomination requirements year-around.

➡ **The existence of the technical potential assessment process in DRC**, which requires more thorough documentation and analysis of likely curtailment compared to the other programs.

➡ **A difference in the number of called events**. The day-ahead portfolios in SCE territory were called more frequently than the other program portfolios (CBP day-ahead portfolios could have been called up to 20 times and DRC day-ahead portfolios could have been called up to 18 times). The next closest were AMP day-of aggregators, who could have been called up to five times. All other portfolios were called three or fewer times.

➡ **A difference in the method of nominations and settlement**. Interaction with APX occurs only for CBP aggregators.

KEY FINDINGS

The following are the key findings from this current process evaluation.

➡ **Program processes had become more streamlined and routine in 2008**. Staff at all three utilities reported improvements to their program processes in 2008. Most often, these involved efforts to streamline and facilitate enrollment. Many program processes that were new or under development in 2007 had become routine in 2008. Contacts from aggregation firms and from the three utilities reported developing solid working relationships with each other. These factors made the 2008 program year a positive experience for everyone involved.

➡ **The value and expertise of the aggregation firms has become apparent to utility staff.** Utility contacts expressed appreciation for the work of the aggregation firms and their perceived ability to identify and recruit a variety of customers for demand response curtailment; utility contacts also described becoming more aware of the specific benefits of working with aggregators.

Utility contacts were optimistic that aggregation firms were tapping into customers who had not already participated in demand response programs. This belief was confirmed during the participant surveys, in which over 75% of contacts reported that their organization had not previously participated in demand response programs.

Both utility contacts and those from aggregation firms reported that account representatives had been reluctant advocates for aggregation demand response programs. However, while over half of participants surveyed reported they had first heard of the program from their aggregator, 25% reported hearing of the program first from their account representative, indicating that account representatives are marketing the program.

➡ **Aggregators enroll participants in a specific program by considering the price paid per curtailed kW and the level of risk**. Aggregators participating in multiple programs consider payment levels and risk in deciding between the CBP and AMP or DRC. Aggregators enrolled in only one program have no choice when nominating load for the month. However, aggregators enrolled in multiple programs in one service territory must decide between programs. Aggregation contacts report enrolling customers and nominating load based on the price paid for capacity and the potential for risk if the customer fails to meet curtailment goals. Other contacts sought to benefit from particular features of the CBP, or used the program as a reserve for load they were considering adding to their DRC or AMP contract. Because of these comments, we expect that, as aggregators begin to exceed their contractual obligations associated with DRC and AMP, they will increasingly place excess capacity into the CBP.

➡ **Participants reported no major problems with their 2008 program experience.** Only about a quarter of the contacts reported having questions that had to be resolved prior to enrollment, of this group, the most common concern centered on penalties and program flexibility. In general participants reported:

- The notification strategy worked well for their organization.
- Payment amounts met or exceeded their expectations.
- The payments were received within the timeframe they expected.
- They intended to participate in the 2009 program.

➡ **We found few discernable differences between participants characterized as *consistent* and *inconsistent* responders**. The post-event survey results revealed no discernible differences in how consistent and inconsistent responders answered questions related to their setting load reduction goals, their experience of event notifications, the actions they typically took to curtail, their methods for tracking demand response performance, and their communications with aggregators

The results of the participant survey indicate that having a specific curtailment plan was related to the effectiveness of demand response activities. Consistent responders were significantly more likely to report possessing a specific action plan than inconsistent responders.

➡ **Enabling technology is installed to facilitate participation, but most participants continue to rely on manual curtailment activities**. When asked what type of action they took in response to the curtailment request, most participants reported manually shutting down equipment. This was followed, somewhat distantly, by manually launching an automatic curtailment system or program.

A majority of participant contacts reported not having an EMS system installed prior to enrollment, and few reported installing one after enrolling in the aggregator's demand response program. In general, participant contacts who reported that they or their aggregator had installed equipment to enable participation could only vaguely describe the type of equipment – most mentioned metering equipment or consumption monitoring equipment.

There is some indication that participants enrolled in SCE's DRC program have more equipment installed – particularly sub-meter, PIB, and communication equipment. These participants were significantly more likely to report that their aggregators had installed technologies in their facilities when compared to other programs.

➡ **Participants report taking actions in response to curtailment requests, but many contacts believe their participation is optional**. Almost all participants that received a notification request reported taking action to reduce their energy use. The most common action was to manually shut down equipment. However, more than three-quarters believed that their response to the curtailment request was optional. We found no difference between programs or utility territory, indicating a widespread perception among participants that they do not necessarily have to curtail when called. It is not clear whether this is communicated to them by their aggregator, or if the aggregators are unaware of this perception.

➡ **Few participants are turning to backup generation to assist in curtailment.** While almost 40% of participant contacts reported having access to back up generation, only 5% ultimately reported that they used this equipment to comply with curtailment requests.

➡ **The diffuse and opaque nature of the aggregated load providers and their relationships with their aggregators creates challenges in obtaining information and characterizing participants**. We were able to interview 10 of the 11 active aggregators, but experienced difficulty obtaining the customer contact information required to launch the customer survey. Several aggregation firms were unresponsive to requests for customer contact information, while others were quick to provide this information. In some cases, utility staff had to compile lists from paper enrollment files. Regardless of the source of contact information, it remained quite difficult to link a specific contact to an SA ID as reported in the data files provided to the impact evaluation.

- Since SA ID numbers do not necessarily map to one meter or badge number, or even one location, the process evaluation contact lists had to be linked to organizations as they appear in the utility customer information system. This listing may or may not match the organization name as reported by the aggregator, and thus, for about 40% of cases, we were unable to link the contact name to a specific event.
- Additionally, since the actual curtailment goals are established in agreements between aggregators and their customer load providers, the impact analysis can only assess if a response occurs, not whether or not participants are consistently or inconsistently meeting their demand response goals.

➡ **The post-event surveys were too removed from curtailment events to permit in-depth assessment with contacts**. We used the results of the impact team's load impact coefficient analysis to classify participants into categories of consistency. This strategy did not allow for an in-depth understanding of the differences between *consistent* and *inconsistent* responders, particularly since interviews followed curtailment events by six months or more. A post-event survey conducted immediately after a demand response event would be more likely to yield detailed responses, but could fail to identify meaningful differences between consistent and inconsistent responders because:

- Curtailment goals could be so low that they fail to emerge in post-event analyses of performance.
- Participants may not have a clear sense of their demand response performance relative to their load reduction commitments.

CONCLUSIONS AND RECOMMENDATIONS

In light of the findings from this process evaluation, we make the following conclusions and recommendations:

➡ ***Conclusion 1:* Opportunities for simplifying the eligibility and enrollment process should be explored**. All three utilities require the Add/Delete form for the CBP, which they developed collaboratively when they agreed to hire APX and use the same enrollment form. AMP also requires an Add/Delete form in order to formally enroll a participant. However, in some cases, an SA template, a CISR, or a TPA also is required. Contacts from utilities and aggregation firms both noted the difficulties associated with the CISR and wondered if this form could be replaced. Only DRC does not require an Add/Delete form, instead relying on the CISR alone.

The enrollment forms serve two major purposes: (1) they ensure that the customer is qualified to participate in the aggregator's demand response program; and (2) they ensure that the customer is aware of and agreeing to participate in the program. It may be possible to design a form that fulfills both purposes. The CISR contains no specific reference to demand response program enrollment, but can be used to determine eligibility, while the Add/Delete form clearly indicates that the customer is enrolling in a demand response program with an aggregation firm, regardless of eligibility.

> ***Recommendation A:*** Consider enabling eligibility verification of a given SA ID or customer on-line through a log-in feature

> ***Recommendation B:*** Consider replacing the CISR with a form designed specifically for aggregation demand response activities, and/or merging the CISR and Add/Delete into a single form

➡ ***Conclusion 2:* The APX interface caused problems for aggregators with numerous enrolled meters**. In 2008 the interface required aggregators to re-load their entire nomination list every month by dragging and dropping each SA ID into the web-based form. Providing access to prior month's lists or defaulting to the last nomination list could simplify and speed up the process for aggregators, who could then focus only on making specific, relevant changes.

> ***Recommendation:*** Encourage APX to improve the nomination interface by creating a nomination process that defaults to the prior month.

➡ ***Conclusion 3:* Ways of speeding up the settlement process should be explored**. Staff from all programs described a somewhat complicated process of receiving, verifying, and confirming meter data prior to releasing it to aggregators. Obtaining settlement-quality meter data generally requires the involvement of multiple people or departments and can take time. While staff reported getting this information out to aggregators within 60 days, this could result in statements being delivered to participants up to 90 days after an event. Aggregators noted that the timeframe for settlements and payments was problematic, with more than half of them saying it could take months to receive payment.

> ***Recommendation A:*** Compare the initial meter data with the final settlement-quality meter data. If the difference between the two data sets is nominal, consider

developing a *true-up* process, whereby initial curtailment is calculated and adjusted if necessary in the next program month to address any difference between the initial calculation and the SQMD.

Recommendation B: Consider assigning all participants to calendar billing to avoid settlement delays caused by meters scheduled to be read late in the month.

➡ ***Conclusion 4:*** **Demand response program options should be streamlined and the features of each clarified on utility websites.** Documenting the program listings on the utility websites confirmed comments from aggregator contacts that numerous demand response programs are listed on utility websites. Given the large number of demand response programs listed on utility websites, it is difficult for many customers (and aggregators) to gauge eligibility and determine which program is most appropriate.

➡ ***Recommendation:*** **Consider allowing customers to enter their account or SA ID information to obtain a list of demand response** programs for which they are eligible.

➡ ***Conclusion 5:*** **Aggregators can be helped in marketing demand response programs by translating the triggers into meaningful social and i*ndividual benef*its**. Aggregators struggled to explain the trigger and/or likelihood of events to potential CBP participants. The official *heat-rate* trigger is difficult for aggregators to explain or predict. Few aggregators reported they were able to predict the likelihood of curtailment events, particularly for the CBP. Post-event survey respondents indicated that knowing the reason behind the demand response event could help them enlist the cooperation of others by helping them communicate about the event to large groups of students, staff, or customers.

Participants believe they are curtailing because of grid-reliability issues. When asked if they knew why they had been asked to curtail in 2008, almost half reported they believed they were responding to grid-reliability issues, including a subset specifically mentioning they were asked to curtail to avoid brownouts and rolling blackouts.

Demand response programs often appeal to participants for both social and individual benefits, and both are important motivators for participation. Improved understanding of when and why curtailment events are called could help aggregators recruit customers and help customers understand why they are being called to curtail.

Recommendation: Consider clarifying or refining the reasons for demand response with both social and individual benefits to make it easier for aggregators to communicate to their customers the circumstances under which curtailment events are likely.

➡ ***Conclusion 6:* Many organizations appear poised to undertake a variety of energy efficiency upgrades and/or consider all options of reducing their peak demand, including investments in permanent demand reduction**. All participant contacts were asked if they were considering installing additional equipment or technologies that might allow for additional demand response during events. Twenty-three percent reported considering additional equipment. When asked to describe the equipment, contacts described a variety of equipment, including efficiency upgrades (such as efficient lighting and HVAC upgrades) and solar panels that might reduce the organization's overall demand, but would be unlikely to help them drop additional load during a curtailment event. The frequency of the solar panel response is notable because the net metering that generally accompanies solar panel installation would disqualify an organization from participating in any of the aggregator-driven demand response programs as currently structured.

> ***Recommendation A:*** Explore the possibility of including participants with solar net metering.
>
> ***Recommendation B:*** Identify strategies for linking participants with energy efficiency programs, as many of these organizations are committed to doing everything possible to reduce their energy use.

APPENDICES

APPENDIX A: METHODOLOGY

APPENDIX B: GENERAL PARTICIPANT SURVEY

APPENDIX C: POST-EVENT PARTICIPANT SURVEY

A METHODOLOGY

This appendix describes: the strategies used to develop the survey instruments and contact lists; the sampling plan and weighting strategy; and the definitions of several key categorical assignments used to analyze the results of the participant surveys.

SURVEY INSTRUMENT DESIGN

The process evaluation work plan identified several key issues to be addressed in the customer surveys, including: communication, administration, program expectations, customer satisfaction, program awareness, and future intentions. In addition, informed by the in-depth interviews with utility program staff and aggregator representatives, we identified additional and, in some cases, more specific questions to include in our surveys of program participants.

The research team first designed a general participant survey, focused on covering the key issues, primarily with close-ended questions appropriate for large samples. Several sections of the general participant survey were removed and others replaced with more in-depth, qualitative questions for a post-event survey conducted with a subset of participants.

The DRMEC and Christiansen Associates reviewed the preliminary survey instruments, offering comments and clarifications to the Research Into Action team, with the goal of developing a 15-minute survey that would best address the DRMEC's evaluation goals. After incorporating this feedback, the research team finalized the *General Participant Survey* and *Post-Event Participant Survey*.

SAMPLING STRATEGY AND PLAN

Obtaining Customer Contacts

Table A.1 summarizes 2008 participation of aggregators, as well as customer counts in contact lists obtained. In 2008, a total of sixteen aggregation firms (aggregators) signed up on at least one of the programs – CBP, AMP, and DRC – in one or more utility territories. Eleven of these aggregators were *active*, having nominated load to any of the three programs in 2008. We requested that all active aggregators provide customer contact information (organization name, contact name, phone, and so forth) to facilitate the participant survey. Most aggregators were responsive to this request and provided their customer contacts. A few aggregation firms were uncooperative or unresponsive. Energy Curtailment Specialists did not provide any customer contact information, while Constellation New Energy and Energy Logic both provided contact information for their PG&E customers but not for their customers in SCE or SDG&E territory. North American Power Partners did not provide contact information for its participating customer in SCE territory. In these cases, utility staff searched program files for contact information and provided the list to the research team. Seven aggregation firms (EnerNOC, Comverge, Energy Connect, CPower, San Francisco Power, SureGrid, and Varisae) provided all requested information. We ultimately received a total of 1,320 contact names.

Table A.1: Summary of 2008 Participating Aggregators and Customer Contacts Obtained

POPULATION	PG&E		SCE		SDG&E	MULTI	TOTAL*
	CBP	AMP	CBP	DRC	CBP		
Number of Aggregators Contracted or Signed Up	12	5	13	4	7	—	16
Number of Active Aggregators	6	5	6	4	5	—	11
Number of Aggregators that Provided Customer Contacts	5	4	4	3	3	—	9
Number of Uncooperative Aggregators Whose Customer Contacts Were Provided by Utility	1	1	2	1	2	—	3
Contact Names Received	402	439	167	113	199	—	1,320
TOTAL UNIQUE CONTACTS (Population)	**243**	**216**	**22**	**108**	**52**	**10**	**651**

* Aggregators could sign up on more than one program or utility territory; therefore, the cell counts do not sum to the total count.

In any case where we had a unique contact name at a unique customer site, we treated that case as a unique participant.[53] However, in reviewing the contact lists, we found that in some cases we had multiple points of contact for a single site, while in other cases we had only one contact for multiple sites. Since we could not interview multiple people about the same site, nor could we interview the same person multiple times, we counted as a unique case each site associated with multiple names and each name uniquely associated with multiple sites. [54]

After removing duplicate names associated with multiple sites, we were left with a list of 651 unique contacts.

53 For example, Company A has two locations, one in Los Angeles and one in San Diego, and the contact for the Los Angeles location is David, while the contact for the San Diego location is Victor. We treated the Los Angeles and San Diego locations as two unique contacts.

54 For example, Company B has ten locations, all of which have the same contact person. In this case, the ten locations were counted as one unique participant. Company C has one location, which has three contact persons. In this case, the one location was treated as one unique participant.

Merging Curtailment Responses and Load Data

For each program in each utility territory, the impact evaluation team used a regression model to estimate load impact (LI) coefficients for all customers that were nominated and called for events in any of the programs during 2008. The impact evaluation team then used data from this model to identify customers who consistently responded to the events. The unit of analysis for the impact evaluation work was the service agreement identification (SA ID). The LI coefficient of each SA ID was used to determine whether the load reduction response was statistically significant relative to baseline load established for each SA ID. The impact team applied a *strong response* label if this coefficient was significant, and a *mild/no response* label if it was not significant. To split our list into *consistent* and *inconsistent* responders for the purpose of the post-event survey, we categorized the impact team's strong respondents as *consistent responders* and the mild/no respondents as *inconsistent responders*. We then applied these categories to our own population list.

A process evaluation is focused on the experiences of the people involved, not the data tracked at a meter or account. Thus, the population of interest is the unique customer by name, not the status of a given SA ID. However, since approximately 40% of the unique customers in the process evaluation contact list were found to have multiple SA IDs, we had to develop a strategy for calculating the consistency status by organization, not SA ID. Customers for whom multiple SA IDs were nominated can have a varied level of load reduction responses. (That is, for customers possessing numerous locations, some may have consistently performed and some may have consistently failed to perform during called events, and the numbers for consistently performing and consistently failing to perform may vary from customer to customer.) To categorize customers with multiple SA IDs, we considered them consistent responders only if the number of *strong response* SA IDs exceeded 50% of the total number of SA IDs. For example, a customer with 20 SA IDs was considered *consistent* if at least 11 of the SA IDs indicated *strong response*.

The impact team also included the estimated maximum demand associated with each SA ID in the impact analysis. This maximum demand was expressed in *Max kW*, and represents the maximum hourly demand for the summer period. Max kW is a typical criterion for classifying customers by load size. For customers with multiple SA IDs, the Max kW value of each SA ID was summed to represent a total Max kW for each of the unique customers. The distribution of the load data indicated that 500 Max kW was an appropriate cutoff point to differentiate between *small* and *large* load customers.[55]

Finally, we merged the unique customer contact list with the curtailment response categories and load size data by matching customer names. We successfully matched 62% of the unique contact names with these data. We were not able to link the contact name from the unique contact list to the impact evaluation files for 38% of the list. This is likely due to the fact that the two lists

55 Approximately 45% of the total population was categorized as *small.*

originated from two different sources: the customer contact list originated from the lists provided by each aggregator; and curtailment response and load-size data originated from data provided by each of the three utilities to the impact evaluation team. While theoretically these two lists should match, there are several reasons why customers in the process evaluation contact list did not appear in the impact evaluation list, and vice versa. One reason may be the inclusion of non-nominated or dropped customers in the aggregator-provided lists. Customer information for customers that had not actually been nominated or curtailed was likely removed from the impact analysis. Aggregators also could have failed to provide the process evaluation team with a complete customer list. Finally, a number of unmatched names are likely due to inconsistent tracking, misspelling, or other differences between the aggregator-provided name and that existing in the utility customer information system. While we reviewed each list carefully and were able to manually-match many names, it is possible we missed some number of matches because the contact name was completely different or the organization had multiple identities.

Identification of the Population and Samples

The above procedures yielded a list of 663 unique customer names, which served as the population for the participant survey activities associated with this study. Table A.2 shows this population by utility programs.

Table A.2: Participant Population by Program

UTILITY PROGRAM	SIZE			TOTAL	
	SMALL KW	LARGE KW	UNKNOWN	PARTICIPANT	PERCENT
Multi-Utility Participant	0	10	0	10	2%
PG&E AMP	43	124	49	216	33%
PG&E CBP	94	37	112	243	37%
SCE CBP	11	9	2	22	3%
SCE DRC	17	20	71	108	17%
SDG&E CBP	21	17	14	52	8%
TOTAL	**186**	**217**	**248**	**651**	**100%**

After removing contacts with invalid phone numbers from the population list, we were left with 638 unique contacts. This became the sampling frame.

To avoid overburdening customers with multiple survey requests and because both the general participant survey and post-event survey efforts were underway simultaneously, customers responding to the general participant survey were not subsequently contacted for the post-event survey. Instead, prior to the general customer survey, we extracted 52 customer names from the sampling frame for the post-event survey and used the rest for the general participant survey.[56]

Our goal for the post-event survey was to reach a sample of both consistent and inconsistent responders. To facilitate this, we randomly drew four customer names from a pool of the respective groups (consistent and inconsistent responders) in each utility program: a total of 52 contacts. Assuming a cooperation rate of 50%, we estimated two to four interviews would be completed for each group, for a total of 26 interviews. As the post-event surveys were completed and our quotas were reached, we returned any extra names to the general participant survey contact list.

Table A.3 summarizes the final sample frame of this study by type of survey sought for each utility program. The survey goal was to achieve an overall confidence level of 95%, with ±10% precision for each utility program. In order to obtain a sufficient number of completed surveys, all 638 contacts were required, thus the sampling frame is equivalent to our sample.

Table A.3: Sample Frame by Program

UTILITY PROGRAM	GENERAL PARTICIPANT SURVEY			POST-EVENT SURVEY		TOTAL SAMPLING FRAME
	SMALL KW	LARGE KW	UNKNOWN	CONSISTENT RESPONDER	INCONSISTENT RESPONDER	
Multi Utilities*	0	6	0	3	1	10
PG&E CBP	85	29	112	8	8	242
PG&E AMP	38	109	49	4	4	204
SCE CBP	8	4	2	4	4	22
SCE DRC	12	17	71	4	4	108
SDG&E CBP	16	14	14	4	4	52
TOTAL	**159**	**179**	**248**	**27**	**25**	**638**

* Customers that participate in multiple utility territories were assigned in a separate category because of their unique importance.

56 Since the post-event survey assumed that all respondents would have received an event notification and taken subsequent action, we included only names that had been categorized as *consistent* or *inconsistent* responders – thus, all had load data and a calculated LI coefficient.

DATA COLLECTION

General Participant Survey

The participant survey was conducted by telephone interview from Abt SRBI's call center using trained, professional survey managers and interviewers. Abt SRBI relies on a computer-assisted telephone interview system (CATI®). To maximize meaningful participation in the survey, all survey staff were thoroughly trained as to the nature of the study, the importance of the information being collected, and how to track completes by sample category.

The survey was fielded from April 24 to May 11, 2009, during the normal Pacific Standard Time (PST) business hours in order to reach as many targets as possible. The survey was completed with a total of 246 respondents. To prevent non-response bias, survey staff called each telephone number a minimum of five times to complete the survey or until a final disposition was obtained. The average length of the survey was less than 12 minutes, including the screening questions. The response rate – the proportion of the number of contacts interviewed in the sample who were eligible to participate – was 49%. The cooperation rate – the proportion of eligible respondents reached that agreed to participate – was 96%. Table A.4 presents a summary of the final dispositions.

Table A.4: Summary of Participant Survey Disposition

DISPOSITION		TOTAL*
Completed		246
Refused	Hard refusal	10
	Soft refusals	1
List Errors	Wrong number/person	2
	Fax/Modem/Line Problems	4
	Disconnected number	17
	No longer with company	17
No Contact Made	Away for duration	2
	Other barrier	3
Not Screened	Call back: appointment or unspecified	119
	Over quota for segment	116
Screened Out	Not qualified	7
Not Dialed	Cell phone, duplicate, quota met	57
TOTAL LIST		**600**

* The total includes 14 from the post-event survey that were added back into the frame for the general participant survey as the quotas for each group were met. The original list contained 586 contacts.

Post-Event Survey

The post-event surveys consisted of telephone interviews conducted by Research Into Action's trained interviewers using a computer-assisted telephone interview system (Vovici®). The survey was in the field from April 29 to May 8, 2009. Calls were made during normal PST business hours to complete the survey with 24 respondents. The response rate was 82% and the cooperation rate was 96%. Table A.5 summarizes the final disposition for the post-event survey.

Table A.5: Summary of Post-Event Survey Disposition

DISPOSITION		TOTAL
Completed		24
Refused	Hard refusal	1
List Errors	Wrong number/person	0
Not Screened	Call back: appointment or unspecified	4
Screened Out	Not qualified	3
Subsample Quota Met		20
TOTAL LIST		**52**

FINAL DATA AND WEIGHTING

Once the data collection was complete, we merged data records from the two different survey efforts – the *General Participant Survey* and the *Post-Event Survey*. The final data set included variables that exist in both surveys, as well as variables that are unique to one or the other. This combined final dataset contained a total of 270 records.

As Table A.6 illustrates, the distribution of the several final sample sizes across utility programs and load sizes deviated somewhat from the population.

Table A.6: Comparison of Final Sample and Population

UTILITY PROGRAM	SMALL MAX KW (> 500 Max kW)		LARGE MAX KW (< 500 MAX KW)		UNKNOWN MAX KW		TOTAL	
	SAMPLE**	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION
Multi Utilities	0%	0%	4%	8%	0%	2%	**1%**	**3%**
PG&E AMP	18%	23%	45%	55%	19%	19%	**27%**	**33%**
PG&E CBP	4%	3%	11%	7%	3%	4%	**6%**	**4%**
SCE CBP	7%	6%	6%	4%	1%	1%	**4%**	**3%**
SCE DRC	14%	9%	12%	9%	35%	28%	**21%**	**16%**

SDG&E CBP	17%	11%	7%	8%	6%	6%	**10%**	**8%**
SF Power*	40%	48%	15%	10%	36%	41%	**30%**	**32%**
TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

* San Francisco Power represented 214 (88%) of the 242 unique PG&E CBP participants. For this reason, we removed its customers from the list and sampled them separately to ensure we had enough non-SF Power customers in the PG&E CBP sample to compare that program to the other CBP programs.

** *Sample* means percentages of the final sample within each utility program. *Population* means percentages of population within each utility program. Since the percentages show distributions of the final sample and population counts across the utility program in each category, the percentages add up to 100% in each column.

As noted above, we attempted contact with all names in the sample frame. If the resulting sample sizes by utility program and load size had been proportional to the population totals, the combined survey results would accurately reflect the combined population. However, as Table A.6 shows, the deviation is at least five percentage points for more than one-third of the 21 sample subgroups.

To address the deviations between the sample and the population percentages – and thus to ensure that the final combined results accurately reflected the combined population – we constructed a set of weights to apply to each of the 21 sample subgroups. The weight for any given subgroup was calculated as the ratio of the population percentage to the sample percentage:[57]

$$W = \text{Percent}_{\text{population}} / \text{Percent}_{\text{sample}}$$

The entire set of weights is shown in Table A.7.

Table A.7: Weights per Subgroup

UTILITY	PROGRAM	MAX KW SIZE	ASSIGNED WEIGHT
Multi Utilities		Small	0
		Large	1.037
		Unknown	0
PGE	**AMP**	Small	1.189
		Large	1.286
		Unknown	1.129
	CBP	Small	0.691
		Large	0.622

[57] A description of this method is provided by Applied Technologies for Learning in the Arts & Sciences, College of Liberal Arts & Sciences, University of Illinois Urbana-Champaign. URL: *https://www.atlas.uiuc.edu/data_stats/resources/spss*. Last accessed: November 11, 2008.

UTILITY	PROGRAM	MAX KW SIZE	ASSIGNED WEIGHT
		Unknown	1.244
SCE	**CBP**	Small	0.760
		Large	0.747
		Unknown	0.829
	DRC	Small	0.588
		Large	0.754
		Unknown	0.866
			Continued
SDG&E	**CBP**	Small	0.622
		Large	1.175
		Unknown	0.968
SF Power	**CBP**	Small	1.086
		Large	0.702
		Unknown	1.221

We then applied these weights to individual cases in the final dataset. This had the effect of giving more weight in the final results to subgroups that were under-sampled relative to their makeup in the population and giving less weight in the results to subgroups that were relatively over-sampled. Table A.8 shows the final weighted sample by utility programs and load size.

Table A.8: Final Weighted Sample

UTILITY PROGRAM	SMALL MAX KW (> 500 Max kW)		LARGE MAX KW (< 500 MAX KW)		UNKNOWN MAX KW		TOTAL	
	SAMPLE*	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION	SAMPLE	POPULATION
Multi Utilities	0	0%	4	5%	0	0%	**4**	**2%**
PG&E AMP	18	23%	51	57%	20	20%	**90**	**33%**
PG&E CBP	39	51%	15	17%	46	45%	**101**	**37%**
SCE CBP	5	6%	4	4%	1	1%	**9**	**3%**
SCE DRC	7	9%	8	9%	29	29%	**45**	**17%**
SDG&E CBP	9	11%	7	8%	6	6%	**22**	**8%**
TOTAL	**77**	**100%**	**90**	**100%**	**103**	**100%**	**270**	**100%**

* Percentages add up to 100% in each column because the percentages show distributions of counts across the utility program.

DATA ANALYSIS

We analyzed the completed survey data using statistical software, *SPSS Version 17*. All procedures employed for the step-by-step data cleaning and data transformation, and all statistical analyses were documented in an associated syntax file.

The participant surveys were designed to explore several key issues associated with the aggregator programs, including: communication, administration, program expectations, customer satisfaction, program awareness, and future intentions.

We stratified our population by four main characteristics in order to ensure that we surveyed an appropriate number of contacts in each of the four groups. Specifically, we sought to compare responses by:

- **Utility service territory:** We assigned each organization to the appropriate utility territory as indicated by their presence on a specific aggregator customer list or because of their presence in one of the utility-generated lists used by the impact team. In some cases, we found organizations that participated in more than one territory. These were assigned a *multi-utility* status.
- **Program:** We assigned each organization to the appropriate program as indicated by the lists provided by aggregators, or because of their presence in one of the utility-generated lists used by the impact team.
- **Load size:** We divided our population into small and large load customers, based on a cut-off of 500 kW of maximum summer hourly demand.
- **Consistency of curtailment responses:** We used performance data as provided by the impact evaluation team to assign *consistent* or *inconsistent* responder status to each of the unique customers identified in the general survey population list. For any contact associated with multiple SA ID, the process evaluation team assigned a consistency status based upon how a majority of SA ID were found to have performed.

All data from the participant survey were analyzed consistently using four categorical schemas in order to identify any discernable difference in responses among groups defined above. For each categorical scheme, we applied appropriate statistical tests such as Chi Square (denoted by χ^2), as well as other nonparametric test methods for finding significant differences among groups.

We analyzed the qualitative responses, collected only in the Post-Event Survey, in detail using *Microsoft Excel*. Coding schemes and other analytical processes were documented in an associated project file.

B GENERAL PARTICIPANT SURVEY

CHRISTIANSEN PG&E AGGREGATOR
STATEWIDE EVALUATION OF AGGREGATOR DR PROGRAMS FOR 2008
PARTICIPANT SURVEY

Note: "Don't know" and "Refused" will be added as categories to all questions.

Customers will be assigned to an aggregator and utility prior to calling. Naming the aggregator will need to be part of the list development and introduction.

Hello, my name is _____. I'm calling from SRBI and am conducting research on behalf of the California Public Utility Commission and [utility]. I'd like to speak with you about your firm's experience with [aggregation firm]'s demand response program. Your firm participated in this program during the summer of 2008.

My questions should take less than 15 minutes. Is this a good time to talk?

S1. Are you the person most knowledgeable about your company's involvement with [aggregator]?
1) Yes
2) No
3) DK
4) REF

[SKIP IF S1=YES]

S1a. May I speak with that person?

[WHEN THE PERSON IS REACHED]

[RESTATE INTRO PARAGRAPH]

INTRODUCTION FOR QUALIFIED RESPONDENT. The information you provide will be used to help improve program services. All information you provide to us is confidential. Your name and your company's name will not be reported and responses will not be attributed to any given participant.

When you signed up with [aggregation firm], you agreed to reduce your energy use when requested. For the purposes of this survey, we will call this activity *demand response*.

Participant Profile

1. Had your firm participated in any *demand response* programs prior to your involvement with [aggregation firm]?
   1) Yes
   2) No
   3) (vol) DK
   4) (vol) REF

2. [IF Q1=1] If yes: When had you participated?
   1) RECORD: ________________________
   2) (vol) DK
   3) (vol) REF

3. How many locations do you have participating in *demand response* activities with [aggregation firm]?
   [RECORD (Programming Note: More than one location = Multi-Site)]
   RANGE 1-10 ________________________
   11) (vol) DK
   12) (vol) REF

Program Awareness & Reasons for Participation

4. I'd like to ask you some questions about your activities with [Aggregator] in 2008. How did you first hear about the [Aggregator] program?
   [DO NOT READ, SINGLE RECORD]
   1) Utility account rep
   2) Utility website/email/bill insert
   3) An existing relationship with [Aggregator]
   4) [Aggregator] marketed the program to us (cold call or sales call)
   5) Trade association
   6) Other: specify ____________________
   7) (vol) DK
   8) (vol) REF

5. I'm going to list several reasons your company might have decided to participate in [Aggregator's] program. For each one I'd like you to tell me how important each reason was for your company, using a 1-5 scale, where one is not all important and 5 is very important.
Can you tell me how important it was for your company to: (ROTATE)
a. To receive financial benefit or bill savings (money) _____
b. To be viewed a good corporate citizen _____
c. To help (utility name/s) avoid outages _____
d. To avoid rolling blackouts _____
e. To help improve electric system reliability _____
RANGE 1-5
6) (vol) DK
7) (vol) REF

5a. Was there any OTHER reason that was important in your decision to participate? [RECORD]
1) Gave Response ____________________
2) (vol) DK
3) (vol) REF

Decision-Making and Information

6. Did you have any questions or concerns that needed to be resolved prior to deciding whether to enroll in the program?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

7. [IF Q6 = 1] What were your concerns?
[RECORD]
1) Gave Response ____________________
2) (vol) DK
3) (vol) REF

8. [IF Q6 = 1] To have your questions or concerns answered, whom did you talk to or where did you look for information or clarification? [Multiple mentions allowed. DO NOT READ LIST insert name of aggregator/utility as appropriate.]
   1) Aggregator
   2) Utility/account rep
   3) Utility website
   4) Other Internet sources
   5) Other (Specify) ____________________
   6) (vol) DK
   7) (vol) REF

9. [IF Q6 = 1] How long did it take to get enough information?
   1) 1 to 2 weeks
   2) 3 to 4 weeks
   3) One month up to two months
   4) Two months up to three months
   5) Three months or more
   6) (vol) DK
   7) (vol) REF
   8) Less than 1 week

10. Did you or your organization have any difficulties completing the program enrollment process?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

11. [IF Q10 =1] What difficulties did you have?
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

12. [IF Q10 = 1] How long did it take to resolve these difficulties?
    1) 1 to 2 weeks
    2) 3 to 4 weeks
    3) More than a month but less than two months
    4) More than two months but less than three months
    5) Three months or more
    6) (vol) DK
    7) (vol) REF
    8) Less than 1 week

Technologies

13. Prior to signing up with [aggregator] did your facility already have an energy management or building control system?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

14. Did your company install any new technologies such as hardware, software, communication devices or metering equipment in order to participate with [aggregator]?
    1) Yes
    2) No [SKIP TO Q16]
    3) (vol) DK [SKIP TO Q16]
    4) (vol) Ref [SKIP TO Q16]

15. [IF Q14 = 1] What did you install?
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

16. Did [aggregator] install any other technologies for you, such as hardware, software, communication devices or metering equipment?
    1) Yes
    2) No [SKIP TO Q20]
    3) (vol) DK [SKIP TO Q20]
    4) (vol)Ref [SKIP TO Q20]

17. [IF Q16 = 1] What was installed?
[RECORD]
1) Gave Response ____________________
2) (vol) DK
3) (vol) REF

18. [IF Q16 = 1] And, was this equipment installed before you enrolled in the program or after?
1) Before
2) After
3) (vol) DK
4) (vol) REF

19. Did you receive any utility rebates or incentives that went towards the purchase or cost of the new technologies?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

20. Are you considering any additional equipment or technologies that might allow for additional *demand response* during events?
1) Yes
2) No
3) (vol) DK
4 (vol) REF

21. [IF Q20 = 1] What are you considering installing?
[RECORD]
1) Gave Response ____________________
2) (vol) DK
3) (vol) REF

Event Notification

22. Were you notified of a *demand response* event or a test event during the 2008 summer season?
1) Yes
2) No [SKIP TO Q32]
3) (vol) DK [SKIP TO Q32]
4) (vol) Ref [SKIP TO Q32]

23. For how many events were you notified to reduce your energy use?
1) 1
2) 2
3) 3
4) 4
5) 5
6) 6-9
7) More than 10 times
8) (vol) Don't know
9) (vol) REF

24. How were you typically notified of an upcoming event? Was it by….. [Multiple responses allowed]
1) Phone
2) Email
3) Fax
4) Pager
5) Other: ______________________________
6) (vol) DK
7) (vol) REF

25. [IF Q3 >1 AND NOT (DK OR REF)][If Multi-Site] Who notifies other locations in your company of *demand response* events?
1) Aggregator notifies each site
2) No notice is required, it's all automatic [SKIP TO Q27]
3) Central staff notifies each site
4) Other, specify: ______________________
5) (vol) DK
6) (vol) REF

26. [IF Q3 >1 AND NOT (DK OR REF)] [If Multi-Site] How are other locations notified of events? Is it by… [Multiple responses allowed]
1) Phone
2) Email
3) Fax
4) Pager
5) Other, specify: ______________________
6) (vol) DK
7) (vol) REF

27. During the 2008 season, were you typically contacted more than once about a single event? (Interviewer note: For example, were they notified the day before and then five minutes before?)
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

28. In thinking about the method, the timeframe and the frequency of notifications, did the notification approach work for your organization?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

29. [IF Q28 = 2] What did not work well
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

30. Is there anything that would improve the notification process for your organization?
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

31. In thinking about your 2008 experience, would you say your response to a *demand response* event was ever optional?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

32. During the 2008 season, did you have a specific plan in place to direct your activities after being notified of an imminent *demand response* event?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

[AFTER Q 32, IF Q22 = NO, DK, OR REF, THEN SKIP TO Q45]

Response to Called Event

33. Did you take action in response to the notification of a *demand response* event?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

34. [IF Q33 = 2] Why did you not take any action after receiving the notification of a *demand response* event? DO NOT READ.
    1) Not required to
    2) Don't have to take action; it's automatic; notification is for information only
    3) Had to meet a production schedule
    4) Internal company miscommunication
    5) To avoid inconvenience to customers
    6) Other, specify: ____________________
    7) (vol) DK
    8) (vol) REF

[IF Q 34 ANSWERED, THEN SKIP TO Q45]

35. [IF Q33 = 1] After receiving the notification of a *demand response* event, what action did you or your staff take? Would you say you: (Read All. Multiple Mentions Allowed.)
    1) Did nothing; it's automatic; notification is for information only
    2) Manually initiated an automated process at the facility
    3) Manually shut down or adjusted equipment
    4) Switched to a back-up generator
    5) Other (SPECIFY): _________________
    6) (vol) DK
    7) (vol) REF

36. [IF Q35 = 3] In your facility, what equipment was shut down or adjusted in response to an event notification? RECORD ALL MENTIONS.
1) Reduced lighting
2) Turn up AC equipment settings or set points
3) Shut down motors or pumps
4) Industrial process reductions: (Examples: partial shutdown of operations, reducing some or all production processes)
5) Other, SPECIFY: ___________________
6) (vol) DK
7) (vol) REF

37. [IF Q3 >1 AND NOT (DK OR REF)] [If Multi-Site] Is the activity (for example lights, motors, cooling equipment) the same at all of your locations?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

38. [IF Q37 = 2] How do the activities differ?
[RECORD]
1) Gave Response _____________________
2) (vol) DK
3) (vol) REF

39. [IF Q3 >1 AND NOT (DK OR REF)] [If Multi-Site] In 2008, did the *demand response* results, and by "results" we mean meeting load reduction goals, vary from location to location?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

40. [IF Q39 = 1) How did the results vary?
[RECORD]
1) Gave Response _____________________
2) (vol) DK
3) (vol) REF

41. Do you have access to back up generation?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

42. [IF Q41 = 1)] Did you use this back-up generation to help you respond to an event?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

Curtailment Results

43. To what extent were you able to meet your demand response goals; that is, were you able to reduce energy use to the level you had expected or committed to? Would you say the reduction you made was:
1) More than expected
2) About what was expected
3) Less than expected, or
4) There was no change in usage
5) (vol) DK
6) (vol) REF

44. As a result of your curtailment during the events, were there any negative effects on the following? Please answer yes or no for each (ROTATE)

1) Employee or tenant comfort	() yes () no () DK
2) Customer comfort	() yes () no () DK
3) Productivity	() yes () no () DK
4) Sales	() yes () no () DK
5) Overall operations	() yes () no () DK

6) (Always ask last) Anything else, specify ___________________
(1) yes (4) no/nothing (2) (vol) DK (3) (vol) REF

Payment

45. Did you receive any payments for participating in [X Aggregator] program in 2008?
1) Yes
2) No [SKIP TO Q50]
3) (vol) DK [SKIP TO Q50]
4) (vol) REF [SKIP TO Q50]

46. [IF Q45 = 1] Did the amounts exceed, meet, or fall short of your expectations?
    1) Exceed
    2) Meet
    3) Fall short
    4) (vol) DK
    5) (vol) REF

47. [IF Q46 = 3] How did the amounts fall short of your expectations?
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

48. Were the payments received within the timeframe you expected?
    1) Yes
    2) No
    3) (vol) DK
    4) (vol) REF

49. [IF Q48 = 2] How did the payment timeframe fall short of your expectations?
    [RECORD]
    1) Gave Response ____________________
    2) (vol) DK
    3) (vol) REF

Satisfaction

I'd like to ask you about a couple of aspects of the program

50. Using 5-point scale, where "1" means not at all important and "5" means very important, how important is it for you to know the reason for the *demand response* event?
    RANGE 1-5 ________________________
    6) (vol) DK
    7) (vol) REF

51. What is your understanding of the reason you were asked to reduce your load in 2008? (Probe to code, do not read. Multiple mentions okay.)
1) High price of power to the utility
2) Grid reliability issues
3) Temperature or Weather related demand
4) Environmental benefits
5) Other, specify: ____________________
6) (vol) DK
7) (vol) REF

52. Using a 1-to-5 scale, where 1 means strongly disagree and 5 means strongly agree, how much do you agree with each of the following statements: ROTATE.
a. The sign up process was easy.
b. Notification of *demand response* events was clear.
c. I had enough time to prepare for *demand response* events.
d. The number of *demand response* events was what I expected.
e. It's important to do our part to save energy in times of peak demand.
f. Participating in this program helps us save money.
g. Participating in this program helps the environment.
RANGE 1-5 ________________________
6) (vol) DK
7) (vol) REF

[PROGRAMMING NOTE: Q53 WILL IMMEDIATELY FOLLOW EACH ATTRIBUTE RATED "2" OR LOWER IN q52]

53. [For any rated "2" or lower in Q52] Why do you disagree that [X aspect]? [RECORD]
1) Gave Response____________________
2) (vol) DK
3) (vol) REF

56. Have you spoken to other companies or other locations within your own company about participating in this program?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

54. Do you expect that your organization will participate in this program again in 2009?
1) Yes
2) No
3) (vol) DK
4) (vol) REF

55. [IF Q54 = 2] Why will your organization not participate in 2009?
[RECORD]
1) Gave Response ____________________
2) (vol) DK
3) (vol) REF

56. What suggestions do you have for improving your experience with demand response?
[RECORD]
1) Gave Response____________________
2) (vol) Nothing
3) (vol) DK
4) (vol) REF

Firmographics

Finally, I have just a few questions about your firm or organization.

F1. What is the primary activity that occurs in your facilities or buildings? (Probe to code)
1) Education
2) Food Sales
3) Food Service
4) Health Care
5) Lodging
6) Retail
7) Office
8) Public (government)
9) Service (other than food service or retail sales)
10) Warehouse and Storage
11) Manufacturing (SPECIFY Industry Type:________________)
12) Other, SPECIFY: _________________
13) (vol) DK
14) (vol) REF

F2. What percentage of your operating costs is represented by electricity costs? (YOUR BEST ESTIMATE IS FINE)
______Percent
RANGE 0-100
101) (vol) DK
102) (vol) REF

F3. What is your largest single use of electricity consumption? Is it….
1) Lighting
2) Air conditioning
3) Industrial equipment, or
4) Something else, SPECIFY: ___________
5) (vol) DK
6) (vol) REF

THANK YOU AND HAVE A GREAT DAY.

C POST-EVENT PARTICIPANT SURVEY

Contact Information

Date of Contact ______________________________

Name ______________________________

Organization ______________________________

Phone Number ______________________________

Email ______________________________

Record ID# ______________________________

Interviewer ______________________________

Utility ______________________________

Aggregator ______________________________

[*These customers will not have been surveyed as part of the general participant survey. The list includes only participants whose overall load reductions in response to called events was categorized as low or high. Probe all open-ended responses as needed to obtain the most complete information possible.*]

Hello, my name is _______________. I'm calling from Research Into Action and am conducting research on behalf of the California Public Utility Commission and [utility] I'd like to speak with you about [organization]'s experience with [aggregator]'s demand response program during the summer of 2008.

S1. Are you the person most knowledgeable about your company's involvement with [program]?
[IF NO ASK TO SPEAK WITH THAT PERSON?]

S2. My questions should take about 20 minutes. Is this a good time to talk?
[IF NO, ASK TO RESCHEDULE]

[WHEN THE PERSON IS REACHED, RESTATE INTRO PARAGRAPH]

S2. My questions should take about 20 minutes. Is this a good time to talk?
[IF NO, ASK TO RESCHEDULE]

All information you provide to us is confidential.

Outreach and Sign-up

When you signed up with [program] you agreed to reduce your energy use when requested. For the purposes of this survey, we will call this activity *demand response*. Will that work for you?

Participant Profile

PP1: 1. Had [organization] participated in any demand response programs prior to your involvement with [program]?

❍ YES
❍ NO
❍ DK
❍ REFUSED
❍ Other (please specify)

If you selected other, please specify ______________________________

[IF Q1≠YES, SKIP TO Q3]

PP2: 2. When had you participated? ______________________________

PP3: 3. How many locations do you have participating in demand response activities with [program]? [DURING SUMMER '08] ______________________________
[RECORD]

❍ MULTIPLE
❍ SINGLE

Program Awareness & Reasons for Participation

PA1: 4. I'd like to ask you some questions about your activities with [aggregator] in 2008. How did you first hear about the [aggregator]'s program?
[DO NOT READ, SINGLE RECORD]
❍ UTILITY ACCOUNT REPRESENTATIVE
❍ UTILITY WEBSITE/EMAIL BILL INSERT
❍ AN EXISTING RELATIONSHIP WITH AGGREGATOR
❍ AGGREGATOR MARKETED THE PROGRAM TO US (COLD CALL OR SALES CALL)
❍ TRADE ASSOCIATION
❍ DK
❍ REFUSED
❍ Other (please specify)
If you selected other, please specify ___________________________________

PA2: 5. I'm going to list several reasons your company might have decided to participate in [aggregator]'s program. For each one I'd like you to tell me how important each reason was for your company, using a 1-5 scale, where one is not all important and 5 is very important. Can you tell me how important it was for your company to:

	1.	2.	3.	4.	5	DK	REFUSED
a. To receive financial benefit or bill savings (money)	❍	❍	❍	❍	❍	❍	❍
b. To be viewed a good corporate citizen	❍	❍	❍	❍	❍	❍	❍
c. To help the utilitie(s) avoid outages	❍	❍	❍	❍	❍	❍	❍
d. To avoid rolling blackouts	❍	❍	❍	❍	❍	❍	❍
e. To help improve electric system reliability	❍	❍	❍	❍	❍	❍	❍

Technology

TEC1: 6. Prior to signing up with [aggregator] did your facility already have an energy management or building control system?
❍ YES
❍ NO
❍ DK

TEC2: 7. Did your company have to install any new equipment in order to participate in [aggregator]'s program? (This equipment could include hardware, software, communication devices, or metering equipment)
❍ YES
❍ NO
❍ DK

[IF Q7≠YES, SKIP TO Q11]

TEC3: 8. What did you install? ____

TEC4: 9. And, who installed it: Your organization, [aggregator], or [utility]? ____________

TEC5: 10. Did you receive any utility rebates or incentives that went towards the purchase or cost of the new technologies?
❍ YES
❍ NO
❍ DK

TEC6: 11. Are you considering any additional equipment or technologies that might allow for additional demand response during events?
❍ YES
❍ NO
❍ DK
❍ Other (please specify)
If you selected other, please specify ________________________________

[IF Q11≠YES, SKIP TO Q13]

TEC7: 12. What are you considering installing? ________________________________

TEC8: 13. Were you involved in setting the demand response goals for [program]?
❍ YES
❍ NO
❍ DK
❍ Other (please specify)
If you selected other, please specify ________________________________

[IF Q13≠YES, SKIP TO Q15]

TEC9: 14. Can you describe for me the process of setting reduction goals? [PROBES: IF NOT CLEAR WHAT WAS INVOLVED WITH THIS] How did you determine your load reduction capacity, or how much your organization could reduce its energy use? Did you identify specific equipment that could be shut down? ______________________________

[IF Q13=YES, SKIP TO EVENTS]

TEC10: 15. Do you know how the energy use reduction strategy was developed? [IF YES DESCRIBE BELOW] ______________________________

Events

I'd like to ask you a few questions about demand response events you may have participated in.

EV1: 16. Does [aggregator] keep records of called events and of your responses to them? [ASK THEM IF THEY HAVE ACCESS TO THOSE RECORDS. IF SO, ASK IF THEY WOULD BE WILLING TO FIND THEM BEFORE CONTINUING. IF NOT, ASK WHAT IS INCLUDED IN THE RECORDS AND WOULD THEY BE WILLING TO RECEIVE SUBSET OF Q'S TO CONFIRM THEIR RESPONSES VIA E-MAIL? IF YES, WE HAVE [] AS YOUR E-MAIL ADDRESS, IS THIS CORRECT?]

❍ YES
❍ NO
❍ DK
❍ Other (please specify)

If you selected other, please specify ______________________________

[ASK RESPONDENT IF THEY HAVE ACCESS TO THOSE RECORDS. IF SO, ASK IF THEY WOULD BE WILLING TO FIND THEM BEFORE CONTINUING.]

[IF Q16≠YES, SKIP TO Q19]

EV2: 17. According to your records, how many times were you called to reduce your energy use in response to a demand response event during the 2008 summer season? ______________________________

[RECORD]

❍ NONE
❍ ONE OR MORE
❍ DK

[IF RECODE≠ONE OR MORE, SKIP TO PAYMENTS]

EV3: 18. Is this for one utility, or does your organization do this in multiple utility territories?
❍ One utility
❍ Multiple utility territories

[IF Q16=YES, SKIP TO Q21]

EV4: 19. Were you notified of a demand response event or a test event during the 2008 summer season?
❍ YES
❍ NO
❍ DK/NOT SURE

[IF Q19≠YES, SKIP TO PAYMENTS]

EV5: 20. How many times were you called to reduce your energy use in response to an demand response event during the 2008 summer season? ____________________

EV6: 21. How were you typically notified of an upcoming event? ____________________

[IF Q18≠MULTIPLE UTILITY TERRITORIES, SKIP TO Q24]

EV7: 22. Who notifies other locations of demand response events? ____________________

EV8: 23. How are other locations notified of events? ____________________

EV9: 24. After receiving a notification of a demand response event, what did you do? (Probes: Is it planned? Are activities proscribed? Was there ever any confusion?)
____

EV10: 25. Did you communicate internally about an event when it happened?
❍ YES
❍ NO
❍ DK

[IF Q25≠YES, SKIP TO Q27]

EV11: 26. How, and under what circumstances? ____________________

EV12: 27. Did everyone (staff) know what was occurring? ____________________

EV13: 28. How many people were responsible for coordinating demand response activities at your organization in 2008? [PROBE TO UNDERSTAND] ____________________

[ONLY IF UNCLEAR]

EV14: 29. Probe: How did that work? ____________________

EV15: 30. In thinking about the method, the timeframe, and the frequency of notifications, how well did the notification approach work for your organization?

____

EV16: 31. Is there anything that would improve the notification process for your organization? ____________________

Response to Called Event

RE1a-f: 32. In your facility, what equipment was shut down or adjusted in response to an event notification?

- ❍ Reduced lighting
- ❍ Turn up AC equipment settings or set points
- ❍ Shut down motors or pumps
- ❍ Industrial process reductions: (Examples: partial shutdown of operations, reducing some or all production processes)
- ❍ Don’t know
- ❍ Other (please specify)

If you selected other, please specify ____________________

[IF Q18≠MULTIPLE UTILITY TERRITORIES, SKIP TO Q37]

RE2: 33. Is the activity (for example lights, motors, cooling equipment) the same at all of your locations?

- ❍ YES
- ❍ NO
- ❍ DK

[IF Q33≠YES, SKIP TO Q35]

RE3: 34. How do they differ? ______________________________

RE4: 35. In 2008, did the demand response results (meeting load reduction goals) vary from location to location?
❍ YES
❍ NO
❍ DK

[IF Q35≠YES, SKIP TO Q37]

RE5: 36. How did the results vary? ______________________________

RE6: 37. Do you have access to back up generation?
❍ YES
❍ NO
❍ DK

[IF Q37≠YES, SKIP TO CURTAILMENT RESULTS]

RE7: 38. Did you use this back-up generation to help you respond to an event?
❍ YES
❍ NO
❍ DK

Curtailment Results

CU1: 39. Did you track your demand response performance independently, or do you rely on information provided from [aggregator]? ______________________

[IF TRACKED INDEPENDENTLY]

CU2: 40. How do you track your demand response performance? ________________

CU3: 41. Were you able to reduce energy use to the level you had expected or committed to? ______________________________

CU4: 42. [IF MORE THAN ONE EVENT] Was this true for every event? __________

CU5: 43. As a result of lowering your energy use, did your organization experience any negative effects?
❍ YES
❍ NO
❍ DK
❍ Other (please specify)
If you selected other, please specify ________________________________

[IF Q43≠YES, SKIP TO PAYMENTS]

CU6: 44. What negative effects did you experience? ________________________________

Payment

PAY1: 45. Did you receive any payments for participating in [aggregator]'s program in 2008?
❍ YES
❍ NO
❍ DK

[IF Q45≠YES, SKIP TO COMMUNICATION WITH AGGREGATOR]

PAY2: 46. Did the amounts exceed, meet, or fall short of your expectations?
❍ EXCEED
❍ MEET
❍ FALL SHORT
❍ DK

PAY3: 47. Were the payments received within the timeframe you expected?
❍ YES
❍ NO
❍ DK
❍ Other (please specify)
If you selected other, please specify ________________________________

[IF Q47≠NO, SKIP TO COMMUNICATION WITH AGGREGATOR]

PAY4: 48. How did the payment timeframe fall short of your expectations? _______________

Communication with Aggregator

COM1: 49. Did you communicate with [aggregator] after enrolling in the program?
❍ YES
❍ NO
❍ DK

[IF Q49≠YES, SKIP TO Q52]

COM2: 50. How frequently? ____

COM3: 51. About what? ____

COM4: 52. Did you communicate with [aggregator] during an event?
❍ YES
❍ NO
❍ DK

[IF Q52≠YES, SKIP TO SATISFACTION]

COM5: 53. [PROBE]: How frequently and under what circumstances? ___________________

Satisfaction

SAT1: 54. Is it important for you to know the reason for the demand response event? _______

SAT2a-f: 55. Do you know why you were asked to reduce your energy use in 2008? (Do not read: Probe to code. Multiple mentions okay.)
❍ High price of power to the utility
❍ Grid reliability issues
❍ Temperature or Weather related demand
❍ Environmental benefits
❍ No idea
❍ Other (please specify)
If you selected other, please specify ______________________________________

I'd like to ask you about a couple of aspects of the program.

SAT3: 56. Using a 1-to-5 scale, where 1 means strongly disagree and 5 means strongly agree, how much do you agree with each of the following statements:

	1.	2.	3.	4.	5	DK
a. The sign up process was easy.	❍	❍	❍	❍	❍	❍
b. Notification of demand response events was clear	❍	❍	❍	❍	❍	❍
c. I had enough time to prepare for demand response events. [NOTIFICATION TIME PERIOD WAS ADEQUATE]	❍	❍	❍	❍	❍	❍
d. The number of demand response events was what I expected.	❍	❍	❍	❍	❍	❍
e. It's important to do our part to save energy in times of peak demand.	❍	❍	❍	❍	❍	❍
f. Participating in this program helps us save money.	❍	❍	❍	❍	❍	❍
g. Participating in this program helps the environment.	❍	❍	❍	❍	❍	❍

[FOR ANY RATED "2" OR LOWER]

SAT4: 57. Why did you rate [X aspect] this low? : ______________________________

SAT5: 58. Do you expect that your organization will participate in this program again in 2009?

❍ YES
❍ NO
❍ DK
❍ Other (please specify)
If you selected other, please specify ______________________________

[IF Q58≠NO, SKIP TO Q60]

SAT6: 59. Why not? [WHY DO YOU EXPECT THAT YOUR ORGANIZATION WILL NOT PARTICIPATE IN THIS PROGRAM AGAIN IN 2009?] ______________

SAT7: 60. What worked best about this program? ______________________________

SAT8: 61. Do you have any suggestions for how to improve the program? ______________

Firmographics

Finally, I have just a few questions about your firm or organization.

DEM1a-l: 62. What is the primary activity that occurs in your facilities or buildings? (Probe to code)

❍ Education
❍ Food Sales
❍ Food Service
❍ Health Care
❍ Lodging
❍ Retail
❍ Office
❍ Public (government)
❍ Service (other than food service or retail sales)
❍ Warehouse and Storage
❍ Manufacturing (Identify Industry Type:
❍ Other (please specify)
If you selected other, please specify ______________________________________

DEM2: 63. What portion of your operating costs is represented by electricity costs? ________

DEM3: 64. What is your largest single use of electricity consumption? Is it….

❍ Lighting
❍ Air conditioning
❍ Industrial equipment, or
❍ Other (please specify)
If you selected other, please specify ______________________________________

Those are all of my questions. Thanks so much for your time.