EVALUATION OF 2005 STATEWIDE LARGE NONRESIDENTIAL DAY-AHEAD AND RELIABILITY DEMAND RESPONSE PROGRAMS

FINAL REPORT

Prepared for

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and

Working Group 2 Measurement and Evaluation Committee

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ABSTRACT

This report presents findings and results from an evaluation of day-ahead notification and reliability-triggered demand response programs targeted at California's large non-residential customers. The in-scope programs for this evaluation include the investor-owned utilities' voluntary Critical Peak Pricing (CPP) tariff, Demand Bidding Program (DBP), Base Interruptible Program (BIP), Optional Binding Mandatory Curtailment (OBMC) program, traditional interruptible tariffs, and Technical Assistance/Technical Incentive programs, as well as the California Power Authority's Demand Reserves Partnership (DRP). This evaluation was performed under the guidance of the Working Group 2 measurement and evaluation project advisory committee, consisting of representatives from California investor-owed electric utilities, the California Energy Commission (CEC) and the California Public Utilities' Commission (CPUC).

A key aspect of the CPUC's decision approving the 2005 DR programs was its definitional focus on categorizing day-ahead notification as unique from reliability-triggered programs. For 2005, the Commission recast price-responsive programs as "day-ahead notification" programs whose purpose was to reduce predictable high peak loads, as different from "reliability-triggered" programs, like interruptible rates, which serve to mitigate unpredictable emergency conditions that threaten system reliability. In accordance with this categorization, we refer to CPP, DBP, and DRP collectively as "day-ahead" programs in this evaluation. Similarly, we refer to the BIP, OBMC, and interruptible rates collectively as "reliability" programs.

Specific key findings related to the <u>day-ahead</u> programs are as follows: 1) Enrollment levels for the CPP and DBP programs increased significantly (by roughly two-fold) on an account basis and by 60 percent on a load basis between 2004 and 2005. 2) However, actual impacts from these programs are still relatively small as compared to the CPUC's price-responsive DR goals. 3) Overall, the program penetration rate for voluntary CPP remains low; particularly for SCE (with only eight participants). 4) Although enrollment is comparatively high for DBP, bidding rates for 2005 events were very low. On average, only six percent of participants bid for each of the 2005 events. 5) Average impacts for each of the CPP and DBP programs were about 10 MW; however, impacts varied widely across event days and utilities. 6) DRP impacts were very high due to the participation of one very large government entity; absent this customer, DRP impacts were of similar in magnitude to CPP and DBP. 7) Total impacts for the three day-ahead programs combined, absent the large customer (who contributed roughly 200 MW) were roughly 30 to 50 MW. 8) The presence of a few large customers with highly unpredictable loads adds considerable uncertainty to the impact estimation process for the day-ahead programs. 9) The method currently used by the utilities to estimate baseline loads for the DBP program, and to report both DBP and CPP impacts to the CPUC, appears to be biased high by two or perhaps as much as four times. 10) Motivation to participate is strongly affected by non-financial factors, principally, helping to maintain system reliability.

Key findings related to the <u>reliability</u> programs include: 1) Interruptible program participants are generally very satisfied with their tariffs and are not actively seeking alternatives. 2) Interruptible participants report that event participation imposes significant costs. 3) Current interruptible participants indicate a willingness to accept significant interruptions in "worst case" years but expect these years to be balanced by years in which there are few or no event calls. 4) There is significant reluctance among current traditional interruptible program

participants to migrate to BIP. 5) Few interruptible events were called in 2005. 6) SCE's I-6 program achieved impacts very close to tariff-required reductions. SCE's BIP reductions were significant but not as close to required firm service levels as those achieved by I-6.

Key findings from our analysis of our <u>non-participant market survey</u> include the following: 1) There remain significant customer-perceived barriers to participating in DR programs, principally, "effects on production or productivity" and "inability to significantly reduce peak loads". 2) Ownership of DR-enabling technologies does not yet influence perceptions of key barriers or load reduction potential. 3) Perceptions of default CPP effects are mixed but are generally more unfavorable than what would be expected under actual tariff proposals. 4) Remaining short-term DR potential among non-participants is moderate (roughly 1,300 MW of technical potential and ~300 MW of economic potential based on customer self-reports).

In summary, our analysis of eligible markets and participants over the past two years has shown that the large customer market for voluntary, price responsive programs is still immature. With the exception of the contributions of one large customer to the DRP program, impacts from the 2005 day-ahead programs (voluntary CPP, DBP, and DRP) represent only a small portion of the CPUC's price-responsive DR goals (on the order of 30 to 50 MW statewide). In addition, the evidence indicates that there is only small remaining short-term market potential for additional participation and load reduction given current program incentive levels and customer perceptions of system prices and resource needs. At the same time, there are significant load reduction resources enrolled in the utilities' reliability programs; however, these resources have had few calls since the energy crisis and it is not clear how robust the resource would be if it were called frequently.

Finally, recommendations included in this evaluation are listed below.

<u>Cross-program</u> recommendations: 1) DR policies and plans should address the fact that it will be extremely difficult to reach the CPUC's price-responsive DR goals with the current suite of voluntary DR programs; 2) Consideration should be given to refining these DR goals and differentiating reliability and price-responsive goals; 3) Consideration should be given to further differentiating short-term goals from long-term goals (that require capability building); 4) TA/TI incentives and IDSM should continue but be carefully assessed; 5) Efforts to quantify the value of DR benefits and conduct DR program cost-effectiveness analyses should increase.

<u>Day-Ahead</u> Program Recommendations: 1) Work with participants to increase DBP bidding rates; 2) Consider changing the 3-day DBP baseline method for program settlement and use a more accurate alternative to estimate impacts for reporting, resource planning, and procurement; 3) Increase voluntary CPP enrollment levels and increase promotion of the CPP Bill Protection incentive; 4) Clarify the price-based nature of the DRP program in marketing and consider revising the trigger price to better reflect system load conditions; 5) Consider providing DRP aggregators and customers with access to the price used to trigger the program and changing the structure so that customers truly know the day-ahead that they will be called; 6) Keep a DRP program in place with clearly specified structure and terms for several years.

<u>Reliability</u> Program Recommendations: 1) Further assess the value of the traditional interruptible versus base interruptible programs; 2) Carefully consider the risk of reducing the size of the reliability resource if BIP were to be the only available reliability program; 3) Consider periodically field testing reliability programs in addition to process-only testing.

1. EXECUTIVE SUMMARY

1.1 OVERVIEW OF 2005 LARGE CUSTOMER DR PROGRAM EVALUATION

The goal of this report is to present a summary of findings and results from the evaluation of day-ahead notification and reliability-triggered demand response programs targeted at California's large non-residential customers. Specifically, the in-scope programs for this evaluation include the investor-owned utilities' voluntary Critical Peak Pricing (CPP) tariff, Demand Bidding Program (DBP), Base Interruptible Program (BIP), Optional Binding Mandatory Curtailment (OBMC) program, traditional interruptible tariffs, and Technical Assistance/Technical Incentive programs, as well as the California Power Authority's Demand Reserves Partnership (DRP).

This evaluation was performed under the guidance of the Working Group 2 measurement and evaluation project advisory committee consisting of representatives from the utilities, the California Energy Commission (CEC) and the California Public Utilities' Commission (CPUC). The evaluation is comprised of a number of study elements. The core elements include program tracking analysis and process evaluation, market assessment, and impact evaluation. The impact evaluation provides ex-post estimates of hourly load reduction by program, utility, and event. The process evaluation focuses on assessing the programs' procedures and processes, as well as participants' activity levels and satisfaction with the program experience. The market assessment includes a quantitative survey of non-participants focused on estimating DR program familiarity, barriers, opportunities, and potential.

A key aspect of the CPUC's decision to approve the 2005 DR programs was its definitional focus on categorizing day-ahead notification as unique from reliability-triggered programs. Previously, the CPP and DBP programs had been categorized as price-responsive programs. In approving the 2005 programs, however, the Commission recognized that the lack of a true day-ahead market price available from the California Independent System Operator (ISO), and the fact that the price dimension of the 2004 CPP and DBP programs had been at best indirect, served to limit the ability "to offer rates to customers tied to actual market prices or to test a customer's true 'price responsiveness' to market prices." The Commission therefore recast price-responsive programs as "day-ahead notification" programs whose purpose was to reduce *predictable* high peak loads, as different from "reliability-triggered" programs, like interruptible rates, which serve to mitigate *unpredictable* emergency conditions that threaten system reliability. In accordance with categorization, we refer to CPP, DBP, and DRP collectively as "day-ahead" programs in this evaluation. Similarly, we refer to the BIP, OBMC, and interruptible rates collectively as "reliability" programs.

1.2 KEY FINDINGS

In this section we provide a brief summary of the key findings from our evaluation of the 2005 DR programs targeted at large, nonresidential customers. Full discussion of these findings is provided in the remaining chapters of this report.

1.2.1 Enrollment and Impact Evaluation Findings

Total Penetration of All In-Scope DR Programs on an Enrolled Load Basis is about One Fifth of the Eligible Market

Measured relative to the eligible market, current program penetration rates range from 9 percent for traditional interruptible tariffs, 8 percent for DBP, 5 percent for DRP,[1] and 3 percent for CPP on a non-coincident peak load basis. Taking into account customers that participate in more than one program, the combined penetration rate of day-ahead programs, on a non-coincident peak load basis, is 18 percent or approximately one-fifth of the eligible non-coincident peak load.

Enrollment in Day-Ahead Programs Grew Significantly During the 2005 Program Season; Reliability Program Enrollment Remained Relatively Unchanged

The number of accounts enrolled in day-ahead programs grew substantially during the 2005 program season. The number of accounts enrolled in day-ahead programs more than doubled for CPP, nearly doubled for DBP, and more than tripled for DRP. On a MW basis, enrollment grew by over 60 percent. PG&E customers accounted for most of the growth in statewide program enrollment. Enrollment in reliability programs remained essentially unchanged, with the exception of marginal increases in BIP enrollment, mostly in SCE.

Reliability Programs Had Very Few Calls in 2005

In contrast to the day-ahead programs, the reliability-triggered programs had very few calls in 2005. As has been the case for the last several years, only SCE and SDG&E programs were called (SCE called 1 event while SDG&E called 4 events). The reliability programs have been called very little as compared to allowed maximums since the end of the energy crisis.

Day-Ahead Programs Were Called Numerous Times in 2005

In contrast to 2004, the 2005 CPP, DBP, and DRP programs were called many times in summer 2005. In the case of DRP, all of these events were triggered at the request of the utilities because of price. In the case of the temperature-triggered CPP, periodic adjustments were made to the trigger temperatures to ensure that the program would be called the maximum 12 times prescribed by the tariff. For the DBP, events were triggered by a forecasted statewide system load of 43,000 MW, although this was typically not accompanied by supply shortages.

Overall CPP Impacts Averaged 11 MW or 7 Percent of Baseline Load for All Participants

Total estimated impacts for the 2005 voluntary CPP impacts averaged roughly 11 MW across events, ranging from 10 to 13 MW across event hours. On a percentage basis, voluntary CPP impacts averaged 7 percent across all CPP participants. A small portion of participants delivered most of the impacts. Estimated CPP impacts vary widely across utilities and across events.

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[1] For DRP, it is important to note that twelve large pumping facilities associated with one customer account for roughly 600 MW of the enrolled load. The MW penetration for DRP would otherwise be approximately 2 percent.

2005 DBP Bidding Rates Averaged Approximately 6 Percent Across Utilities and Events

Despite relatively high enrollment levels, the fraction of DBP program enrollees that placed bids in 2005 was very limited. This finding is consistent with results from the 2004 DBP evaluation. The 2004 results were qualified because there were very few DBP events in 2004 and, in some cases, the only events called were test events. In 2005, due to the number of events called, DBP participants had numerous opportunities to place bids. When *averaged over all events*, relatively few DBP participants, 6 percent, placed bids in 2005.[2] About three times as many participants, 18 percent, placed a bid for *at least one event*. Thus, 82 percent of enrolled DBP participants did not place a bid for any of the summer 2005 events.

Overall DBP Impacts Averaged 11 MW or Roughly 1 Percent of Baseline Load for All DBP Participants and 9 Percent of Load for Bidders

Estimated impacts for the 2005 DBP averaged roughly 11 MW across events, ranging from 6 to 15 MW across event hours. Estimated impacts also varied widely across utilities, event days, and customer sub-groups. We also found significant differences between estimated impacts among baseline estimation methods. Much of the variation is associated with differences in estimated impacts across event days, though in the case of SCE, there is also significant variation across hours within an event.

Estimated CPP and DBP Day-Ahead Program Impacts Ranged Widely Across Events

As noted above, estimated impacts for the 2005 CPP and DBP programs vary widely across events throughout the summer. This lack of predictability may make it difficult to accurately incorporate program impacts into resource planning and procurement.

The 3-Day Baseline Method Likely Results in Significant Overestimation and DBP Overpayment

There is convincing evidence that the method used by the utilities for estimating and reporting customer baseline loads and impacts (referred to as the "3-Day" method) and used as the basis for payment settlement with participants in the DBP program is significantly biased toward overestimation. This bias can result in overestimates of impacts of two to possibly four times. The systematic upward bias in this method also likely leads to free-ridership as participants can bid against their 3-Day baseline and achieve perceived load reductions without necessarily changing their next day load behavior.

DRP Impacts Average Well Over 200 MW But Are Dominated by a Single Large Pumping Customer that Accounts for Roughly 90 Percent

The DRP program in 2005 was dominated by a single large pumping customer. This customer made up three-quarters of the total estimated baseline load during the summer events and just over 90 percent of the overall impacts. The overall average load reduction across the DRP participants was roughly 50 percent; however, this was driven entirely by this one large customer who averaged a 66 percent load reduction, compared to an average 15 percent

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[2] Average bidding rates varied from 5 percent of participants for SCE to 14 percent for SDG&E, and 7 percent for PG&E

reduction from the other participants. The average impact from the large customer was 242 MW based on the 10-Day Adjusted baseline, compared to an average reduction from the remaining customers of less than 1 MW (0.7 MW). As shown below, without this large customer the impacts resulting from the DRP program were of a magnitude similar to what was calculated for the CPP and DBP programs.

DRP Impacts Vary Widely Across Events and Event Hours for Participants Other than Its Single Large Pumping Customer

Using the 10-Day Adjusted baseline method, we estimate that 2005 DRP impacts from all program participants, excluding the single large pumping customer, averaged roughly 18 to 24 MW across the late afternoon hours; however, our estimated impacts varied widely across utilities, event days, and customer sub-groups and product types. Hourly impacts for the PG&E large pumping customer are not included in this exhibit. Hourly impacts for this customer ranged from a high of 344 MW for the 5 o'clock hour on July 18th to a low of 117 MW for the 4 o'clock hour on August 23rd based on the 10-Day Adjusted baseline.

Significant Interruptible Impacts Consistent with Required Reductions for SCE I-6 and BIP

In 2005, SCE interruptible programs were called on only one occasion, August 25th, due to transmission difficulties associated with the Pacific Intertie. The I-6 and BIP events called on August 25th lasted only a little over an hour, however, during this time significant load reductions occurred. Participants enrolled in the I-6 program reduced their load by 571 MW based on the difference between the hourly 10-Day Adjusted baseline and the 15-minute interval load data. This was a 78 percent load reduction and was within 18 MW of their Firm Service Level (FSL). The participants enrolled in the BIP program also contributed a significant load reduction, 64 MW, which corresponded to an average load reduction of 58 percent. However, we estimate that a much larger share of I-6 participants met their FSL (72 percent) as compared with BIP participants (45 percent). In addition, we estimate that only 3 percent of I-6 participants did not take any action as compared to 18 percent of BIP participants.

1.2.2 Process Evaluation and Non-Participant Market Findings

CPP and DBP Process Findings

Motivation to Participate and Take Action is Strongly Affected by Non-Financial Factors; Bill Savings are also Important for CPP Participation

Consistent with the 2004 findings, most participants in the CPP and DBP programs report that non-financial factors play a very strong role in their participation. Overall, avoiding rolling blackouts and being able to participate without significantly affecting business operation were rated the most significant reasons for participation. Being a good corporate citizen and the amount of bill savings were also both rated highly as significant reasons for participating. CPP participants were more likely than DBP participants to have been motivated by bill savings.

Bidding and Load Reduction Also Appear to be Linked to Civic Responsibility

Most respondents said they felt the 2005 DR events were important (i.e., somewhat or very critical) to helping maintaining system reliability. In addition, roughly half of CPP participants and DBP bidders reported that they "definitely" or "probably" would have taken the load reductions actions they did even without any direct financial incentives. Over half of customers who did not see the 2005 events as important to maintaining system reliability said their response to the events would have been different if the need had been more urgent, with more than two-thirds saying that they would have tried to reduce more load.

Load Reductions in CPP Appear to be Achieved Primarily Through Industrial Process Reductions and Curtailing Discretionary End Uses; Load Reductions in DBP Appear to be Achieved Primarily Through the Use of Backup Generation

Based on self-reported curtailment actions cited by CPP and DBP participants and a first order decomposition of total program impacts, the curtailment actions that appear to make the largest contributions to total CPP program impacts are reducing production processes, which is consistent with the finding from impact analyses that industrial customers account for the majority of total CPP program impacts. For DBP, the curtailment actions that appear to make the largest contributions to total DBP program impacts are using backup generators together with other secondary actions. This result is consistent with the fact that over half of total DBP program impacts come from interruptible customers that participate concurrently in DBP and that interruptible customers frequently cited the use of backup generation as a curtailment action.

Participants Reported only Moderate Effects on Productivity and Comfort

Overall, slightly less than one-third of DBP participants said they had experienced negative effects on personnel comfort or productivity as a result of their demand reduction actions. Small customers were the most likely to have experienced impacts, while institutional customers were the least likely.

Active Participants Indicate a High Likelihood of Continuing to Participate in the Future, but Half of DBP Non-Bidders Indicate They will not Take DR Actions in the Future

Over 90 percent of CPP participants said they were somewhat or very likely to take demand response actions in the future. DBP bidders also expressed a high likelihood of continuing to participate and take demand response actions in the future. However, slightly less than half of DBP non-bidders indicated that they were not likely to participate in future events.

DRP Process Findings

The Frequency of DRP Events in 2005 Caused Concern among both Aggregators and Program Participants

The DRP program was designed to be triggered by either price or reliability issues, but in the perceptions of aggregators as well as customers the price-responsive aspect of the program is also seen as linked to system reliability. Consequently, neither aggregators nor customers were adequately prepared for the program to be called based on a price trigger alone when there was no evidence of capacity shortages within the system, which was the case with the numerous DRP event calls in 2005. More than half the DRP program participants surveyed were somewhat or very dissatisfied with the number of program interruptions in 2005.

DRP Program Participation Was Motivated both By Bill Savings and By the Desire to Be Good Corporate Citizens and Help Avoid Blackouts

Saving money on energy was cited as the primary reason for enrollment in the DRP program by about a third of surveyed customers. However, non-financial motives were also important, with the combination of "being a good corporate citizen" and "avoiding rolling blackouts" also accounting for almost one-third of responses. Other external factors also played a significant role in encouraging participation. More than one-fourth of respondents cited third party influences, including aggregators, a government DR mandate for state agencies, decisions made at corporate headquarters, and decisions made by the chancellor of a university campus.

Reliability Process Findings

Interruptible Customers are Very Satisfied with Current Tariffs and Are Not Actively Seeking Alternative Tariffs

Interruptible program participants are generally very satisfied with all aspects of current interruptible service, which have involved very few or no interruption events over the recent past, in contrast to the frequent interruptions called in 2000-01. Without exception, participants cited cost savings as the primary benefit of taking service on IR tariffs, with several noting that the reduced rates were essential to their ability to operate in California.

Curtailment Actions Currently Used by Interruptible Customers Have Large Incremental Impacts and Costs

An investigation of current curtailment strategies among IR customers revealed that shutting down production processes and running backup generators are the two most common curtailment actions used (or planned). Load shifting and curtailing discretionary end uses are comparatively less common among curtailment actions reported by interruptible customers. The self-reported costs of curtailing production processes are also an order of magnitude higher on average than the self-reported costs associated with other curtailment actions.

Interruptible Customers Indicate a Willingness to Accept Significant Interruptions in "Worst Case" Years

Despite participants' reports of significant costs of curtailing, more than two-thirds of the interruptible customers surveyed reported a high tolerance for interruption events, stating that they would be likely to remain on their current interruptible tariff even if the maximum number of interruption events were to occur. Note, however, that some customers made clear that they are willing to tolerate some years in which they consider participation a financial loss as long as those years are made up for by years in which participation provides a compensating financial gain. These results should be used cautiously, however, since they are based on customer self reports, which could reflect a certain degree of tactical response on the part of current interruptible customers who want to ensure continuation of their current rate discounts.

There is Significant Reluctance Among Eligible Customers to Migrate to BIP

BIP was designed to attract both current interruptible customers as well as customers who might have enrolled in interruptible tariffs had they not been closed to new customers. To date, however, BIP has attracted very few customers from either target group. Based on customer self-reports, which as noted above, should be viewed cautiously, if current traditional interruptible tariffs were discontinued, about half of the current interruptible customers can be expected to migrate to BIP or day-ahead DR programs.

Non-Participant Market Survey Findings

Ownership of DR-Enabling Technologies Does Not Yet Influence Perception of Key Barriers

Reported ownership of select DR-enabling technologies (specifically on-site generation, energy information systems, and energy management and control systems) did not correlate significantly with perceptions of key barriers to demand response among non-participants, in particular "inability to reduce peak load" and "effects on productivity". This result suggests that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response.

Perceptions of Default CPP

Self-reported familiarity with default CPP is low across all three utilities, with only 12 percent of the eligible non-participant market reporting to be "very" familiar, and 26 percent reporting to be "somewhat" familiar with their utility's proposed default CPP tariff. Of the customers reporting to be "very" or "somewhat" familiar with the proposed rates, the majority perceive that default CPP will result in negative net bill impacts, i.e., increases in their annual electricity bills. Overall, the average perceived impact of default CPP on customers' individual annual electricity bills was a 4 percent increase. In contrast, utility rate analyses of default CPP indicate that approximately half of eligible customers would benefit from proposed default CPP rates without taking any action to reduce summer peak loads. Thus, it appears that among eligible non-participants in current DR programs, default CPP is perceived as having higher negative bill impacts on average than what is actually expected.

Short-Term DR Potential Among Non-Participants Continues to be Moderate

Based on self-reported estimates of load reduction potential (given "sufficient financial motivation"), the average technical DR potential across the eligible non-participant market was estimated to be 11 percent, or approximately 1,300 MW. We also estimated the economic potential associated with current DR programs – that is, the DR resource realistically available under incentive levels similar to current programs. The results yield an estimated economic DR potential of 2 percent, or approximately 300 MW.

1.3 RECOMMENDATIONS

In this section we present a summary of a subset of our recommendations. A complete and more detailed discussion of our recommendations is provided at the end of Chapter 3.

1.3.1 Cross-Program Recommendations

DR Policies and Plans Should Address the Fact That It Will Be Extremely Difficult to Reach the CPUC's Price-Responsive DR Goals with the Current Suite of Voluntary DR Programs

Our analysis of eligible markets and participants over the past two years has shown that the large customer market for voluntary, price responsive programs is still immature. With the exception of one large customer's contributions to the DRP program, impacts from the 2005 day-ahead programs (voluntary CPP, DBP, and DRP) represent only a small portion of the CPUC's price-responsive DR goals (on the order of 30 to 50 MW statewide). In addition, the evidence indicates that there is only small remaining short-term market potential for additional participation and load reduction given current program incentive levels and customer perceptions of system prices and resource needs. Under the current portfolio of voluntary programs (and associated customer incentive levels and expected market prices) it would likely take many years to reach the CPUC's price-responsive goals, if they could be reached at all.

The results of this evaluation, related DR research, resource needs assessments, and stakeholder input through the regulatory process should continue to be used to modify the current portfolio, as well as specific program features, as necessary, to increase the likelihood of meeting current, or modified, price-responsive DR goals, while also maintaining a significant DR reliability resource.

Consider Refining DR Goals and Differentiating Reliability from Price-Responsive Goals

As noted above, the market today for voluntary day-ahead or price-responsive load, motivated by incentive levels similar to those used in the DBP and CPP programs, is much smaller than the price responsive goals established by the CPUC. It is difficult to assess the exact size of this gap partly because the goals are not established separately for different customer groups (i.e., the goals also could be reached with contributions from mass market programs targeted at customers below 200 kW).

While we understand that many policy makers are most interested in expanding the price-responsive market, we believe that it could be helpful to further differentiate the DR goals among program types and customer groups so that any tradeoffs that may exist, both among existing reliability programs or between reliability and day-ahead programs, can be more easily identified and analyzed. In addition, consideration should be given to disaggregating the goals by customer size given the significant differences in characteristics among size classes. Similarly, it may be useful to separate the load from the large government entity (which contributes ~200MW of load reductions) from the overall price-responsive goal because this load is many times larger than all remaining day-ahead load combined. Moreover, this load is controlled by a single governmental customer, and does not seem representative of the general market for price-responsive load.

Consider Differentiating Shorter Term Goals from Longer Term Capability-Building Objectives

Another aspect of the day-ahead/price-responsive demand response goals that we believe should perhaps be reconsidered is their time dimension. We believe that it will take longer to achieve the day-ahead/price-responsive goals through voluntary programs than originally anticipated. Although there is a significant infrastructure of energy management and related controls systems in the marketplace, these systems are generally not configured or utilized for DR. It will likely take several more years, coupled with a stronger market incentive for customers to modify these systems, purchase enhancements, and develop other internal procedures that would combine to enable greater levels of DR, while simultaneously reducing customer transaction costs and productivity impacts.

Continue and Carefully Assess Effectiveness of TA/TI Incentives and IDSM; Target TA/TI to Current Program Participants with Low Activity Levels

Closely related to the recommendation above, if DR resources are desired sooner rather than later, the market will need increased technical assistance. Care should be taken to develop and deploy technical support services that are cost effective. A key to this is to require recipients of TA/TI to demonstrate impact reduction capability, sign up for one of the existing DR programs, and, at a minimum, make good faith efforts to take DR actions. It is also possible that participants may need to be required to take load reduction actions in order for TA/TI activities to be cost effective. The extent to which TA/TI participants take DR actions should be closely monitored in the future. In addition, technical support services and incentives should be targeted at current program participants who have generated few program impacts to date but credibly indicate that they remain interested in providing impacts in the future.

Continue Efforts to Quantify the Value of DR Benefits and Conduct DR Program Cost-Effectiveness Analyses

As we noted in last year's evaluation of the 2004 programs, it is important that a DR valuation framework be agreed upon and that cost-effective analysis be completed so that benefit-cost results are available to inform DR program and portfolio-related decision-making. A threshold concern about the voluntary CPP and DBP programs is whether these programs, with the current levels of customer financial incentive and participation levels, are cost-effective or under what conditions in the future they could be. In addition, more information is needed to quantify and compare the value and cost of the increased reliability associated with interruptible programs. To this end, the Commission has appropriately initiated several recent activities on demand response benefit-cost issues and impact estimation protocols that will be continued in the remainder of 2006.

1.3.2 DBP-Related Recommendations

Work with Participants to Increase DBP Bidding Rates

Efforts to enroll customers in DBP have been fairly successful, however, the fraction of participants that bid on DBP events is low (6 percent on average for 2005). Efforts should be made to encourage and assist enrollees to more actively participate in the program through bidding and load reduction activities. Increasing bidding and load reduction actions would provide multiple benefits to participants, program administrators, and policy makers.

Consider Changing the 3-Day DBP Baseline Method for Program Settlement and Use a More Accurate Alternative to Estimate Impacts for Reporting, Resource Planning, and Procurement

As summarized above, we believe the evidence is conclusive that the 3-day settlement method used to estimate customer baselines is systematically biased high. Given the magnitude of the bias we believe that the utilities should not use the 3-day method to report program impacts and should instead consider an alternative method for DBP program settlement. Utilities and policy makers will have to weigh the pros and cons of increased accuracy and reduced overpayment (which would have a positive impact on overall program cost effectiveness) against the possible decrease in program impacts (which could lower program cost effectiveness) that may occur with a change to a more accurate settlement method.

1.3.3 CPP-Related Recommendations

Increase Voluntary CPP Enrollment Levels and Continue to Promote Bill Protection Incentive

To date, voluntary CPP participation levels are fairly low. There is also a wide discrepancy in participation levels among the IOUs (from a high of 3.5 percent for PG&E to a low of 0.1 percent for SCE). The utilities have estimated that a large portion of the eligible market would receive bill savings if they participated in the CPP program. In addition, the CPP Bill Protection Incentive is intended to assure participants that they will not pay more under the CPP tariff than they would have under their otherwise applicable tariff (OAT) for the first year that they participate in the program. The low levels of participation in CPP are likely a function of high levels of customer risk aversion and the effectiveness of CPP marketing efforts (particularly in the case of SCE. Some customers may have concerns about the stability of programs and rates given experiences with the energy crisis as well as how the voluntary CPP relates to the possible implementation of default CPP. However, even if default CPP is implemented in 2007, it would likely be beneficial for customers to participate in the voluntary CPP in summer 2006 in order to develop experience that will help them manage their peak loads in the future. Thus, in either case (with or without default CPP), marketing efforts should continue to encourage participation in the voluntary CPP for summer 2006.

1.3.4 DRP-Related Recommendations

Clarify the Price-Based Nature of the Program in Marketing and Consider Revising the Trigger Price to Better Reflect System Load Conditions

Marketing materials and efforts should emphasize the fact that the program can be called based on price alone, with explanations that this may impact customers' ability to shed weather-dependent load. All of the utilities and aggregators should also develop a consistent state-wide marketing piece to be used on utility websites, by utility reps, and by aggregators. Aggregators say that the utilities, CPA, and even DWR appear to agree that the current strike price for the DRP program is too low. If there is in fact general agreement on this point then consideration should be given to increasing the trigger price and perhaps combining it with a system-wide or zone-based load forecast similar to that used for DBP.

Consider Providing Aggregators and Customers Access to the Price Used to Trigger the Program and Changing the Structure So That Customers Truly Know Day-Ahead That They Will Be Called

For business reasons, utilities have expressed concern about making the spot price they pay in the market public. However, it may be appropriate to provide aggregators and customers with access to a spot market price, subject to non-disclosure if appropriate, on one of the market exchanges so that they are better informed about market conditions and can plan accordingly. As originally designed, the DRP program was intended to be a day-ahead program, but it currently operates as a *de facto* day-of program, since DWR can "reserve" capacity for the next day on virtually every day of the summer. In line with the original intent of the program, it would be both possible and desirable to require DWR and the utilities to make a firm decision on whether or not the program will be called on a day-ahead basis.

Keep a Successor Program in Place with Clearly Specified Structure and Terms for Several Years

Proposals for a successor program have been put forward by the aggregators/CPA and by the utilities. While these proposed programs have some different features, they share several key elements that should be incorporated into the successor DRP program, and we recommend that the details of the program be resolved through negotiations between the CPUC, aggregators, and utilities, with input from customers, other stakeholders, and this evaluation.

1.3.5 Reliability Program Recommendations

Further Assess the Value of Traditional Interruptible Versus Base Interruptible Programs

In its initial decision on default CPP, the CPUC expressed a desire to narrow the DR portfolio to default CPP and BIP. This raised a number of questions including how well aligned benefits and costs are for BIP versus the traditional reliability programs, as well as how much of the reliability resource would be willing to move to BIP. With respect to the first question, additional benefit-cost analysis is needed to assess the relative cost-effectiveness among reliability programs.

Carefully Consider the Risk of Reducing the Size of the Reliability Resource if BIP Were to Be the Only Available Reliability Program

Related to the second question above, results from this evaluation and market participation in BIP to date indicate that there could be a significant reduction in the amount of load enrolled in reliability programs if the traditional programs were discontinued. At the same time, it should also be noted that current interruptible tariffs represent a more robust resource than the newer price-based DR programs. Indeed, our impact evaluation results confirm that current interruptible customers (for SCE and SDG&E) delivered a very high percentage of nominated load reductions in 2005, albeit for only a few short events. This is a very attractive aspect of interruptible tariffs that is strongly emphasized by program managers.

Consider Field Testing Reliability Programs in Addition to Process-Only Testing

The reliability programs have had very few event calls over the past few years. While the programs should definitely not be called arbitrarily, there are benefits to periodically field testing these types of programs. Consideration should be given to such field testing, for example, perhaps once a year. Such testing would help to periodically quantify the timing and magnitude of response and help customers be prepared for situations in which the capacity is needed to meet system constraints.

2. INTRODUCTION

2.1 DR PROCEEDING, WORKING GROUP 2, AND CPUC PRICE-RESPONSIVE DR GOALS

On June 6, 2002, the Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." In the Administrative Law Judge's Ruling following the pre-hearing conference, dated August 1, 2002, a procedural framework was established. This framework includes three working groups: Working Group 1 (WG1) functions as an oversight committee; Working Group 2 (WG2) is responsible for the design and evaluation of demand response (DR) tariffs and programs for large (>200 kW) customers; and Working Group 3 (WG3) is responsible for the design and evaluation of DR tariffs and programs for small (<200 kW) customers.

WG2 conducted a series of workshops in 2003 to draft DR tariffs and programs and submitted a final report to the Commission on January 16, 2004. Based on these draft programs and tariff designs, the Commission authorized three statewide DR programs for large customers for operation during the summer of 2004: the Critical Peak Pricing (CPP) tariff, the Demand Bidding Program (DBP), and the Demand Reserves Partnership (DRP) program. The Commission also approved a process and impact evaluation plan developed by WG2. The evaluation of 2004 DR tariffs and programs operated by the three investor-owned utilities was conducted by Quantum Consulting in accordance to the measurement and evaluation (M&E) requirements of Decision 03-06-032. The final evaluation report was delivered to WG2 on December 21, 2004.

All three IOUs proposed significant changes to their DR tariffs and programs for 2005. On June 6, 2005, the Commission authorized a subset of those proposed changes to the CPP, DBP, and DRP programs as well as modifications to the Base Interruptible Program (BIP) that became effective for the 2005 program season.[1] The Commission again authorized process and impact evaluation activities for each of these statewide programs similar those carried out for the 2004 DR programs. In contrast to the 2004 evaluation, however, the Commission expanded the scope of the 2005 evaluation activities to also include process and impact assessments of reliability programs (e.g. interruptible service tariffs and BIP).

The goal underlying all of the DR programs evaluated for this report is to provide California with cost-effective and flexible ways of responding to periods of high peak electricity demand beyond what exists in current reliability programs. To this end, the Commission adopted specific price-responsive resource goals for each IOU in Decision 03-06-032. These quantitative goals are shown in Exhibit 2-1 below, as well as the revised goals for 2004 resulting from ALJ Cooke's Ruling on June 2, 2004 and the revised goals for 2005 resulting from Decision 04-12-048 on December 20, 2004.

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[1] Among the approved modifications were changes to the eligibility requirements for SDG&E's 2005 CPP and DBP programs allowing customers with peak demands of 20 kW and greater to participate. Despite the lowered eligibility requirements, these programs remain under the scope of WG2 DR programs for large customers.

Exhibit 2-1
Overall CPUC Price-Responsive Demand Reduction Goals

Year	**Utility**		
	PG&E	**SCE**	**SDG&E**
2003	150 MW	150 MW	30 MW
2004 (revised)	333 MW	205 MW	24 MW
2004 (original)	*(400 MW)*	*(400 MW)*	*(80 MW)*
2005 (revised)	450 MW	628 MW	125 MW
2005 (original)	*(3 percent of system peak demand)*		
2006	4 percent of system peak demand		
2007	5 percent of system peak demand		

To delineate how the 2004 and 2005 evaluations relate to each other and the evolving DR-related regulatory proceedings, we briefly summarize the main findings from the 2004 evaluation and review the specific regulatory contexts of the 2004 and 2005 evaluations, respectively.

2.1.1 2004 Evaluation Regulatory Context

The objective in rolling out the new 2004 statewide DBP and CPP programs relatively rapidly, with limited formal rate design research, was to achieve a "quick win" that: a) would take advantage of the new interval meters installed on customers with peak demand over 200 kW (100kW for SDG&E), b) give both customers and utilities experience in implementing statewide DR programs, c) deliver significant load reductions for summer 2004, and d) make a significant contribution to achieving the CPUC's overall price-responsive demand response goals (which were scheduled to ramp up to 5 percent of system peak by 2007).[2] We noted last year that the DBP and CPP program results for 2004 could be assessed differently depending on the contextual lens through which they were viewed. In an environment that lacked the urgency associated with the CPUC's aggressive price-responsive DR goals, the tone of findings and recommendations in 2004 would have been less urgent. If the programs were not expected to make major contributions for many years, and could be fine tuned and modified gradually over time, we would have concluded that, for first-year DR programs, the 2004 accomplishments were reasonable and in line with experiences with similar voluntary price-responsive programs in other parts of the country. However, our charge was to assess the 2004 program experience from the perspective of how likely they were to quickly make large contributions to the CPUC's aggressive price-responsive DR goals.

From that perspective, the results of the 2004 evaluation pointed to significant challenges associated with achieving high levels of participation in, and associated load reduction from,

[2] The primary regulatory context for the 2004 WG2 evaluation was established by Decision 03-06-032, in which the Commission authorized the three investor-owned utilities' Critical Peak Pricing (CPP) tariff, Demand Bidding Program (DBP), and the California Power Authority's Demand Reserves Partnership (DRP), as well as the statewide demand response measurement and evaluation (M&E) effort. Specific numeric goals for the price-responsive DR programs were also included in Decision 03-06-032 for all DR programs.

the 2004 DBP and CPP programs. The primary areas of concern regarded levels of participation for CPP and potential levels of bidding activity for DBP. The issue of DBP bidding levels was particularly difficult to assess given that only day-of events were called in 2004 and most of those were test events. Although we noted that adoption typically takes time for these types of programs and that the programs had been actively marketed only since late 2003, the 2004 results provided fairly strong evidence that the CPP and DBP programs would not make as large a contribution to achieving overall DR goals as desired. Based on the results of the 2004 evaluation, we emphasized that the market needed stronger motivation, knowledge, and capability for the CPP and DBP programs to make significant contribution to the CPUC's price-responsive DR goals.

In the 2004 evaluation we also cautioned, however, that the narrow range of 2004 program events and, in some cases, small potentially unrepresentative mix of participant types, limited the extent to which summer 2004 experiences could be projected for 2005 and beyond. Despite those limitations, a number of modifications and considerations were suggested. The utilities also proposed significant modifications in their October 15, 2004 filings. In addition, reflecting the urgency with which the CPUC believes price-responsive DR needs to be increased, the CPUC issued an Assigned Commission Ruling directing the utilities to file new rate design proposals that would include default Critical Peak Pricing rates for large customers.[3]

2.1.2 2005 Evaluation Regulatory Context

The regulatory context for this 2005 evaluation was established by the CPUC's Decision 05-01-056 approving 2005 DR programs and by the Commission's opinion on default Critical Peak Pricing tariffs for customers over 200 kW (see footnote 1). In addition, by ruling on June 2, 2004, the Assigned Administrative Law Judge (ALJ) modified the 2004 goals based on program performance as of April 1, 2004. However, the goals for subsequent years, which are expressed as percentages of utility system peak demand, were not modified.

A key aspect of D. 05-01-056 was its definitional focus on categorizing day-ahead notification from reliability-triggered programs as follows. The Commission noted that there were two general types of demand response programs that had been used to reduce demand when energy prices are high or when supplies are tight:

> "'price-responsive' programs (in which customers choose how much load reduction they can provide based on either the electricity price or a per-kilowatt (kW) or Kilowatt-hour (kWh) load reduction incentive), and 'reliability-triggered' programs (in which customers agree to reduce their load to some contractually-determined level in exchange for an incentive, often a commodity price discount)." [4]

The decision further noted that both types of programs could motivate customers to reduce their loads in exchange for some type of benefit such as reduced energy rates, bill credits, or exemptions from rotating outages but that "Increasingly the line between these two types of

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[3] *Assigned Commissioner and Administrative Law Judge's Ruling Directing The Filing Of Rate Design Proposals For Large Customers*, Rulemaking 02-06-001, December 8, 2004, http://www.cpuc.ca.gov/PUBLISHED/RULINGS/42078.htm

[4] D. 05-01-056, op. cit., page 4.

programs has blurred. This blurring occurs because high market price forecasts often coincide with high temperatures and high system or local peak demands, which are two drivers of reliability concerns." The Commission acknowledged that because there was not a day-ahead market price established by the California Independent System Operator (ISO), utilities had been forced to use forecasted temperature of system demand levels to trigger the 2004 price-responsive programs and that the "price" dimension of these programs was indirect, occurring in the form of credits or other discounts. These factors had combined, the Commission noted, "to limit our ability to offer rates to customers tied to actual market prices or to test a customer's true "price responsiveness" to market prices."

As a result, the Commission redefined DR programs for 2005 as follows:

> "For purposes of this decision, any demand response program that is designed to be triggered the day ahead, whether for price, temperature, or system demand conditions, will be a day-ahead notification program and will count towards meeting the utilities goals for price responsive demand. In contrast, reliability-triggered programs are called on a shorter time frame, the day of, hour of, or as late as 15 minutes before, being needed. It is these programs, designed to truly respond to any emergency conditions that will be considered 'reliability-triggered' programs for today's decision. This delineation is somewhat different than how we, and the utilities, have characterized programs in the past, but helps to clarify the types of programs we are focusing on and why.
>
> In theory, price-responsive programs are called on before reliability programs and serve to reduce system load and the need to call on reliability-triggered programs (historically, the interruptible tariffs). The availability of price-responsive load to reduce demand with a slightly longer lead time (generally the day ahead) is an important tool in meeting day-to-day demand requirements; because they have some lead time notice requirements, day-ahead notification programs are valuable for reducing predictable high peak loads. Reliability-triggered programs, like interruptible rates, have much shorter notice times, and serve as an important tool in mitigating unexpected shortages, local distribution problems, or transmission constraints that could result in system failures.[5]

Within this context, the Commission also referred to its ALJ/Assigned Commissioner Ruling on default Critical Peak Pricing:

> "Every rate schedule provides a price signal that causes a customer to place load on the system consistent with that signal. Although all large customers are currently enrolled on TOU tariffs, the current volumetric TOU rates for the largest customers do not send a strong signal to reduce load during the critical peak period because the energy price differentials between peak, mid-peak and off-periods are generally less than 3 to 1. In addition, the summer peak period is currently applied to a fixed afternoon period, generally from May through September, whereas the most critical peak loads are of much shorter duration. Without modifying our rate design, customers will not have strong ongoing price incentives to systematically move their load during **critical** peak demand periods off of the system. If we truly want to reduce our critical peak demand, we must modify our rate design to provide a stronger price signal to customers to shift

[5] Ibid., pages 5-6.

load out of the critical peak. We have begun this process through the joint ALJ/Assigned Commissioner ruling issued on December 8, 2004."

As a result, the day-ahead notification programs that we will approve for 2005 will focus on providing incremental peak demand reduction driven by day ahead high temperature, price, or demand level forecasts. The reliability-triggered programs we will approve for 2005 will focus on providing quick response and targeted locational load reduction capability. We will also carefully review and approve technology and technical assistance programs to automate customer response to demand reduction signals, and education of customers about their power to reduce their bills by driving their load off peak."[6]

The Commission then clarified that only reductions from day-ahead programs would count toward its demand response goals:

Programs that are triggered the day-of serve a different purpose, to support immediate system reliability, and do not count toward the program goals adopted in the Energy Action Plan, our procurement decision, or D.03-06-032. We retain this approach for 2005 programs and retain the goals adopted in D.04-12-048.[7]

Given this contextual background, the next sections summarize the objectives, methods, and scope of the 2005 evaluation and the organization of this report.

2.2 OVERVIEW OF WG2 DR EVALUATION

This report presents a summary of the results and findings of the 2005 evaluation of in-scope Working Group 2 (WG2) DR programs. The in-scope programs for this evaluation include the Critical Peak Pricing (CPP) tariff, the Demand Bidding Program (DBP), and Demand Reserves Partnership (DRP) program – collectively referred to as "day-ahead programs" – as well as the Base Interruptible Program (BIP), traditional interruptible service tariffs, and the Optional Binding Mandatory Curtailment (OBMC) program – collectively referred to as "reliability programs".

The primary goals of the 2005 evaluation, as described in Decision 05-01-056, were to assess program marketing and implementation and analyze the load impacts attributable to these programs. From these high-level goals, Quantum Consulting then developed the following principal research objectives with guidance from the WG2 oversight committee:

- Track and analyze 2005 participation levels;
- Assess changes since 2004 in customer awareness, knowledge, and motivations to participate in DR programs and improve the understanding of customer costs and barriers associated with implementing DR;

[6] Ibid., pages 6-7.

[7] Ibid., page 8.

- Derive load impacts from 2005 DR programs and evaluate methods to improve planning estimates of future impacts from DR programs;

- Assess customer and program manager experience with 2005 DR programs in terms of program satisfaction, effectiveness of program design, customer curtailment actions, barriers to curtailment, and likelihood of continued participation;

- Estimate remaining potential for the Base Interruptible Program and the traditional reliability programs;

- Develop draft protocols for estimating the load impacts and costs of DR programs in support of the Commission's effort to develop relevant cost-effectiveness tests for DR[8];

- Assess the effectiveness of Technical Assistance and Technology Incentive Programs (TA/TI) and Integrated Demand Side Management (IDSM); and

- Continue collecting sub-metering data from the twelve 2004 sub-metering participants to provide a more in-depth understanding of DR program participant behavior.

To accomplish these research objectives, this evaluation is comprised of a number of sub-studies. The core sub-studies include process evaluations of each in-scope program, a market assessment of non-participants, a load baseline analysis, and an impact evaluation. The process evaluations focus on assessing the programs' procedures and processes, as well as participants' activity levels and satisfaction with the program experience. The market assessment includes a quantitative survey focused on estimating technical and economic DR potential and identifying participation barriers and opportunities among eligible non-participants. The load baseline analysis systematically assesses the performance of different representative-day baseline methods as well as regression-based methods. The impact evaluation uses these baseline methods together with interval load data to bound and quantify summer 2005 load impacts for each in-scope DR program.

Exhibit 2-2 summarizes the key data collection activities associated with each of these core sub-studies. Each of these data collection activities is presented in more detail in the proceeding chapters of this report. Exhibit 2-3 provides a more detailed summary of the specific interview and survey data collection activities carried out for the 2005 evaluation. Again, these activities are presented in more detail in the proceeding chapters of this report. For reference, CATI refers to Computer-Aided Telephone Interviews, which were used in the standardized, large-sample surveys, as different from "in-depth" interviews, which were open-ended and administered to smaller sample sizes.

[8] This research is being conducted as a separate deliverable from this report.

Exhibit 2-2
2005 Data Collection Vs. Evaluation Research Matrix

Data Collection Tasks		Evaluation Research Objective		
		Process Evaluation	Market Evaluation	Impact Evalulation
Utility Marketing Materials	**TA/TI Marketing Materials**	❍	☆	
	Reliability Updated Marketing Materials	❍	☆	
	CPP/DBP Updated Marketing Materials	❍	☆	
Utility Data	**Participant Data Files**	● ▲	●	✖
	Eligible Population File	● ▲	●	
	Interval Meter Data (15-min)			✖
	Event Data	▲ ■		✖
	Weather Data			✖
	Sub-Metering Data	■		✖ ■
Interviews and Surveys	**Program Manager Interviews**	❍ ■	❍	
	CPP & DBP Post Event Surveys	▲ ■		✖
	End of Summer Market Surveys	▲ ■	✻ ☆	✖
	CPP/DBP Participants	▲ ■	✻ ☆	✖
	DRP Participants	▲ ■	✻ ☆	■
	Interruptible Participants	▲ ■	✻ ☆	■
	Non-Participants	❍ ▲ ■	✻ ☆	
	BIP Potential Interviews	▲	✻ ☆	

Matrix Key	
●	Data Element Used in Sample Design
❍	Data Element Used to Assess Recent Program Changes
▲	Data Element used to Analyze Participation Levels
✻	Data Used to Estimate Program Potential
☆	Data Element Used to Assess Awareness and Barriers
✖	Data Element Used to Calculate Impacts
■	Data Element Used to Identify Curtailment Actions

Exhibit 2-3
2005 Interview and Survey Data Collection

Population	Program	Evaluation	Completed Surveys	
			In-depth	CATI
Program Managers	CPP, DBP, DRP	Process & Market	15	0
Participants	CPP & DBP	Process & Impact (post event)	0	171
Participants	CPP & DBP	Process, Market, & Impact (end of summer)	0	211
Participants	DRP	Process & Market (end of summer)	0	26
Participants	Interruptible	Process & Market (end of summer)	0	99
Non-Participants	BIP	Process & Market (end of summer)	34	0
Non-Participants	ALL	Process & Market (end of summer)	0	573
ALL			49	1180

2.3 OVERVIEW OF IN-SCOPE PROGRAMS

Below we present a detailed description of the terms and operation of all in-scope 2005 DR programs. Tariff sheets and utility-produced materials associated with each program described below are presented in Appendix A.

2.3.1 The Critical Peak Pricing Tariff

The Critical Peak Pricing (CPP) Tariff is a rate that includes increased prices during 6 or 7 hours of up to 12 "Critical Peak Pricing" days each year and reduced prices during non-critical-peak periods. Specific prices in the tariff are applied based on participating customers Otherwise Applicable Tariff (OAT).[9] For PG&E CPP customers, savings can occur in summer only; for SCE and SDG&E customers, savings can occur year-round. PG&E and SCE customers must have an annual maximum demand greater than 200 kW; for SDG&E customers the threshold is 20 kW of annual maximum demand. The rate is not available to direct access customers.

[9] Across the three utilities, all of the OATs applicable to CPP tariffs are three-period Time of Use (TOU) tariffs. The OATs for CPP-eligible customers in PG&E are Schedules A-10 TOU, E-19, E-20, AG-4 C, AG-4 F, AG-5 C, and AG-5 F. For SCE customers, the OATs are Schedules TOU-8, TOU GS-2, and GS-2. For SDG&E, the OATs are Schedules A-TOU, AL-TOU, AL-TOU-DER, AY-TOU, A6-TOU and PA-T-1.

There are two levels of Critical Peak Pricing periods. In SCE's and PG&E's programs they are High-Price Periods (3 to 6PM) and Moderate-Price Periods (Noon to 3PM). In SDG&E's program, they are CPP Period 1 (3 to 6PM) and CPP Period 2 (11AM to 3PM). The amounts and percentages of rate credits and charges represented in each utility's 2005 CPP tariff is presented below.

- PG&E's on-peak energy rates during High-Price Periods and Moderate-Price Periods are 5 times and 3 times higher, respectively, than on-peak energy rates during non-event days. Compared to participants' OAT on non-critical days, PG&E's on-peak and part-peak energy rates for CPP participants are reduced by 11 to 42 percent and 1 to 7 percent, respectively, depending on the applicable OAT.

- SCE's on-peak energy rates during High-Price Periods and Moderate-Price Periods are about 9.3 times and 3.3 times higher, respectively, than on-peak rates during non-event days. Compared to participants' OAT on non-critical days, CPP participants' on-peak rates are reduced by 30 to 57 percent, and their mid-peak rates are reduced by 24 to 30 percent, depending on the applicable OAT.

- SDG&E's on-peak energy rates during CPP Period 1 and CPP Period 2 are 10.8 times and 4.0 times higher, respectively, than on-peak rates during non-event days. Compared to participants' OAT on non-critical days, SDG&E's on-peak and semi-peak rates for CPP participants are reduced by 25 percent and 6 percent, respectively.

Operationally, each utility determines the day before whether there will be a Critical Peak Pricing Day the next day and notifies participants by 3PM. PG&E and SDG&E notify participants via email, text messages sent to alphanumeric pagers, and the utilities' respective websites. SCE notifies participants primarily via direct telephone calls, but participants can elect to receive notification via alphanumeric pager, email, cellular telephone, or fax. The determination of Critical Peak Pricing Days is based on the forecasted temperatures at specific locations, high forecasted spot market power prices, or for testing purposes.[10]

In 2004, all of the utilities conducted a rate analysis to determine whether eligible customers would pay more or less on the CPP tariff than on their OAT, assuming their previous year's pattern of energy usage with load shifting ranging from 0 to 20 percent. Sample results of these rate analyses are summarized below:

- For both PG&E and SCE,[11] of the roughly half of eligible customers who would benefit from CPP rates without making any changes to their consumption pattern, 75 percent of them would save less than 1 percent per year, or roughly $2,000 per year.

- For SDG&E, of roughly two-thirds that would benefit on CPP without making any changes to their consumption pattern, 75 percent would have savings less than 1.7 percent per year.

[10] The CPP triggers actually used during the 2005 program season are discussed in detail in Chapters 7 and 8.

[11] SCE results are based on GS-2 as the OAT.

- For both PG&E and SCE, of the 99 percent of eligible customers who would benefit from CPP rates with a roughly 20 percent reduction during each CPP event, 75 percent would save less than 1.6 percent per year, or roughly $4,000 per year.
- For SDG&E, of roughly 75 percent that would benefit on CPP with a 10 percent reduction,[12] 75 percent of them would have savings less than 2 percent per year.

For PG&E, the energy charges of their 2005 CPP tariff were virtually identical to those of their 2004 CPP tariff. Thus, the bill impacts presented above for their 2004 CPP tariff provide a reasonable estimate of the bill impacts from their 2005 CPP tariff. In contrast, both SCE and SDG&E made significant revisions the critical and non-critical day energy charges for their respective CPP tariffs. In both cases, on-peak and mid-peak energy charges were increased during critical days and decreased during non-critical days. Based on updated rate analyses provided by SDG&E, these changes result in the following estimated bill impacts:

- Without making any changes to their consumption patterns, roughly half of all eligible customers would benefit from SDG&E's revised CPP tariff.
- By reducing load 10 percent during critical periods, roughly two-thirds of all eligible customers would benefit from SDG&E's revised CPP tariff.
- Of the customers that would benefit from SDG&E's CPP tariff in both scenarios, annual bill savings average less than 2 percent.

2.3.2 The Demand Bidding Program

The Demand Bidding Program (DBP) provides opportunities for customers to promise or "bid" load reductions during critical periods in return for payments based on predetermined per-kWh incentives and actual load reduction performance. The PG&E and SCE DBP programs are open to customers with demand over 200 kW who are capable of voluntarily committing to load reductions of at least 50 kW per hour during critical periods. PG&E and SCE accounts with demands below 200 kW but share the same federal tax identification number with "lead accounts" with demands 200 kW and above can also participate in DBP as an aggregated group, provided that they can voluntarily commit aggregate load reductions of at least 200 kW. SDG&E's DBP program is open to customers with demands of 20 kW or greater who are capable of voluntarily committing load reductions of at least 10 percent of their monthly average peak demand. SDG&E customers with demands 20 kW or greater can also participate as an aggregated group, provided that they can voluntarily commit aggregate load reductions of at least 100 kW. The DBP programs in all three utilities are open to both bundled service customers and Direct Access customers.

Operationally, DBP Bidding Events are triggered by one of two possible declarations from the California Independent System Operator (ISO). The first ISO declaration is a "System Alert" based upon a forecasted shortfall in required reserve margins in the affected service territory for the next day. The second ISO declaration is when forecasted system peak demand exceeds

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[12] The rate analysis provided by SDG&E included only 0, 3, and 10 percent reduction scenarios.

43,000 MW for the next day.[13] Once triggered, each utility notifies participants by 3PM that a Bidding Event will occur the following day. DBP Bidding Events always fall between the hours of 12 noon and 8PM. As with the CPP notification, PG&E and SDG&E notify DBP participants via email, text messages sent to alphanumeric pagers, and the utilities' respective websites. SCE notifies DBP participants primarily via direct telephone calls, but participants can elect to receive notification via alphanumeric pager, email, cellular telephone, or fax.

Participating customers then submit load reduction bids between 3PM and 4PM via utility-provided program websites, and customers receive confirmation of accepted bids after 5PM. A customer's actual hourly reductions are determined by subtracting actual hourly usage from their "Expected Demand" (SDG&E's term) or "Customer Specific Energy Baseline" (SCE and PG&E's term). In all three utilities, customer baselines for each hour are determined by averaging the same hours during the three highest usage days of the last ten non-event weekdays.

DBP incentive payments are based on actual hourly load reductions during the hours bid and per-kW incentives. There are no penalties assessed for non-performance, but all three utilities only pay DBP incentives for actual load reductions that are at least 50 percent and no more than 150 percent of bid load. DBP incentive levels are determined by the day-ahead market price for power. In PG&E and SCE, DBP participants are also paid a $0.10/kW adder (called a "participation bonus" by PG&E) when day-ahead market prices are below $0.25/kW. Day-ahead prices are posted on the utilities' respective websites such that DBP participants can view the incentive levels associated with each DBP Bidding Event before submitting load reduction bids. Importantly, the total DBP incentive (i.e., the day-ahead market price plus the participation bonus) is capped at $0.35/kW in all three utilities. While there is no limit to the number of Bidding Events, each utility also may declare up to two "test events." Compliant customers receive a fixed price of $0.35/kWh for actual reductions during test events.

Examples of potential savings for DBP customers were estimated below based on amount of demand reduction and the type of bid, assuming participation in four demand reduction incidents per year and four hours per demand reduction incident. Savings were calculated using a total incentive of $0.35/kWh. As shown in Exhibit 2-4, the resulting savings ranged from $560 for 100 kW bid for 4 hours to $16,800 for 1000 kW bid for 12 hours.

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[13] The DBP triggers actually used during the 2005 program season are discussed in detail in Chapters 7 and 8.

Exhibit 2-4
Example of Customer Savings from DBP Participation

# of Events (4 hours each)	**Load Reductions** (kW)	**Total Payment** (@$0.35/kWh)
4	100	$560
	200	$1,120
	500	$2,800
	1,000	$5,600
12	100	$1,680
	200	$3,360
	500	$8,400
	1,000	$16,800

2.3.3 CA Power Authority Demand Reserves Partnership

The California Power Authority's Demand Reserves Partnership (DRP) Program is available to direct access customers as well as large bundled service customers. This program is offered by the California Power Authority (CPA), marketed by the utilities and CPA-registered "demand service providers" (often referred to as "aggregators"), and operated by APX, a private firm. To participate, customers enter into contracts either directly with CPA or with aggregators. There are no eligibility restrictions based on customer size, but the CPA does not encourage customers with demands below 200 kW to participate.

Like the DBP, customers submit load reduction bids (referred to as "nominations" in the DRP program), provide those load reductions during DRP events, and receive payments for actual load reductions. The key difference between DRP and DBP, however, is that DRP nominations are "call-options", where participants submit nominations of how much load they can reduce when called upon between the hours of 11AM and 7PM. These nominations are submitted one month in advance, and can be adjusted upwards on a day-ahead basis.[14] The California ISO or the California Department of Water Resources (DWR) (via its scheduling subsidiary, California Energy Resource Scheduling) makes the decision to "call" DRP nominations based on forecasted system conditions or spot market power prices. DRP participants are notified by 3PM that DRP events will occur the following day.[15] DRP nominations can be called for a maximum of 24 hours per month.

DRP participants receive payments for actual load reductions during DRP events, as well as lump-sum capacity payments for load reductions committed a month in advance. Both the

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[14] In 2005, customers who were going to be unable to meet their monthly nominations were exceptionally allowed to submit negative daily nominations. This had the effect of reducing their previously submitted monthly nominations.

[15] The DRP triggers actually used during the 2005 program season are discussed in detail in Chapters 7 and 10.

performance payments and the capacity payments are based on rates established in each customer's contract with either their aggregator or the CPA. Participants that fail to meet their load reduction commitments can be assessed non-performance penalties. Actual load reductions are measured by subtracting actual hourly usage from an hourly baseline constructed from the previous 10 weekdays.[16]

2.3.4 Traditional Interruptible Rates

PG&E's E-19/20 Non-Firm

Beginning in the 1980s PG&E offered a "Non-Firm" rate based on its E-19 and E-20 rate schedules. This rate was open to all customers eligible for the E-19 and E-20 rate until 1992, when capacity surpluses led to it being closed to new customers. Existing customers were allowed to continue on the rate through name changes and moves. Beginning in 2004 the rate has been closed even to existing customers if they have changed the account name or moved. Both direct access and bundled customers are enrolled.

The rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy above a contracted firm service level (FSL). Eligibility is based on a minimum average peak demand of 500 kW during the prior six summer months. Customers commit to an FSL of their choosing, but it must be at least 500 kW less than the lowest of the customer's average peak-period demands in the prior six-month summer period.

Up to five "pre-emergency" curtailments, each lasting no more than 5 hours, may be called annually. Emergency curtailments may last up to 6 hours, or until PG&E notifies the customer that the period has ended if less than 6 hours have passed, with a 100-hour annual cap. The general conditions for pre-emergency curtailments are based on temperature forecasts. Emergency curtailments are called according to Stage 2 and Stage 3 system reliability conditions. A 30-minute advance notification is provided to customers, communicated via telephone, email, or other communications means.

Noncompliance penalties of $8.40/kWh are assessed on excess energy taken during the curtailment period (i.e., demand above the contracted firm service level multiplied by the hours during which the excess is taken). A penalty limit applies, however, that restricts the total penalty amount to no more than 200 percent of the annual incentive level. Additionally, penalty charges are reduced by 50 percent on a one-time only basis for customers that complied with all curtailment calls during the previous year.

SCE's I-6

SCE began offering Large Power Interruptible service under its I-6 rate schedule in the 1990s. The rate continues to be open to "new" loads and "new" customers, but is closed otherwise. Both direct access customers and bundled service customers eligible for the Large General

[16] To construct baselines, APX first identifies the load profiles of the previous 10 weekdays. The days with the highest and lowest peak demand are then removed, as well as DRP event days. The remaining daily load profiles are then averaged to determine a customer's hourly baseline.

Service TOU-8 rate schedule may choose I-6 interruptible service, provided they meet the new-load requirements.

Under the I-6 tariff, a customer's FSL must be at least 500 kW less than their maximum peak demand. Thus, a customer must have a maximum demand of at least 500 kW. The rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy above the contract FSL taken during curtailment events.

Curtailments are called during Stage 2 or Stage 3 system conditions, on 30-minute advance notice. A remote terminal unit communications system in conjunction with telephone lines is used, for which there is a fee to cover installation and maintenance costs. Curtailments are limited to 1 event per day, 4 events per calendar week, and 25 events annually. Events are limited to a maximum of 6 hours and total hours of interruption are limited to 40 hours per month or 150 hours per year. Interruptions may be called at any time of day or week throughout the year.

Noncompliance penalties range from $7.20-$9.30/kWh of excess energy (demand above FSL multiplied by hours in excess of that demand), depending on the customer's service voltage level. Continuing non-compliance may result in suspension of the discounts applied to the customer's demand and energy billings.

SDG&E's AL-TOU-CP

The "traditional" interruptible rate offered by SDG&E is different than those offered by PG&E and SCE. Where those utilities' traditional non-firm programs have contractually based FSLs and a discount/penalty scheme applied to demand and energy usage, SDG&E's AL-TOU-CP rate schedule is actually a time of use program with critical peak price periods. No firm service levels are specified, nor are there particular discounts or penalties. Instead the energy charge changes according to system conditions with a $1.80/kWh "signal price" that applies during critical peak periods (events) defined by Stage 2 or Stage 3 system conditions. These critical peak periods occur between 11AM and 6PM. The AL-TOU-CP rate closed to new enrollment on January 1, 2006.

Only customers with self-generation are eligible for this rate, with no minimum demand or minimum load reduction requirements. The customer may operate their self-generation facilities at any time while on the rate. While it is open to both bundled and direct access customers it has no particular benefit to DA customers because its benefits are all contained in the energy charges, and DA customers purchase their energy through other providers. Participants must provide interconnection facilities to enable their self-generation facilities to operate in parallel with the utility's system.

2.3.5 Base Interruptible Program

The Base Interruptible Program (BIP) is a relatively new program developed in 2001 that offers customers capacity payments for committing to reduce load to a specified FSL during system emergencies. The program is open to both bundled and direct access customers with average monthly peak demands of at least 100 kW in PG&E and SDG&E and at least 200 kW in SCE. Like the traditional interruptible programs PG&E and SCE have, BIP is based on an FSL, but it has lower impact requirements. BIP participants must commit minimum load reductions of either 15 percent of their monthly average peak load or 100 kW, whichever is higher. In return, participants receive capacity payments of approximately $7/kW-month for load above their FSL. If participants fail to reduce load to their FSL during BIP events, a noncompliance penalty ($6/kWh in PG&E and SDG&E, $10/kWh in SCE) is assessed on excess energy use above the FSL.

BIP events are called on a 30-minute advance notice, and customers are notified via email and pager. BIP event notices are also posted on utility websites. BIP events are triggered by ISO declaration of Stage 2 or Stage 3 system conditions. Curtailments are limited to one event per day up to 4 hours, 10 events per month and 120 total hours annually. Customers may re-designate their FSL or discontinue program participation during November of each year.

PG&E and SDG&E also offer a lower-risk, lower-reward version of the BIP program terms described above called "Option B". Under Option B, participants receive 3-hour advance notice of BIP events. Additionally, noncompliance penalties are reduced from $6/kWh to $2.50/kWh. However, in return for longer advance notice and lower penalties, participants in Option B receive capacity payments of $3/kW-month (as opposed to $7/kW-month in Option A). Under Option B, curtailments are also limited to 3 hours per event and 90 total hours of events per year.

2.3.6 Optional Binding Mandatory Curtailment Program

The Optional Binding Mandatory Curtailment (OBMC) program is another recent development resulting from the energy crisis of 2000-2001.[17] Instead of offering financial incentives, the OBMC program offers protection from rotating outages during extreme system emergencies, in return for up to 15 percent reduction in circuit load during events. The program is unique in its focus on the circuit, or feeder, as the basis for the load being reduced, instead of a building or campus situation within a circuit. Thus, there is a cooperative aspect to the program in that customers who wish to participate in OBMC may need to coordinate load management with other customers on the circuit in order to meet the curtailment requirements.

The program requires that an OBMC curtailment plan be submitted that shows how the circuit loads will be managed in 5 percent increments up to the 15 percent maximum curtailment level. The plan must be updated annually. To measure impacts the program compares event loads with two differently measured baselines. A 30-minute-based, previous 10-day average is used for determining when 10 percent curtailment levels can be achieved, with certain restrictions detailed in the tariff regarding varying customer operations, unplanned outages, etc. A facility load-adjusted baseline from the previous year's same month's average peak demand is used for measuring impacts to determine when 15 percent curtailment levels can be achieved.

Curtailments are called for when Stage 3 rotating outages are required by the ISO. Customers have 15 minutes to respond before becoming subject to the program's non-compliance provisions. There are no limitations on the number or duration of events. A $6/kWh noncompliance penalty is applicable to actual loads above the maximum load level for the

[17] PG&E also fielded a pilot version, POBMC.

circuit determined in the curtailment plan. If the circuit load reduction requirements are not met to within 5 percent of the required amount for two occasions in any one year, the customer may be removed from the program and prohibited from participating again for 5 years.

2.3.7 Multiple Program Participation

An important aspect of both day-ahead and reliability programs in California is that customers can participate in multiple programs simultaneously. Exhibit 2-5 shows a matrix of the in-scope 2005 DR programs and indicates where multiple program participation is possible and where multiple program participation is restricted.

Exhibit 2-5
Matrix of Multiple Program Participation Allowances and Restrictions

		Day-ahead programs:			Reliability programs:		
		CPP	**DBP**	**DRP**	**IR**	**BIP**	**OBMC**
Day-ahead programs:	**CPP**				no	no	no
	DBP	yes			yes	yes	yes
	DRP	yes	no		yes	yes	yes
Reliability programs:	**IR**	no	yes	yes		no*	yes
	BIP	no	yes	yes			yes
	OBMC	no	yes	yes			

As Exhibit 2-5 shows, several different multi-program scenarios are possible. CPP participants can also participate in either DBP or DRP. Customers participating in one of the reliability programs can also participate in DBP or DRP. Among reliability programs, IR and BIP participants can also participate in OBMC. In all of these multi-program scenarios, CPP and reliability events take precedence over DBP and DRP events. That is, when CPP events and DBP/DRP events occur simultaneously, customers participating in both programs do not receive DBP or DRP energy payments. Similarly, customers participating in reliability programs as well as DBP do not receive DBP energy payments during reliability events. In the case of reliability customers who also participate in DRP, their DRP nominations must be for incremental load reductions below their FSL.

The asterisk in Exhibit 2-5 refers to an "Experimental Interruptible Load Aggregation Option" in SCE's I-6 tariff that allows customers with multiple IR accounts to aggregate load reductions across those accounts and also participate in BIP with load reduction commitments beyond their I-6 FSL. In PG&E and SDG&E, however, customers taking service on traditional interruptible rates are strictly prohibited from also participating in BIP.

2.3.8 Transitional Incentives

To help facilitate customer participation in day-ahead programs and/or the BIP program, all three utilities offer two transitional incentives. The first incentive is called the Bill Protection Incentive (BPI) and guarantees CPP participants that they will not pay more under the CPP tariff that they would under their otherwise applicable tariff (OAT). The only requirement for enrolling in BPI is that participants remain on the CPP tariff for at least 12 months. If, at the end of 12 months, a customer's CPP bill is higher than it would have been under their OAT, the utility provides bill credits equal to the difference.

The second incentive is called the Technical Assistance and Technology Incentives (TA/TI) Program. TA/TI is available to current and prospective participants in CPP, DBP, DRP, and BIP and has three main components. The first component of TA/TI is cursory, on-site audits provided free of charge. These audits are meant to identify DR opportunities. If significant DR opportunities are found, customers can then arrange a detailed DR analysis to be performed at no charge by utility engineers. Alternatively, a technical assistance incentive of $50/kW (of load reduction identified) can be used to help offset the cost of having the detailed audit performed by a utility-approved engineer of the customer's choice. Finally, a technology incentive of up to $100/kW (of load reduction enabled) can be used to help offset the cost of purchasing and installing certain types of DR-enabling technologies. Participation in DR programs is not required to take advantage of the TA/TI program.

2.4 GUIDE TO THIS REPORT

Below we present an overview of the structure and content of the remainder of this report.

- Chapter 3 – Summary of Key Findings and Recommendations

  Chapter 3 draws upon the results of all of the evaluation's sub-studies to highlight the key integrated findings and recommendations of the 2005 evaluation from both the DR portfolio perspective as well as the program-specific perspective.

- Chapter 4 – 2005 Program Tracking and Analysis

  Chapter 4 presents a detailed summary of the participation levels and market penetration of 2005 DR programs and tracks participation changes that have occurred since 2004, particularly for the day-ahead programs.

- Chapter 5 – Non-Participant Market Survey

  Chapter 5 presents a market assessment of the current population of customers eligible for, but not participating in, 2005 DR programs. The assessment is based on a large-sample quantitative survey focused on elucidating the characteristics, knowledge, and technology infrastructure of the non-participating customer population and evaluating the impact of recent DR program changes on customer awareness, familiarity, and perceived barriers to participation.

- Chapter 6 – Impact Evaluation Data and Methodology

  Chapter 6 presents the data requirements and methodologies used to evaluate the impacts resulting from customer participation in 2005 DR programs. Multiple representative-day and statistical regression methods are developed, as well as multiple impact accounting frameworks.

- Chapter 7 – Impact Evaluation Results

Chapter 7 presents the impact estimates for the 2005 DR programs using the multiple approaches developed and described in Chapter 6. The results are presented and compared in terms of hourly impacts by customer, by event, and by program. The distributions of customer-level impacts are also presented and estimation issues associated with high load-variance customers are highlighted. The chapter also presents a bidding trend analysis for DBP participants and discusses estimated impacts from the perspective of resource adequacy requirements.

- Chapter 8 – CPP and DBP Process Evaluation

Chapter 8 addresses key process issues relating to the implementation of and customer participation in the CPP and DBP programs. The evaluation focuses on the effectiveness of event notification, tracking, and settlement systems, customer perceptions of curtailment events, curtailment actions used, barriers to curtailment, and likelihood of continued program participation.

- Chapter 9 – Reliability Programs: Market and Process Analyses

Chapter 9 addresses process issues related to the implementation of reliability programs and assesses the potential market for reliability programs going forward, particularly for the BIP program. The analyses are based on interviews with reliability program managers and both participating and eligible customers and focus on customer perceptions of the relative risks and merits of BIP compared to traditional interruptible tariffs.

- Chapter 10 – Cal-DRP Process Analysis and Participant Survey

Chapter 10 addresses key process issues relating to the implementation of and customer participation in the Cal-DRP program. The evaluation focuses on a number of issues specific to the DRP program, including the effectiveness of communication and coordination between the multiple actors involved, perceptions regarding DRP energy and capacity payments, and perceptions regarding baseline calculations and non-compliance penalties.

- Chapter 11 – Sub-metering Summary

Chapter 11 presents the key findings from a sub-metering study of 12 sites participating in DR programs in 2004 and 2005. The findings highlight the results of detailed impact analyses for individual equipment and circuit loads as well as in-depth interviews with study participants.

- Appendix A – Program Materials

- Appendix B – Survey Instruments

- Appendix C – Survey Results

- Appendix D – Impact Tables

- Appendix E – Sub-metering Materials

3. SUMMARY OF KEY FINDINGS AND RECOMMENDATIONS

In this chapter, we present our overall and integrated key findings and recommendations. This section draws on the detailed analyses and results from the core sub-studies of the evaluation, which are presented in detail in the subsequent chapters and appendices of this report. The first section of this chapter briefly summarizes the scope, goals, and regulatory context of the evaluation. The second section summarizes the key findings from the participation tracking analyses. The third section summarizes the key findings from the program impact evaluation, while the fourth section summarizes the key findings from the process evaluation. The fifth section summarizes the key findings from the non-participant market assessment. Finally, the last section presents recommendations at both the cross-program and program-specific level.

3.1 EVALUATION SCOPE, GOALS, AND REGULATORY CONTEXT

For the 2004 evaluation, Quantum Consulting's primary charge was to assess the program experience with the newly rolled-out Critical Peak Pricing (CPP) tariff and Demand Bidding Program (DBP) from the perspective of how likely these programs were to quickly make large contributions to the CPUC's aggressive price-responsive demand response (DR) goals. For the 2005 evaluation, the Commission expanded the scope of the evaluation activities to include the California Power Authority's Demand Reserves Partnership (DRP) program as well as process and impact assessments of reliability programs, specifically interruptible service tariffs, the Base Interruptible Program (BIP), and the Optional Binding Mandatory Curtailment (OBMC) program.

A key aspect of the CPUC's decision approving the 2005 DR programs was its definitional focus on categorizing day-ahead notification as unique from reliability-triggered programs. Previously, the CPP and DBP programs had been categorized as price-responsive programs. In approving the 2005 programs, however, the Commission recognized that the lack of a true day-ahead market price available from the California Independent System Operator (ISO), and the fact that the price dimension of the 2004 CPP and DBP programs had been at best indirect, which served to limit the ability "to offer rates to customers tied to actual market prices or to test a customer's true 'price responsiveness' to market prices." The Commission therefore recast price-responsive programs as "day-ahead notification" programs whose purpose was to reduce *predictable* high peak loads, as different from "reliability-triggered" programs, like interruptible rates, which serve to mitigate *unpredictable* emergency conditions that threaten system reliability. In accordance with categorization, we refer to CPP, DBP, and DRP collectively as "day-ahead" programs in this evaluation. Similarly, we refer to the BIP, OBMC, and interruptible rates collectively as "reliability" programs.

The primary research goals of the 2005 evaluation, as described in Decision 05-01-056, are to assess program marketing and implementation and analyze the load impacts attributable to these programs. From these high-level research goals, Quantum Consulting then developed the following principal research objectives with guidance from the WG2 oversight committee:

- Track and analyze 2005 participation levels;

- Derive load impacts from 2005 DR programs and evaluate methods to improve planning estimates of future impacts from DR programs;

- Assess customer and program manager experience with 2005 DR programs in terms of program satisfaction, effectiveness of program design, customer curtailment actions, barriers to curtailment, and likelihood of continued participation;

- Estimate remaining potential for the Base Interruptible Program and the traditional reliability programs;

- Assess changes in customer awareness, knowledge, and motivations to participate in DR programs among non-participants and improve the understanding of customer costs and barriers associated with implementing DR;

- Continue collecting sub-metering data from the twelve 2004 sub-metering participants to provide a more in-depth understanding of DR program participant behavior.

Below we present the key findings associated with each of these principle research tasks. These findings are organized as follows: Enrollment and Participation Tracking, Event and Impact-Related Findings, Process Evaluation Findings, and Market Survey Findings,

3.2 ENROLLMENT AND PARTICIPATION TRACKING FINDINGS

The findings in this subsection draw principally from the study results presented in Chapter 4. Readers are referred to Chapter 4 for more detailed results and discussion.

The analyses supporting these findings are based on Quantum Consulting's analysis of program participant tracking data and customer population data provided by the utilities. These data included flags that allow identification of eligible customers and program participants by utility, business type, annual peak demand, and other customer characteristics.

Large Customers in PG&E and SCE Account for the Majority of Enrolled Load in Both Day-Ahead and Reliability Programs

Statewide enrollment in reliability programs, as shown in Exhibit 3-1, currently stands at 767 customer accounts, representing 2,325 MW of non-coincident peak load. Large customers (i.e., those with annual peak demands of at least 1 MW) make up two-thirds of these enrolled accounts and over 90 percent of enrolled load statewide. In particular, large customers that take service on traditional interruptible tariffs in PG&E and SCE account for more than 70 percent of the total non-coincident peak load enrolled in reliability programs.

Statewide enrollment in day-ahead programs currently stands at 1,838 customer accounts, representing 2,822 MW of non-coincident peak load. Exhibit 3-1 shows that, in contrast to reliability programs, large customers make up less than a third of all accounts enrolled in day-ahead programs. However, on an enrolled load basis, large customers in PG&E and SCE again make up more than 70 percent of non-coincident peak load enrolled in day-ahead programs statewide.

Exhibit 3-1
Statewide Program Enrollment and Penetration to Date

	3 IOUs	Day-Ahead Programs				Reliability Programs				
		CPP	DBP	DRP	Total	BIP	OBMC	INTER*	Total	Total DR
	Enrolled Accounts									
size	Extra Small (20-100 kW)	3	46	0	48	0	0	8	8	56
size	Very Small (100-200 kW)	12	28	4	43	1	0	16	17	59
size	Small (200-500 kW)	149	431	202	762	6	0	33	39	794
size	Medium (500-1000 kW)	145	345	26	485	44	0	168	212	635
size	Large (1000-2000 kW)	74	215	16	282	23	1	192	216	440
size	Extra Large (2000+ kW)	27	166	37	218	28	43	204	269	403
sector	Commercial	157	595	232	937	22	4	56	82	994
sector	Institutional	127	270	37	424	16	2	95	113	496
sector	Industrial	124	363	16	473	63	38	476	571	899
	Total Accounts	410	1,231	285	1,838	102	44	627	767	2,393
	Market Penetration, Account Basis (%)									
size	Extra Small (20-100 kW)**	0.0%	0.0%	0.0%	0.3%	-	0.0%	0.0%	-	0.3%
size	Very Small (100-200 kW)**	0.4%	0.1%	0.0%	1.4%	0.0%	0.0%	0.3%	0.6%	1.3%
size	Small (200-500 kW)	1.0%	2.4%	1.2%	4.2%	0.0%	0.0%	0.2%	0.2%	4.4%
size	Medium (500-1000 kW)	3.6%	6.5%	0.5%	9.1%	0.8%	0.0%	3.3%	4.0%	11.9%
size	Large (1000-2000 kW)	5.5%	10.9%	1.0%	14.1%	1.2%	0.1%	10.0%	10.8%	21.9%
size	Extra Large (2000+ kW)	4.3%	13.4%	3.7%	17.0%	2.2%	3.4%	16.6%	21.0%	31.4%
sector	Commercial	0.8%	2.4%	0.9%	3.8%	0.2%	0.0%	0.2%	0.6%	3.8%
sector	Institutional	1.4%	2.5%	0.3%	4.0%	0.2%	0.0%	0.8%	1.4%	4.2%
sector	Industrial	1.9%	4.6%	0.2%	6.0%	1.0%	0.6%	6.1%	8.7%	10.0%
	Total Penetration	1.1%	2.7%	0.7%	4.1%	0.4%	0.2%	1.4%	2.6%	5.3%
	Enrolled Non-coincident Peak Load (MW)									
size	Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	1
size	Very Small (100-200 kW)	1	2	0	3	0	0	2	3	6
size	Small (200-500 kW)	52	139	73	257	2	0	12	14	268
size	Medium (500-1000 kW)	101	244	16	339	31	0	126	157	450
size	Large (1000-2000 kW)	104	296	25	391	33	2	273	308	618
size	Extra Large (2000+ kW)	121	927	825	1,831	185	418	1,376	1,843	3,089
sector	Commercial	130	456	116	646	22	25	91	137	747
sector	Institutional	82	386	669	1,124	22	8	248	279	1,275
sector	Industrial	168	759	154	1,043	200	387	1,451	1,903	2,402
	Total Non-coincident Load	380	1,609	939	2,822	250	420	1,790	2,325	4,433
	Market Penetration, Non-coincident Peak Load Basis (%)									
size	Extra Small (20-100 kW)**	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
size	Very Small (100-200 kW)**	0.4%	0.1%	0.0%	0.8%	0.0%	0.0%	0.4%	0.6%	1.0%
size	Small (200-500 kW)	1.2%	2.5%	1.4%	4.6%	0.0%	0.0%	0.2%	0.3%	4.9%
size	Medium (500-1000 kW)	3.7%	6.7%	0.5%	9.2%	0.9%	0.0%	3.6%	4.3%	12.2%
size	Large (1000-2000 kW)	5.7%	11.0%	1.1%	14.4%	1.2%	0.1%	10.5%	11.2%	22.6%
size	Extra Large (2000+ kW)	3.7%	12.6%	12.4%	22.1%	2.4%	5.3%	18.2%	23.4%	39.2%
sector	Commercial	2.4%	6.1%	1.8%	8.5%	0.3%	0.4%	1.2%	1.9%	9.7%
sector	Institutional	2.1%	6.3%	11.0%	16.5%	0.4%	0.1%	4.1%	4.6%	20.3%
sector	Industrial	4.7%	11.9%	3.1%	15.7%	3.0%	5.8%	22.4%	28.1%	34.8%
	Total Penetration	2.9%	8.0%	5.3%	13.2%	1.3%	2.1%	8.8%	11.5%	21.2%

*Penetration based on eligible population if interruptible tariffs were open to enrollment
**Data reflect SDG&E only

Significant Overlap between DBP Participants and Interruptible Customers

Participants in the DBP program and traditional interruptible tariffs make up the majority of total participants in statewide day-ahead and reliability programs, respectively. DBP participants make up 67 percent of all accounts and 57 percent of all non-coincident peak load enrolled in day-ahead programs, and traditional interruptible customers make up 81 percent of all accounts and 77 percent of all non-coincident load enrolled in reliability programs. However, these two programs share a significant pool of customers that participate in both programs. Traditional interruptible customers represent 14 percent of enrolled DBP accounts and about 34 percent of enrolled DBP load. Conversely, interruptible customers that also participate in DBP represent 27 percent of accounts and 30 percent of non-coincident load enrolled in interruptible tariffs.

This overlap is important to note and understand not only because customers in reliability programs tend to be larger, but also because customers in reliability programs, in particular interruptible customers, tend to have larger and more developed load reduction capabilities compared to other customers. This finding indicates two important but conflicting participation trends. First, a significant portion of reliability customers have adapted their curtailment planning and actions from the infrequent, compliance-driven framework of reliability programs to the more frequent, voluntary framework of day-ahead programs. From this perspective, the utilities and the state are now able to get more flexible and more frequent DR out of the existing reliability resource. However, the fact that a significant portion of participation in day-ahead programs is coming from existing reliability customers also indicates that the level and growth of day-ahead program participation from customers who had not previously participated in any DR program is significantly less that it would otherwise appear. In addition, as discussed further under impact-related findings in Section 3.3, although DBP bidding rates are higher for reliability participants, they are still not particularly high.

Active CPP and DBP Participants Tend to be Industrial and Institutional Customers

Comparing the business type and size attributes between day-ahead participants who actively provide significant load reductions and participants who are enrolled but have yet to actively provide significant load reductions reveals some important differences. Specifically, "active" CPP participants (i.e., those who have reduced their load by at least 5 percent on average during critical peak events) are made up of higher shares of Industrial and Institutional customers compared to "non-active" CPP participants.[1] Similarly, DBP "bidders" (i.e., those that have submitted at least one load reduction for DBP events) are also made up of higher shares of Industrial and Institutional customers compared to DBP "non-bidders". The one exception to these trends is DBP participants in SDG&E, where Institutional customers actually make up a smaller share of DBP bidders compared to non-bidders.

Industrial and Institutional customers already account for 65 percent of load enrolled in CPP and 71 percent of load enrolled in DBP. The findings above, however, indicate that Industrial and Institutional customers account for even higher shares of the enrolled load that actively delivers program-induced load reductions. Indeed, Industrial and Institutional customers account for 75 percent of "active" load enrolled in CPP and 83 percent of "active" load enrolled in DBP.

Total Penetration of All In-Scope DR Programs on an Enrolled Load Basis is about One Fifth of the Eligible Market

Measured relative to the eligible market, current program penetration rates range from 8.8 percent for traditional interruptible tariffs, 8.0 percent for DBP, 5.3 percent for DRP, and 2.9 percent for CPP on a non-coincident peak load basis. Taking into account customers that

[1] This load reduction is measured relative to each customer's 10-Day Adjusted baseline (see Chapter 6).

participate in more than one program, the combined penetration rate of day-ahead programs on a non-coincident peak load basis is 18 percent or approximately one-fifth of the eligible non-coincident peak load. For DBP, these penetration rates should be interpreted with caution, due to the large number of customers enrolled who do not make load reduction bids.[2] If only bidders are counted, the MW penetration rate for DBP drops from 8.0 percent to 2.4 percent. Additionally for DRP, it is important to note that twelve large pumping facilities associated with one customer account for roughly 600 MW of the enrolled load. The MW penetration for DRP would otherwise be approximately 2 percent.

Across market segments, there are two overall penetration trends of note. First, overall program penetration levels tend to be much lower among customers with annual peak demands below 500 kW, both on an account basis and a MW basis. Indeed, with the exception of CPP, all of the in-scope programs exhibit their highest penetration rates amongst customers whose annual peak demands exceed 2 MW. Second, program penetration levels tend to be higher among Industrial customers compared to Commercial and Institutional customers. This difference is more pronounced in the penetration of reliability programs compared to day-ahead programs. The highest penetration rates among both day-ahead and reliability programs occurs in the Mining, Metals, Stone, Clay, Glass, and Concrete sector, with 20 percent of eligible peak load enrolled in DBP and over 50 percent of "eligible" peak load enrolled in traditional interruptible tariffs.[3]

Enrollment in Day-Ahead Programs Grew Significantly During the 2005 Program Season; Reliability Program Enrollment Remained Relatively Unchanged

The number of accounts enrolled in day-ahead programs grew substantially during the 2005 program season. By the end of the 2005 program season, the number of accounts enrolled in day-ahead programs had more than doubled for CPP, nearly doubled for DBP, and more than tripled for DRP. On a MW basis, growth in enrollment was less dramatic, but still significant, growing by over 60 percent over the course of the 2005 program season. For CPP, PG&E customers accounted for most of the growth in statewide program enrollment, although a significant portion of this growth (~30% of 2005 enrollment) occurred after the last CPP event of the summer. For DBP, PG&E customers again accounted for most of the growth in statewide program enrollment, with SCE customers also accounting for a significant portion of the increase in statewide enrollment.

One factor that clearly contributed to DBP enrollment trends during the 2005 program season was the modification to the 2005 DBP programs allowing Direct Access (DA) customers to participate. In PG&E, DA customers accounted for 31 percent of all accounts that enrolled in DBP during the 2005 program season. Similarly in SCE, DA customers accounted for 24 percent of all accounts that enrolled in DBP during the 2005 program season. In SDG&E, however, none of the accounts that joined the DBP in 2005 were DA customers.

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[2] The issue of DBP non-bidders is addressed in more detail in Chapter 7 and Section 3.3.

[3] The penetration rates calculated for traditional interruptible tariffs use a denominator that describes all accounts that would be eligible if these interruptible tariffs were open for new enrollment.

In contrast to these trends in day-ahead program enrollment, enrollment in reliability programs remained essentially unchanged during the 2005 program season, with the sole exception of marginal increases in BIP enrollment, mostly in SCE. Overall, however, enrollment in the BIP and OBMC programs remains low relative to interruptible tariffs and day-ahead programs.

Higher Shares of Commercial Customers Signed up for Day-Ahead Programs in 2005 Compared to 2004

Comparing the basic size and business type characteristics of customers that enrolled during the 2005 program season and those that enrolled in 2004 reveals that for CPP, Commercial customers account for a significantly larger share of 2005 sign-ups compared to 2004 sign-ups. Overall, the share of Commercial accounts in new enrollment increased from 30 percent to 47 percent between 2004 and 2005. Additionally, customers with annual peak demands below 500 kW accounted for an increasing share of CPP sign-ups in 2005 compared to 2004. Similar trends also appear among recent DBP sign-ups. In general, Commercial customers account for an increasing share of new sign-ups for the DBP program and now account for the vast majority of new DBP accounts in both PG&E and SDG&E and 60 percent of new DBP accounts overall. This shift away from Industrial and Institutional customers and towards Commercial customers signing up for DBP translates to a shift away from larger customers and towards relatively smaller customers in terms of new participants going forward.

These trends indicate that future growth in day-ahead program participation is likely to come from a more diverse set of Commercial customers with lower peak demand associated with each account. These trends also indicate that most large customers who are willing and capable of providing day-ahead demand response at current incentive levels may already be participating. Together these findings imply that future incremental growth in enrolled load will likely necessitate, on average, higher relative incremental growth in enrolled accounts than has been experienced to date.

3.3 EVENT AND IMPACT-RELATED FINDINGS

The findings in this subsection draw principally from the impact evaluation results presented in Chapter 7 and Appendix D. Readers are referred to that chapter and appendix for more detailed results and discussion.

The key findings presented below are based on actual hourly load data of all participants using representative-day and regression-based calculation methodologies. The methodologies are presented in detail in Chapter 6. The findings are presented first for day-ahead programs, then for reliability programs.

3.3.1 Day-Ahead Program Impact Findings

<u>CPP and DBP Impact Findings</u>

Day-Ahead Programs Were Called Numerous Times in 2005

In the 2004 evaluation we noted that the DBP and CPP programs were called infrequently in summer 2004 and that the limited number and types of events that were called constrained the 2004 impact evaluation and associated confidence with which program impacts were estimated.

In contrast to 2004, the 2005 CPP, DBP, and DRP programs were called many times in summer 2005 as shown in Exhibit 3-2. In the case of DRP, all of these events were triggered at the request of the utilities because of price. In the case of the temperature-triggered CPP, periodic adjustments were made to the trigger temperatures (specific to utilities and climate zones within utilities) to ensure that the program would be called the maximum 12 times prescribed by the tariff. For the DBP, events were triggered by a predicted statewide system load of 43,000 MW, which was reached multiple times – even though this was typically not accompanied by supply shortages.

Exhibit 3-2
Number of Day-Ahead Program Events in 2004 versus 2005

Program	Utility	Day-Ahead Program Events	
		2004	2005
CPP	PG&E	5	9*
	SCE	12	12
	SDG&E	6	5
DBP	PG&E	1	17
	SCE	2	13
	SDG&E	3	12
Cal-DRP	PG&E	3	24
	SCE	2	19
	SDG&E	3	7

* First PG&E CPP not billed due to late notification

Overall CPP Impacts Averaged 11 MW or 7 Percent of Baseline Load for All Participants

Based on the 10-Day Adjusted baseline method, total estimated impacts for the 2005 voluntary CPP program are similar in size to those from the 2005 DBP program at roughly 11 MW.[4] On a percentage basis, CPP impacts averaged 7 percent across all CPP participants.[5] As discussed later in this section, a small portion of participants delivered most of the impacts. Estimated CPP impacts vary widely across utilities and across events. Although there is considerable variation across event hours, the estimated CPP impacts remain positive across all hours and vary far less than DBP impacts. Exhibit 3-3 below presents the average CPP hourly load reduction across all summer 2005 events for each of the utilities and statewide. Exhibit 3-4 below presents the average CPP hourly load reduction as a percentage of estimated base load for all summer 2005 events for each of the utilities and statewide.

[4] Impacts for all event hours are provided in Appendix D.

[5] Note that CPP impacts estimated using customer-specific regression models are somewhat lower than those summarized here from the 10-Day Adjusted baseline day method. Regression-based results are summarized in a separate finding below.

Exhibit 3-3
Average Hourly Load Reduction Impact for Summer 2005 CPP Events
(Note that Hour Ending 12 was a Program Hour for SDG&E Only)

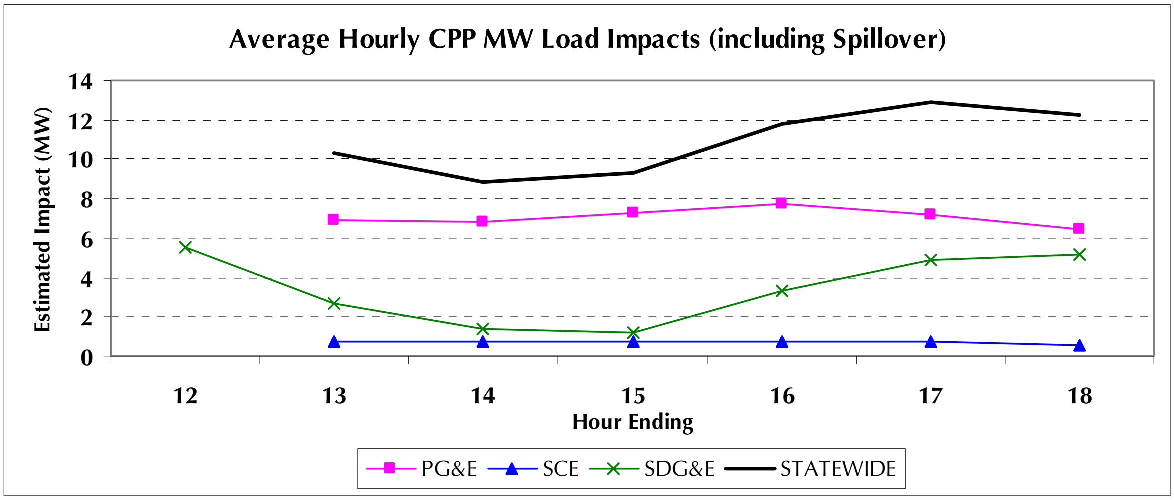
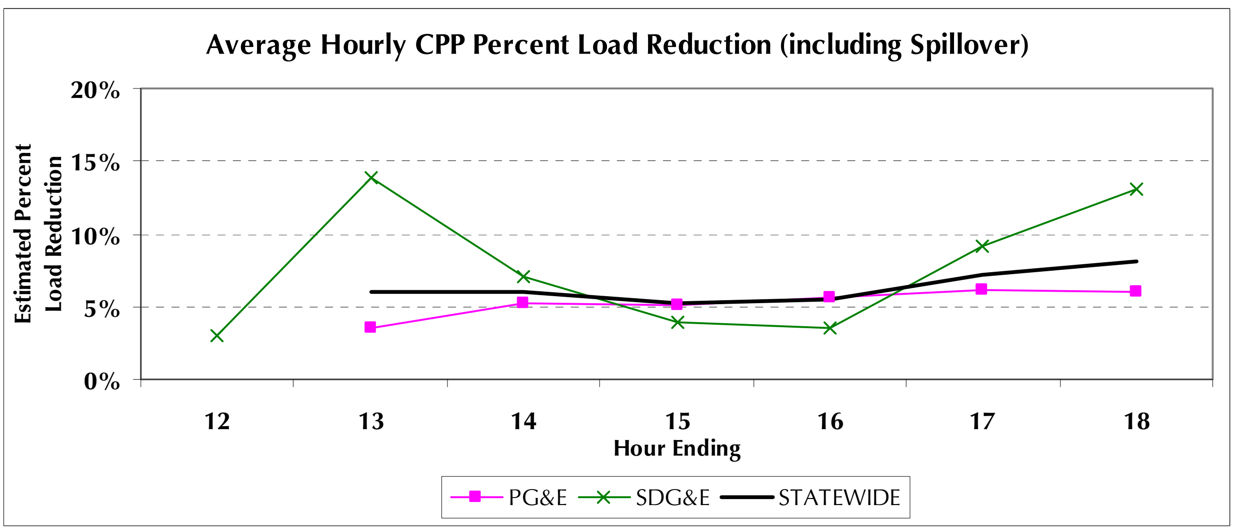


Exhibit 3-4
Average Percent Load Reduction for Summer 2005 CPP Events[6]



These results indicate that, regardless of whether a large portion of the voluntary CPP participants are structural benefitters, there are consistent, observable load reductions

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[6] SCE was excluded from this CPP Percent Load Reduction exhibit because there were only eight customers enrolled in the program. The average load reduction SCE was 45 percent, however, almost all of this was attributable to one of the eight customers.

attributable to the program.[7] "Structural benefitters" refer to the participants that benefit from the tariff without making load reductions on CPP event days.

2005 DBP Bidding Rates Averaged Approximately 6 Percent Across Utilities and Events

Despite relatively high enrollment levels, the fraction of program enrollees that placed bids in 2005 was very limited. This finding is consistent with results from the 2004 DBP evaluation. The 2004 results were qualified because there were very few DBP events in 2004 and, in some cases, the only events called were test events. In 2005, due to the number of events called, DBP participants had numerous opportunities to place bids.

When *averaged over all events*, relatively few DBP participants, 6 percent, placed bids in 2005. About three times as many participants, 18 percent, placed a bid for *at least one event*.[8] Thus, 82 percent of enrolled DBP participants did not place a bid for any of the summer 2005 events. Averaged across all events in 2005, bidding rates varied from 5 percent of participants for SCE to 14 percent for SDG&E, and 7 percent for PG&E.

Overall DBP Impacts Averaged 11 MW or Roughly 1 Percent of Baseline Load for All DBP Participants and 9 Percent of Load for Bidders

Using the 10-Day Adjusted baseline method, we estimate that 2005 DBP impacts averaged roughly 11 MW[9]; however, the estimated impacts varied widely across utilities, event days, and customer sub-groups. This variation is presented in detail in Chapter 7 and in Appendix D. One way of summarizing the amount of variation across events is to look at the quartile ranges of impacts for all of the 2005 DBP event hours. Estimated impacts range from 5 to 15 MW between the 25th and 75th percentiles. Much of the variation is associated with differences in estimated impacts across event days, though in the case of SCE, there is also significant variation across hours within an event. Exhibit 3-5 below presents the average DBP hourly load reduction across all summer 2005 events (where bids were available) for each of the utilities and statewide. The exhibit below includes spillover impacts resulting from participants who bid for only a portion of the actual event hours.

Estimated DBP impacts also vary significantly across utilities. Average estimated impacts as a percent of bidders' baseline loads are 22 percent for PG&E, 10 percent for SDG&E, and 3 percent for SCE. As shown in Chapter 7, Exhibits 7-59 through 7-61, the impacts for PG&E and SDG&E can be easily seen from the graphic analysis of estimated and actual load shapes on

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[7] We did not have the information available for the 2005 CPP participants to estimate the share of structural benefitters; however, in 2004 the portion was roughly 80 percent.

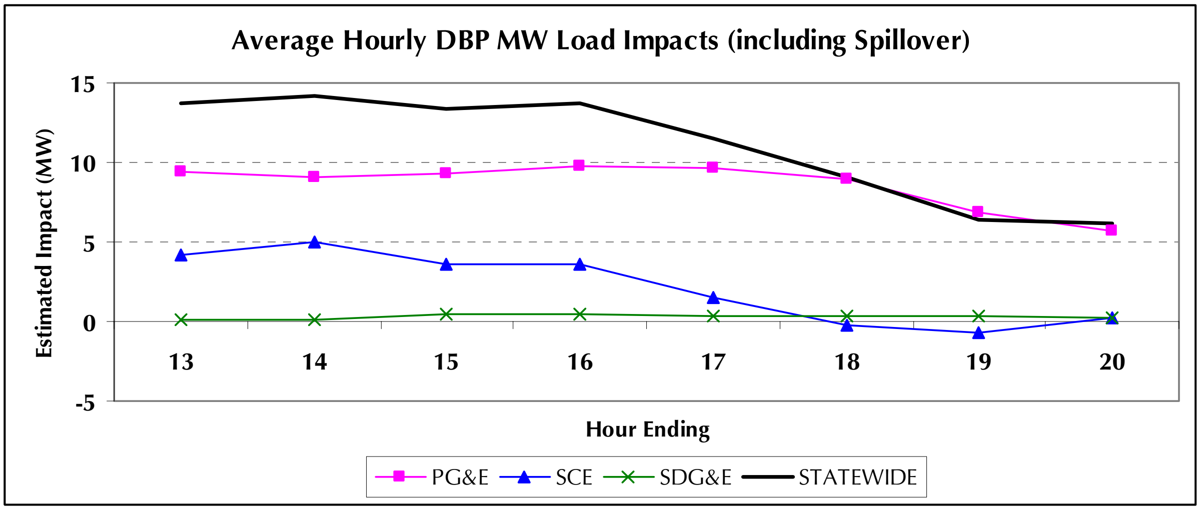
[8] Bidding rates for at least one event by utility were 14% for SCE; 22% for PG&E; and 37% SDG&E.

[9] These results are based on estimation of baseline load using the 10-Day Adjusted method. However, the evidence from this evaluation, the 2004 evaluation, and the CEC's DR Protocol study (*Protocol Development For Demand Response Calculations – Findings and Recommendations.* Prepared by KEMA-XENERGY, February 2003) all indicate that a 10-Day Adjusted method is good estimator and is superior to the 3-Day program settlement method (which is more systematically biased [upward]), there is also error and some potential for bias associated with the 10-Day Adjusted method, as documented in *Chapter 6 – Baseline Assessment* of the 2004 WG2 DR Evaluation (*Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December 2004)

event days, whereas the DBP impacts for SCE are not nearly as apparent. As discussed further below, small numbers of very large customers with highly variable loads contribute significantly to uncertainty in the impact estimates, particularly for SCE. Exhibit 3-6 below presents the average DBP hourly load reduction as a percentage of estimated base load for all summer 2005 events (where bids were available) for each of the utilities and statewide.

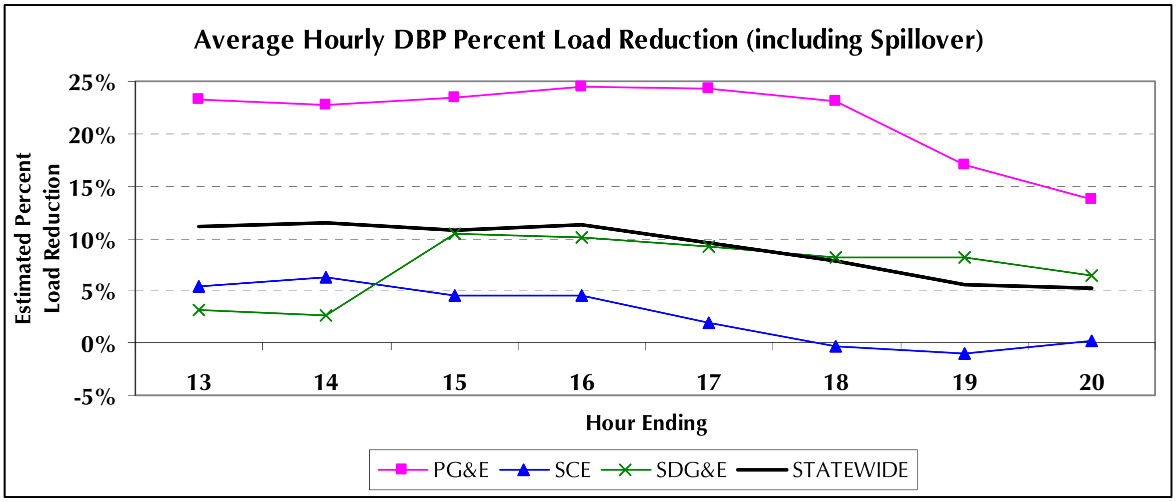
Exhibit 3-5

Average Hourly Load Reduction Impact for Summer 2005 Events where Bids were Captured [10]



10 Although DBP events in SDG&E service territory could be called between noon and 8pm, all 2005 summer events were called for shorter two to five hour blocks of time. No events were called to start prior to 1 p.m. (hour ending 14) or end after 6 p.m. (hour ending 18) and thus all SDG&E impacts in hours ending 13, 19 and 20 are pre- or post-event spillover impacts. All utilities also include in-event spillover impacts for customers who bid for only a portion of the total event hours.

Exhibit 3-6
Average Percent Load Reduction for Summer 2005 Events where Bids were Captured



Estimated CPP and DBP Program Impacts Varied Widely Across Events

As noted above and shown in the event-specific results in Chapter 7, estimated impacts for the 2005 CPP and DBP programs vary widely across events throughout the summer. This lack of predictability may make it difficult to accurately incorporate program impacts into resource planning and procurement. The event by event variation is largely due to three factors. First, some customers take action in one event but not another. Second, a small number of very large customers with highly variable loads have a correspondingly large effect on the estimated impact. Third, the number of customers that take action in any particular event remains small and very heterogeneous. Without a much larger pool of active participants, average impacts are likely to remain highly variable.

Estimated CPP and DBP Impacts Also Ranged Varied Across Estimation Methods

Among the representative day baseline estimation methods, estimated 2005 program impacts using the 3-Day baseline method are about three times as high as impacts estimated using the preferred 10-Day Adjusted baseline method. Based on the research conducted over past three years, there is conclusive evidence that the 3-Day baseline method is biased upward and significantly overestimates customer baselines and program impacts.

For this 2005 evaluation, we also included multivariate regression analysis as a method to estimate customer-specific baselines. The multivariate regression analysis resulted in lower impact estimates than all of the representative day methods. Even compared to the 10-Day Adjusted baseline method, the regression-based results were roughly half as large (or nearly a quarter of the estimated impacts under the 3-Day method). This may be because the regression approach more accurately captures load impacts that are program induced by controlling for seasonal, day-of-week, post-event days, and other effects that are not explicitly addressed in the backward-looking representative methods. If this is indeed the case, this indicates that net impacts for the 2005 programs may be even lower than those presented based on the 10-Day Adjusted method.

The 3-Day Method Likely Results in Significant Overestimation and DBP Overpayment; Bid Realization Rates Were Significantly Lower under the 10-Day Adjusted Method as Compared to the 3-Day Method

There is convincing evidence that the method for estimating customer baseline loads and impacts (referred to as the "3-Day" method) used to by the utilities' to report program impacts and as the basis for payment settlement with participants in the DBP program is significantly biased toward overestimation. This bias can result in overestimates of impacts of two to possibly four times. The systematic upward bias in this method also likely leads to free-ridership as participants can bid against their 3-Day baseline and achieve perceived load reductions without necessarily changing their next day load behavior.

Across all three utilities, roughly 90 percent of bids were estimated to be impacts under the 3-Day baseline method.[11,12] This is somewhat as expected since participants place their bids relative to the 3-Day method. However, bid realization rates under the more accurate 10-Day Adjusted baseline were far lower and averaged only 30 percent.[13] Moreover, based on the regression results, only about 12 percent of the bid amounts are estimated to have been realized. In short, based on the 10-Day method and regression approach, the DBP program significantly over paid (by roughly two- to four-fold) for actual impacts delivered. Thus, the bias in the 3-Day method may have led to significant free-ridership.

Small Numbers of DBP and CPP Participants Contribute a Large Portion of Total Impacts

Similar to our findings for 2004, our 2005 analysis indicates that a small percentage of DBP bidders and CPP participants account for a very large percentage of total program impacts. Roughly 20 percent of DBP bidders and CPP participants contributed 80 percent of the estimated program impacts under the 10-Day Adjusted method. The average percent load reductions for these two sub-groups are presented in Exhibit 3-7 below. As this exhibit shows, there are significant differences between the percent load reductions achieved by the 20 percent of program participants who are the most active and the 80 percent who are the least active.

Exhibit 3-7
Distribution of Percent Load Reductions Between Most Active and Least Active Participants

Active Level	Average Percent Load Reduction (10-Day Adjusted Baseline)					
	PG&E		SCE		SDG&E	
	CPP	DBP	CPP	DBP	CPP	DBP
Overall	5.6%	23.0%	44.1%	3.3%	9.4%	11.0%
20% Most Active	9.3%	41.7%	83.2%	17.0%	42.6%	18.9%
80% Least Active	0.0%	5.9%	1.3%	-3.7%	-2.3%	2.5%

11 Bid realization rate equals bid amount divided by estimated reduction.

12 The bid realization rate based on the 3-Day baseline method varied significantly across the three utilities with PG&E participants realizing 106 percent of their bids, SCE participants realizing 77 percent, and SDG&E participants realizing 20 percent.

13 The bid realization rate for the 3-Day Utility Coincident baseline was approximately 50 percent.

Small Numbers of DBP and CPP Participants Also Contribute a Large Portion of Measurement Uncertainty

Also similar to our findings for 2004, our 2005 analysis indicates that a small percentage of DBP bidders and CPP participants account for a very large percentage of measurement uncertainty. Many of these participants are large customers with loads that vary significantly from day to day for reasons that are not readily observable (e.g., they are not highly weather-dependent). At an individual customer level, we found that baseline loads for many of these large customers varied considerably from day to day, sometimes by up to tens of megawatts.

Consequently, we developed an algorithm to identify those customers with both large and highly variable loads to assess the extent to which the 10-Day Adjusted impact estimates varied for this sub-group as compared to the remaining bidders. We refer to these participants as "High Load-High Variance" (HLHV) customers.

By addressing seasonality, day-of-the-week, and other factors, the regression approach to estimating customer-specific impacts provided increased ability to control for some of the variation in load for the HLHV participants. The regression analysis results also showed much larger standard errors and wider confidence intervals for the HLHV group, providing a statistical indication of the greater uncertainty in estimated impacts for those customers.

Roughly 50 Percent of 2005 DBP Impacts Were Delivered by Interruptible Customers

Nearly 20 percent of SCE DBP participants are also enrolled in the I-6 program, and these customers delivered more than half of the DBP program impacts over the course of summer 2005 events. In the PG&E service territory, 7 percent of the DBP participants take service on the E19/20 non-firm tariff, and these customers delivered nearly 60 percent of the DBP program impacts. In the SDG&E service territory, the overlap is much less with only 3 percent of the DBP participants being signed up for AL-TOU-CP rate, and they only delivered 7 percent of the 2005 DBP program impacts overall. The bids placed by interruptible customers were between 3.5 and 8.5 times larger across the three utilities than the bids coming from the non-interruptible participants.

The Majority of CPP and DBP Load Reductions Are Associated with Institutional and Industrial Customers

The majority of CPP program impacts for PG&E and SCE came from the Industrial segment, while the majority of SDG&E's CPP impacts were associated with the Institutional segment (primarily water pumping facilities). For DBP, across all three utilities, the Institutional segment placed bids at the highest rate. For PG&E and SCE, the majority of DBP program impacts were associated with the Institutional segment, while the majority of SDG&E's DBP impacts came from the Commercial segment.

Pre-, Post- and In-Event Spillover Contributed Additional Program Savings for CPP and DBP Programs

Spillover impacts, as defined here, consist of the impacts occurring in the hours before or after event participation. One difference between the spillover that occurs within the CPP versus the DBP program is that, for the DBP program, the spillover can also occur within the hours for which an event was called. We refer to this as "in-event" spillover. In-event spillover occurs because the DBP program allows customers to bid for a subset of the total event hours, as long as they bid for at least two consecutive hours. Spillover can result in positive or negative impacts depending on the type of actions participants take during these pre- and post-event hours. Generally, positive spillover for both the CPP and DBP programs was found. The exception was for SCE DBP where both the post-event and in-event spillover was found to be negative.

CPP and DBP Programs had Small Effects on Overall Daily Consumption

The load reductions that occurred during the CPP and DBP events had mixed effects on the total daily consumption of the participant population. Our analysis shows that the net daily change in consumption (MWh) was negative for the PG&E and SDG&E CPP participants and that some of the participants who shed load for the CPP events continued to operate at lower levels throughout the entire event day. SDG&E CPP participants also had a net negative average daily consumption across event days; however this negative impact was equal to the total event impact. This indicates that these participants operated at normal levels during non-event hours, neither making up for their previous reduction, nor keeping their load at reduced levels for the remainder of the day.

For DBP, we found that the total daily consumption went down across all three of the utilities. PG&E DBP bidders seemed to operate at normal levels throughout the remaining event day non-event hours, SCE bidders made up about half of their event reduction during these hours, and SDG&E bidders continued to decrease their load throughout the rest of the day.

Changes to 2005 DBP Eligibility and Bid Minimums had Mixed Effects on Program Impacts

One of the changes made to the DBP program eligibility for 2005 allowed Direct Access (DA) customers to participate in the DBP program. This change appears to have increased enrollment but had a mixed effect on program impacts. Since this change went into effect, DA customers now make up approximately 24 percent of all PG&E DBP participants. For SCE, DA customers now comprise approximately 4 percent of the overall DBP program participants. Based on the last SDG&E participant data made available to us, no DA customers had enrolled in the DBP program. In the case of PG&E, the DA participants contributed about a quarter of the program impact, whereas the additional DA participants for SCE do not appear to have contributed any load reductions.

Another program change implemented for 2005 lowered the DBP bid minimum from 100 kW to 50 kW for PG&E and SCE, and to 10 percent of maximum demand for SDG&E. These changes also had a mixed effect on program impact estimates. Although a significant number of participants did place small bids in 2005, the portion of overall impacts contributed by these participants was modest at 8 percent for PG&E, 3 percent for SCE and a negative 4 percent for SDG&E.

DRP Impact Findings

Average DRP Event Length Was Similar Across Product Types; Dissatisfaction Was Expressed by the 1-8 Hour Product Participants

DRP events can be called for any number of consecutive hours, so long as the event length does not exceed the maximum event hours for a particular product type (i.e., the 1-3 hour product cannot be called for more than three consecutive hours in one day) and the maximum number of monthly event hours for each product within a utility congestion zone is 24 hours. Exhibit 7-102 provided the average DRP event length across all utility zones for this past summer. This exhibit illustrated how there were only minor differences in the average program length between the 1-3, 1-5 and 1-8 hour products. In the PG&E congestion zone, for example, the average event length was 2.5 hours for the 1-3 hour product, 3 hours for the 1-5 hour product, and 3.3 hours for the 1-8 hour product. The 1-8 hour product events were typically called seven to eight times a month, for three to four hours at a time. This caused dissatisfaction for some of the program participants enrolled in this product type since they reported signing up for this product believing that longer events would be called and that they would be called less frequently than the shorter period products. These participants were unhappy because curtailing for a few hours on multiple occasions was more difficult for their operation than curtailing for longer periods a few days a month.

Variations in Methods Used Among Utilities to Estimate DRP Program Impacts; SCE Approach Over-reports

DRP differs from the other programs included in this evaluation in that the utilities do not necessarily have access to the load data for all of the DRP participants within their congestion zone. As a result, they are not able to calculate the estimated program impacts for individual DRP events as they do for the other day-ahead programs. Instead, they rely on various reports from the DRP website (developed and administered by APX) to determine the estimated program impact. Currently each of the utilities uses a different methodology to determine the individual event impacts they report to the CPUC each month. Both PG&E and SCE base their estimated event impacts on the nominations submitted for the event. PG&E calculates the average hourly nomination across all event hours and uses this for their estimate, and SCE reports the maximum hourly nomination across all event hours. SDG&E references a different section of the DRP website and bases their estimate on the average hourly load reduction across all event hours. As Exhibits 7-108, 7-111 and 7-112 illustrate in Chapter 7, the methodologies employed by PG&E and SDG&E resulted in the most accurate overall impact estimates. The SCE method overstated our estimated program impacts by nearly 100 percent.

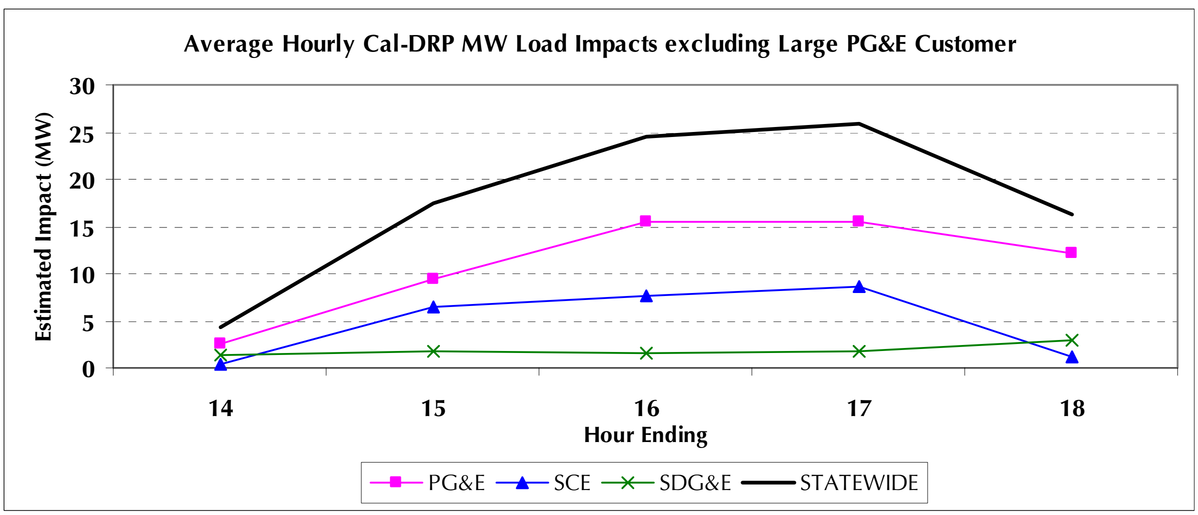
DRP Impacts Average Well Over 200 MW But Are Dominated by a Single Large Pumping Customer that Accounts for Roughly 90 Percent

The DRP program in 2005 was once again dominated by a single large pumping customer. This customer made up three-quarters of the total estimated baseline load during the summer events, slightly less than 90 percent of the event nominations, and just over 90 percent of the overall impacts. The overall average load reduction across the DRP participants was roughly 50 percent; however, this was driven entirely by this one large customer who averaged a 66 percent load, compared to an average 15 percent reduction from the other participants. The average impact from the large customer was 242 MW based on the 10-Day Adjusted baseline, compared to an average reduction from the remaining customers of less than 1 MW (0.7 MW). This one large customer also tended to reduce its load by more than its original nomination by about 20 percent. As shown below, without this large customer the impacts resulting from the DRP program were of a magnitude similar to what was calculated for the CPP and DBP programs.

DRP Impacts Vary Widely Across Events and Event Hours for Participants Other than Its Single Large Pumping Customer

Using the 10-Day Adjusted baseline method, we estimate that 2005 DRP impacts from all program participants, excluding the single large pumping customer, averaged roughly 18 to 24 MW across the late afternoon hours; however, our estimated impacts varied widely across utilities, event days, customer sub-groups, and product types. Exhibit 3-8 below presents the average 2005 DRP hourly load reduction across all participants who nominated load for each of the utilities and statewide. Hourly impacts for the PG&E large pumping customer are not included in this exhibit. Hourly impacts for this customer ranged from a high of 344.4 MW for the 5 o'clock hour on July 18th to a low of 117 MW for the 4 o'clock hour on August 23rd based on the 10-Day Adjusted baseline.

Exhibit 3-8
Average Hourly Load Reduction Impact for Summer 2005 DRP Events (Non-Coincident) Excluding Large PG&E Pumping Customer – Based on the 10-Day Adjusted Baseline



Comparing the results above to those for the CPP and DBP programs shows, without the large pumping customer, the size of the average hourly impacts across all three programs is similar.

3.3.2 Reliability Program Impact Findings

Reliability Programs Had Very Few Calls in 2005

In contrast to the day-ahead programs, the reliability-triggered programs had very few calls in 2005, as shown in Exhibit 3-9. As has been the case for the last several years, only SCE and SDG&E programs were called. As discussed elsewhere in this chapter and report, the reliability programs have been called very little as compared to allowed maximums since the end of the energy crisis. The extent to which current reliability program participants are willing to accept more program calls is explored as part of the research conducted for this evaluation. Complete results are discussed in Chapter 9.

Exhibit 3-9
Number of Reliability Program Events for 2005

Reliablity Program Events Summer 2005			
Utility	Traditional Interruptible	Base Interruptible Program (BIP)	Other Programs
PG&E	0	0	0
SCE	1	1	1
SDG&E	4	0	0

Significant Interruptible Impacts Consistent with Required Reductions for SCE I-6 and BIP programs

In 2005, SCE interruptible programs were called on only one occasion, August 25th, due to transmission difficulties associated with the Pacific Intertie. The I-6 and BIP events called on August 25th lasted only a little over an hour, however, during this time significant load reductions occurred. Participants enrolled in the I-6 program reduced their load by 571 MW based on the difference between the hourly 10-Day Adjusted baseline and the 15-minute interval load data. This was a 78 percent load reduction and was within 18 MW of their Firm Service Level (FSL). The participants enrolled in the BIP program also contributed a significant load reduction, 64 MW, which corresponded to an average load reduction of 58 percent. However, we estimate that a much larger share of I-6 participants met their FSL (72 percent) as compared with BIP participants (45 percent). In addition, we estimate that only 3 percent of I-6 participants did not take any action as compared to 18 percent of BIP.

The OBMC event that was also called on this day was cancelled after a little less than 30 minutes. Because this event lasted less than 45 minutes, the program minimum, this event was not considered a valid event, and penalties were not assessed. A slight load reduction of 3 MW appeared to occur during short time period the event was in effect. This estimated load reduction was significantly less than what was reported by SCE since two participants who were also enrolled in the BIP program, and had considerable reductions, were removed from our impact estimate.

SDG&E AL-TOU-CP Program Averaged 15 Percent Load Reduction Across Events

The AL-TOU-CP program is unlike the traditional interruptible programs in the other service territories in that it does not require participants to pre-determine a Firm Service Level that they will attempt to achieve during events. As shown in Exhibit 7-94, the average estimated base load of the AL-TOU-CP participants during the four summer 2005 events was around 10 MW and the average load reduction was approximately 1.5 MW, or 15 percent of base load.

3.4 PROCESS-RELATED FINDINGS

3.4.1 CPP and DBP Process-Related Findings

The findings in this subsection draw principally from the process evaluation results presented in Chapter 8 and Appendix C. Readers are referred to that chapter and appendix for more detailed results and discussion.

The analyses supporting these findings are based on the results of interviews with program managers and other utility staff, post-event surveys with program participants, a final end-of-summer survey with program participants, and a review of utility filings and program documents.

Motivation to Participate and Take Action is Strongly Affected by Non-Financial Factors; Bill Savings are also Important for CPP Participation

Consistent with the 2004 findings, most participants in the CPP and DBP programs report that non-financial factors play a very strong role in their participation. Overall, avoiding rolling blackouts and being able to participate without significantly affecting business operation were rated the most significant reasons for participation. Being a good corporate citizen and the amount of bill savings were also both rated highly as significant reasons for participating. CPP participants were more likely than DBP participants to have been motivated by bill savings. As a voluntary program, DBP would be more likely to appeal to customers based on their civic duty, while CPP, with its imbedded price signals, would be judged based on bottom line impacts before customers make a commitment.

Program managers say that customers generally are not doing these programs – particularly DBP – for the money. Certainly, customers would like to see some financial benefit, say the program managers, but the majority of customers participate to be good corporate citizens and help avoid rolling blackouts. As a result, when customers see neither a pressing need nor a substantive financial benefit, they question their participation in the DR Programs.

Bidding and Load Reduction Also Appear to be Linked to Civic Responsibility

Most respondents said they felt the 2005 DR events were important (i.e., somewhat or very critical) to helping maintain system reliability. In addition, roughly half of CPP participants and DBP bidders reported that they “definitely” or “probably” would have taken the load reduction actions they did even without any direct financial incentives. The survey results for DBP non-bidders lend some support to that claim; when average per-event impacts for DBP participants who said they took action even though they did not submit bids are compared to impacts for those who said they never took action, the results show a 5 percent load reduction for those who said they acted and a 1 percent increase for those who did not.

In addition, over half of customers who did not see the 2005 events as important to maintaining system reliability said their response to the events would have been different if the need had been more urgent, with more than two-thirds saying that they would have reduced more load or would have tried harder to reduce load.

Most Participants were Satisfied with Their Overall Program Experience; Satisfaction was Somewhat Lower for DBP Non-Bidders

CPP participants generally have higher levels of satisfaction than DBP participants with their program overall and with specific aspects of the program (number of events, event duration, notification time and process, and amount of credit or incentive). The difference diminishes when only DBP participants who placed bids or took action are considered, reflecting the influence of customers who appear to be poorly suited to program participation and probably should not have been enrolled.

Overall, 90 percent of CPP and 87 percent of DBP bidders reported they were "very" or "somewhat" satisfied with their overall program experience in 2005. With regard to specific program features, over eighty percent of all participants were satisfied with the notification process and the service they received from their utility. In contrast, only 65 percent of respondents overall were satisfied with the amount of advance notification.

Despite Concerns Among Program Managers and Some Customers, CPP and DBP Customers are Generally Satisfied with 2005 Day-Ahead Event Triggering

With DBP now called based upon predicted overall system load and CPP on temperature, neither of these programs is currently directly price based. Program managers question whether the triggers may be too sensitive, since there are many days when the overall load or temperature trigger is reached, but price is low and supplies are ample. As a result, program managers and account executives say they lose credibility when they urge program participation (not only signup, but bidding) and some customers see that there is no real need.

However, despite these trigger conditions and the numerous resulting program events in 2005, the customer survey results for 2005 do not indicate that CPP and DBP participants had concerns about the number of events or the rationale for calling them. A strong majority of participants stated that the number of events was about what they expected or less than what they expected. In addition, over 80 percent of CPP participants and DBP bidders indicated that they were "very" or "somewhat" satisfied with the number of events called in 2005.

Load Reductions in CPP Appear to be Achieved Primarily Through Industrial Process Reductions and Curtailing Discretionary End Uses; Load Reductions in DBP Appear to Achieved Primarily Through the Use of Backup Generation

The most frequent self-reported curtailment actions reported by CPP and DBP participants were reductions in discretionary end uses, i.e. reducing overhead lighting, turning off non-critical equipment, and allowing temperatures to rise in occupied spaces. Partial operations shut down and reducing some or all production processes were also cited frequently by CPP and DBP participants. In comparison, using backup generation, shutting down operations completely, and rescheduling energy management systems were cited by relatively few CPP and DBP participants.

Based on a first order decomposition of total program impacts into specific groups of curtailment actions, the curtailment actions that appear to make the largest contributions to total CPP program impacts are reducing production processes, which is consistent with the finding from impact analyses that industrial customers account for the majority of total CPP program impacts. Reducing discretionary end uses, which likely result in smaller load reductions on a per-customer basis, also appear to contribute significantly to total CPP program impacts due to the high relative frequency of CPP participants reporting to use these types of actions. For DBP, the curtailment actions that appear to make the largest contributions to total DBP program impacts are using backup generation together with other secondary actions. This result is consistent with the fact that over half of total DBP program impacts come from interruptible customers that participate concurrently in DBP and that interruptible customers frequently cite the use of backup generation as a curtailment action (see Section 3.4.3).

Participants Reported only Moderate Effects on Productivity and Comfort

Overall, slightly less than one-third of DBP participants said they had experienced negative effects on personnel comfort or productivity as a result of their demand reduction actions. Small customers were the most likely to have experienced impacts, while institutional customers were the least likely. Of those that experienced negative effects, 48 percent cited a warm or uncomfortable work environment and 42 percent cited staff complaints, while a third cited lost production and 16 percent cited financial impacts. The fact that the percentage of customers reporting negative effects from demand reductions is relatively low indicates that most participants have been able to implement demand reduction actions without major impacts to their operations.

Some Evidence of Increased DR-Related Knowledge Among Active CPP and DBP Participants

As a result of their 2005 DR program participation, about three-fourths of surveyed CPP and DBP participants said they were somewhat or much more knowledgeable about managing their energy usage at times of peak demand. In addition, while the overall bidding percentage for DBP participants was low, a high percentage of those who placed bids in 2005 said they planned to do so in the future.

Active Participants Indicate a High Likelihood of Continuing to Participate in the Future, but Half of DBP Non-Bidders Indicate They will not Take DR Actions in the Future

Over 90 percent of CPP participants said they were somewhat or very likely to take demand response actions in the future. DBP bidders also expressed a high likelihood of continuing to participate and take demand response actions in the future. However, slightly less than half of DBP non-bidders indicated that they were not likely to participate in future events. Among the DBP participants who said they were very unlikely to take action for future events, 35 percent said there were no circumstances under which they would take demand reduction actions in the future. When asked why they had signed up for the program in light of their intentions, most of these respondents either said they had originally thought they could participate (38%), had signed up by mistake (25%), or had been told to sign up by their account representative (17%). Others said they signed up for the incentives or to gain access to real-time monitoring software.

Many DBP Participants Indicated that an Extra Hour of Bidding Time Would Increase Their Ability to Place Bids

While almost half of DBP participants overall said that increasing the bidding window to 2 hours would increase their bidding activity, nearly three fourths of DBP bidders said it would do so. In other words, DBP participants who only bid for some events would likely have bid for more of them if they had more time. Of those who wanted to see the broader window, almost half preferred to see 1 hour earlier notification, about a third preferred a one-hour later bid deadline, and a remaining fifth did not care as long as they got an extra hour.

Preliminary Indications of Need for and Strong Interest in 2005 TA/TI Incentives

Less than one-fourth of all DR program participants said they had taken advantage of utility assistance services to help them prepare for DR events, and only one third of day-ahead participants said they felt their organization had been very well prepared to manage demand reductions during the summer of 2005. These findings, together with the high degree of reported awareness and interest in TA/TI among DR program participants, suggest that the TA/TI programs could prove very valuable in increasing participation and active response to DR events in 2006 and beyond. Program managers across utilities also noted the enthusiastic response to the TA/TI program, despite the relatively late rollout of the 2005 program.

3.4.2 DRP Process-Related Findings

The findings in this subsection draw principally from the study results presented in Chapter 10 and Appendix C. Readers are referred to that chapter and appendix for more detailed results and discussion.

The analyses supporting these findings are based on the results of a review of program materials and the DRP website and interviews with aggregators, participating customers, and program managers at the utilities, the California Power Authority, and APX (the program's data management contractor).

The Unique Status of DRP among DR Programs Has Created Some Confusion among Utility Account Executives and Customers

Although utility program managers recognize that DRP can play a significant role in attaining DR objectives, they find it difficult to determine how to promote the program in the context of their broader product offerings. In-the-field account executives in particular are generally reluctant to do anything more than mention the program, both because DRP is not "their" program and because most details of the program are outside their control and they do not wish to interfere with the aggregators.

For their part, aggregators feel that the utilities tend to distance themselves from the program (for example, one aggregator stated that that DRP is "the red-headed stepchild" among utility programs). Ambiguity with regard to DRP has sometimes come to light when events are called and customers contact the utility. Utility reps may then point to the Department of Water Resources (DWR) as having called the program, which is technically correct, even though DWR – through its scheduling subsidiary, California Energy Resource Scheduling (CERS) – only initiates price-triggered events at the request of the utilities.

Modifications to the DRP Program Carried Forward into 2005, Combined with Market Conditions, Led to Frequent Program Events that Directly Affected Customer and Aggregator Perceptions of the Program

During 2004, DWR initiated a number of changes to the terms of the DRP program. Finalized during the summer of 2004 and carried forward into 2005, these changes significantly altered the risk-reward equation for program participants. Under the terms of the revised program, aggregators could no longer aggregate other than on an individual customer level, which limited their role to marketing the program and coordinating participation of individual customers.

The revised program also reduced capacity payments from DWR to CPA: from $15,000/MW to $12,000/MW per month (for 1-8 hour blocks) for the four summer months, with a corresponding decline in payments to aggregators and customers. In addition, the revised program allowed DWR to call events as short as one hour duration. While the timing and duration of potential interruptions created greater uncertainty for participants, performance criteria and penalties became more stringent, raising the possibility of significant downside risk from participation.

Combined with the program revisions, market conditions in 2005 were such that the program was called far more frequently than in previous years,[14] with some customers being called for the maximum number of events for multiple months.

The Frequency of DRP Events in 2005 Caused Concern among both Aggregators and Program Participants

The DRP program was designed to be triggered by either price or reliability issues, but in the perceptions of aggregators as well as customers the price-responsive aspect of the program is also seen as linked to system reliability. Consequently, neither aggregators nor customers were prepared for the program to be called based on a price trigger alone when there was no evidence of capacity shortages within the system.

While there were no actual capacity constraints to trigger the DRP program during the summer of 2005, the program was called on price frequently in 2005, with back-to-back events starting as early as June. All of these events were triggered at the request of the utilities because of price. Moreover, because events occurred on days that were not particularly hot (or had not been preceded by a number of hot days that established hot weather baseline usage), customers whose nominations were based on shedding weather-dependent load found it difficult to do so because their baseline had been determined by a series of mild days.

In addition, back-to-back interruptions of relatively short duration over a number of days severely impacted some industrial and other customers who planned to deal with curtailments by shifting production to other days. With these frequent, short interruptions, more than half the DRP program participants surveyed were somewhat or very dissatisfied with the number of program interruptions in 2005.

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[14] That is, prices often went or were predicted to go above $80/MW on a day-ahead basis.

Despite Concerns about the Frequency of Interruptions in 2005 and Dissatisfaction with Some Program Elements, Most DRP Participants Said They Were Satisfied With the Program, and Plan to Stay With It

Almost three fourths of participants surveyed said they were somewhat or very satisfied with their overall participation in the DRP program. Customers who expressed dissatisfaction with the program overall typically attributed it to the baseline calculations, the frequency or duration of events, and the complexity of the program. At least half of survey respondents were dissatisfied with the capacity and energy payments, the frequency of interruptions, the level of penalties, and the timeliness of payments for participation.

Almost three fourths of respondents also said they planned to remain on the DRP program next year, and over half said they would be very or somewhat likely to stay with the program even if the maximum curtailments allowed under the program were called.

DRP Program Participation Was Motivated both By Bill Savings and By the Desire to Be Good Corporate Citizens and Help Avoid Blackouts

Saving money on energy was cited as the primary reason for enrollment in the DRP program by about a third of surveyed customers. However, non-financial motives were also important, with the combination of "being a good corporate citizen" and "avoiding rolling blackouts" also accounting for almost one-third of responses. Other external factors also played a significant role in encouraging participation. More than one-fourth of respondents cited third party influences, including aggregators, a government DR mandate for state agencies, decisions made at corporate headquarters, and decisions made by the chancellor of a university campus.

DRP Participants and Aggregators Often Perceive the Program to Be Driven Primarily By Capacity/Reliability Constraints Rather Than Price

While the terms of the program clearly state that it may be called either because of price or reliability, several aggregators noted that they were surprised by the number of purely price-driven events in 2005, and commented that this appeared to represent a change from previous years. Customer comments also emphasize the disconnect between the explicit price-responsive nature of the DRP program and the customer perception that events should be tied to system emergencies. As noted above, many customers signed up for the program at least in part to help address supply shortages, and several customers said they felt they had been misled by aggregators during the marketing effort.

Both Aggregators and Utilities Have Proposed Successor Programs to Take Effect when the Current Program Expires in May 2007

The aggregators and CPA have proposed a framework that retains several fundamental elements of the current program, including statewide consistency, a capacity payment (proposed at $15/kW/month) as well as an energy payment, marketing through third-party aggregators, and a separate organization to manage the program (which could be either CPA or the ISO). There are, however, other areas where the group proposes significant changes, including two participation options (a "Reliability Program," called only for ISO Stage 2 Emergencies and a "Peak Reduction Program" called at the discretion of the IOUs as an economic resource), aggregation across customers, a revised baseline, a revised penalty structure, and extension of the summer program through October.

The utilities envision the DRP program as requiring more commitment (along with greater compensation and penalties) than DBP, but greater flexibility (along with lower compensation and penalties) relative to BIP. The utility-proposed successor program also retains many of the DRP program features (e.g., aggregators, monthly nominations, capacity and energy payments, penalties for non-performance), but suggests changes in that: customers could participate directly with the utility as well as with an aggregator; the program would have an explicit temperature trigger rather than a price trigger; dispatch would truly be day-ahead; 1-3, 2-6, and 4-8 hour options would be offered; and the program would run June through October.

3.4.3 Reliability Program Process-Related Findings

The findings presented in this subsection draw principally from the study results presented in Chapter 9 and Appendix C. Readers are referred to that chapter and appendix for more detailed results and discussion.

The analyses supporting these findings are based on the results of in-depth interviews with reliability program managers at each utility, a quantitative survey of current participants in traditional interruptible tariffs, and in-depth interviews with customers eligible for but not currently participating in the BIP program.

Interruptible Customers are Very Satisfied with Current Tariffs and Are Not Actively Seeking Alternative Tariffs

Participants are generally very satisfied with all aspects of current interruptible service, which have involved very few or no interruption events over the recent past, in contrast to the frequent interruptions called in 2000-01. Two-thirds of the interruptible customers surveyed reported being "very" satisfied with their current non-firm service, while the remainder was "somewhat" satisfied. Traditional programs also received high satisfaction ratings with respect to specific program elements. Without exception, participants cited cost savings as the primary benefit of taking service on IR tariffs, with several noting that the reduced rates were essential to their ability to operate in California.

Consistent with this reported level of satisfaction, the survey responses indicated that most interruptible customers are not actively seeking out or investigating alternatives to their current interruptible service, with only a fifth of those surveyed reporting to be "very familiar" with the BIP program, and less than 2 percent reporting any current plans to enroll in BIP.

Curtailment Actions Currently Used by Interruptible Customers Have Large Incremental Impacts and Costs

An investigation of current curtailment strategies among IR customers revealed that shutting down production processes and running backup generators are the two most common curtailment actions used (or planned). Load shifting and curtailing discretionary end uses are comparatively less common among curtailment actions reported by interruptible customers. The self-reported costs of curtailing production processes are also an order of magnitude higher on average than the self-reported costs associated with other curtailment actions. Together, these findings indicate that load reduction among interruptible customers currently tends to be dominated by actions with large incremental impacts and significant participant costs.[15] Indeed, customers who had recently opted out of traditional interruptible tariffs indicated they did so because of the detrimental impact of multiple curtailments on their business or because of more stringent air quality regulations that limit their ability to use on-site generators during interruption events.

Overall, one-fourth of the interruptible customers surveyed find it generally easy for their organization to reduce required loads within the required timeframes, and about 40 percent of customers find it somewhat easy. The most common reasons given by these customers to explain the general ease of short-notice curtailments were having an established curtailment plan, having the ability to switch to backup generation, and using automated controls. In contrast, another quarter of the interruptible customers reported it was somewhat difficult for their organization to reduce required loads within the required timeframe, while less than 10 percent of interruptible customers find it very difficult. The most common reasons given by these customers to explain the general difficulty of short-notice curtailment were cost and production losses, not having enough time to curtail after receiving interruption notices, and difficulties in shutting down production processes.

Interruptible Customers Indicate a Willingness to Accept Significant Interruptions in "Worst Case" Years

Despite participants' reports of significant costs of curtailing, more than two-thirds of the interruptible customers surveyed reported a high tolerance for interruption events, stating that they would be likely to remain on their current interruptible tariff even if the maximum number of interruption events were to occur. Conversely, about a third of participants indicated they would likely leave their program/tariff if the maximum number of events did occur. These customers reported a mean interruption tolerance of 9.5 events per year. Note, however, that results from in-depth interviews with interruptible participants indicate that some customers assess the overall benefits and costs of participation on a long-term (i.e., multi-year) basis. As a result, it is not clear that those customers indicating they would tolerate a high number of events in a worst-case year would tolerate this for consecutive years. Some customers made clear that they are willing to tolerate some years in which they consider participation a financial loss as long as those years are made up for by years in which participation provides a compensating financial gain.

There is Significant Reluctance Among Eligible Customers to Migrate to BIP

BIP was designed to attract both current interruptible customers as well as customers who might have enrolled in interruptible tariffs had they not been closed to new customers. To date, however, BIP has attracted very few customers from either target group. From the perspective of current interruptible customers, program managers noted two aspects of BIP incentives that interruptible customers perceive as significantly less attractive compared to traditional interruptible tariffs. First, BIP's capacity payments are based on the difference between a customer's *average* monthly peak and firm service level (FSL), as opposed to a customer's

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[15] Note, however, that only half of the interruptible customers interviews were able to provide an estimate of the costs of their load curtailment actions.

maximum monthly peak and FSL, which is the basis of the demand charge discounts in traditional interruptible tariffs. Second, BIP offers participants only capacity payments, while traditional interruptible tariffs also offer discounts on the energy charges associated with nominated loads. Lower total payments, coupled with penalty levels that are identical to those of traditional interruptible tariffs, thus provide little financial incentive for current interruptible customers to switch to BIP.[16] Program managers also noted that even though most other BIP program features are nearly identical to those in traditional interruptible tariffs (particularly the maximum number events that can be called), current interruptible customers tend to compare BIP's terms of service to the actual very low number of interruption events that they have experienced in the past few years.

Based on customer self-reports, which should be viewed cautiously, if current traditional interruptible tariffs were discontinued, about half of the current interruptible customers can be expected to migrate to BIP or day-ahead DR programs. Twenty-five percent indicated that they would seek another non-firm service tariff such as BIP, including 20 percent that said they would seek non-firm service and also participate in day-ahead DR programs. Another 20 percent indicated that they would seek a firm service rate but would also participate in day-ahead DR programs, while seventeen percent indicated that they would likely seek a firm service tariff and not participate in day-ahead DR programs.

From the perspective of non-interruptible customers eligible for BIP, program managers offered that BIP's penalty levels are often perceived as being prohibitively high, particularly as a downside risk for customers who may not have much experience with curtailing peak demand. Perhaps more importantly, however, program mangers offered that relatively few eligible firm service customers have the capability to respond quickly and consistently with just 30-minutes advance notice. This sentiment was echoed by the vast majority of the eligible customers interviewed, that it would be difficult or impossible to shed the required load in response to day-of event notifications without severely disrupting operations. These results strongly suggest that those eligible customers that do possess the capability to significantly curtail load on short notice are already on interruptible tariffs or enrolled in BIP.

3.5 MARKET SURVEY FINDINGS

The findings in this subsection draw principally from the study results presented in Chapter 5 and Appendix C. Readers are referred to that chapter and appendix for more detailed results and discussion.

Outside of program-related analyses presented above, the other core task of this evaluation was to carry out a general market assessment focused on demand response familiarity, receptivity, barriers, opportunities, and load reduction potential among eligible customers that currently do not participate in day-ahead DR programs. For perspective, non-participants currently account for approximately 96 percent of total eligible customer accounts. The analyses supporting the findings presented in this subsection are based on the results of a quantitative survey of eligible

[16] For PG&E Schedule 19/20 Non-firm customers, non-compliance penalties are reduced by 50 percent for customers that successfully curtailed to their FSL for all events in the previous 12 calendar months. These lower penalty levels compared to BIP contribute significantly to the perceived inequities between BIP payments and Schedule 19/20 Non-firm payments.

non-participants conducted in the fall 2005 and a similar quantitative survey that was conducted in spring 2004 as part of the 2004 evaluation.

General Market is Increasingly Familiar with DR Programs but not DR Incentives

The majority of the non-participant market reports to have some familiarity with day-ahead and reliability programs. Overall, 73 percent of the eligible non-participant market indicated that they were either "very" or "somewhat" familiar with CPP, compared to 69 percent for DBP, 68 percent for BIP, and 43 percent for DRP. At this aggregate level, these values represent significant increases in familiarity with CPP, DBP, and DRP among non-participating customers compared to the values reported in the 2004 survey (64 percent, 61 percent, and 32 percent, respectively). Remaining unfamiliarity with day-ahead programs and BIP is concentrated among smaller customers in service-oriented business sectors.

General familiarity with the Bill Protection Incentive also increased slightly from 2004 levels, with 44 percent of eligible non-participants reporting to be "very" or "somewhat" familiar with the incentive. In contrast, however, general familiarity with the Technical Assistance and Technology Incentive (TA/TI) Program declined slightly from 2004 levels, with 40 percent of eligible non-participants reporting to be either "very" or "somewhat" familiar with the program. Among customers who reported to be very familiar with the CPP or DBP programs, familiarity with these incentive programs was markedly higher. However, these levels again represent a significant decline compared to those reported in 2004. In particular, familiarity with the TA/TI Program fell by more than a factor of two, due entirely to a large decrease in customers reporting to be "very" familiar with the incentive.

Non-participants Continue to Perceive Significant Barriers to Participating in DR Programs; Self-Reported Barriers Vary Significantly Across Market Segments

Non-participants ranked "effects on production or productivity" and "inability to significantly reduce peak loads" as the two most important barriers to participating in day-ahead programs, just as they did in 2004. Significantly higher shares of manufacturing and industrial customers ranked these two barriers as "very significant" compared to customers in service-oriented sectors. Higher shares of larger customers also ranked these two barriers as "very significant" compared to smaller customers. These results imply that the primary concerns among large manufacturing and industrial non-participants are related to the structure of their electricity consumption and the opportunity costs of temporary demand reductions. This finding is consistent with the fact that large manufacturing and industrial customers tend to have high load factors and load profiles that are dominated by process and production end uses.

Customers in the service-oriented sectors also ranked "effects on occupant comfort" and "need for more information on how to achieve demand reductions" as very significant barriers to participation in day-ahead programs. The results for the Institutional sector reflect a similar level of concern with occupant comfort as in other service sectors, as one would expect, but a lower need for information, reflecting relatively higher levels of knowledge about peak load management and demand response among Institutional customers. Higher shares of smaller customers consistently ranked "need for more information on how to achieve demand reductions" as an important barrier compared to the rest of the market. This result is consistent with smaller customers also reporting a high share of "no one assigned responsibility for controlling energy usage and costs".

Ownership of DR-Enabling Technologies Does Not Yet Influence Perception of Key Barriers

Self-reported ownership of select enabling technologies (specifically on-site generation, energy information systems, and energy management and control systems) did not correlate significantly with perceptions of key barriers to demand response among non-participants, in particular "inability to reduce peak load" and "effects on productivity". This result suggests that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response. In this respect, the installed base of enabling technologies can be viewed as a significant, but mostly dormant, demand response resource in the eligible non-participant population in California. Because of the potentially important ramifications of this finding in terms of demand response program and incentive design, further investigation into customer perceptions of the costs and feasibility of using such technologies for demand response is clearly warranted.

2005 Program Changes Appear to Address Important Barriers for a Significant Number of Non-Participants

More than a quarter of the non-participant market judged that the 2005 Bill Protection Incentive addresses "most" of their concerns about the risk of bill increases from participating in CPP. Similarly, 16 percent of the market judged that the lower DBP bid minimums and aggregation allowances of the 2005 DBP program address "most" of their concerns about being unable to significantly reduce peak loads. Finally, more than a third of the non-participant market judged that the free on-site audits and financial incentives of the revised TA/TI program address "most" of their concerns about the time, effort, and knowledge required to participate in demand response programs.

Taken together, these results indicate that the changes made to the 2005 day-ahead programs significantly mitigate customer concerns related to bill risk, peak load reduction capability, and time and knowledge barriers, but only for modest *shares* of the non-participant market. However, given the size of the non-participant population relative to the number of current participants, these shares represent a significant *number* of customers for whom the 2005 program changes, at face value, significantly mitigate important perceived barriers to participation. Given that the overall awareness of these recent program changes is rather low (e.g. less than 9 percent of the non-participant market reported to be "very" familiar with the DBP program changes), these results therefore indicate that education and marketing efforts highlighting these program changes could potentially yield a significant number of new participants in day-ahead programs.

Perceptions of Default CPP

Self-reported familiarity with default CPP is low across all three utilities, with only 12 percent of the eligible non-participant market reporting to be "very" familiar, and 26 percent reporting to be "somewhat" familiar with their utility's proposed default CPP tariff. Of the customers reporting to be "very" or "somewhat" familiar with the proposed rates, the majority perceive that default CPP will result in negative net bill impacts, i.e. increases in their annual electricity bills. Overall, the average perceived impact of default CPP on customers' individual annual electricity bills was a 3.9 percent increase. In contrast, utility rate analyses of default CPP indicate that approximately half of eligible customers would benefit from proposed default CPP rates without taking any action to reduce summer peak loads. In the absence of customer-specific rate analyses, it is difficult to determine the extent to which customer perceptions of default CPP bill impacts diverge from these utility estimates. However, on the whole, it appears that among eligible non-participants, default CPP is perceived as having higher negative bill impacts on average than what is actually expected.

Short-Term Market Potential Among Non-Participants Continues to be Moderate and Unaffected by Ownership of DR-Enabling Technologies

Based on self-reported estimates of load reduction potential (given "sufficient financial motivation"), the average technical DR potential across the eligible non-participant market was estimated to be 11 percent. This average technical DR potential is slightly lower but compares well to the value estimated from the 2004 market survey (13%). Based on an estimate of the coincident peak demand for eligible non-participants (~12,000 MW), we estimate the total technical DR potential resource to be approximately 1,340 MW.

Importantly, self-reported technical potential does not correlate significantly with ownership of either back-up generators or energy management and control systems. These results, while perhaps surprising, are consistent with the finding presented earlier – that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response.

To benchmark the technical potential estimates, we estimated the economic potential associated with current DR programs – that is, the DR resource realistically available under current incentive levels – based on customer self-reports of the amount of bill savings required as an incentive to temporarily reduce their peak demand during twelve of the hottest summer weekdays. The results yield an estimated economic DR potential of 2.3 percent, which is again similar to the economic potential estimated from 2004 market survey results (1.8 percent). Again, based on a preliminary estimate of the coincident peak demand of eligible non-participants, the total additional DR resource potentially available at current incentive levels is approximately 280 MW.

These market potential results reveal two important findings regarding the potential demand response resource available in California going forward. First, the potential DR resource available through current programs at current incentive levels appears to be only a fraction of the CPUC's price-responsive DR resource goals. Furthermore, although there appears to be significant opportunities to achieve this market potential (notably through mobilizing the existing infrastructure of DR-enabling technologies, marketing efforts to increase awareness of program features designed to mitigate key perceived barriers to participation, and targeting marketing of the TA/TI program), future increases in program participation are likely to be gradual in the absence of significant increases in program incentives. Second, our estimated technical DR potential estimate equates to roughly 3 percent of system peak (based on 43,500 MW) and is of the same order of magnitude as the CPUC's price-responsive resource goals. However, it is important to consider this technical potential estimate only from a long-term perspective and that only a portion of this potential DR resource is likely to be cost-effective. In the absence of accepted estimates of both the value and costs of DR resources and programs, it is difficult to estimate exactly how much of the technical DR potential could be captured cost-effectively. Regardless of cost-effectiveness, however, achieving technical potential is necessarily a long-term process extends well beyond current policy and planning timelines.

3.6 SUB-METERING

The sub-metering element of the evaluation was established to provide a more in-depth understanding of DR program participant behavior - beyond what is revealed by analysis of revenue meter data or qualitative data obtained by traditional survey methods. Recruitment efforts in summer 2004 were intentionally biased in favor of selecting sub-metering participants that utilize more complex DR strategies and are very likely to take action in DR events. Detail on the process by which sub-metering installations were recruited, planned and executed can be found in Chapter 11 of this report and in Appendix J of the December WG2 2004 Evaluation report. Individual Sub-metering Site Reports were prepared for the 2004 sample, and a separate 2004 Summary Report provided integrated findings drawn from all 12 monitored sites. Results from the 2005 sub-metering effort were used to update the summary findings of the 2004 Sub-Metering Summary Report. Integrated findings from the 2004 and 2005 sub-metering evaluations are presented in Chapter 11 of this report.

3.7 RECOMMENDATIONS

In this section we present our recommendations. We begin with a set of broad suggestions that cut across individual DR programs. These recommendations focus on encouraging the Commission, CEC, utilities, and other stakeholders to continue working together to further refine the state's DR goals, program features, and cost-effectiveness framework using both stakeholder input and empirically-based data and analysis such as this and other DR-related evaluation and research studies. Following the cross-program recommendations, we present program specific recommendations for CPP, DBP, DRP, and reliability programs.

3.7.1 Cross-Program Recommendations

DR Policies and Plans Should Address the Fact That It Will Be Extremely Difficult to Reach the CPUC's Price-Responsive DR Goals with the Current Suite of Voluntary DR Programs

This evaluation has sought to provide as much empirical information as possible to support the development of future DR policies and programs. Our analysis of eligible markets and participants over the past two years has shown that the large customer market for voluntary, price responsive programs is still immature. With the exception of one large customer's contributions to the DRP program, impacts from the 2005 day-ahead programs (voluntary CPP, DBP, and DRP) represent only a small portion of the CPUC's price-responsive DR goals (on the order of 30 to 50 MW statewide). In addition, based on our surveys of the non-participating eligible markets for these programs, the evidence indicates that there is only small remaining short-term market potential for additional participation and load reduction given current program incentive levels and customer perceptions of system prices and resource needs. Under the current portfolio of voluntary programs (and associated customer incentive levels and expected market prices) it would likely take many years to reach the Commission's price-responsive goals, if they could be reached at all.

At the same time, there are significant load reduction resources enrolled in the utilities' reliability programs; however, these resources have had few calls since the energy crisis and it is not clear how robust the resource would be if it were called much more frequently. Current reliability customers generally indicate that they are prepared to deliver load reductions under the terms of their tariffs but there is some indication that they expect years for which there are event calls to be balanced by years in which there are very few or no calls. In theory, some of this load reduction capability could be captured through customers' joint participation in both reliability and the DBP program. Indeed, reliability customers currently account for about 50 percent of DBP impacts. However, the total amount of reliability load actively participating in DBP is small.

An additional approach that the CPUC, utilities, and other stakeholders have been considering over the past year or so is to deploy a default CPP tariff for large nonresidential customers. The intent of such proposals is to significantly expand the use of critical peak price signals. Assessment of default CPP proposals is not in the scope of this evaluation; however, deploying such price signals to a much larger share of the large nonresidential market than is currently participating in voluntary programs might produce significant increases in DR impacts.

The results of this evaluation, related DR research, resource needs assessments, and stakeholder input through the regulatory process should continue to be used to modify the current portfolio, as well as specific program features, as necessary, to increase the likelihood of meeting the current (or any modified) price-responsive DR goals (see below), while also maintaining a significant DR reliability resource.

Consider Refining DR Goals and Differentiating Reliability from Price-Responsive Goals

As noted above, the market today for voluntary day-ahead or price-responsive load motivated by incentive levels similar to those used in the DBP and CPP programs is much smaller than the price responsive goals established by the CPUC. This conclusion is not based only on the current program enrollment and action levels but also on our surveys of the non-participant population. It is difficult to assess the exact size of this gap partly because the goals are not established separately for different customer groups (i.e., the goals also could be reached with contributions from mass market programs targeted at customers below 200 kW).

While we understand that many policy makers are most interested in expanding the price-responsive market, we believe that it could be helpful to further differentiate the DR goals among program types and customer groups. Currently, load reductions associated with the reliability programs are not included in the DR goals. We also understand that this was by intent, in that the goals were oriented around load incremental to the traditional reliability programs within the context of the expansion of interval metering for the over 200 kW customers. Nonetheless, we believe that it might be helpful to now also specify goals for reliability programs so that any tradeoffs that may exist, both among existing reliability programs or between reliability and day-ahead programs, can be more easily identified and analyzed. In addition, consideration should be given to disaggregating the goals by customer size given the significant differences in characteristics and available load per customer (for example, goals might be set for residential, nonresidential under 200 kW, nonresidential 200 to 500 kW, and nonresidential larger than 500 kW).

Similarly, it may be useful to separate the load from the large government entity (which contributes ~200MW of load reductions) from the overall price-responsive goal because this load is many times larger than all remaining day-ahead load combined. Moreover, this load is controlled by a single governmental customer, and does not seem representative of the general market for price-responsive load.

Consider Differentiating Shorter Term Goals from Longer Term Capability Building Objectives

Another aspect of the day-ahead/price-responsive demand response goals that we believe should perhaps be reconsidered is their time dimension. The original pace of the goals was very aggressive, consistent with the "quick win" context from which they were articulated. Little empirical research on DR potential was available when the goals were developed. We believe that the results from this and last years' evaluations of the large nonresidential DR programs and markets indicate that it will take longer to achieve the day-ahead/price-responsive goals through voluntary programs than originally anticipated. As we emphasized last year, there are two related reasons for this. First, the level of incentives currently offered for day-ahead programs like voluntary CPP and DBP, typically less than two percent as compared to annual bills, appear insufficient to motivate large numbers of customers to take frequent DR actions. Second, the market lacks the capability and knowledge necessary to carry out significant DR actions without impacting normal operations and business costs. Although there is a significant infrastructure of energy management and related controls systems in the marketplace, these systems are generally not configured or utilized for DR. It will likely take several more years, coupled with a stronger market incentive (such as could be provided by default CPP), for customers to modify these systems, purchase enhancements, and develop other internal procedures that would combine to enable greater levels of DR, while simultaneously reducing customer transaction costs and productivity impacts.

Carefully Assess Effectiveness of TA/TI Incentives and IDSM; Target TA/TI to Current Program Participants with Low Activity Levels

If DR resources are desired sooner rather than later, the market will need increased technical assistance. In response to the 2004 DR results, the proposal to modify the Technical Assistance and Technical Incentives for DR was approved by the CPUC for 2005 and for 2006-2008. Because the 2005 TA/TI program generally did not roll out until after the summer of 2005, we were not able to address its effectiveness on an ex post basis in this evaluation. As we noted last year, care should be taken to develop and deploy technical support services that are cost effective. A key to this is to require recipients of TA/TI to demonstrate impact reduction capability, sign up for one of the existing DR programs, and, at a minimum, make good faith efforts to take DR actions. It is also possible that participants need to be required to take load reduction actions in order for TA/TI activities to be cost effective. This remains to be seen, however, and the extent to which TA/TI participants take DR actions should be closely monitored in the future.

In addition, technical support services and incentives should be targeted at current program participants who have generated few program impacts to date but credibly indicate that they remain interested in providing impacts in the future.[17]

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[17] Note that the results of this year's impact evaluation, which are calculated for each individual program participant, could be used to help target these services.

Continue Efforts to Quantify the Value of DR Benefits and Conduct DR Program Cost-Effectiveness Analyses

As we noted in last year's evaluation of the 2004 programs, it is important that a DR valuation framework be agreed upon and that cost-effective analysis be completed so that benefit-cost results are available to inform DR program and portfolio-related decision-making. A threshold concern about the voluntary CPP and DBP programs is whether these voluntary programs with the current levels of customer financial incentive and participation levels are cost-effective or under what conditions in the future they could be. In addition, more information is needed to quantify and compare the value and cost of the increased reliability associated with interruptible programs. It is difficult for policy makers and resource planners to make informed decisions about changes in the program mix, features, prices, and payments without the results of comprehensive benefit-cost analyses. To this end, the Commission has initiated several recent activities[18] including a workshop on March 21, 2006 on demand response benefit-cost issues and development of an initial draft discussion of DR impact estimation protocols on April 3, 2006. The Commission appropriately plans to continue these efforts in the remainder of 2006.

3.7.2 DBP-Related Recommendations

Work with Participants to Increase DBP Bidding Rates

Efforts to enroll customers in DBP have been fairly successful, however, the fraction of participants that bid on DBP events is low (6 percent on average for 2005). The evidence to date indicates that the price incentive associated with the DBP program is insufficient to motivate large fractions of participants to bid load for program events. It is still not clear, though, to what extent non-price motivators, such as system reliability, might motivate higher levels of participation in future events should participants perceive greater system need for load reductions. Nonetheless, efforts should be made to encourage and assist enrollees to more actively participate in the program through bidding and load reduction activities. Increasing bidding and load reduction actions would provide multiple benefits to participants, program administrators, and policy makers.[19]

Consider Changing the 3-Day DBP Baseline Method for Program Settlement and Use a More Accurate Alternative to Estimate Impacts for Reporting, Resource Planning, and Procurement

Including this year's evaluation results, there are now two years of impact evaluation and baseline analysis results with which we can assess the performance of methods used to estimate customer's event day load shapes. Based on our findings from this evaluation as well as findings from last year's 2004 evaluation and the CEC's DR protocol study (CEC, 2001), we believe the evidence is conclusive that the 3-day settlement method used to estimate customer

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[18] *CPUC Draft Decision Closing Rulemaking 02-06-001*

[19] For example, benefits could include: Increased customer experience and knowledge developing, estimating, and implementing DR actions; increased program administrator knowledge of which customers and customer strategies can provide the most reliable resources; increased volume and diversity to load reductions which can help to increase the predictability of total load reductions; and improved information for resource planners and policy makers on the true magnitude of the DBP program resource.

baselines is systematically biased high. A high systematic bias in the baseline results in a high systematic bias in the impact estimates since impacts are simply the difference between the estimated baseline load for an event day minus the actual load for the event day. The 3-Day method has been used for the past two years as the basis for program payments to customers in the DBP program. It has also been used by some utilities to estimate and report impacts for the voluntary CPP program (though there is no customer settlement for CPP so CPP participants are not affected by this calculation). The evidence indicates that the 3-day method may overestimate impacts by two to four times. As discussed previously, there is also evidence that this systematic upward bias of the 3-day method also contributes to free ridership.

Given the magnitude of the overestimate bias we believe that the utilities should not use the 3-day method to report program impacts and should strongly consider an alternative method for DBP program settlement. We recommend that the 10-day adjusted baseline or a regression-based approach (applied to individual customers) be used for reporting program impacts. For DBP program settlement, we recommend that the utilities use the results of this evaluation, last year's evaluation, and the CEC DR protocol study (CEC 2001), to decide on a whether to implement a new method to replace the 3-day method. We recognize that the decision on what baseline calculation to use for settlement is more complex than the decision on which methods to use for estimating and reporting overall program impacts. The baseline method decision for settlement must consider other factors in addition to statistical accuracy and bias, in particular, transparency, vulnerability to gaming, and practicality. These issues are addressed at length for different baseline methods in the CEC's DR protocol study.

We also recognize that conversion to a new method may result in increased program costs (e.g., to reprogram the settlement baseline method in the program software, to modify program agreements with participants, and to communicate the change to participants) and, possibly, decreased program enrollment and event participation (because average payments will decrease since the 3-day method is systematically biased high). Utilities and policy makers will have to weigh the pros and cons of increased accuracy and reduced overpayment (which would have a positive impact on overall program cost effectiveness) against the possible decrease in program impacts (which could lower program cost effectiveness) that may occur with a change to a more accurate settlement method.

Consider New Strategies for High Load, High Variance (HLHV) Participants.

As presented in the findings above and in Chapter 7, HLHV participants pose challenges for the DBP program as currently implemented. These challenges are associated with the difficulty of developing meaningful and reliable baselines for these customers and the level of impact of any errors associated with these customers' baselines on the overall program impact estimates and ability to forecast events-specific impacts. Some of the options to consider for these types of customers are developing and agreeing to customer-specific baselines, encouraging or requiring some of these customers to participate in other DR programs that do not require a baseline calculation, and investigating whether sub-metering can improve the reliability of impact estimates. It is likely that the first and third option will not be sufficient to resolve the issues for DBP participants with the largest and most variable loads. In addition, those approaches are likely to be time intensive and potentially of concern to other customers participating under more standard terms.

With respect to screening customers or encouraging participation in programs that do not require baseline estimation for settlement, consideration should be given to screening participation eligibility based on analysis of historical interval data. For example, a customer that routinely shuts down completely in August or September should not be permitted to bid in those months. Comprehensive customer-specific load analysis also should be considered for very large customers. The results of this analysis should be used to negotiate fair and appropriate participation criteria or to prohibit participation in DBP and encourage participation in alternative DR programs that are more appropriate given the customer's load characteristics.

We recognize that there is a potential tradeoff associated with improving baseline estimates for certain customers, or prohibiting their participation, and maintaining and increasing program impacts because some customers may decide to drop out of the program if their current participation terms were to change. Of course, for any of those customers for whom net impacts were small but payments high due to overestimated baselines, the overall cost effectiveness of the program may actually improve with their absence.

Consider Increasing DBP Bidding Window

Some DBP participants indicated that increasing the bidding window would also increase their ability to place bids. Although this seems reasonable from the customer's perspective, consideration must be given to the day ahead procurement and scheduling needs. In addition, it is worth noting that one would have expected that the change from day-of events in 2004 to day-ahead events in 2005 to have led to a significant increase in bidding rates, however, that did not occur.

3.7.3 CPP-Related Recommendations

Increase Voluntary CPP Enrollment Levels and Continue to Promote Bill Protection Incentive

As presented in our findings above and Chapter 4, voluntary CPP participation levels are fairly low. We also have noted the wide discrepancy in participation levels among the IOUs (from a high of 3.5 percent for PG&E to a low of 0.1 percent for SCE). The utilities have estimated that a large portion of the eligible market would receive bill savings if they participated in the CPP program. In addition, the CPP Bill Protection Incentive is intended to assure participants that they will not pay more under the CPP tariff than they would have under their otherwise applicable tariff (OAT) for the first year that they participate in the program. In our 2004 evaluation report, we recommended that utility marketing efforts emphasize the no-risk aspect of the voluntary CPP to encourage greater participation. Our market survey results conducted for this 2005 evaluation indicate that familiarity with the Bill Protection Incentive remains moderate. Even though potential bill savings in the voluntary CPP program are somewhat small (typically one to three percent), one would expect higher levels of voluntary CPP than those achieved to date, particularly given the availability of Bill Protection.

The low levels of participation in CPP are likely a function of high levels of customer risk aversion and the effectiveness of CPP marketing efforts (particularly in the case of SCE). The market survey results presented in Chapter 5 indicate that more aggressive marketing of the Bill Protection Incentive could mitigate some of these concerns. Still, customers may also have concerns about the stability of programs and rates given experiences with the energy crisis as well as about how the voluntary CPP relates to the possible implementation of default CPP. However, even if default CPP is implemented in 2007, it would likely be beneficial for customers to participate in the voluntary CPP in summer 2006 in order to develop experience that will help them most effectively manage their peak loads in the future. Thus, in either case (with or without default CPP) marketing efforts should continue to encourage participation in the voluntary CPP for summer 2006.

3.7.4 DRP-Related Recommendations

The recommendations resulting from the key findings of the DRP process evaluation tend to revolve around clarifying the program's somewhat ambiguous status and making sure that aggregators, utilities, and customers are able to work with DRP as a clearly defined, stable program that provides an alternative to other utility DR offerings.

Clarify the Price-Based Nature of the Program in Marketing

Survey results and interviews clearly indicate that customers and aggregators perceive the DRP program to be triggered by both overall load and price – as specified in the original design of the program and illustrated by the DRP website, which states that program events can be initiated "due to short supplies and/or price spikes." Marketing materials and efforts should emphasize the fact that the program can be called based on price alone, with explanations that this may impact customers' ability to shed weather-dependent load. All of the utilities and aggregators should also develop a consistent state-wide marketing piece to be used on utility websites, by utility reps, and by aggregators.

Consider Revising the Trigger Price to Better Reflect System Load Conditions

Aggregators say that the utilities, CPA and even DWR recognize that the current strike price for the DRP program is too low. If there is general agreement on this point then consideration should be given to increasing the trigger price and perhaps combining it with a system-wide or zone-based load forecast similar to that used for DBP.

Consider Providing Aggregators and Customers with Access to the Price That Will Be Used to Trigger the Program

For business reasons, utilities have expressed concern about making the spot price they pay in the market public. However, it may be appropriate to provide aggregators and customers with access to a spot market price, subject to non-disclosure if appropriate, on one of the market exchanges so that they are better informed about market conditions and can plan accordingly.

Consider Changing the Structure So That Customers Truly Know Day-Ahead That They Will Be Called

As originally designed, the DRP program was intended to be a day-ahead program, but it currently operates as a *de facto* day-of program, since DWR can "reserve" capacity for the next day on virtually every day of the summer. In line with the original intent of the program, it would be both possible and desirable to require DWR and the utilities to make a firm decision on whether or not the program will be called on a day-ahead basis.

Allow Aggregation across Customers (But Within IOU Territories or Demand Zones), In Line With the Original Intent of the Program

One of the benefits of the original DRP program was that it enabled aggregators to combine the loads of a number of individual customers and "shape" them in a way that provides customers with greater flexibility and the system with greater assurance that a specific amount of load will be shed in response to program events.

For 2007 and Beyond, Keep a Successor Program in Place with Clearly Specified Structure and Terms for Several Years

Proposals for a successor program have been put forward by the aggregators/CPA and by the utilities. While these proposed programs have some different features, they share several key elements that should be incorporated into the successor DRP program, and we recommend that the details of the program be resolved through negotiations between the CPUC, aggregators, and utilities, with input from customers, other stakeholders, and this evaluation.

Develop a Consistent CPUC Reporting Procedure for DRP Impacts

Using the results of this evaluation and other resources as appropriate, the utilities should work together to implement an agreed upon impact reporting method for DRP. It may be possible to have this programmed and implemented by APX and included on one of the DRP reports already included on the website. Coordinating this calculation would improve the consistency of the impact estimates provided to the CPUC and reduce the efforts currently required of each of the utilities.

3.7.5 Reliability Program Recommendations

The findings of the reliability program evaluation presented in this report indicate that under current system conditions (i.e., few, if any, interruption events per year) the interruptible customer base can be expected to be stable going forward, with little to no natural migration to day-ahead DR programs or alternative non-firm rates (e.g., BIP). Because incentives under traditional interruptible programs are currently very attractive, there is little financial motivation for participants to consider shifting to day-ahead DR programs or BIP. Moreover, curtailment strategies used by interruptible customers are currently dominated by actions with large incremental impacts that also have large costs associated with them, indicating that it may not be a straightforward process to adapt these curtailment actions to the higher event frequencies and lower financial incentives typical of day-ahead DR programs.

Should future system conditions warrant more regular and frequent reliability events, the evaluation results indicate that only a small portion of the interruptible customer market would either switch to other non-firm service rates or take firm service and participate in day-ahead DR programs. This result is consistent with the fact that the vast majority of traditional interruptible customers are survivors of the 2000-2001 Energy Crisis.

Further Assess the Value of Traditional Interruptible Versus Base Interruptible Programs

In its initial decision on default CPP, the CPUC expressed a desire to narrow the DR portfolio to default CPP and BIP. This raised a number of questions including how well aligned benefits and costs are for BIP versus the traditional reliability programs, as well as how much of the reliability resource would be willing to move to BIP. With respect to the first question, additional benefit-cost analysis is needed to assess the relative cost-effectiveness among reliability programs.

Carefully Consider the Risk of Reducing the Size of the Reliability Resource if BIP Were to Be the Only Available Reliability Program

Related to the second question above, results from this evaluation and market participation in BIP to date indicate that there could be a significant reduction in the amount of load enrolled in reliability programs if the traditional programs were discontinued. This is, however, very difficult to gauge given that our results are based on customer self reports, which could reflect a certain degree of tactical response on the part of current interruptible customers who want to ensure continuation of their current rate discounts. At the same time, however, it should also be noted that current interruptible tariffs represent a more robust resource than the newer price-based DR programs. Indeed, the impact analysis presented in Chapter 7 confirms that current interruptible customers (for SCE and SDG&E) delivered deep load reduction in 2005, albeit for only a few short events. This is a very attractive aspect of interruptible tariffs that is emphasized by program managers. As one program manager opined, "there's not any other way to get another 300 MW at 30 minutes notice."

Consider Field Testing Reliability Programs in Addition to Process-Only Testing

The reliability programs have had very few event calls over the past few years. While the programs should definitely not be called arbitrarily, there are benefits to periodically field testing these types of programs. Consideration should be given to such field testing, for example, perhaps once a year. Such testing would help to periodically quantify the timing and magnitude of response and help customers be prepared for situations in which the capacity is needed to meet system constraints.

3.7.6 Recommendations for Further Research

In this section we present a few suggestions for further research related to evaluation of the 2005 DR programs as well as future programs. Note that these are strictly initial suggestions based on our assessment of current knowledge and information gaps. They do not reflect any trade-off analysis of relative cost versus relative value. Such trade-offs should be conducted by the utility and regulatory staff charged with developing DR research and evaluation budgets and objectives.

Further investigation of the use of regression analysis to estimate customer baselines and overall program impacts. In theory, regression-based estimation methods should be more accurate than even the best representative-day based methods because the former approach uses more data and can account for more explanatory factors that affect baseline load shapes. However, there are some challenges associated with applying regression-based techniques to load shape estimation for groups of large nonresidential customers with small numbers of participants and highly variable loads. The use of multivariate regression models for estimating load impacts from the day-ahead programs was tested in this year's evaluation with useful results. However, the project schedule did not allow for a complete development of these models and their results. Further analysis that should be considered includes:

- Revisiting the pooled regression model. A pooled regression model was explored in the current study but the results were not satisfactory due to hetereoskedasticity. Additional analysis should be conducted to determine whether these issues can be addressed.

- Testing the customer-specific regression model results using the same metrics and procedures for assessing accuracy that were utilized in the 2004 WG2 Evaluation and CEC DR Protocol studies. These tests involve estimating baselines for non-event days, when actual loads are known, and calculating a standard set of statistical performance metrics. The performance metrics for the customer-specific regression models can then be explicitly compared to the representative-day methods.

Conduct real-time and ex-post evaluation of the new Technical Assistance and Technology Incentive (TA/TI) programs. The 2005 TA/TI programs did not get off the ground until late in 2005 and thus they were not analyzed as part of the 2005 evaluation. Both process and impact evaluation of these programs are needed.

Consider conducting more comprehensive analyses of DR potential. Current estimates of statewide technical and economic DR potential are based on customer self-reports from large sample telephone surveys. Similarly, our current understanding of the curtailment strategies used by DR program participants in California is largely based on customer self-reports solicited through telephone surveys. The California IOUs have conducted extensive bottom-up analyses of energy efficiency potential. However, much less work has been conducted and published on bottom-up estimation of DR potential. Developing a deeper understanding of both current curtailment strategies and DR potential would help frame policy targets more rationally and help optimize program designs and incentives. Conducting on-site surveys and in-depth interviews with both current program participants and non-participants should be considered in order to identify and catalogue both current and potential curtailment strategies with particular attention to the use of DR-enabling technologies.

Within these activities, we also recommend explicit investigation of two issues in particular. The first issue is how customer exposure to TOU rates impacts their ability to provide significant, temporary demand reductions during peak hours. Anecdotal evidence currently points to a potentially mitigating effect of TOU rates on DR potential. The existence of mandatory TOU rates for large non-residential customers in California warrants explicit consideration of this potential tradeoff between load management strategies. The second issue is how current participants use on-site backup generators as a curtailment strategy. The results of the 2005 non-participant survey indicate that approximately half of the large non-residential market in California own on-site backup generators. Moreover, the results of the 2005 participant surveys indicate that the use of backup generators among DBP participants is significant. This use of backup generators, while representing a potentially large DR resource in California, is in conflict with air quality regulations. The impact of this tension between air quality regulations and DR potential on DR policy goals and program design should be investigated explicitly.

Estimate the impacts associated with DR actions taken outside of incentive programs in response to public appeals. One of the analyses that could be conducted in this area would be to obtain summer 2005 interval data for all of the customers in this year's non-participant survey (since this was a statistically representative sample of those customers). From this, the analysis should identify the subset of non-participants who indicated during the general market survey they had received and taken curtailment actions in response to the Flex Your Power NOW (FYPN) Alerts. The analysis should quantify any load reductions for these customers and compare these reductions to the remaining group of customers that did report receiving alerts or taking actions. These results should then be weighted up to the entire non-participant population.

Refocus on analysis of DR marketing activities and effectiveness. The 2004 WG2 evaluation included detailed summary and analysis of the IOUs efforts to market DR programs to large customers. The 2005 evaluation had less focus on this area. There remain unresolved questions on program penetration, such as the extremely low penetration of voluntary CPP in SCE and BIP (especially in SDG&E), that further analysis of marketing activities may help to illuminate.

Estimate the combined effect of DR programs and the thresholds at which these impacts are observable at the system level and influence procurement. Now that hourly event by event results have been developed, these results should be aggregated to estimate total DR impacts. In addition, methods to observe these effects at the utility system or ISO level should be investigated. Investigation of how DR impact forecasts are used, or not, by resource planners and procurers should also be considered. Questions to consider in this research include whether DR resources must achieve a certain aggregate size before they actually affect avoided cost-related decisions, as well as the extent to which the accuracy of DR event day forecasts affects resource procurement decisions and associated benefits or costs.

Assess the relative costs and benefits of customer aggregation. It would be useful to further analyze the extent to which aggregation strategies were used within the 2005 DRP program, as well as other DR aggregation programs, to assess the relative benefits and costs of those strategies. Note that assessment of the load impacts associated with aggregation requires more disaggregated load interval data than was available for this evaluation.

Investigate methods to build impact evaluation methods into program tracking systems. The process of extracting interval and associated event data from utility program tracking and related CIS systems and conducting stand alone external impact analyses can be time consuming and costly (relative to the small size and avoided cost benefits of some of the programs, i.e., CPP and DBP). Over time, it is possible that improved impact estimation methods could be implemented automatically within DR program systems. If so, there may be periods during which evaluation activities could be scaled back from the current third party estimation of impacts for a census of participants to more of a verification process. For example, if one or more agreed upon estimation methods were implemented within the program tracking processes, an evaluator could conduct a verification analysis of a sample of these impact estimates. If the verification rate was extremely high, the estimates from the tracking system could be used for reporting. If not, further evaluation could be initiated. Complete independent impact evaluations could be scheduled periodically to estimate and explore impacts in more detail. The frequency at which the detailed impact evaluations are conducted should be related to the size of the programs, the degree of uncertainty in the impacts, and the costs of the evaluation. This issue should be investigated more fully as part of the CPUC's development of impact evaluation protocols for DR programs currently underway.

4. 2005 PROGRAM PARTICIPATION TRACKING AND ANALYSIS

One of the primary tasks of this evaluation is to track and analyze customer participation in the day-ahead demand response and reliability programs. This chapter summarizes participation levels and market penetration of in-scope programs in 2005 and tracks participation changes that have occurred since 2004. The first section describes and quantifies the population of customers eligible for in-scope programs in 2005. The second section summarizes current program participation and the extent to which in-scope programs have penetrated the eligible customer market. The third section summarizes changes in program enrollment that have occurred since the 2004 program season. Finally, the fourth section compares basic customer characteristics between current program participants and eligible non-participants.

4.1 ELIGIBILE POPULATION

To quantify and track customer participation in demand response and reliability programs, each of the three investor-owned utilities (PG&E, SCE, and SDG&E) provided the following types of data:

- Demand Response Participant Tracking Data. The participant tracking data was used to identify accounts that had signed up to participate in the CPP, DBP, DRP, BIP, OBMC, or traditional interruptible programs.

- Commercial Population Data. Customer Information System (CIS) data was used to determine whether an account was eligible for the CPP, DBP, DRP, BIP, OBMC, or traditional interruptible programs. It also was used to create the size and business type classifications for each account. Premise and Customer identifiers from the CIS were used to identify unique premises (across multiple accounts at a site) and customers (across multiple accounts and premises), and classification variables associated with these aggregated units.

Using this data, accounts were then assigned flags indicating their size and business type. These flags were created on an account level, a premise level and a customer level. The premise level flags were selected based on the largest account at that premise. In a similar manner the customer level flags were selected based on the largest account for that customer. The size flags were defined based on an account's annual maximum demand as follows:

- Extra Small customers are defined as those having a maximum demand between 20 kW and 100 kW

- Very Small customers are defined as those having a maximum demand between 100 kW and 200 kW

- Small customers are those with maximum demand between 200 kW and 500 kW

- Medium customers are those with maximum demand between 500 kW and 1000 kW

- Large customers are those with maximum demand between 1000 kW and 2000 kW
- Extra Large customers are those with maximum demand greater than 2000 kW

The business type flags were defined based on SIC code for SCE and SDG&E and a mapping of NAICS to SIC codes for PG&E. Exhibit 4-1a shows this mapping and the nine business types used for this evaluation.

Exhibit 4-1a
Mapping of SIC Codes to Business Type Categories

SIC code	QC Business Type
60, 61, 62, 63, 64, 65, 67, 73, 81, 4720, 4724, 4725, 4729, 8111, 8320, 8399, 8610, 8699, 8710, 872, 8740, 8748	Office
54, 5210, 5399, 5510, 5736, 5910, 5999, 7210, 7299, 7620, 7699	Retail/Grocery
43, 80, 82, 91, 92, 93, 94, 95, 96, 97, 99	Institutional
50, 51, 52, 53, 55, 56, 57, 58, 59, 70, 72, 75, 76, 78, 79, 83, 84, 86, 87, 88, 89, 4222, 4225	Other Commercial
40, 41, 42, 44, 45, 46, 47, 48, 49	Transportation/Communication/Utility (TCU)
28, 29, 30	Petroleum/Plastic/Rubber/Chemicals (PPRC)
10, 12, 13, 14, 32, 33	Mining/Metals/Stone/Glass/Concrete (MMSGC)
34, 35, 36, 37	Electronics/Machinery/Fabricated Metals (EMFM)
01, 02, 07, 08, 09, 15, 16, 17, 20, 21, 22, 23, 24, 25, 26, 27, 31, 38, 39	Other Industrial/Agriculture (OIA)

An alternate set of business type flags was also defined in order to facilitate more aggregate comparisons across economic sectors. For such higher-level comparisons, the nine business types defined above were aggregated into three business types as follows:

- Office, Retail/Grocery, and Other Commercial ⇒ Commercial
- Institutional and TCU ⇒ Institutional
- PPRC, MMSGC, EMFM, and OIA ⇒ Industrial

Quantum Consulting then created an eligible population frame containing all PG&E, SCE and SDG&E accounts that were eligible for the in-scope demand response programs. The main eligibility criteria for each in-scope program are shown below in Exhibit 4-1b along with any changes to these criteria that have occurred since 2004. Note that PG&E and SCE's traditional interruptible tariffs have been closed to new enrollment since the mid-1990s, and SDG&E's traditional interruptible tariff is closed to new enrollment as of January 1, 2006.

Exhibit 4-1b
Eligibility Criteria for 2005 Day-Ahead and Reliability Programs

Program	Utility	Max Demand		Conflicting Programs
		2004 Programs	2005 Programs	
CPP	PG&E	average >200 kW	annual >200 kW	BIP, OBMC, Interruptible tariffs, Direct Access
	SCE	annual >200 kW	same	
	SDG&E	annual >100 kW	annual >20 kW	
DBP	PG&E	average >200 kW	annual >200 kW	DRP
	SCE	annual >200 kW	same	
	SDG&E	annual >200 kW	annual >20 kW	
DRP	PG&E SCE SDG&E	no explicit max demand criteria	same	DBP
BIP	PG&E	monthly >100 kW	same	CPP, Interruptible tariffs
	SCE	monthly >500 kW	monthly >200 kW	
	SDG&E	monthly >100 kW	same	
OBMC	PG&E SCE SDG&E	no explicit max demand criteria	same	CPP
Interruptible tariffs*	PG&E	3 months >500 kW	same	CPP, BIP
	SCE	monthly >500 kW		
	SDG&E	annual >20 kW		

* Closed to new enrollment

The size and business type distributions of the accounts in the eligible population frame are presented in Exhibit 4-2. This exhibit also displays the breakdown of accounts eligible for CPP, DBP, DRP, BIP, OBMC, or traditional interruptible tariffs across the six customer sizes and nine business types. There are two issues to note regarding the statewide eligible populations:

- Because traditional interruptible tariffs are closed, the data shown in Exhibit 4-2 only reflect current participants.
- The “Extra Small” and “Very Small” size categories reflect only the SDG&E service territory.

Exhibit 4-2
Statewide Eligible Populations, Account Basis
(Note: "Extra Small" and "Very Small" represent only SDG&E)

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	BIP (accts)	OBMC (accts)	INTER** (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)*	14,512	15,397	15,394	15,397	0	0	1	1	15,397
Very Small (100-200 kW)*	2,611	2,938	2,926	2,938	2,938	0	10	2,938	2,938
Small (200-500 kW)	14,250	17,673	17,556	18,009	17,111	17,985	33	18,016	18,016
Medium (500-1000 kW)	4,005	5,315	4,890	5,349	5,216	5,312	168	5,354	5,356
Large (1000-2000 kW)	1,341	1,974	1,656	1,998	1,944	1,990	192	2,007	2,010
Extra Large (2000+ kW)	623	1,243	1,000	1,285	1,262	1,276	204	1,283	1,283
Unknown	234	235	277	283	24	22	6	46	283
Business Type									
Commercial and TCU									
Office	7,830	8,403	8,937	8,429	4,448	3,957	11	4,578	9,168
Retail/Grocery	5,246	7,122	7,447	7,278	4,419	3,944	19	4,479	7,632
Institutional	6,159	6,921	7,599	6,946	5,060	4,601	26	5,190	7,723
Other Commercial	7,263	9,125	9,464	9,209	4,894	4,540	26	5,226	9,682
Transportation/Communication/Utility	2,840	3,685	3,821	3,736	2,960	2,890	69	3,099	4,013
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	751	1,002	1,050	1,012	902	859	105	924	1,177
Mining, Metals, Stone, Glass, Concrete	620	803	817	825	758	774	136	793	974
Electronic, Machinery, Fabricated Metals	2,048	2,363	2,504	2,368	1,862	1,779	77	1,931	2,677
Other Industrial and Agriculture	3,247	3,728	3,872	3,733	2,883	2,807	158	2,952	4,128
Unclassified									
Unknown	1,702	1,812	1,823	1,799	459	434	0	495	1,826
Total Accounts	37,576	44,775	43,699	45,259	28,495	26,585	614	29,645	45,283
Utility Breakdown									
PG&E	8,415	11,808	11,559	12,008	10,910	11,898	95	11,906	12,073
SCE	9,576	11,659	14,346	11,807	11,823	11,976	501	11,848	15,407
SDG&E	19,715	21,497	21,429	21,520	5,912	2,853	31	5,913	21,520

*Data reflect SDG&E only
**Closed to new enrollment; only current participants shown as eligible

Exhibit 4-2b shows a similar breakdown of the eligible population frame in terms of non-coincident peak load associated with eligible accounts. The Exhibit shows that although more than three quarters of all eligible accounts are Small (i.e., maximum annual demand less than 500 kW), this population accounts for less than a third of the overall eligible non-coincident peak load. On the other extreme, only 3 percent of eligible accounts are classified as Extra Large (i.e., maximum annual demand greater than 2 MW), however this population accounts for more than a third of the eligible non-coincident peak demand. It should be noted here that the eligible customer demand that is coincident with utility system peaks will be significantly less than the non-coincident peak load figures shown in Exhibit 4-2b.

Exhibit 4-2b
Statewide Eligible Populations, Non-Coincident Peak Load Basis
(Note: "Extra Small" and "Very Small" represent only SDG&E)

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	BIP (MW)	OBMC (MW)	INTER** (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)*	657	704	0	704	0	0	0	0	704
Very Small (100-200 kW)*	361	406	0	406	406	0	1	406	406
Small (200-500 kW)	4,366	5,448	5,383	5,530	5,306	5,520	12	5,532	5,532
Medium (500-1000 kW)	2,746	3,650	3,339	3,669	3,577	3,648	126	3,674	3,674
Large (1000-2000 kW)	1,813	2,690	2,245	2,723	2,655	2,717	273	2,740	2,740
Extra Large (2000+ kW)	3,262	7,333	6,665	8,301	7,776	7,855	1,376	7,876	7,876
Unknown	7	7	0	7	2	0	0	2	7
Business Type									
Commercial and TCU									
Office	2,249	2,687	2,289	2,704	2,459	2,445	21	2,531	2,751
Retail/Grocery	1,120	1,827	1,631	1,889	1,748	1,689	11	1,768	1,911
Institutional	2,221	3,240	2,927	3,296	3,147	3,104	67	3,196	3,337
Other Commercial	2,052	2,946	2,435	2,991	2,689	2,685	59	2,805	3,026
Transportation/Communication/Utility	1,734	2,860	3,154	3,510	2,848	2,841	182	2,893	2,944
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	708	1,227	1,116	1,354	1,355	1,365	241	1,374	1,389
Mining, Metals, Stone, Glass, Concrete	405	1,059	685	1,181	1,313	1,336	631	1,338	1,349
Electronic, Machinery, Fabricated Metals	942	1,682	1,232	1,687	1,605	1,643	257	1,668	1,713
Other Industrial and Agriculture	1,546	2,395	1,909	2,413	2,311	2,371	323	2,391	2,458
Unclassified									
Unknown	234	317	253	317	251	261	0	270	320
Total Non-coincident Load	13,211	20,238	17,631	21,340	19,723	19,740	1,789	20,231	20,939
Utility Breakdown									
PG&E	5,263	8,942	8,794	9,688	8,587	9,088	416	9,089	9,094
SCE	5,273	7,787	6,495	8,119	8,312	8,317	1,355	8,319	8,569
SDG&E	2,675	3,511	2,342	3,535	2,826	2,335	19	2,826	3,535

*Data reflect SDG&E only
**Closed to new enrollment; only current participants shown as eligible

Exhibits 4-3 through 4-5b display similar breakdowns of eligible accounts and non-coincident peak loads in the service territories of PG&E, SCE, and SDG&E, respectively. As noted above, eligible accounts with annual peak demands below 200 kW are only shown for SDG&E. Technically, customers in PG&E and SCE with peak demands below 200 kW are eligible to participate in DBP (via aggregation across accounts that share the same tax ID number), as well as DRP. However, the available population data did not allow us to accurately and consistently frame small accounts in PG&E and SCE that are potentially eligible to participate in these programs. Additionally, the OBMC program does not explicitly target these smaller customer classes.

Exhibit 4-3
Eligible Populations in PG&E, Account Basis

PG&E	Day-Ahead Programs CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	Reliability Programs BIP (accts)	OBMC (accts)	INTER* (accts)	Total (accts)	Total DR (accts)
Size									
Small (200-500 kW)	5,737	7,821	7,828	7,937	7,153	7,937	0	7,937	7,937
Medium (500-1000 kW)	1,696	2,311	2,197	2,326	2,192	2,324	7	2,324	2,326
Large (1000-2000 kW)	656	965	866	976	913	973	23	973	976
Extra Large (2000+ kW)	324	650	559	676	644	664	65	664	664
Unknown	0	0	26	26	0	0	0	0	26
Business Type									
Commercial and TCU									
Office	1,822	2,136	1,964	2,146	1,965	2,086	0	2,086	2,148
Retail/Grocery	809	1,391	1,453	1,456	1,400	1,453	0	1,453	1,457
Institutional	1,281	1,515	1,500	1,522	1,401	1,520	7	1,520	1,523
Other Commercial	1,593	2,737	2,744	2,809	2,481	2,804	3	2,805	2,814
Transportation/Communication/Utility	691	1,208	1,215	1,238	1,073	1,206	25	1,212	1,284
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	162	284	280	285	266	285	4	285	288
Mining, Metals, Stone, Glass, Concrete	225	297	276	301	273	300	16	300	301
Electronic, Machinery, Fabricated Metals	512	589	552	589	520	588	1	588	590
Other Industrial and Agriculture	1,060	1,284	1,201	1,290	1,218	1,289	39	1,290	1,291
Unclassified									
Unknown	260	367	374	372	313	367	0	367	377
Total Accounts	8,415	11,808	11,559	12,008	10,910	11,898	95	11,906	12,073

*Closed to new enrollment; only current participants shown as eligible

Exhibit 4-3b
Eligible Populations in PG&E, Non-Coincident Peak Load Basis

PG&E	Day-Ahead Programs CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	Reliability Programs BIP (MW)	OBMC (MW)	INTER* (MW)	Total (MW)	Total DR (MW)
Size									
Small (200-500 kW)	1,740	2,377	2,380	2,418	2,194	2,418	0	2,418	2,418
Medium (500-1000 kW)	1,184	1,607	1,523	1,616	1,522	1,616	7	1,616	1,616
Large (1000-2000 kW)	898	1,324	1,189	1,342	1,258	1,342	34	1,342	1,342
Extra Large (2000+ kW)	1,441	3,634	3,702	4,312	3,612	3,712	375	3,712	3,712
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	1,162	1,450	1,357	1,465	1,393	1,465	0	1,465	1,465
Retail/Grocery	354	601	624	624	605	624	0	624	624
Institutional	608	826	806	844	795	844	17	844	844
Other Commercial	978	1,655	1,599	1,693	1,577	1,693	9	1,693	1,693
Transportation/Communication/Utility	513	1,348	1,793	1,957	1,313	1,357	73	1,358	1,361
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	241	614	583	615	598	615	28	615	616
Mining, Metals, Stone, Glass, Concrete	159	418	322	450	426	450	119	450	450
Electronic, Machinery, Fabricated Metals	333	535	449	535	472	535	36	535	535
Other Industrial and Agriculture	789	1,294	1,070	1,304	1,226	1,304	133	1,305	1,305
Unclassified									
Unknown	125	200	192	200	181	200	0	200	200
Total Non-coincident Load	5,263	8,942	8,794	9,688	8,587	9,088	416	9,089	9,094

*Closed to new enrollment; only current participants shown as eligible

Exhibit 4-4
Eligible Populations in SCE, Account Basis

SCE	Day-Ahead Programs CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	Reliability Programs BIP (accts)	OBMC (accts)	INTER* (accts)	Total (accts)	Total DR (accts)
Size									
Small (200-500 kW)	6,873	7,865	7,742	8,065	7,951	8,072	27	8,072	8,072
Medium (500-1000 kW)	1,834	2,407	2,126	2,424	2,425	2,431	153	2,431	2,431
Large (1000-2000 kW)	533	809	606	822	831	834	164	834	834
Extra Large (2000+ kW)	208	450	304	465	474	475	138	475	475
Unknown	0	0	16	22	0	22	6	22	22
Business Type									
Commercial and TCU									
Office	1,249	1,404	2,118	1,420	1,411	1,420	10	1,420	2,157
Retail/Grocery	1,162	1,993	2,246	2,062	2,049	2,055	7	2,055	2,415
Institutional	2,102	2,288	2,989	2,305	2,293	2,304	19	2,304	3,081
Other Commercial	1,162	1,283	1,649	1,295	1,287	1,295	21	1,295	1,763
Transportation/Communication/Utility	1,193	1,398	1,530	1,419	1,426	1,425	43	1,426	1,650
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	382	494	547	503	512	509	101	515	665
Mining, Metals, Stone, Glass, Concrete	312	419	455	437	452	455	119	460	586
Electronic, Machinery, Fabricated Metals	817	979	1,171	984	987	987	70	988	1,292
Other Industrial and Agriculture	1,159	1,363	1,599	1,362	1,368	1,364	111	1,365	1,756
Unclassified									
Unknown	38	38	42	20	38	20	0	20	42
Total Accounts	9,576	11,659	14,346	11,807	11,823	11,976	501	11,848	15,407

*Closed to new enrollment; only current participants shown as eligible

Exhibit 4-4b
Eligible Populations in SCE, Non-Coincident Peak Load Basis

SCE	Day-Ahead Programs CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	Reliability Programs BIP (MW)	OBMC (MW)	INTER* (MW)	Total (MW)	Total DR (MW)
Size									
Small (200-500 kW)	2,133	2,467	2,399	2,500	2,501	2,502	10	2,502	2,502
Medium (500-1000 kW)	1,233	1,629	1,424	1,639	1,640	1,643	114	1,643	1,643
Large (1000-2000 kW)	713	1,098	810	1,113	1,129	1,130	233	1,130	1,130
Extra Large (2000+ kW)	1,194	2,591	1,863	2,866	3,041	3,041	997	3,041	3,041
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	569	689	648	691	691	691	18	691	737
Retail/Grocery	494	863	826	894	892	893	9	893	916
Institutional	1,129	1,441	1,312	1,463	1,449	1,449	49	1,449	1,504
Other Commercial	586	720	574	726	726	726	47	726	762
Transportation/Communication/Utility	746	1,007	911	1,049	1,058	1,059	108	1,059	1,078
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	424	563	495	689	712	714	213	714	724
Mining, Metals, Stone, Glass, Concrete	235	627	355	718	875	877	509	877	885
Electronic, Machinery, Fabricated Metals	443	914	606	919	921	922	217	922	945
Other Industrial and Agriculture	639	957	761	964	979	980	185	981	1,010
Unclassified									
Unknown	7	7	7	7	7	7	0	7	9
Total Non-coincident Load	5,273	7,787	6,495	8,119	8,312	8,317	1,355	8,319	8,569

*Closed to new enrollment; only current participants shown as eligible

Exhibit 4-5
Eligible Populations in SDG&E, Account Basis

SDG&E	Day-Ahead Programs CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	Reliability Programs BIP (accts)	OBMC (accts)	INTER* (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)*	14,512	15,397	15,394	15,397	0	0	1	1	15,397
Very Small (100-200 kW)*	2,611	2,938	2,926	2,938	2,938	0	10	2,938	2,938
Small (200-500 kW)	1,640	1,987	1,986	2,007	2,007	1,976	6	2,007	2,007
Medium (500-1000 kW)	475	597	567	599	599	557	8	599	599
Large (1000-2000 kW)	152	200	184	200	200	183	5	200	200
Extra Large (2000+ kW)	91	143	137	144	144	137	1	144	144
Unknown	234	235	235	235	24	0	0	24	235
Business Type									
Commercial and TCU									
Office	4,759	4,863	4,855	4,863	1,072	451	1	1,072	4,863
Retail/Grocery	3,275	3,738	3,748	3,760	970	436	12	971	3,760
Institutional	2,776	3,118	3,110	3,119	1,366	777	0	1,366	3,119
Other Commercial	4,508	5,105	5,071	5,105	1,126	441	2	1,126	5,105
Transportation/Communication/Utility	956	1,079	1,076	1,079	461	259	1	461	1,079
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	207	224	223	224	124	65	0	124	224
Mining, Metals, Stone, Glass, Concrete	83	87	86	87	33	19	1	33	87
Electronic, Machinery, Fabricated Metals	719	795	781	795	355	204	6	355	795
Other Industrial and Agriculture	1,028	1,081	1,072	1,081	297	154	8	297	1,081
Unclassified									
Unknown	1,404	1,407	1,407	1,407	108	47	0	108	1,407
Total Accounts	19,715	21,497	21,429	21,520	5,912	2,853	31	5,913	21,520

*Closed to new enrollment; only current participants shown as eligible

Exhibit 4-5b
Eligible Populations in SDG&E, Non-Coincident Peak Load Basis

SDG&E	Day-Ahead Programs CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	Reliability Programs BIP (MW)	OBMC (MW)	INTER* (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	657	704	0	704	0	0	0	0	704
Very Small (100-200 kW)	361	406	0	406	406	0	1	406	406
Small (200-500 kW)	492	604	604	612	612	600	2	612	612
Medium (500-1000 kW)	330	414	392	415	415	389	5	415	415
Large (1000-2000 kW)	202	268	246	268	268	244	7	268	268
Extra Large (2000+ kW)	626	1,108	1,100	1,123	1,123	1,102	3	1,123	1,123
Unknown	7	7	0	7	2	0	0	2	7
Business Type									
Commercial and TCU									
Office	518	548	284	548	375	289	3	375	548
Retail/Grocery	272	362	182	371	251	172	2	251	371
Institutional	485	974	809	989	902	811	0	902	989
Other Commercial	487	572	262	572	386	266	2	386	572
Transportation/Communication/Utility	475	505	450	505	477	426	0	477	505
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	42	49	37	49	44	36	0	44	49
Mining, Metals, Stone, Glass, Concrete	11	14	8	14	12	10	2	12	14
Electronic, Machinery, Fabricated Metals	165	232	177	232	211	186	4	211	232
Other Industrial and Agriculture	118	144	78	144	106	86	6	106	144
Unclassified									
Unknown	103	110	55	110	63	55	0	63	110
Total Non-coincident Load	2,675	3,511	2,342	3,535	2,826	2,335	19	2,826	3,535

*Closed to new enrollment; only current participants shown as eligible

An important component of participation in day-ahead and reliability programs is the presence of an interval meter at the customer site. Exhibit 4-6 shows the percentage of eligible accounts for each utility that are believed to have an interval meter. As the exhibit clearly shows, the share of eligible customers with interval meters varies significantly across the three utilities. Currently, interval meters are present at 100 percent of eligible SCE accounts and 75 percent of eligible PG&E accounts, while only 25 percent of eligible SDG&E accounts have interval meters currently installed. This difference is to be expected since 85 percent of eligible SDG&E population has an annual maximum demand of less than 200 kW and are not required to have an interval meter installed. Exhibit 4-7 illustrates that the share of eligible customers with interval meters in SDG&E increases greatly among customers with demands larger than 200 kW. In fact, if eligible customers with demands smaller than 200 kW are excluded, the overall share of eligible SDG&E customers with interval meters is identical to that in PG&E (75%).

Exhibit 4-6
Share of Eligible Accounts with Interval Meters Currently Installed by Utility

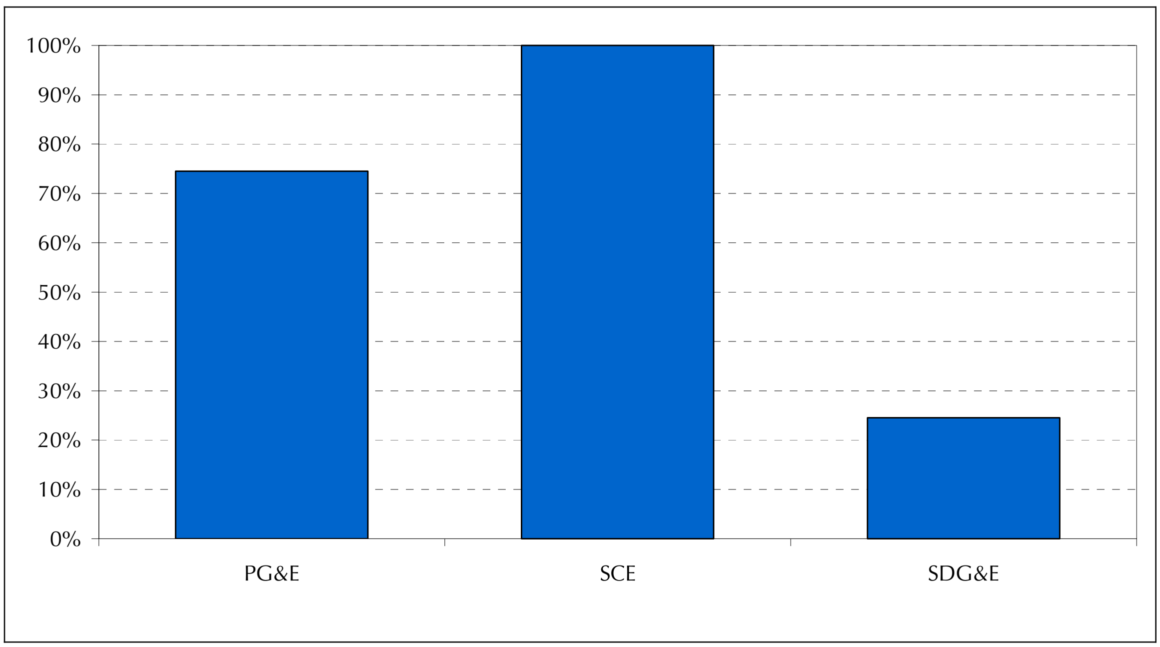
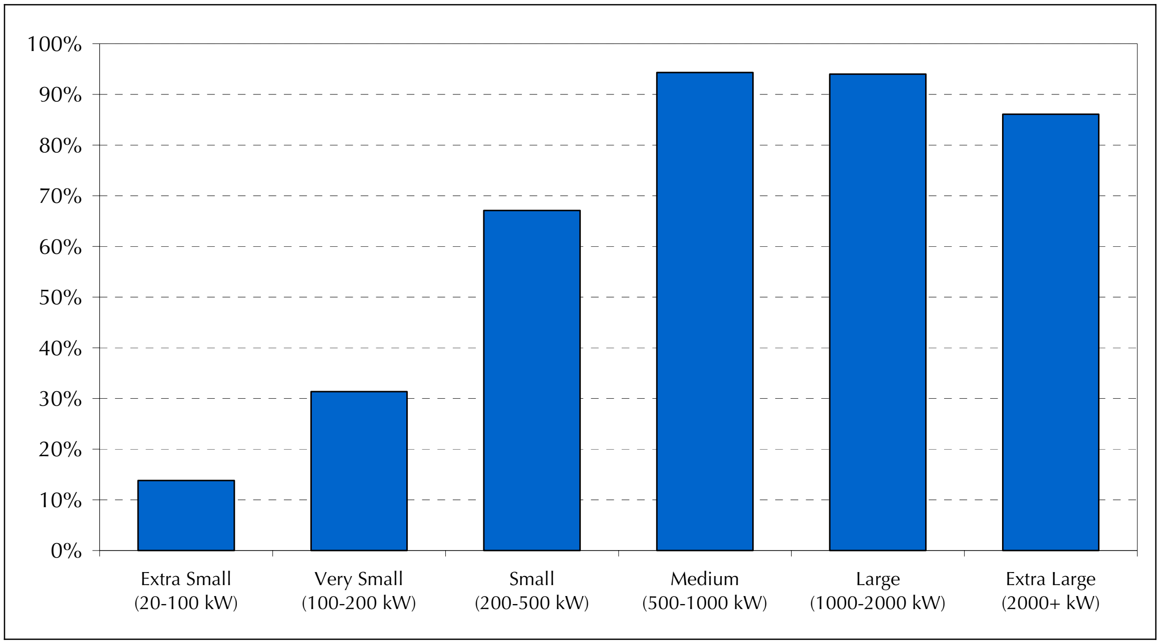


Exhibit 4-7
Share of SDG&E Eligible Accounts with Interval Meters Currently Installed by Customer Size



4.2 PROGRAM PARTICIPATION

Exhibits 4-8 and 4-8b summarize overall participation in the day-ahead and reliability programs across the three utilities and the distribution of participants by customer size and business type. These figures were current as of mid-October 2005 for PG&E and as of mid-August 2005 for SCE and SDG&E.[1]

As Exhibit 4-8 shows, participation to date varies widely across both utilities and programs. Across day-ahead programs, statewide participation on an account basis is highest in the DBP program (1,231 accounts), followed by CPP (410 accounts), and DRP (285 accounts). Within these programs, the majority of accounts enrolled in DBP are SCE customers (57%), while the majority of accounts enrolled in CPP and DRP statewide are PG&E customers (76% and 59%, respectively). SDG&E customers comprise 27 percent of accounts enrolled in CPP statewide but only 5 percent of accounts enrolled in DBP and 8 percent of accounts enrolled in DRP. Among reliability programs, statewide participation in interruptible tariffs remains significant and largely concentrated among SCE customers taking service on the I-6 tariff. Statewide participation in the OBMC and BIP programs, however, is comparatively low, with only 102 accounts statewide enrolled in BIP and 44 accounts statewide enrolled in OBMC. PG&E customers account for the majority of current OBMC participants, while SCE customers account

[1] It should be noted that 50 of PG&E's current CPP participants and 3 of PG&E's current DBP participants enrolled after the last CPP and DBP events of the 2005 season (August 5th and September 30th, respectively). These accounts are included in the participation tables shown in Chapter 4 but are excluded from the CPP and DBP impact assessment presented in Chapter 7.

for the majority of current BIP participants. No customers in SDG&E's service territory have enrolled in either the BIP or OBMC programs to date.

Exhibit 4-8
Statewide Program Participation to Date, Account Basis

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	BIP (accts)	OBMC (accts)	INTER (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)	3	46	0	48	0	0	8	8	56
Very Small (100-200 kW)	12	28	4	43	1	0	16	17	59
Small (200-500 kW)	149	431	202	762	6	0	33	39	794
Medium (500-1000 kW)	145	345	26	485	44	0	168	212	635
Large (1000-2000 kW)	74	215	16	282	23	1	192	216	440
Extra Large (2000+ kW)	27	166	37	218	28	43	204	269	403
Unknown	0	0	0	0	0	0	6	6	6
Business Type									
Commercial and TCU									
Office	48	227	7	263	1	0	11	12	270
Retail/Grocery	30	167	157	353	4	0	19	23	374
Institutional	80	108	11	193	4	1	26	31	216
Other Commercial	79	201	68	321	17	4	26	47	350
Transportation/Communication/Utility	47	162	26	231	12	1	69	82	280
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	11	46	4	59	15	3	105	122	152
Mining, Metals, Stone, Glass, Concrete	12	62	5	77	17	10	136	160	191
Electronic, Machinery, Fabricated Metals	55	117	1	156	8	9	77	93	225
Other Industrial and Agriculture	46	138	6	181	23	16	158	196	331
Unclassified									
Unknown	2	3	0	4	1	0	0	1	4
Total Accounts	410	1,231	285	1,838	102	44	627	767	2,393
Unique Customers	197	598	45	780	86	41	474	583	1,192
Utility Breakdown									
PG&E	292	466	169	856	24	31	95	147	956
SCE	8	703	93	803	78	13	501	589	1,229
SDG&E	110	62	23	179	0	0	31	31	208

Exhibit 4-8b shows current statewide participation in terms of enrolled non-coincident peak load across programs. Across day-ahead programs, statewide participation is again highest in the DBP program, with 1,609 MW of non-coincident peak load currently enrolled in the program. Enrolled non-coincident peak load in the DRP program currently totals more than twice that enrolled in CPP (939 MW and 380 MW, respectively) despite a far fewer number of participating accounts. This is due to the influence of twelve very large pumping facilities that currently participate in the DRP program that have a combined non-coincident peak load of approximately 600 MW. SCE customers again account for the majority of non-coincident peak load enrolled in DBP (53%), and PG&E customers account for the majority of non-coincident peak load enrolled in CPP and DRP (76% and 79%, respectively). Across reliability programs, statewide participation is again highest in interruptible tariffs, with 1,790 MW of non-coincident peak load enrolled in these tariffs, of which 1,355 MW are enrolled in SCE's I-6 tariff. Total non-coincident peak load enrolled in the OBMC program is currently 420 MW and exceeds that enrolled in BIP (250 MW) largely because nearly all OBMC participants have individual peak demands that exceed 2 MW.

In total, statewide enrollment in day-ahead programs stands at 1,838 accounts and 2,822 MW of non-coincident peak load. Total statewide enrollment in reliability programs stands at 767 accounts and 2,325 MW of non-coincident peak load.

Exhibit 4-8b
Statewide Program Participation to Date, Non-Coincident Peak Load Basis

3 IOUs	Day-Ahead Programs				Reliability Programs				
	CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	BIP (MW)	OBMC (MW)	INTER (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	1
Very Small (100-200 kW)	1	2	0	3	0	0	2	3	6
Small (200-500 kW)	52	139	73	257	2	0	12	14	268
Medium (500-1000 kW)	101	244	16	339	31	0	126	157	450
Large (1000-2000 kW)	104	296	25	391	33	2	273	308	618
Extra Large (2000+ kW)	121	927	825	1,831	185	418	1,376	1,843	3,089
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	51	152	15	190	1	0	21	22	217
Retail/Grocery	15	61	62	137	6	0	11	17	153
Institutional	45	166	56	260	7	5	67	78	303
Other Commercial	64	243	39	318	15	25	59	98	377
Transportation/Communication/Utility	37	220	613	865	16	3	182	201	972
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	16	71	17	102	28	31	241	286	323
Mining, Metals, Stone, Glass, Concrete	20	216	118	346	107	185	631	807	853
Electronic, Machinery, Fabricated Metals	62	231	4	277	18	84	257	354	540
Other Industrial and Agriculture	70	240	15	319	48	87	323	455	685
Unclassified									
Unknown	1	8	0	8	7	0	0	7	8
Total Non-coincident Load	380	1,609	939	2,822	250	420	1,790	2,325	4,433
Utility Breakdown									
PG&E	290	692	745	1,640	53	225	416	661	2,094
SCE	6	853	171	1,029	197	195	1,355	1,646	2,171
SDG&E	84	64	24	153	0	0	19	19	167

Exhibits 4-9, 4-9b, 4-10, 4-10b, 4-11 and 4-11b provide similar breakdowns of current participation in in-scope programs in PG&E, SCE and SDG&E, respectively.

Exhibit 4-9
PG&E Program Participation to Date, Account Basis

PG&E	Day-Ahead Programs CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	Reliability Programs BIP (accts)	OBMC (accts)	INTER (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)	0	44	0	44	0	0	0	0	44
Very Small (100-200 kW)	2	17	4	23	0	0	0	0	23
Small (200-500 kW)	115	109	114	322	4	0	0	4	323
Medium (500-1000 kW)	99	124	14	211	4	0	7	11	218
Large (1000-2000 kW)	56	93	11	140	8	1	23	32	164
Extra Large (2000+ kW)	20	79	26	116	8	30	65	100	184
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	43	184	7	215	0	0	0	0	217
Retail/Grocery	9	4	65	77	1	0	0	1	77
Institutional	72	17	6	92	0	1	7	8	98
Other Commercial	41	67	67	160	3	2	3	8	166
Transportation/Communication/Utility	12	71	15	94	7	1	25	33	106
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	7	5	1	11	3	2	4	9	19
Mining, Metals, Stone, Glass, Concrete	10	15	3	26	3	8	16	25	43
Electronic, Machinery, Fabricated Metals	52	38	0	74	0	2	1	3	78
Other Industrial and Agriculture	44	62	5	103	6	15	39	59	148
Unclassified									
Unknown	2	3	0	4	1	0	0	1	4
Total Accounts	292	466	169	856	24	31	95	147	956
Unique Customers	140	238	30	356	20	28	73	115	436

Exhibit 4-9b
PG&E Participation to Date, Non-Coincident Peak Load Basis

PG&E	Day-Ahead Programs CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	Reliability Programs BIP (MW)	OBMC (MW)	INTER (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	0
Very Small (100-200 kW)	0	0	0	0	0	0	0	0	0
Small (200-500 kW)	40	39	41	113	2	0	0	2	113
Medium (500-1000 kW)	71	88	8	148	3	0	7	9	154
Large (1000-2000 kW)	79	127	18	193	12	2	34	48	230
Extra Large (2000+ kW)	100	439	678	1,186	37	223	375	603	1,597
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	47	108	15	142	0	0	0	0	161
Retail/Grocery	4	1	23	27	0	0	0	0	27
Institutional	37	23	18	75	0	5	17	22	90
Other Commercial	33	84	37	138	3	10	9	22	153
Transportation/Communication/Utility	10	140	608	754	7	3	73	83	782
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	13	24	1	36	6	18	28	51	67
Mining, Metals, Stone, Glass, Concrete	19	61	31	103	5	90	119	184	218
Electronic, Machinery, Fabricated Metals	58	86	0	127	0	17	36	53	158
Other Industrial and Agriculture	69	157	10	230	26	82	133	238	429
Unclassified									
Unknown	1	8	0	8	7	0	0	7	8
Total Non-coincident Load	290	692	745	1,640	53	225	416	661	2,094

Exhibit 4-10
SCE Program Participation to Date, Account Basis

SCE	Day-Ahead Programs				Reliability Programs				
	CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	BIP (accts)	OBMC (accts)	INTER (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	7	7	7
Very Small (100-200 kW)	0	9	0	9	1	0	6	7	15
Small (200-500 kW)	3	307	68	378	2	0	27	29	403
Medium (500-1000 kW)	4	197	10	210	40	0	153	193	345
Large (1000-2000 kW)	1	110	5	116	15	0	164	179	246
Extra Large (2000+ kW)	0	80	10	90	20	13	138	168	207
Unknown	0	0	0	0	0	0	6	6	6
Business Type									
Commercial and TCU									
Office	0	35	0	35	1	0	10	11	40
Retail/Grocery	1	163	70	234	3	0	7	10	243
Institutional	0	82	4	86	4	0	19	23	103
Other Commercial	0	102	1	103	14	2	21	37	124
Transportation/Communication/Utility	1	89	11	101	5	0	43	48	137
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	1	40	3	44	12	1	101	113	129
Mining, Metals, Stone, Glass, Concrete	2	46	2	50	14	2	119	134	147
Electronic, Machinery, Fabricated Metals	1	71	1	73	8	7	70	84	132
Other Industrial and Agriculture	2	75	1	77	17	1	111	129	174
Unclassified									
Unknown	0	0	0	0	0	0	0	0	0
Total Accounts	8	703	93	803	78	13	501	589	1,229
Unique Customers	8	327	13	347	66	13	385	452	666

Exhibit 4-10b
SCE Participation to Date, Non-Coincident Peak Load Basis

SCE	Day-Ahead Programs				Reliability Programs				
	CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	BIP (MW)	OBMC (MW)	INTER (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	0
Very Small (100-200 kW)	0	2	0	2	0	0	1	1	3
Small (200-500 kW)	1	95	25	121	1	0	10	11	130
Medium (500-1000 kW)	3	139	7	148	28	0	114	142	248
Large (1000-2000 kW)	1	153	7	161	21	0	233	253	346
Extra Large (2000+ kW)	0	465	132	596	148	195	997	1,238	1,444
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	0	35	0	35	1	0	18	19	43
Retail/Grocery	1	60	30	92	6	0	9	15	106
Institutional	0	134	22	156	7	0	49	56	183
Other Commercial	0	127	2	128	12	15	47	74	170
Transportation/Communication/Utility	1	78	5	84	9	0	108	117	162
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	1	47	16	65	22	13	213	235	254
Mining, Metals, Stone, Glass, Concrete	1	153	87	241	102	95	509	621	634
Electronic, Machinery, Fabricated Metals	0	137	4	141	18	67	217	297	370
Other Industrial and Agriculture	1	82	5	87	22	5	185	212	249
Unclassified									
Unknown	0	0	0	0	0	0	0	0	0
Total Non-coincident Load	6	853	171	1,029	197	195	1,355	1,646	2,171

Exhibit 4-11
SDG&E Program Participation to Date, Account Basis

SDG&E	Day-Ahead Programs				Reliability Programs				
	CPP (accts)	DBP (accts)	DRP (accts)	Total (accts)	BIP (accts)	OBMC (accts)	INTER (accts)	Total (accts)	Total DR (accts)
Size									
Extra Small (20-100 kW)	3	2	0	4	0	0	1	1	5
Very Small (100-200 kW)	10	2	0	11	0	0	10	10	21
Small (200-500 kW)	31	15	20	62	0	0	6	6	68
Medium (500-1000 kW)	42	24	2	64	0	0	8	8	72
Large (1000-2000 kW)	17	12	0	26	0	0	5	5	30
Extra Large (2000+ kW)	7	7	1	12	0	0	1	1	12
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	5	8	0	13	0	0	1	1	13
Retail/Grocery	20	0	22	42	0	0	12	12	54
Institutional	8	9	1	15	0	0	0	0	15
Other Commercial	38	32	0	58	0	0	2	2	60
Transportation/Communication/Utility	34	2	0	36	0	0	1	1	37
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	3	1	0	4	0	0	0	0	4
Mining, Metals, Stone, Glass, Concrete	0	1	0	1	0	0	1	1	1
Electronic, Machinery, Fabricated Metals	2	8	0	9	0	0	6	6	15
Other Industrial and Agriculture	0	1	0	1	0	0	8	8	9
Unclassified									
Unknown	0	0	0	0	0	0	0	0	0
Total Accounts	110	62	23	179	0	0	31	31	208
Unique Customers	49	33	2	77	0	0	16	16	90

Exhibit 4-11b
SDG&E Participation to Date, Non-Coincident Peak Load Basis

SDG&E	Day-Ahead Programs				Reliability Programs				
	CPP (MW)	DBP (MW)	DRP (MW)	Total (MW)	BIP (MW)	OBMC (MW)	INTER (MW)	Total (MW)	Total DR (MW)
Size									
Extra Small (20-100 kW)	0	0	0	0	0	0	0	0	0
Very Small (100-200 kW)	1	0	0	2	0	0	1	1	3
Small (200-500 kW)	12	5	7	23	0	0	2	2	25
Medium (500-1000 kW)	26	18	1	43	0	0	5	5	48
Large (1000-2000 kW)	23	17	0	36	0	0	7	7	41
Extra Large (2000+ kW)	21	23	16	49	0	0	3	3	49
Unknown	0	0	0	0	0	0	0	0	0
Business Type									
Commercial and TCU									
Office	4	8	0	13	0	0	3	3	13
Retail/Grocery	10	0	8	19	0	0	2	2	21
Institutional	8	10	16	29	0	0	0	0	29
Other Commercial	31	32	0	52	0	0	2	2	54
Transportation/Communication/Utility	26	1	0	27	0	0	0	0	28
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	1	0	0	2	0	0	0	0	2
Mining, Metals, Stone, Glass, Concrete	0	2	0	2	0	0	2	2	2
Electronic, Machinery, Fabricated Metals	3	8	0	8	0	0	4	4	12
Other Industrial and Agriculture	0	2	0	2	0	0	6	6	7
Unclassified									
Unknown	0	0	0	0	0	0	0	0	0
Total Non-coincident Load	84	64	24	153	0	0	19	19	167

Customers who enroll in CPP are eligible to simultaneously enroll in the Bill Protection Incentive (BPI), which provides 12 months of guaranteed protection against increases in annual electric bills compared to what they would have been charged on their Otherwise Applicable Tariff (OAT). As of mid-August 2005, nearly all customers who had signed up for CPP in SCE and SDG&E were also enrolled in BPI (all eight CPP customers in SCE and 108 out of 110 CPP participants in SDG&E). In PG&E, the share of CPP participants who had also enrolled in BPI was comparatively lower than in the other utilities, with 192 out of 292 CPP participants having enrolled in BPI as of mid-October 2005.

Customers who are considering participating in CPP, DBP, DRP, and/or BIP can also take advantage of free cursory audits, detailed technical audits, and technology incentives available through the Technical Assistance & Technology Incentives (TA/TI) Program to help identify demand response opportunities and install enabling technologies. To date, participation in the TA/TI program has been low, as the program features have evolved significantly since the 2004 program season and the utilities just beginning to comprehensively market the new TA/TI program. As of mid-August 2005, SCE reported that 4 customers had requested and completed preliminary audits and one customer had completed a detailed technical audit.[2] Similarly, SDG&E reported that 5 customers had requested and completed preliminary audits and one customer had completed a detailed technical audit. PG&E did not report any completed audits during the 2005 program season, and none of the utilities reported paying technology incentives under the TA/TI program in 2005.

4.2.1 Participants by Market Segment

Based on the data shown in Exhibits 4-9 through 4-11b, this section takes a closer look at the relative distribution of current participants across customer sizes and business types for each in-scope program. Additionally, this section reviews the extent of multiple program participation and examines the size and business type characteristics of customers that currently participate in multiple WG2 programs. Finally, this section compares the customer size and business type characteristics between "active" versus "non-active" participants within the CPP and DBP programs.

Total participation in CPP is fairly evenly distributed across business types, with Commercial, Industrial, and Institutional customers each comprising about a third of total CPP participants, in large part reflecting the distribution of CPP participants in PG&E. For SCE and SDG&E customers, however, Exhibit 4-12 shows that Commercial customers make up more than half of SDG&E's CPP participants, whereas Industrial customers account for 75 percent of SCE's CPP participants. Note that the relative distribution of CPP participants in SCE is based on only 8 accounts and thus should not be thought of as representative of the likely customer distribution for this program going forward.

Across all DBP participants, a larger share are Commercial customers (48%), with Industrial customers accounting for 29 percent and Institutional customers comprising the remaining 22 percent. In large part, this overall distribution reflects the characteristics of DBP participants in PG&E and SCE, who account for 95 percent of all DBP participants. As Exhibit 4-12 shows,

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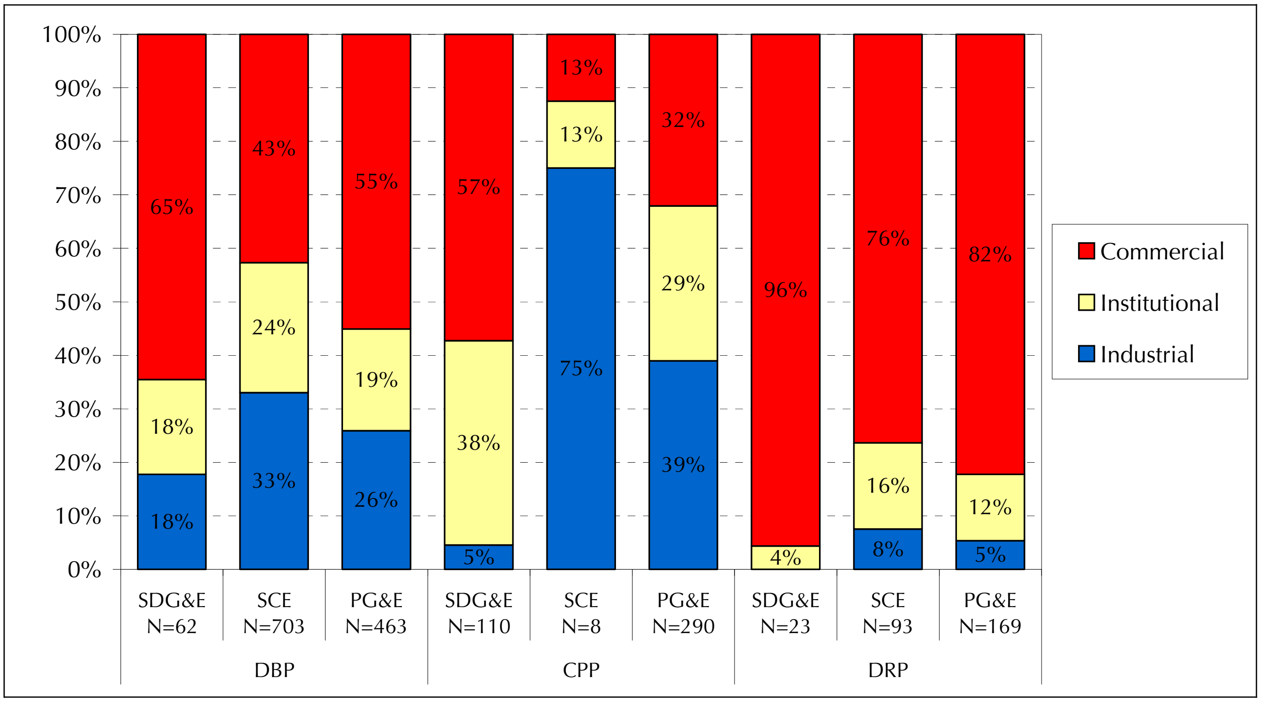
[2] SCE reported that through mid-December 2005, 160 customers had expressed interest in the TA/TI program.

however, DBP participants in PG&E, SCE, and SDG&E exhibit fairly similar relative distributions across business types.

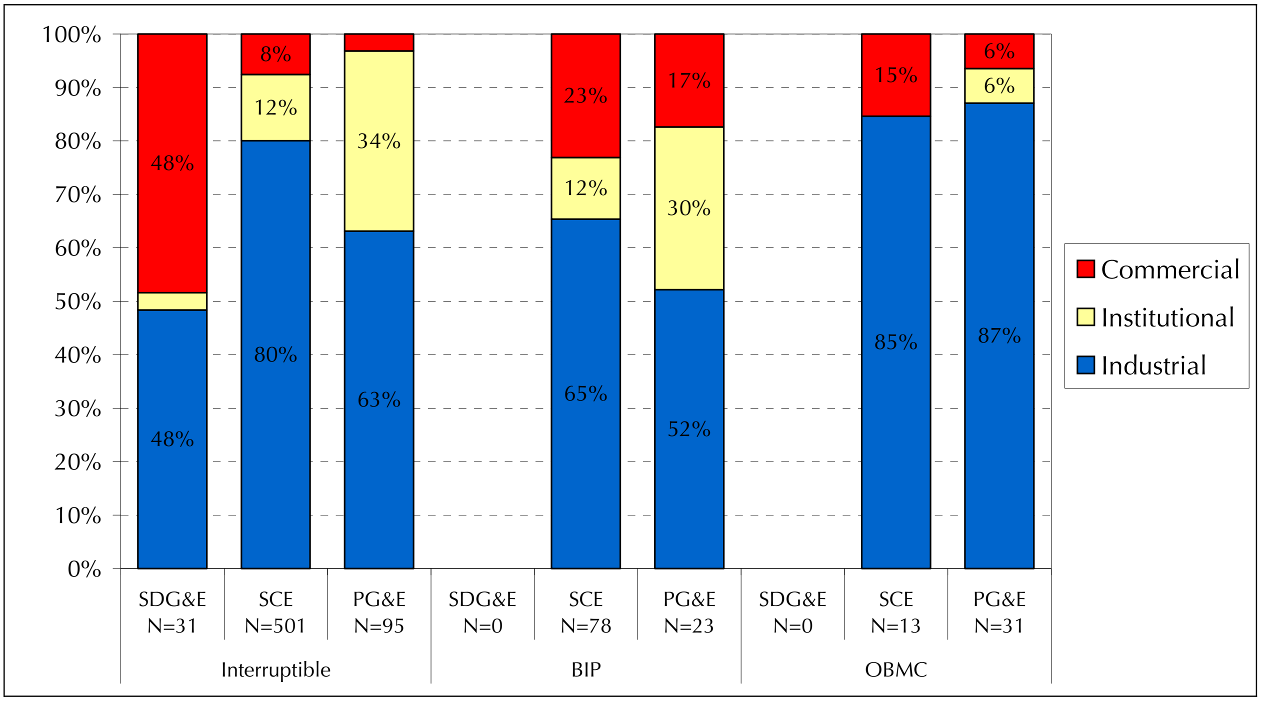
Exhibit 4-12
Day-Ahead Program Participants by Business Type for each Utility



As might be expected, DRP participants exhibit a similar distribution across business types as DBP participants, but as Exhibit 4-12 shows, Commercial customers account for an even larger share of total DRP participants (86% overall). As Exhibit 4-12 shows, the distribution of DRP participants across business types does not vary significantly across the three utilities, with the sole exception that none of SDG&E's DRP participants are Industrial customers.

In contrast to the large shares of Commercial customers among current participants in WG2 day-ahead programs, Commercial customers account for a much smaller share of current participants in WG2 reliability programs (traditional interruptible tariffs, BIP, and OBMC). Overall, Commercial customers account for only 22 percent of all accounts currently enrolled in BIP and 9 percent of all accounts currently enrolled in traditional interruptible tariffs and OBMC. In contrast, Industrial customers account for 62 percent of accounts enrolled in BIP, 76 percent of accounts enrolled in traditional interruptible tariffs, and 86 percent of accounts enrolled in OBMC. Looking at enrollment by business type across utilities, the most important differences are the higher relative shares of Institutional customers among reliability program participants in PG&E and the higher relative share of Commercial customers among reliability program participants in SDG&E.

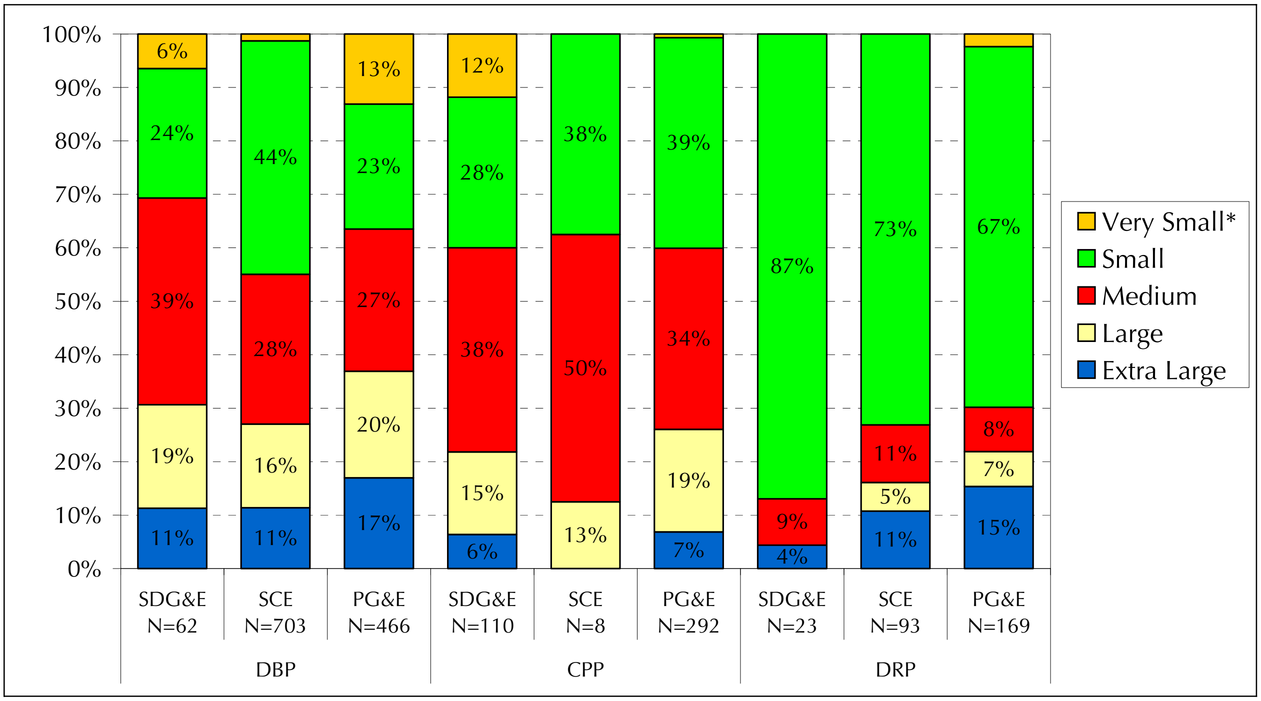
Exhibit 4-13
Reliability Program Participants by Business Type for each Utility



Looking at participation across customer sizes, overall participation in the 2005 CPP and DBP programs is composed primarily of Small and Medium customers, each accounting for roughly a third of accounts enrolled in CPP and DBP. Large and Extra Large customers account for smaller but significant shares of total CPP and DBP participants. Very Small and Extra Small customers combined, however, currently account for less than 6 percent of total accounts currently enrolled in CPP and DBP. These distributions of participants across customer sizes vary only slightly within each utility, as shown in Exhibit 4-14. The higher relative share of Very Small customers among SDG&E's DBP and CPP participants reflects the lower eligibility requirements for SDG&E customers compared to PG&E and SCE customers, i.e. maximum demand of 20 kW instead of 200 kW. The small number of Very Small customers among DBP participants in PG&E and SCE reflect accounts that currently participate under the aggregation allowances of their respective DBP programs.

Among current DRP participants, Small customers currently account for 75 percent of total accounts enrolled with Medium, Large, and Extra Large customers accounting for roughly equal shares of the remaining participants. As Exhibit 4-14 shows, the distribution of DRP participants across customer sizes is fairly similar in each utility, although Small customers make up a higher relative share of DRP participants in SDG&E.

Exhibit 4-14
Day-Ahead Program Participants by Customer Size for each Utility

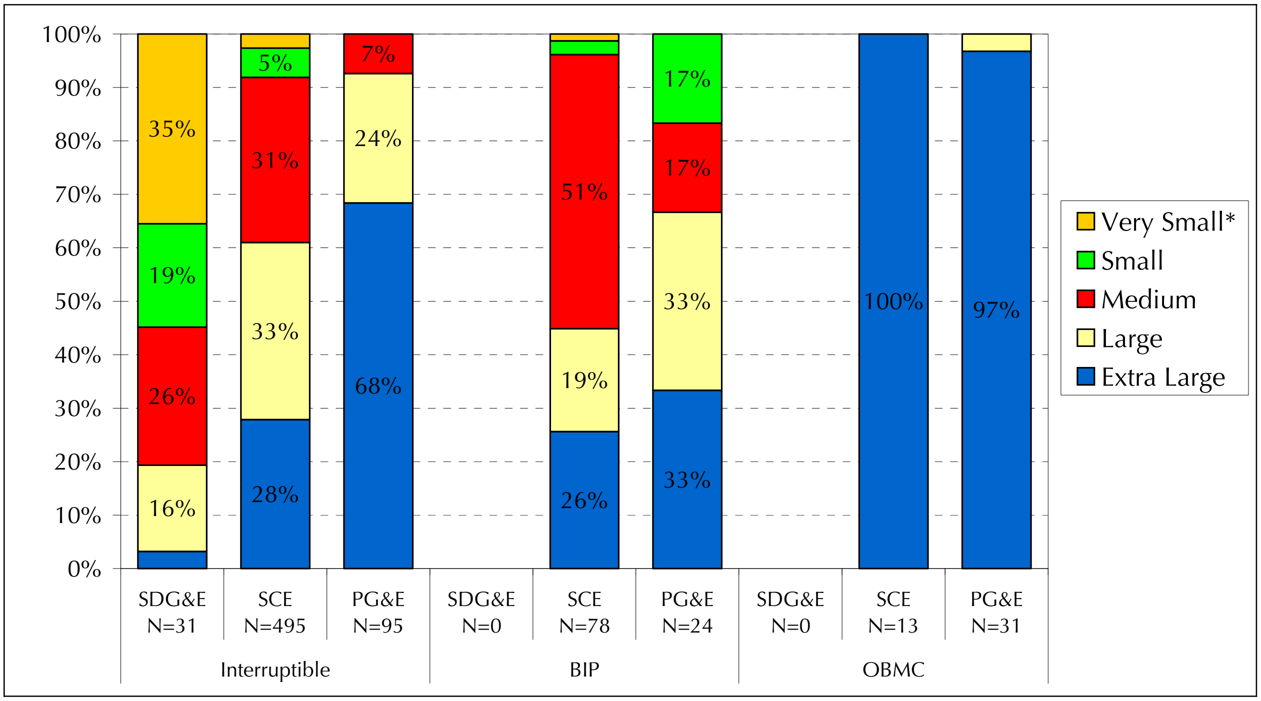


* Extra Small customers shown aggregated with Very Small customers

Among participants in reliability programs, Exhibit 4-15 shows that the majority of current participants are Large and Extra Large customers (i.e. annual maximum demands greater than 1 MW). Indeed, as the Exhibit shows, Large and Extra Large customers currently account for the entire participant population in the OBMC program. In contrast to participation in day-ahead programs, Small and Very Small customers (i.e. annual max demands less than 200 kW) account for less than 10 percent of the total accounts currently enrolled in reliability programs. Since more than 75 percent of all reliability program participants are in SCE, these overall distributions by customer size largely reflect the size of participants in SCE's reliability programs.

As Exhibit 4-15 shows, however, the distribution of reliability program participants across customer sizes differs significantly in both PG&E and SDG&E. In PG&E, Extra Large customers account for by far the largest share of participants in traditional interruptible tariffs and only 7 percent of participating accounts have max demands less than 1 MW. In contrast, more than half of the accounts enrolled in SDG&E's interruptible tariff (AL TOU CP) are Small or Very Small customers, and less than 20 percent have annual max demands greater than 1 MW. The distribution of interruptible participants in SDG&E reflects both the lower eligibility requirements for SDG&E's AL TOU CP tariff compared to SCE's I-6 tariff or PG&E's E19/E20 Non-firm tariffs.

Exhibit 4-15
Reliability Program Participants by Customer Size for each Utility



* Extra Small customers shown aggregated with Very Small customers

The data shown in the previous exhibits have been exclusively in terms of the number of accounts currently participating in WG demand response and reliability programs. In Exhibits 4-16 and 4-17, the total enrolled load (in terms of base non-coincident peak load) is shown by business type in order to show how the total enrolled DR resource is distributed across sectors for each program.

Exhibit 4-16 shows that for CPP and DBP participants in PG&E and SCE, Industrial loads comprise the majority of total program participation in MW terms despite the fact that Commercial and Institutional customers generally comprise the majority of participating accounts. For SDG&E, the distribution of enrolled load by business type shown Exhibit 4-16 is not significantly different from the distribution of enrolled accounts shown in Exhibit 4-12. This result indicates that customer size does not vary dramatically with business type among SDG&E's CPP and DBP participants.

Exhibit 4-16
Enrolled Load in Day-Ahead Programs by Business Type for each Utility

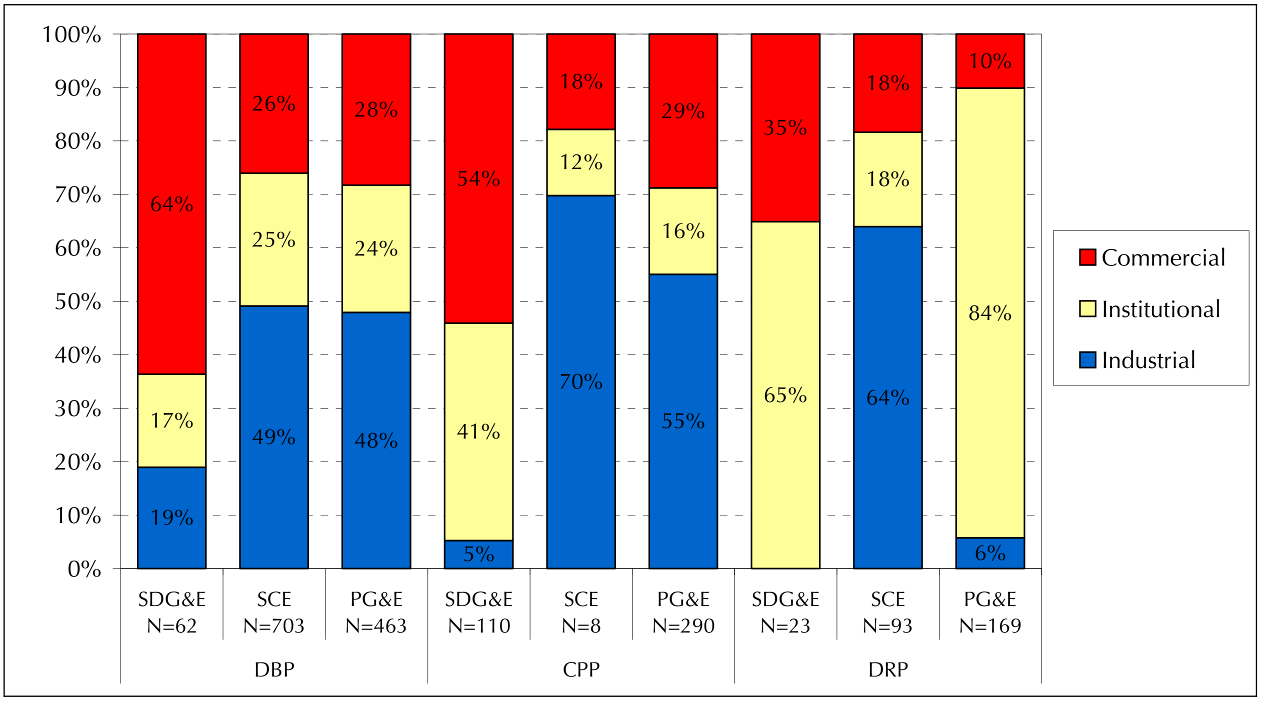
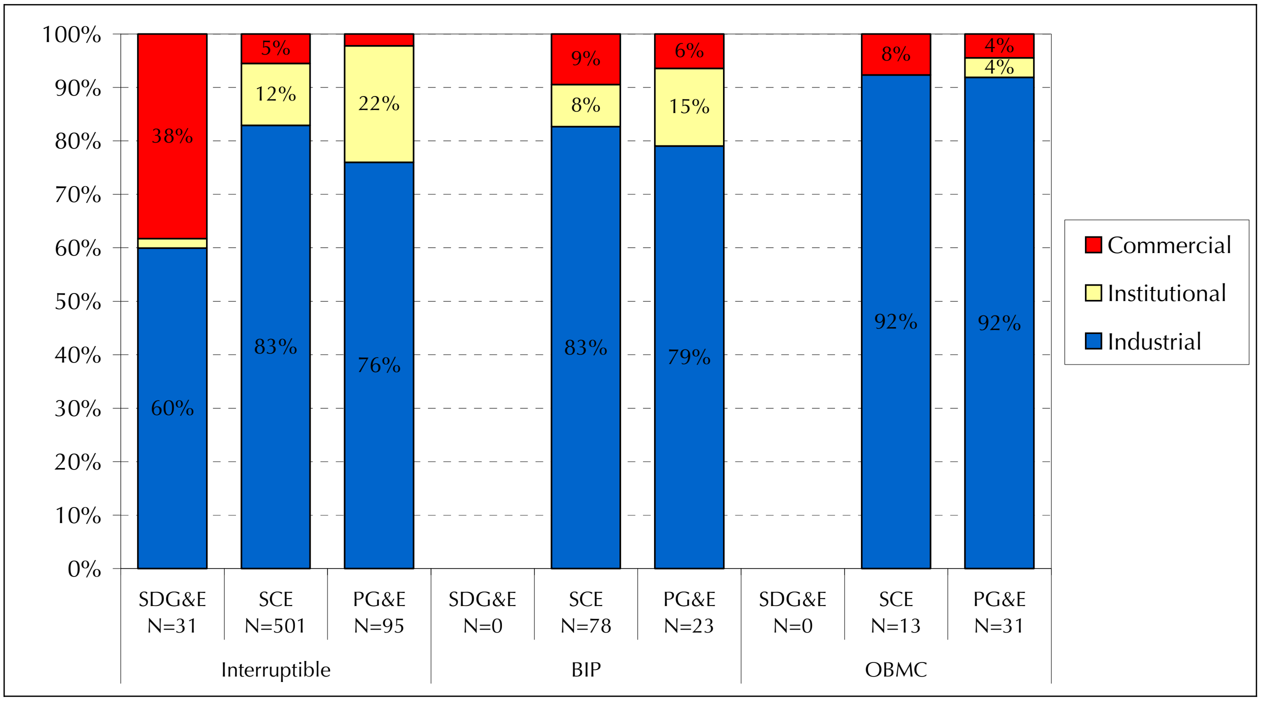


Exhibit 4-16 shows that although the vast majority of accounts participating in DRP are Commercial customers, these customers account for much smaller shares of total DRP participation in MW terms in each of the three utilities. In SCE, Industrial customers make up 64 percent of the total non-coincident load participating in DRP despite accounting for only 8 percent of enrolled accounts. In SDG&E, Institutional customers account for 65 percent of the total non-coincident load participating in DRP, despite accounting for only 4 percent of enrolled accounts. Similarly in PG&E, Institutional customers account for 84 percent of the total non-coincident load participating in DRP despite accounting for only 12 percent of the total enrolled accounts. For PG&E, this result reflects the influence of twelve very large pumping facilities that participate in the DRP program. Together, these twelve accounts have a combined non-coincident peak load of approximately 600 MW. The influence of these accounts on the total load reduction impacts from the 2005 DRP program is discussed in Chapter 7.

For reliability programs, Exhibit 4-17 shows that Industrial customers account for the vast majority of enrolled load in BIP, traditional interruptible tariffs, and OBMC. In contrast, Institutional and Commercial customers make up smaller relative shares of total enrolled load in reliability programs compared to the relative number of Institutional and Commercial accounts enrolled.

Exhibit 4-17
Enrolled Load in Reliability Programs by Business Type for each Utility



Multiple Program Participants

Exhibit 4-18 shows a matrix of the number of customers participating in multiple demand response or reliability programs. To date, the number of customers participating in multiple programs has been limited. However, Exhibit 4-18 shows one important overlap in the participant population that should be considered explicitly – roughly 30 percent of customers currently enrolled in reliability programs also participate in DBP.

Exhibit 4-18
Customer Participation in Multiple Day-Ahead and Reliability Programs

	CPP	DBP	DRP	BIP	OBMC	Interruptible
CPP	410					
DBP	**82**	1231				
DRP	**6**	-	269			
BIP	-	**30**	**2**	102		
OBMC	-	**10**	**3**	**2**	44	
Interruptible	-	**172**	**4**	-	**4**	627

This overlap is important to note not only because customers in reliability programs tend to be larger customers but also because customers in reliability programs tend to have larger and more developed load reduction capabilities compared to other customers, particularly customers enrolled in traditional interruptible tariffs. The influence of traditional interruptible customers on the total load reduction impacts from 2005 DBP participants is treated explicitly in Chapter 7. Below, the basic size and business type attributes of multiple program participants are compared to those of the rest of the participant population.

Exhibits 4-19 and 4-20 show the breakdown of participants in DBP and traditional interruptible tariffs by business type and customer size, respectively. As the Exhibits show, the interruptible customers that also participate in DBP are fairly representative of the total population of interruptible customers, both in terms of business type and customer size. Compared to the rest of the DBP participant population, however, interruptible customers that also participate in DBP are clearly much larger on average and tend to be Industrial customers rather than Commercial or Institutional customers.

Exhibit 4-19
Participation in DBP and Traditional Interruptible Tariffs by Business Type

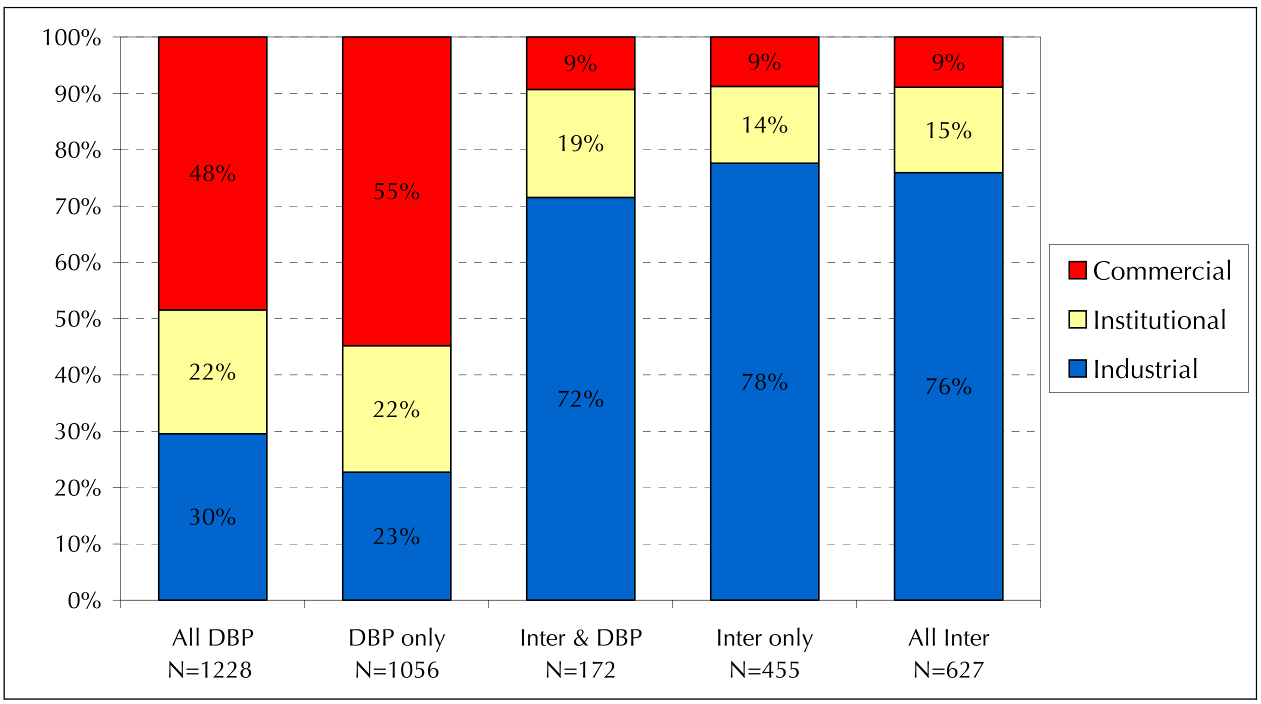
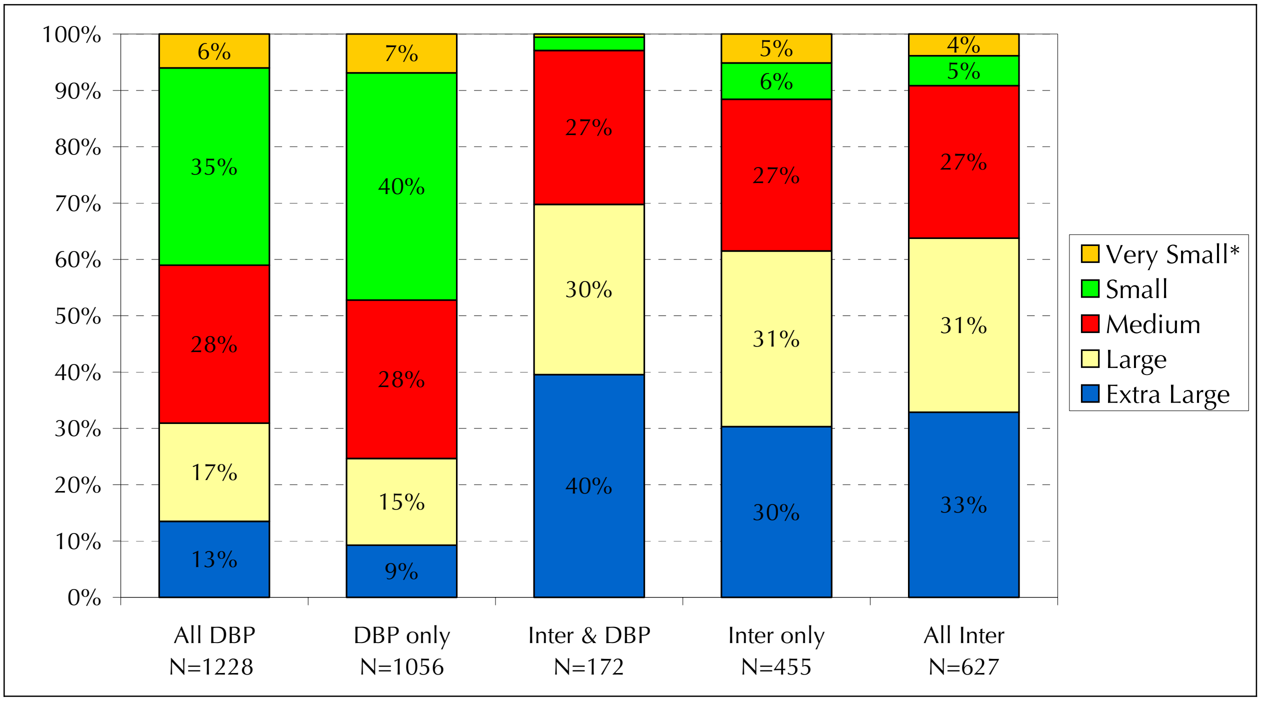


Exhibit 4-20
Participation in DBP and Traditional Interruptible Tariffs by Customer Size



* Extra Small customers shown aggregated with Very Small customers

Active and Non-active Participants

It is also informative to compare the basic business type and size attributes between program participants who actively provide significant load reductions and participants who are enrolled but have yet to actively provide significant load reductions. The comparison presented below focuses on "active" and "non-active" participants in the CPP and DBP programs. For purposes of this comparison, "active" CPP participants are defined as those who reduced their load by at least 5 percent on average during critical peak events during the summer of 2005.[3] For DBP, "active" participants are defined as those who submitted at least one load reduction bid for DBP events during the summer of 2005. "Active" DBP participants are referred to as "bidders" in the discussion below in order to differentiate them from "active" CPP participants.

Exhibit 4-21 compares the distribution of "active" and "non-active" CPP participants by business type, weighted by each participant's annual maximum demand. Exhibit 4-21 shows two important findings for CPP participants. First, only a third of total CPP participants provided load reductions that average at least 5 percent of their peak load. Second, the bulk of these "active" CPP participants were either Industrial customers in PG&E and SCE or Institutional customers in SDG&E.

[3] This load reduction is measured relative to each customer's 10-day adjusted baseline (see Chapter 6).

Exhibit 4-22 presents a similar comparison of DBP "bidders" and "non-bidders" and shows that DBP bidders also make up a relatively small share of total DBP participants. In contrast to "active" CPP participants, however, DBP "bidders" do not differ dramatically from "non-bidders" in terms of size or business type. Industrial customers do account for higher shares of DBP "bidders" compared to "non-bidders" in all three utilities but only marginally.

Exhibit 4-21
Active and Non-active CPP Participants by Business Type Weighted by Participant Demand

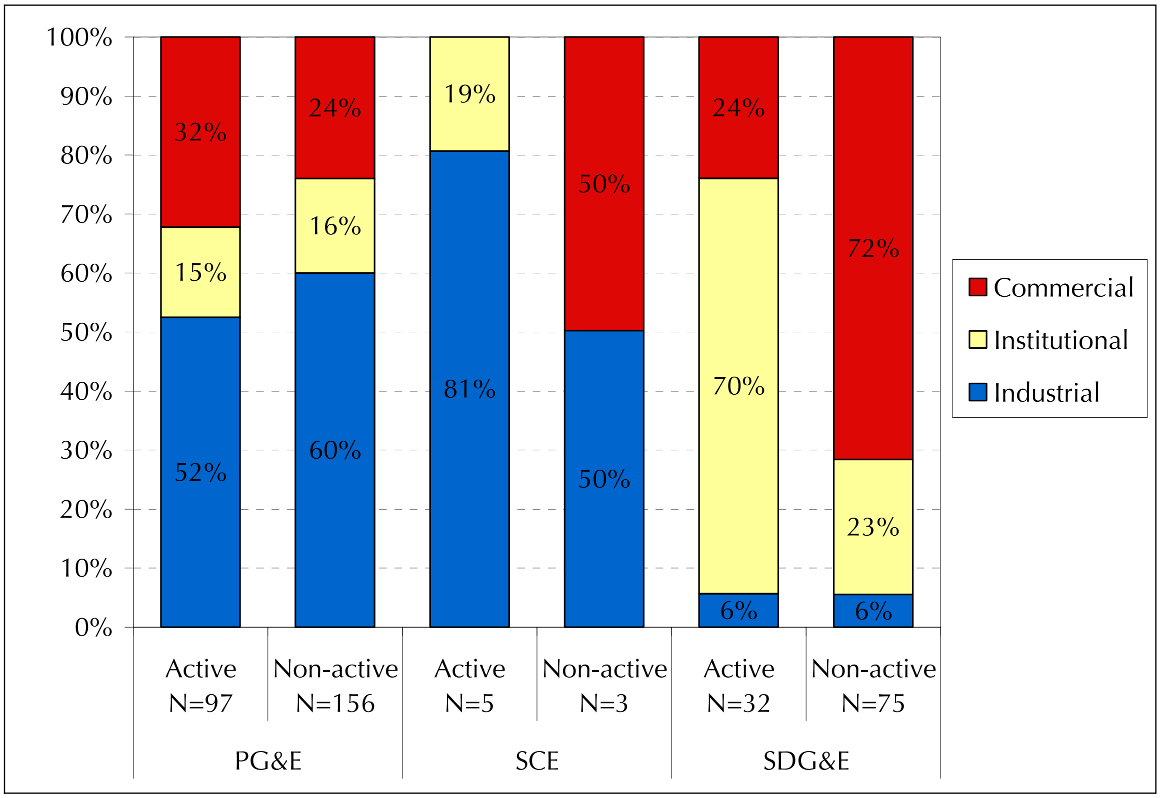
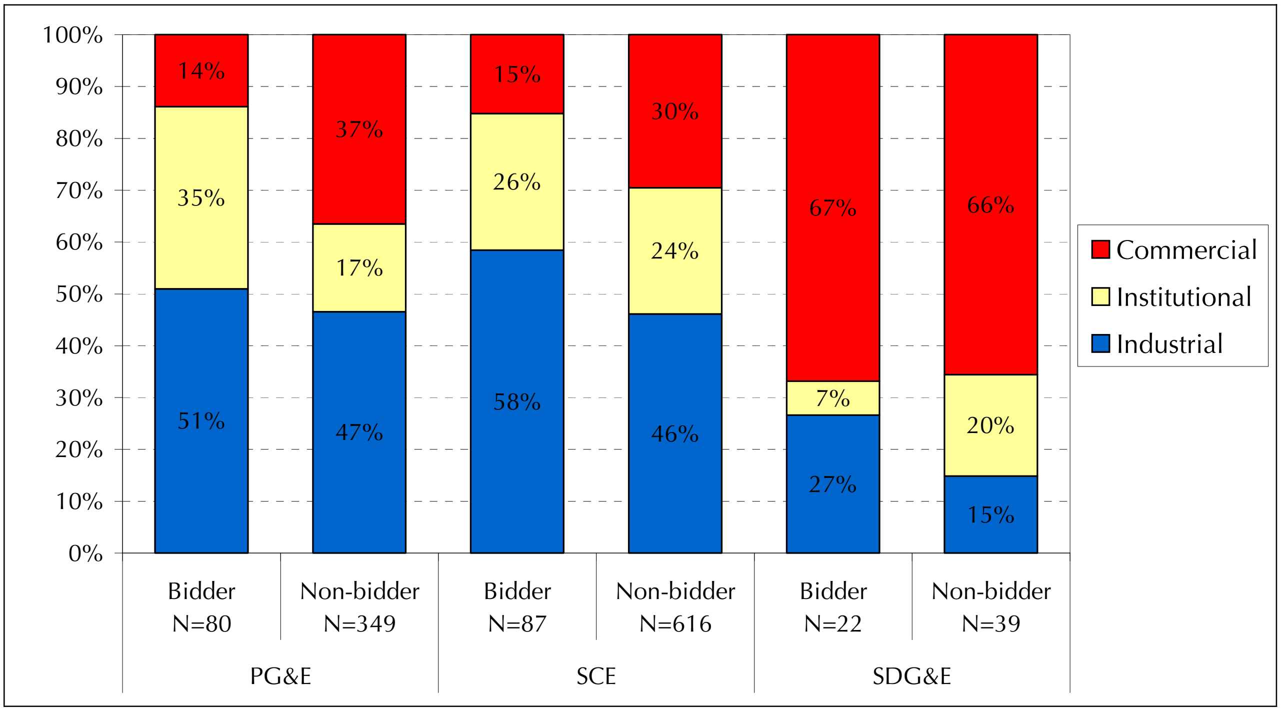


Exhibit 4-22
DBP Bidders and Non-bidders by Business Type Weighted by Participant Demand



4.2.2 Program Penetration

Information on eligible participants combined with the actual program participation figures indicate the extent to which various customer groups have been drawn towards participating in these demand response and reliability programs. Exhibit 4-23a presents the degree to which eligible accounts have been penetrated by the 2005 programs across the three utilities. Further breakdowns by business type and customer size are also provided, as well as program-specific penetration rates. Similarly, Exhibit 4-23b presents the degrees to which eligible non-coincident peak loads have been penetrated by the 2005 programs across all three utilities. Note that for purposes of comparison, the penetration rates shown for traditional interruptible tariffs use a denominator that describes all accounts that would be eligible if these interruptible tariffs were open for new enrollment.[4]

As Exhibits 4-23a and 4-23b show, the overall penetration rates of 2005 programs are low. On an account basis, current penetration rates range from 2.7 percent for DBP, 1.1 percent for CPP, and only 0.6 percent for DRP. On a MW basis, current penetration rates are comparatively higher

[4] Because traditional interruptible tariffs are closed to new enrollment, the ratio of participating customers to eligible customers would technically be one, or a penetration rate of 100%. However, this ratio does not describe the penetration of interruptible tariffs in the larger market of C&I customers. For purposes of comparing and contrasting market penetration rates across in-scope demand response and reliability programs, we therefore use a denominator that describes all accounts or non-coincident peak load that would be eligible if these tariffs were open to new customer enrollment.

(but still relatively low for CPP and DRP) ranging from 8.8 percent for traditional interruptible tariffs, 8.0 percent for DBP, 2.9 percent for CPP, and 1.9 percent for DRP. For DBP, the MW penetration rate should be interpreted with caution, due to the large number of customers enrolled who do not make load reduction bids (see Exhibit 4-22). If only bidders are counted, the MW penetration rate for DBP drops from 8.0 percent to 2.4 percent, and the account penetration drops from 2.7 percent to 0.4 percent.

As is evident in Exhibits 4-23a and 4-23b, there are two overall penetration trends that should also be noted. First, overall program penetration levels tend to be much lower among Small, Very Small, and Extra Small customers, both on an account basis and a MW basis. Indeed, with the exception of CPP, all of the 2005 programs exhibit their highest penetration rates amongst Extra Large customers. Second, program penetration levels tend to be higher among Industrial customers compared to Commercial and Institutional customers. Moreover, as Exhibits 4-23a and 4-23b show, this difference is more pronounced in the penetration of reliability programs compared to demand response programs. Indeed, the highest penetration rates among both demand response and reliability programs occurs in the Mining, Metals, Stone, Clay, Glass, and Concrete sector, with 20.4 percent of eligible peak load enrolled in DBP and fully 51.9 percent of "eligible" peak load enrolled in traditional interruptible tariffs.

Exhibit 4-23a
Statewide Program Penetrations, Account Basis
(Note: "Extra Small" and "Very Small" represent only SDG&E)

3 IOUs	CPP Penetration (Accounts)	DBP Penetration (Accounts)	DRP Penetration (Accounts)	BIP Penetration (Accounts)	OBMC Penetration (Accounts)	INTER Penetration (Accounts)
Size						
Extra Small (20-100 kW)*	0.0%	0.0%	0.0%	-	0.0%	0.0%
Very Small (100-200 kW)*	0.4%	0.1%	0.0%	0.0%	0.0%	0.3%
Small (200-500 kW)	1.0%	2.4%	1.2%	0.0%	0.0%	0.2%
Medium (500-1000 kW)	3.6%	6.5%	0.5%	0.8%	0.0%	3.3%
Large (1000-2000 kW)	5.5%	10.9%	1.0%	1.2%	0.1%	10.0%
Extra Large (2000+ kW)	4.3%	13.4%	3.7%	2.2%	3.4%	16.6%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%
Business Type						
Commercial and TCU						
Office	0.6%	2.7%	0.1%	0.0%	0.0%	0.1%
Retail/Grocery	0.6%	2.3%	2.1%	0.1%	0.0%	0.3%
Institutional	1.3%	1.6%	0.1%	0.1%	0.0%	0.4%
Other Commercial	1.1%	2.2%	0.7%	0.3%	0.0%	0.3%
Transportation/Communication/Utility	1.7%	4.4%	0.7%	0.4%	0.0%	1.7%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	1.5%	4.6%	0.4%	1.7%	0.3%	10.6%
Mining, Metals, Stone, Glass, Concrete	1.9%	7.7%	0.6%	2.2%	1.2%	16.7%
Electronic, Machinery, Fabricated Metals	2.7%	5.0%	0.0%	0.4%	0.4%	3.3%
Other Industrial and Agriculture	1.4%	3.7%	0.2%	0.8%	0.4%	4.3%
Unclassified						
Unknown	0.1%	0.2%	0.0%	0.2%	0.0%	-
Totals	1.1%	2.7%	0.6%	0.4%	0.1%	1.4%
Utility Breakdown						
PG&E	3.5%	3.9%	1.5%	0.2%	0.3%	0.8%
SCE	0.1%	6.0%	0.6%	0.7%	0.1%	4.3%
SDG&E	0.6%	0.3%	0.1%	0.0%	0.0%	0.1%

* Data reflects SDG&E only

Exhibit 4-23b
Statewide Program Penetrations, Non-Coincident Peak Load Basis
(Note: "Extra Small" and "Very Small" represent only SDG&E)

3 IOUs	CPP Penetration (MW)	DBP Penetration (MW)	DRP Penetration (MW)	BIP Penetration (MW)	OBMC Penetration (MW)	INTER Penetration (MW)
Size						
Extra Small (20-100 kW)*	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Very Small (100-200 kW)*	0.4%	0.1%	0.0%	0.0%	0.0%	0.4%
Small (200-500 kW)	1.2%	2.5%	1.4%	0.0%	0.0%	0.2%
Medium (500-1000 kW)	3.7%	6.7%	0.5%	0.9%	0.0%	3.6%
Large (1000-2000 kW)	5.7%	11.0%	1.1%	1.2%	0.1%	10.5%
Extra Large (2000+ kW)	3.7%	12.6%	12.4%	2.4%	5.3%	18.2%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Business Type						
Commercial and TCU						
Office	2.3%	5.6%	0.7%	0.0%	0.0%	0.8%
Retail/Grocery	1.3%	3.3%	3.8%	0.4%	0.0%	0.6%
Institutional	2.0%	5.1%	1.9%	0.2%	0.2%	2.1%
Other Commercial	3.1%	8.3%	1.6%	0.5%	0.9%	2.0%
Transportation/Communication/Utility	2.1%	7.7%	19.4%	0.6%	0.1%	6.3%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	2.2%	5.8%	1.6%	2.0%	2.3%	18.0%
Mining, Metals, Stone, Glass, Concrete	4.9%	20.4%	17.3%	8.1%	13.8%	51.9%
Electronic, Machinery, Fabricated Metals	6.5%	13.8%	0.3%	1.1%	5.1%	15.9%
Other Industrial and Agriculture	4.6%	10.0%	0.8%	2.1%	3.7%	14.0%
Unclassified						
Unknown	0.3%	2.5%	0.0%	2.7%	0.0%	0.0%
Totals	2.9%	8.0%	5.3%	1.3%	2.1%	8.8%
Utility Breakdown						
PG&E	5.5%	7.7%	8.5%	0.6%	2.5%	4.8%
SCE	0.1%	11.0%	2.6%	2.4%	2.3%	16.7%
SDG&E	3.2%	1.8%	1.0%	0.0%	0.0%	0.5%

* Data reflects SDG&E only

Exhibits 4-24a through 4-26b present current program penetration levels for each utility first in terms of accounts (a), then in terms of non-coincident peak load (b). Again, due to difficulties in accurately framing eligible customers in PG&E and SCE with peak demands below 200 kW, the following exhibits only show penetration rates for these customer sizes in SDG&E.

Exhibit 4-24a
PG&E Program Penetration Levels, Account Basis

PG&E	CPP Penetration (Accounts)	DBP Penetration (Accounts)	DRP Penetration (Accounts)	BIP Penetration (Accounts)	OBMC Penetration (Accounts)	INTER Penetration (Accounts)
Size						
Small (200-500 kW)	2.0%	1.4%	1.5%	0.1%	0.0%	0.0%
Medium (500-1000 kW)	5.8%	5.4%	0.6%	0.2%	0.0%	0.3%
Large (1000-2000 kW)	8.5%	9.6%	1.3%	0.9%	0.1%	2.5%
Extra Large (2000+ kW)	6.2%	12.2%	4.7%	1.2%	4.5%	10.2%
Unknown	-	-	0.0%	-	-	0.0%
Business Type						
Commercial and TCU						
Office	2.4%	8.6%	0.4%	0.0%	0.0%	0.0%
Retail/Grocery	1.1%	0.3%	4.5%	0.1%	0.0%	0.0%
Institutional	5.6%	1.1%	0.4%	0.0%	0.1%	0.5%
Other Commercial	2.6%	2.4%	2.4%	0.1%	0.1%	0.1%
Transportation/Communication/Utility	1.7%	5.9%	1.2%	0.7%	0.1%	2.1%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	4.3%	1.8%	0.4%	1.1%	0.7%	1.5%
Mining, Metals, Stone, Glass, Concrete	4.4%	5.1%	1.1%	1.1%	2.7%	5.6%
Electronic, Machinery, Fabricated Metals	10.2%	6.5%	0.0%	0.0%	0.3%	0.2%
Other Industrial and Agriculture	4.2%	4.8%	0.4%	0.5%	1.2%	3.1%
Unclassified						
Unknown	0.8%	0.8%	0.0%	0.3%	0.0%	-
Totals	3.5%	3.9%	1.5%	0.2%	0.3%	0.8%

Exhibit 4-24b
PG&E Program Penetration Levels, Non-Coincident Peak Load Basis

PG&E	CPP Penetration (MW)	DBP Penetration (MW)	DRP Penetration (MW)	BIP Penetration (MW)	OBMC Penetration (MW)	INTER Penetration (MW)
Size						
Small (200-500 kW)	2.3%	1.6%	1.7%	0.1%	0.0%	0.0%
Medium (500-1000 kW)	6.0%	5.5%	0.5%	0.2%	0.0%	0.4%
Large (1000-2000 kW)	8.8%	9.6%	1.5%	0.9%	0.1%	2.7%
Extra Large (2000+ kW)	6.9%	12.1%	18.3%	1.0%	6.0%	10.5%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Business Type						
Commercial and TCU						
Office	4.0%	7.5%	1.1%	0.0%	0.0%	0.0%
Retail/Grocery	1.0%	0.1%	3.7%	0.0%	0.0%	0.0%
Institutional	6.1%	2.7%	2.3%	0.0%	0.6%	2.2%
Other Commercial	3.3%	5.1%	2.3%	0.2%	0.6%	0.6%
Transportation/Communication/Utility	1.9%	10.4%	33.9%	0.5%	0.3%	5.5%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	5.4%	3.8%	0.2%	0.9%	2.9%	4.7%
Mining, Metals, Stone, Glass, Concrete	11.7%	14.7%	9.8%	1.2%	20.1%	28.0%
Electronic, Machinery, Fabricated Metals	17.5%	16.1%	0.0%	0.0%	3.1%	7.6%
Other Industrial and Agriculture	8.8%	12.1%	0.9%	2.1%	6.3%	11.0%
Unclassified						
Unknown	0.5%	4.0%	0.0%	3.7%	0.0%	0.0%
Totals	5.5%	7.7%	8.5%	0.6%	2.5%	4.8%

Exhibit 4-25a
SCE Program Penetration Levels, Account Basis

SCE	CPP Penetration (Accounts)	DBP Penetration (Accounts)	DRP Penetration (Accounts)	BIP Penetration (Accounts)	OBMC Penetration (Accounts)	INTER Penetration (Accounts)
Size						
Small (200-500 kW)	0.0%	3.9%	0.9%	0.0%	0.0%	0.3%
Medium (500-1000 kW)	0.2%	8.2%	0.5%	1.6%	0.0%	6.4%
Large (1000-2000 kW)	0.2%	13.6%	0.8%	1.8%	0.0%	20.0%
Extra Large (2000+ kW)	0.0%	17.8%	3.3%	4.2%	2.7%	30.3%
Unknown	-	-	0.0%	-	-	27.3%
Business Type						
Commercial and TCU						
Office	0.0%	2.5%	0.0%	0.1%	0.0%	0.7%
Retail/Grocery	0.1%	8.2%	3.1%	0.1%	0.0%	0.3%
Institutional	0.0%	3.6%	0.1%	0.2%	0.0%	0.8%
Other Commercial	0.0%	8.0%	0.1%	1.1%	0.2%	1.6%
Transportation/Communication/Utility	0.1%	6.4%	0.7%	0.4%	0.0%	3.0%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	0.3%	8.1%	0.5%	2.3%	0.2%	20.4%
Mining, Metals, Stone, Glass, Concrete	0.6%	11.0%	0.4%	3.1%	0.4%	27.1%
Electronic, Machinery, Fabricated Metals	0.1%	7.3%	0.1%	0.8%	0.7%	7.2%
Other Industrial and Agriculture	0.2%	5.5%	0.1%	1.2%	0.1%	8.3%
Unclassified						
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	-
Totals	0.1%	6.0%	0.6%	0.7%	0.1%	4.3%

Exhibit 4-25b
SCE Program Penetration Levels, Non-Coincident Peak Load Basis

SCE	CPP Penetration (MW)	DBP Penetration (MW)	DRP Penetration (MW)	BIP Penetration (MW)	OBMC Penetration (MW)	INTER Penetration (MW)
Size						
Small (200-500 kW)	0.1%	3.9%	1.0%	0.0%	0.0%	0.4%
Medium (500-1000 kW)	0.3%	8.5%	0.5%	1.7%	0.0%	7.1%
Large (1000-2000 kW)	0.2%	13.9%	0.9%	1.8%	0.0%	21.0%
Extra Large (2000+ kW)	0.0%	17.9%	7.1%	4.9%	6.4%	34.5%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Business Type						
Commercial and TCU						
Office	0.0%	5.1%	0.0%	0.1%	0.0%	2.6%
Retail/Grocery	0.2%	7.0%	3.7%	0.7%	0.0%	1.0%
Institutional	0.0%	9.3%	1.7%	0.5%	0.0%	3.4%
Other Commercial	0.0%	17.6%	0.3%	1.6%	2.1%	6.6%
Transportation/Communication/Utility	0.1%	7.8%	0.5%	0.9%	0.0%	10.3%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	0.3%	8.4%	3.3%	3.1%	1.9%	30.8%
Mining, Metals, Stone, Glass, Concrete	0.5%	24.4%	24.5%	11.6%	10.8%	65.9%
Electronic, Machinery, Fabricated Metals	0.1%	15.0%	0.7%	1.9%	7.3%	24.0%
Other Industrial and Agriculture	0.2%	8.5%	0.6%	2.2%	0.5%	19.3%
Unclassified						
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Totals	0.1%	11.0%	2.6%	2.4%	2.3%	16.7%

Exhibit 4-26a
SDG&E Program Penetration Levels, Account Basis

SDG&E	CPP Penetration (Accounts)	DBP Penetration (Accounts)	DRP Penetration (Accounts)	BIP Penetration (Accounts)	OBMC Penetration (Accounts)	INTER Penetration (Accounts)
Size						
Extra Small (20-100 kW)	0.0%	0.0%	0.0%	-	0.0%	0.0%
Very Small (100-200 kW)	0.4%	0.1%	0.0%	0.0%	0.0%	0.3%
Small (200-500 kW)	1.9%	0.8%	1.0%	0.0%	0.0%	0.3%
Medium (500-1000 kW)	8.8%	4.0%	0.4%	0.0%	0.0%	1.4%
Large (1000-2000 kW)	11.2%	6.0%	0.0%	0.0%	0.0%	2.7%
Extra Large (2000+ kW)	7.7%	4.9%	0.7%	0.0%	0.0%	0.7%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Business Type						
Commercial and TCU						
Office	0.1%	0.2%	0.0%	0.0%	0.0%	0.0%
Retail/Grocery	0.6%	0.0%	0.6%	0.0%	0.0%	0.3%
Institutional	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%
Other Commercial	0.8%	0.6%	0.0%	0.0%	0.0%	0.0%
Transportation/Communication/Utility	3.6%	0.2%	0.0%	0.0%	0.0%	0.1%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	1.4%	0.4%	0.0%	0.0%	0.0%	0.0%
Mining, Metals, Stone, Glass, Concrete	0.0%	1.1%	0.0%	0.0%	0.0%	1.1%
Electronic, Machinery, Fabricated Metals	0.3%	1.0%	0.0%	0.0%	0.0%	0.8%
Other Industrial and Agriculture	0.0%	0.1%	0.0%	0.0%	0.0%	0.7%
Unclassified						
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Totals	0.6%	0.3%	0.1%	0.0%	0.0%	0.1%

Exhibit 4-26b
SDG&E Program Penetration Levels, Non-Coincident Peak Load Basis

SDG&E	CPP Penetration (MW)	DBP Penetration (MW)	DRP Penetration (MW)	BIP Penetration (MW)	OBMC Penetration (MW)	INTER Penetration (MW)
Size						
Extra Small (20-100 kW)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Very Small (100-200 kW)	0.4%	0.1%	0.0%	0.0%	0.0%	0.4%
Small (200-500 kW)	2.4%	0.9%	1.2%	0.0%	0.0%	0.3%
Medium (500-1000 kW)	8.0%	4.3%	0.3%	0.0%	0.0%	1.4%
Large (1000-2000 kW)	11.5%	6.4%	0.0%	0.0%	0.0%	2.8%
Extra Large (2000+ kW)	3.4%	2.1%	1.4%	0.0%	0.0%	0.3%
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Business Type						
Commercial and TCU						
Office	0.8%	1.5%	0.0%	0.0%	0.0%	0.5%
Retail/Grocery	3.7%	0.0%	4.6%	0.0%	0.0%	0.6%
Institutional	1.7%	1.0%	1.9%	0.0%	0.0%	0.0%
Other Commercial	6.4%	5.6%	0.0%	0.0%	0.0%	0.4%
Transportation/Communication/Utility	5.5%	0.2%	0.0%	0.0%	0.0%	0.1%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	3.4%	0.3%	0.0%	0.0%	0.0%	0.0%
Mining, Metals, Stone, Glass, Concrete	0.0%	13.6%	0.0%	0.0%	0.0%	13.6%
Electronic, Machinery, Fabricated Metals	1.8%	3.6%	0.0%	0.0%	0.0%	1.7%
Other Industrial and Agriculture	0.0%	1.2%	0.0%	0.0%	0.0%	3.8%
Unclassified						
Unknown	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Totals	3.2%	1.8%	1.0%	0.0%	0.0%	0.5%

Because SDG&E's eligible population extends down to customers with annual peak demands of 20 kW, SDG&E's program penetration rates shown in Exhibit 4-26a and 4-26b are not directly comparable to those in PG&E or SCE. The comparable penetration rates in SDG&E considering only eligible customers with peak demands 200 kW and above are 5.0% for CPP, 2.6% for DBP, 1.0% for DRP, 6.2% for all day-ahead programs, and 0.7% for AL-TOU-CP on a MW basis.

Exhibit 4-27 shows the aggregate penetration rates for day-ahead programs (CPP, DBP, and DRP) compared to reliability programs (BIP, OBMC, and interruptible tariffs), as well as the aggregate penetration across all in-scope programs. Readers should note an important caveat associated with interpreting and comparing the aggregate MW penetration rates. The aggregate rates shown below reflect only the relative amount of eligible non-coincident load *enrolled* in demand response and reliability programs and do not reflect the varying degrees of *responsiveness* associated with different program participants.

Exhibit 4-27
Statewide Aggregate Program Penetration Levels

3 IOUs	Total		Day-Ahead Programs		Reliability Programs	
	Account Penetration	MW Penetration*	Account Penetration	MW Penetration*	Account Penetration	MW Penetration*
Size						
Extra Small (20-100 kW)**	0.3%	0.1%	0.3%	0.0%	-	-
Very Small (100-200 kW)**	1.3%	1.0%	1.4%	0.8%	0.6%	0.6%
Small (200-500 kW)	4.4%	4.9%	4.2%	4.6%	0.2%	0.3%
Medium (500-1000 kW)	11.9%	12.2%	9.1%	9.2%	4.0%	4.3%
Large (1000-2000 kW)	21.9%	22.6%	14.1%	14.4%	10.8%	11.2%
Extra Large (2000+ kW)	31.4%	39.2%	17.0%	22.1%	21.0%	23.4%
Unknown	2.1%	0.0%	0.0%	0.0%	13.0%	0.0%
Business Type						
Commercial and TCU						
Office	2.9%	7.9%	3.1%	7.0%	0.3%	0.9%
Retail/Grocery	4.9%	8.0%	4.9%	7.3%	0.5%	1.0%
Institutional	2.8%	9.1%	2.8%	7.9%	0.6%	2.4%
Other Commercial	3.6%	12.5%	3.5%	10.6%	0.9%	3.5%
Transportation/Communication/Utility	7.0%	33.0%	6.2%	24.6%	2.6%	6.9%
Industrial and Agricultural						
Petroleum, Plastic, Rubber and Chemicals	12.9%	23.3%	5.8%	7.5%	13.2%	20.8%
Mining, Metals, Stone, Glass, Concrete	19.6%	63.3%	9.3%	29.3%	20.2%	60.3%
Electronic, Machinery, Fabricated Metals	8.4%	31.5%	6.6%	16.4%	4.8%	21.2%
Other Industrial and Agriculture	8.0%	27.9%	4.8%	13.2%	6.6%	19.0%
Unclassified						
Unknown	0.2%	2.6%	0.2%	2.6%	0.2%	2.5%
Totals	4.9%	20.9%	4.1%	13.2%	2.6%	11.5%

* Non-coincident peak load
** Data reflects SDG&E only

4.3 CHANGES IN PARTICIPATION SINCE 2004

Apart from analyzing current participation levels and program penetration rates, one of the key objectives of this chapter is to track and compare customer new enrollment in in-scope DR programs.[5] In the two sections that follow, changes in customer enrollment in these programs are first examined in terms of growth over time, then in terms of the characteristics of customers that enrolled in 2005 compared to those that enrolled in 2004.

4.3.1 Program Enrollment over Time

Enrollment in day-ahead programs has grown substantially since 2004. At the end of the 2004 program season (defined here as November 1, 2004), there were 189 accounts enrolled in CPP, 714 accounts enrolled in DBP, and 89 accounts enrolled in DRP across the three utilities.[6] By the end of the 2005 program season, the number of account enrolled in day-ahead programs had more than doubled for CPP, nearly doubled for DBP, and more than tripled for DRP. On a MW basis, growth in enrollment was less dramatic, but still significant. Non-coincident peak load enrolled in day-ahead programs grew by over 60 percent over the course of the 2005 program season.

Exhibit 4-28 shows that the overall growth in CPP enrollment was driven mainly by sign-ups in PG&E, where CPP enrollment grew fairly steadily throughout the 2005 program season, from 129 accounts and 182 MW in November 2004 to 293 accounts 289 MW by the end of October 2005. CPP enrollment also grew in SDG&E but only by 60 accounts (42 MW), many of whom enrolled during the month of June. In contrast, enrollment in SCE's CPP program remained flat at its initial level of only 8 participants (6 MW) during the 2005 program season.

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[5] Traditional interruptible tariffs are closed to new enrollment and were excluded from this analysis.

[6] With the exception of PG&E's CPP program, all in-scope day-ahead programs operate year-round. However, the last program events called during 2004 occurred on August 5th (DBP) and September 30th (CPP). We thus chose to categorize all enrollments after October 31, 2004 as part of new enrollment for the 2005 program season. While this cutoff date is arbitrary, it coincides with PG&E's CPP program season.

Exhibit 4-28
CPP Program Enrollment Since 2004 Program Season

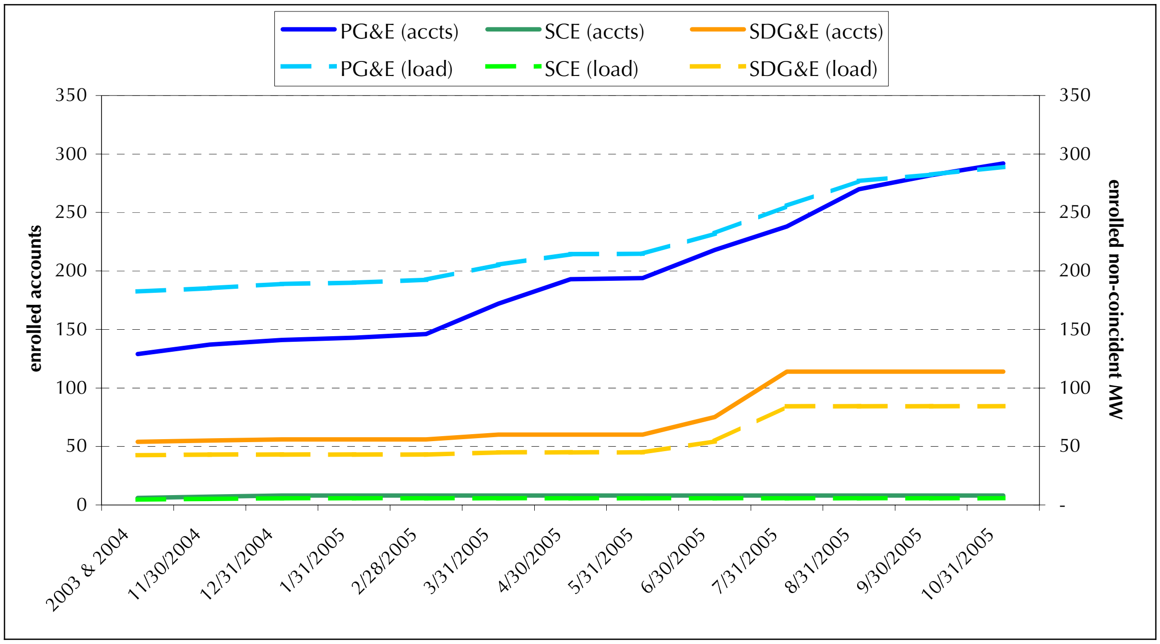
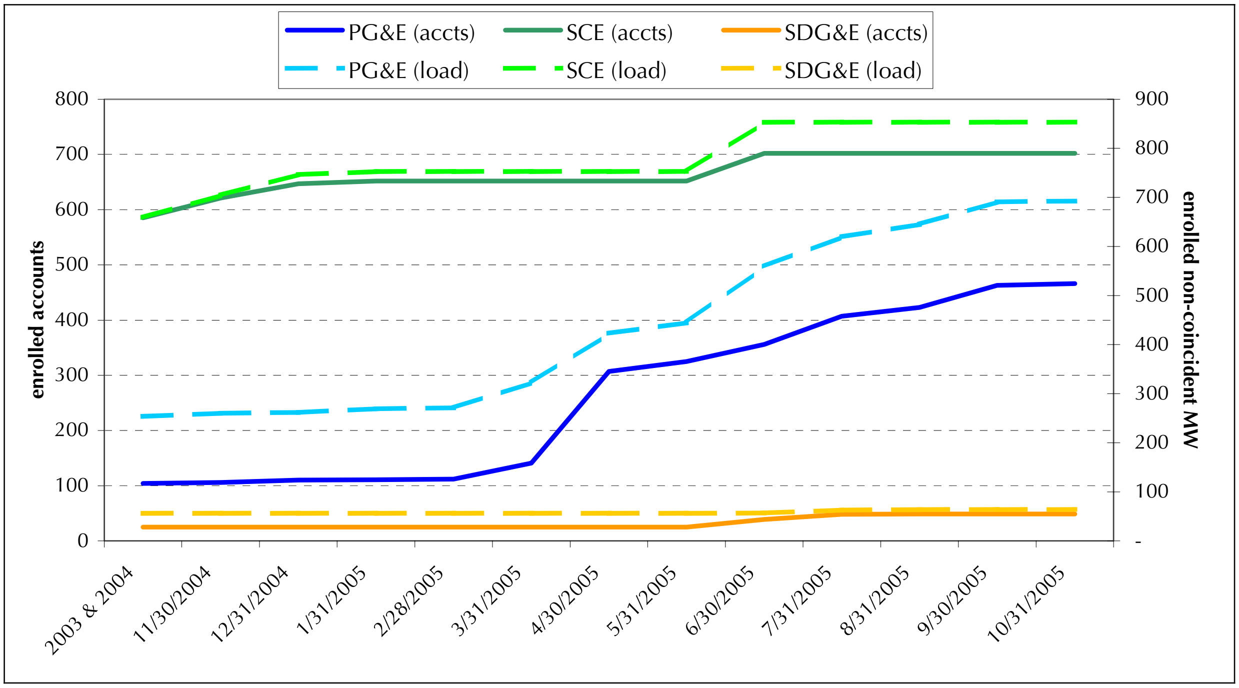


Exhibit 4-29 shows that the overall growth in DBP enrollment was also driven mainly by enrollment in PG&E's service territory, where DBP enrollment again grew fairly steadily throughout the 2005 program season, from 104 accounts and 254 MW in November 2004 to 466 accounts and 692 MW of non-coincident peak load by the end of October 2005. In SCE's service territory, DBP enrollment grew moderately during late 2004 and again during the month of June, with SCE enrolling a total of 117 accounts and 194 MW of non-coincident peak load. In SDG&E, enrollment in DBP was only modest during the 2005 program season, with 24 accounts joining the program representing 8 MW of non-coincident peak load.

One factor that clearly contributed to DBP enrollment trends during the 2005 program season was the modification to the 2005 DBP programs allowing Direct Access (DA) customers to participate. In PG&E, DA customers accounted for 31 percent of all accounts that enrolled in DBP during the 2005 program season. Similarly in SCE, DA customers accounted for 24 percent of all accounts that enrolled in DBP during the 2005 program season. In SDG&E, however, none of the accounts that joined the DBP in 2005 were DA customers.

It should be reiterated here that Exhibits 4-28 and 4-29 show all accounts that had enrolled as of October 28, 2005 for PG&E and mid-August for SCE and SDG&E. It should also be noted that 50 of PG&E's 2005 CPP sign-ups and three of PG&E's 2005 DBP sign-ups occurred after the last CPP and DBP events of the season (August 5th and September 30th, respectively). These accounts, therefore, are not included in the CPP and DBP impact assessment presented in Chapter 7.

Exhibit 4-29
DBP Program Enrollment Since 2004 Program Season

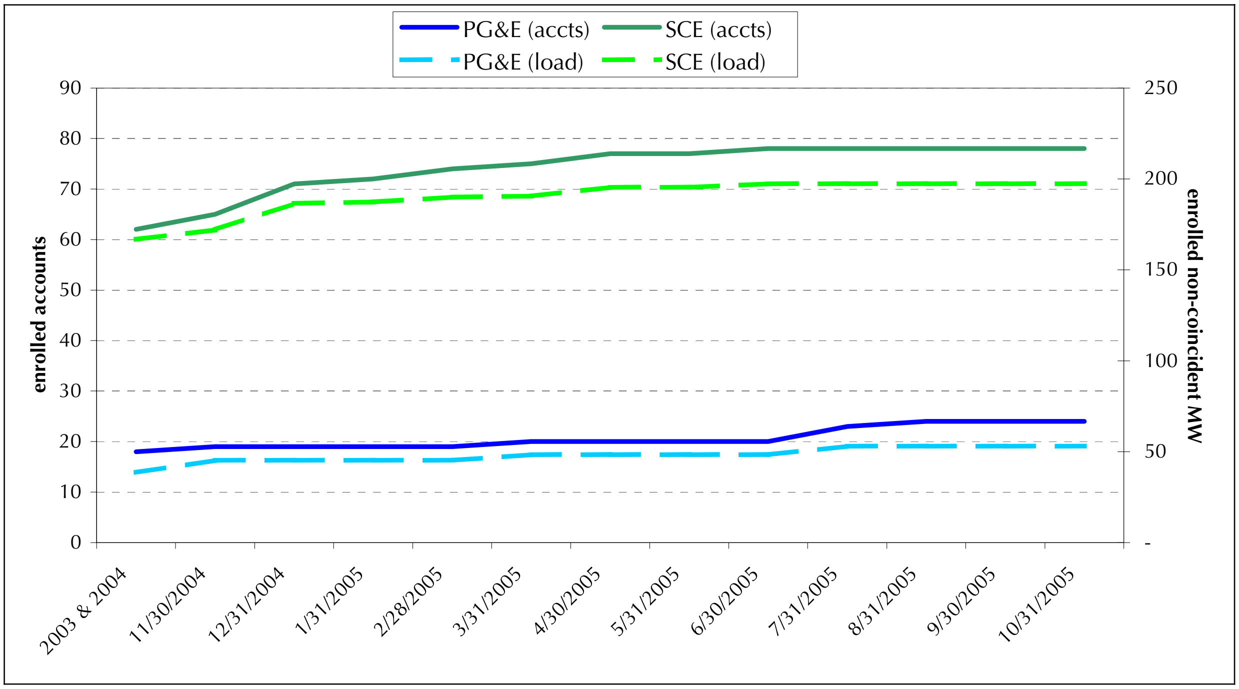


In the DRP program, statewide enrollment grew more than three fold on an account basis. Most of this growth was again driven mainly by enrollment in PG&E. Prior to the 2005 program season, PG&E had no accounts enrolled in the DRP program. By the end of the 2005 program season, however, 157 accounts in PG&E territory had enrolled in DRP. DRP enrollment in SCE also increased significantly during the summer of 2005 from 62 accounts to 89 accounts. SDG&E reported only one additional account enrolling in DRP during the 2005 program season.

In contrast to the increasing enrollment in day-ahead programs, enrollment levels in reliability programs have remained largely unchanged since the end of the 2004 program season, with the exception of modest enrollment in the BIP program. PG&E and SCE's traditional interruptible tariffs have been closed to new customers since the mid-1990s, and SDG&E's traditional interruptible tariff closed to new enrollment on January 1, 2006. As for the OBMC program, all but one current participant enrolled in 2001 shortly after the program debuted, with one customer enrolling in SCE's OBMC program in June 2004.

In the case of BIP, statewide enrollment increased from 80 accounts and 205 MW in November 2004 to 102 accounts and 250 MW of non-coincident peak load by the end of October 2005. Most of this new enrollment occurred in SCE, with 16 accounts representing 31 MW enrolling in BIP during the 2005 program season. New customer enrollment was lower in PG&E, with 6 accounts representing 14 MW of non-coincident peak load enrolled in BIP during the 2005 program season. SDG&E currently has no accounts signed up for the BIP program in its service territory.

Exhibit 4-30
BIP Program Enrollment Since 2004 Program Season



4.3.2 2004 Sign-ups vs. 2005 Sign-ups

Now that the statewide CPP and DBP demand response programs have been in operation for two full seasons, it is informative to compare the basic size and business type characteristics of customers that enrolled during the 2005 program season and those that enrolled in 2004. These comparisons serve to identify potentially important differences between "early adopter" customers and new participants going forward.

Exhibits 4-31 and 4-32 compare the distribution of 2004 and 2005 CPP sign-ups across business types, customer sizes, and utilities. In PG&E, nearly half of the customers that enrolled in CPP during 2004 were Industrial customers. In 2005 however, only a third of PG&E's CPP sign-ups were Industrial customers. As Exhibit 4-31 shows, the share of Commercial customers in PG&E's CPP sign-ups increased substantially between 2004 and 2005, growing from 26 percent to 38 percent of new accounts enrolling in CPP. Exhibit 4-31 shows a similar trend among SDG&E's CPP sign-ups. In 2004, half of SDG&E's CPP sign-ups were Institutional customers, but this share fell substantially among 2005 CPP sign-ups, and Commercial customers accounted for over two-thirds of new accounts enrolling in CPP in 2005.

With this shift away from Industrial and Institutional customers and towards Commercial customers signing up for CPP, Large and Extra Large customers constitute a declining share of new CPP sign-ups, as shown in Exhibit 4-32.

Exhibit 4-31
Distribution of 2004 and 2005 CPP Sign-ups by Business Type

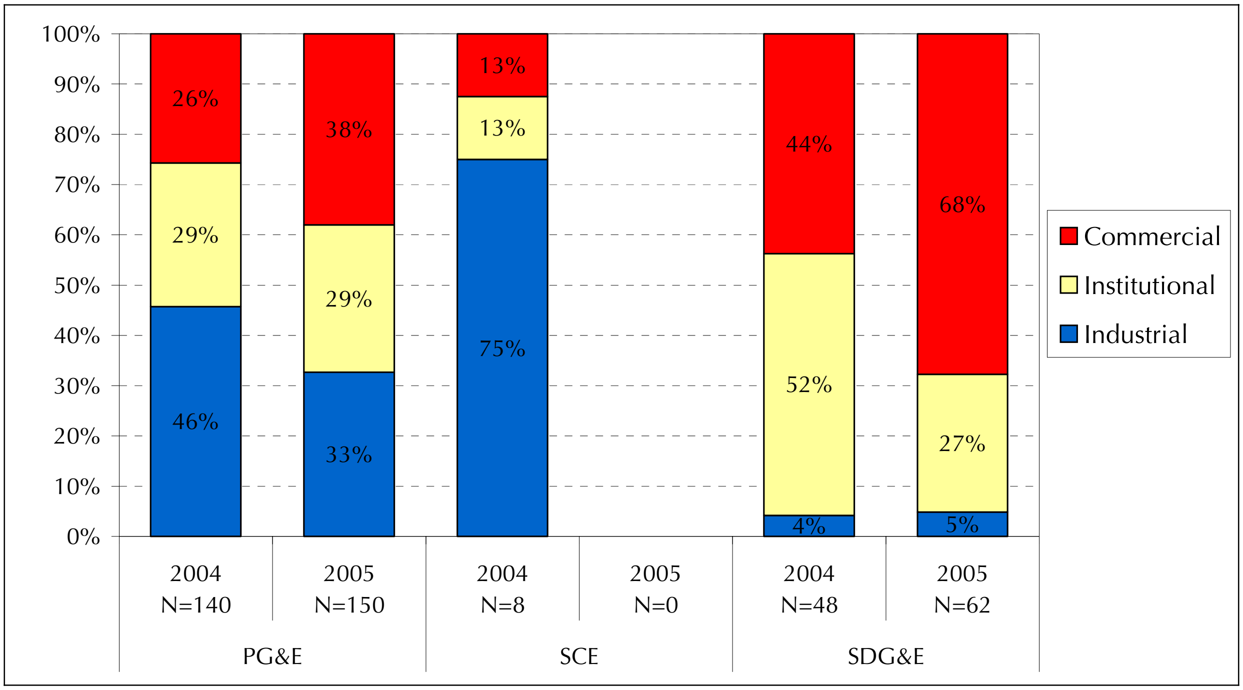
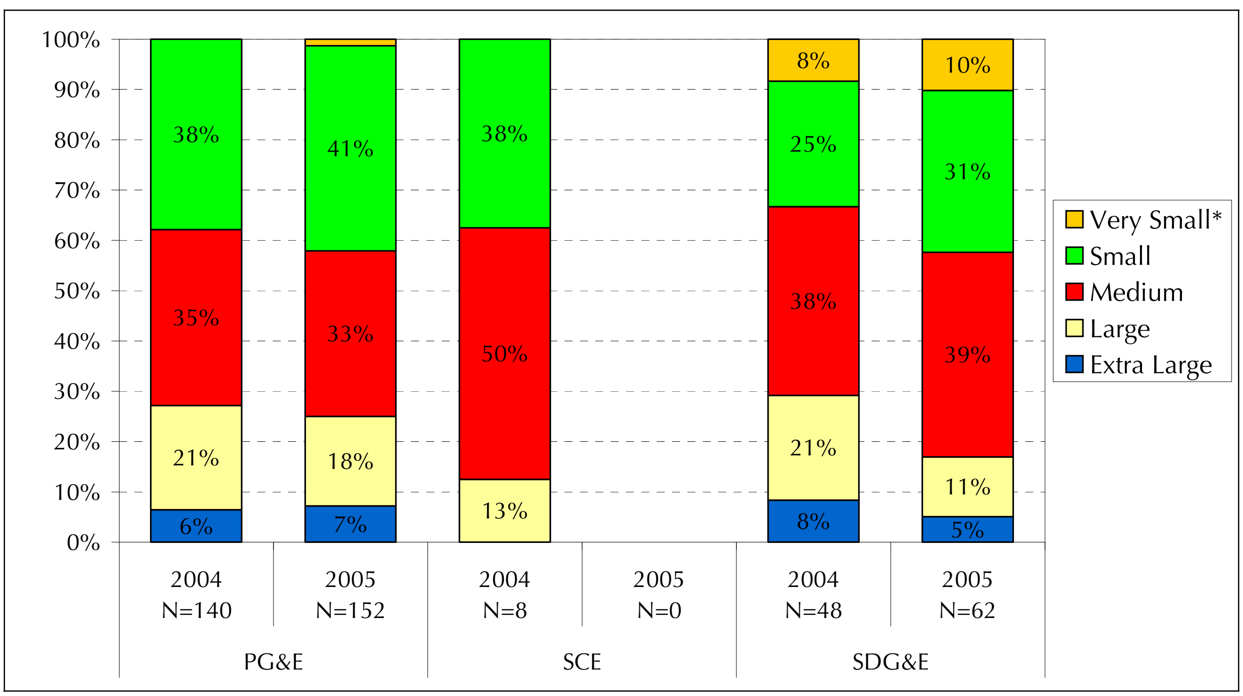


Exhibit 4-32
Distribution of 2004 and 2005 CPP Sign-ups by Customer Size



* Extra Small customers shown aggregated with Very Small customers

The enrollment trends for CPP discussed above also apply to DBP sign-ups, as shown in Exhibits 4-33 and 4-34 below. In general, Commercial customers account for an increasing share of new sign-ups for the DBP program and now account for the vast majority of new participants in both PG&E and SDG&E. In SCE, the share of Commercial customers among DBP sign-ups in 2005 actually declined compared to 2004, while the share of Institutional customers among DBP sign-ups grew from 23 percent to 44 percent. It should be noted, however, that very few SCE customers signed up for DBP in 2005 compared to the number that signed up in 2004 which limits the value of this comparison.

This shift away from Industrial and Institutional customers and towards Commercial customers signing up for DBP translates to a shift away from larger customers and towards smaller customers in terms of new participants going forward. As Exhibit 4-34 shows, Large and Extra Large customers constitute a declining share of new DBP sign-ups in both PG&E and SDG&E, with Medium, Small, and Very Small customers accounting for the majority of new program sign-ups in 2005. In SCE, the data shown in Exhibit 4-34 indicate the opposite trend – that Large and Extra Large customers account for a growing share of new DBP sign-ups in SCE – but again the relatively small number of 2005 DBP sign-ups compared to 2004 DBP sign-ups limits the value of this comparison.

Exhibit 4-33
Distribution of 2004 and 2005 DBP Sign-ups by Business Type

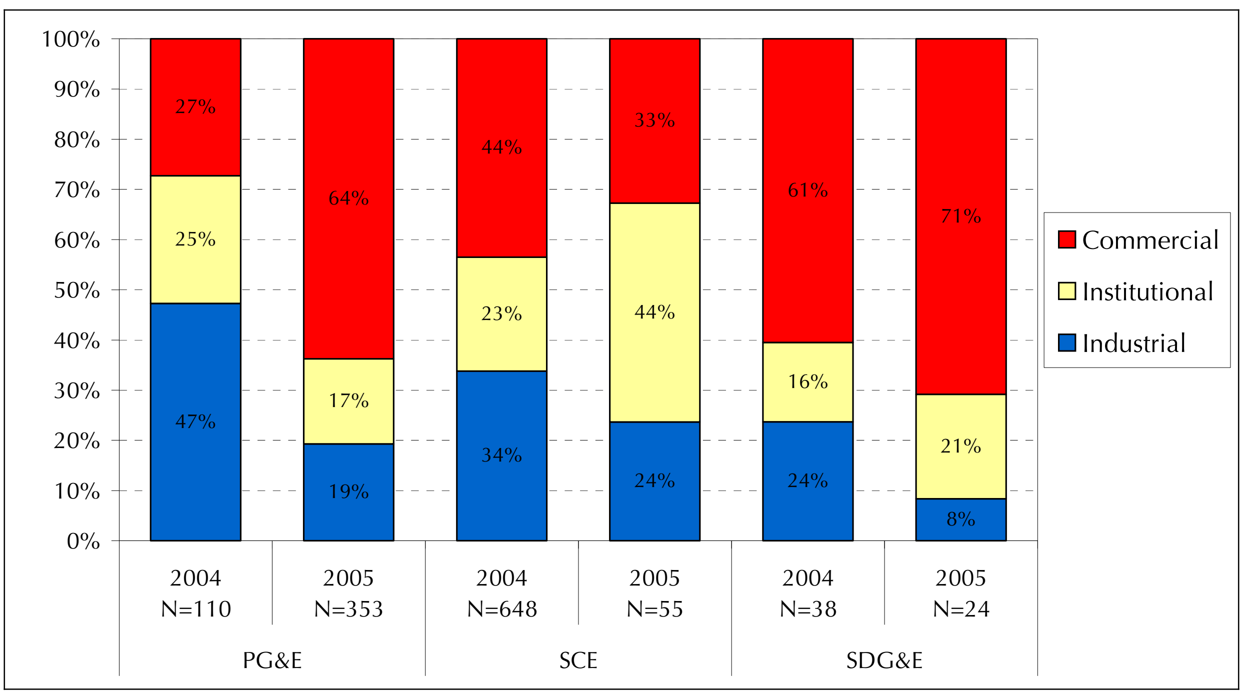
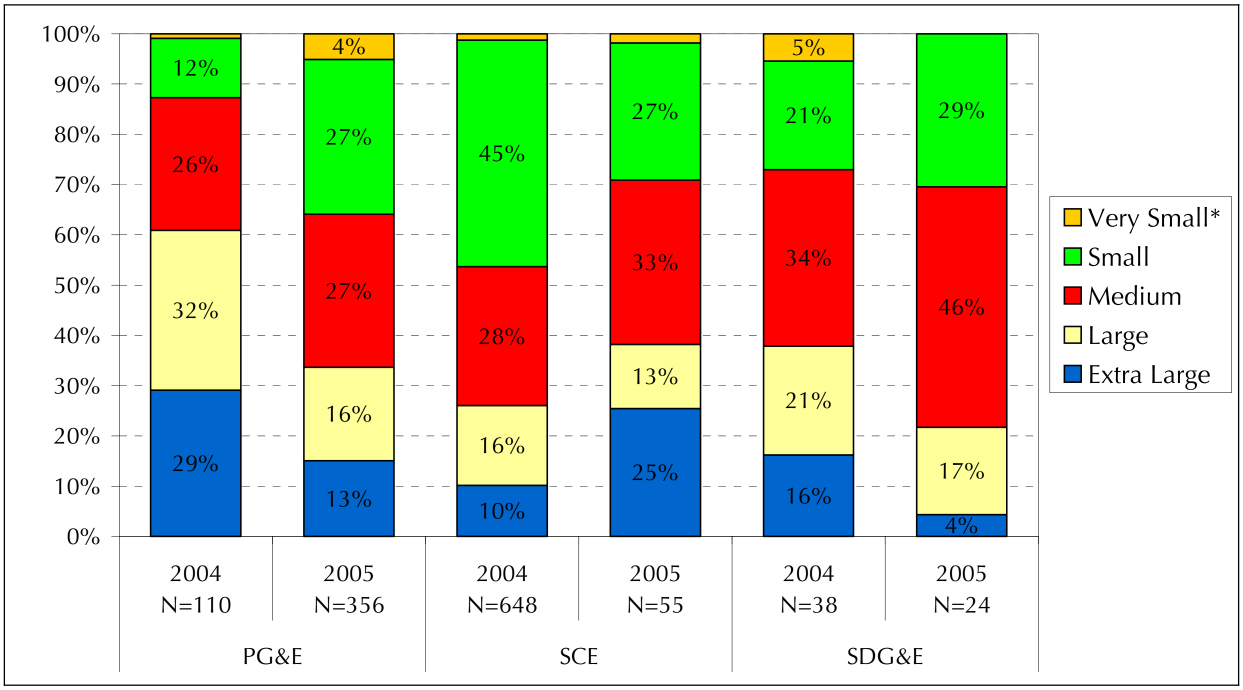


Exhibit 4-34
Distribution of 2004 and 2005 DBP Sign-ups by Customer Size



* Extra Small customers shown aggregated with Very Small customers

4.4 PARTICIPANT VERSUS NON-PARTICIPANT CHARACTERISTICS

Finally, this section presents a comparison of basic business type and customer size characteristics between current participants in the in-scope demand response programs and the eligible non-participant population. These comparisons serve to complement the inter- and intra-program comparisons of participant characteristics presented earlier in this chapter and highlight key, high-level differences between the current participant and non-participant customer populations.

Exhibits 4-35 and 4-36 present the distribution of business types and customer sizes among current participants in voluntary CPP and eligible non-participants in each utility. As Exhibit 4-35 shows, Commercial customers account for the largest shares of eligible non-participants but account for much smaller shares of CPP participants, although in SDG&E, Commercial customers still account for a significantly larger share of current CPP participants than Institutional or Industrial customers. In PG&E and SCE, Industrial customers account for roughly a quarter of the eligible non-participant population but make up the largest share of CPP participants in those two utilities. Exhibit 4-36 shows that roughly three-fourths of the eligible non-participant population is made up of Small and Very Small customers but account for 40 percent or less of current CPP participants.

Exhibit 4-35
CPP Participants and Eligible Non-Participants by Business Type in each Utility

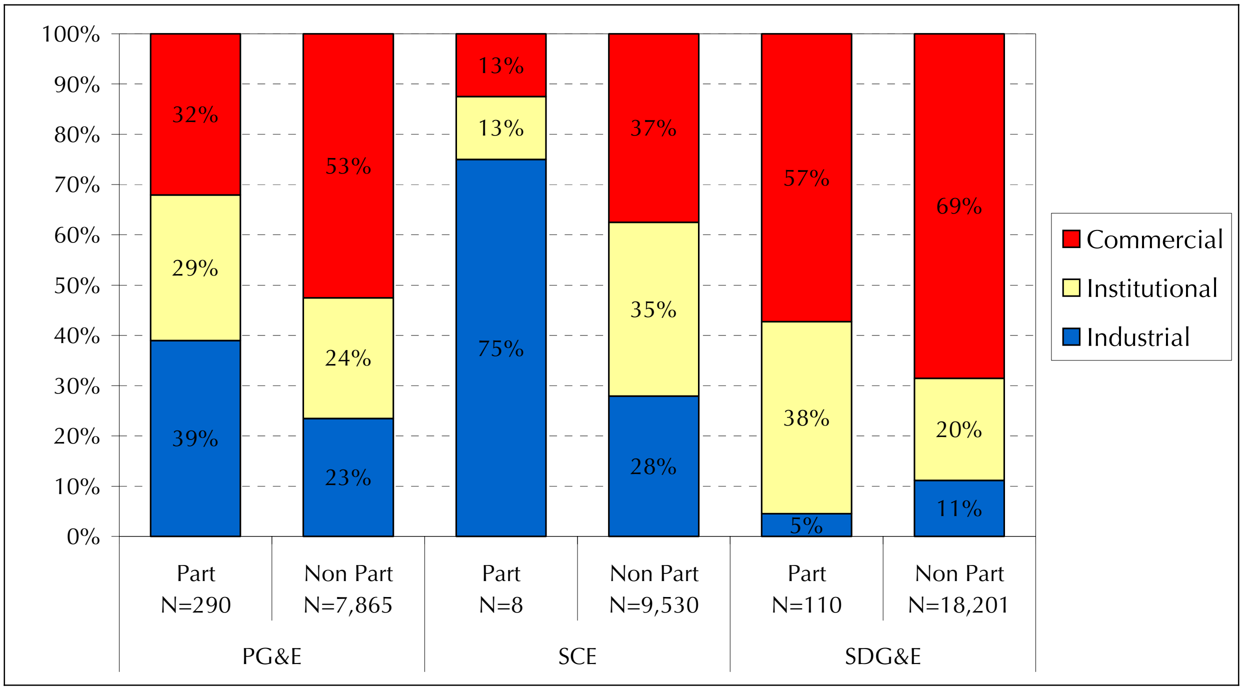
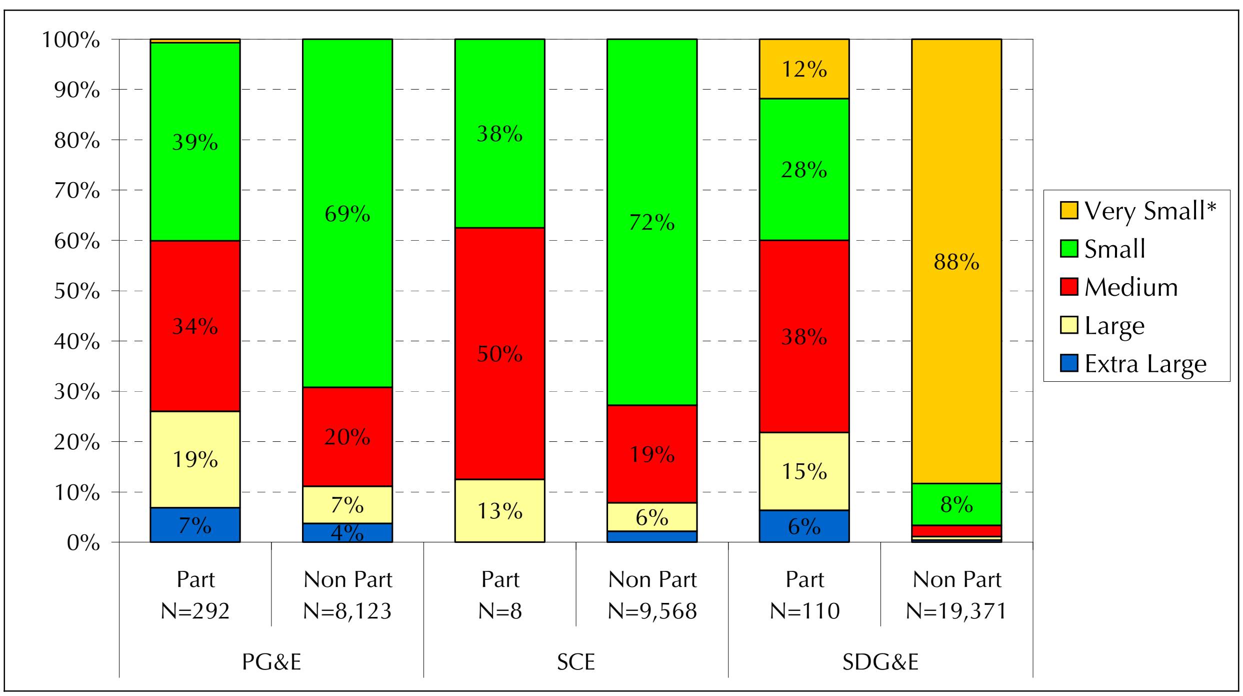


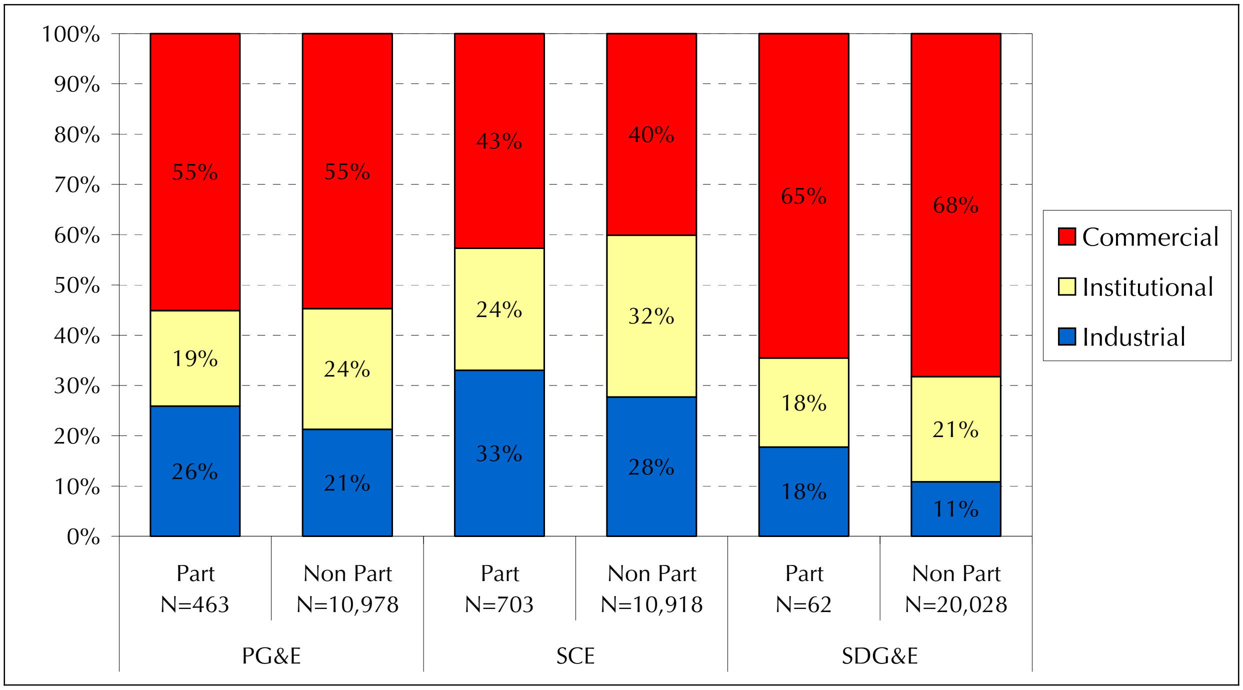
Exhibit 4-36
CPP Participants and Eligible Non-Participants by Customers Size in each Utility



* Extra Small customers shown aggregated with Very Small customers

In contrast to the differences shown above between CPP participants and eligible non-participants, Exhibit 4-37 shows that DBP participants and eligible non-participants do not differ significantly when compared across business types. The most notable difference is the slightly smaller share of Institutional customers among DBP participants compared to eligible non-participants.

Exhibit 4-37
DBP Participants and Eligible Non-Participants by Business Type in each Utility



Across customer sizes, however, DBP participants differ considerably compared to eligible non-participants, as Exhibit 4-38 shows below. More than two-thirds of eligible non-participants in PG&E and SCE have annual peak demands less than 200 kW, and 86 percent of eligible non-participants in SDG&E have annual peak demands less than 100 kW.[7] As the Exhibit shows, however, the majority of DBP participants have annual peak demands greater than 500 kW and roughly a third of DBP participants have annual peak demands over 1 MW.

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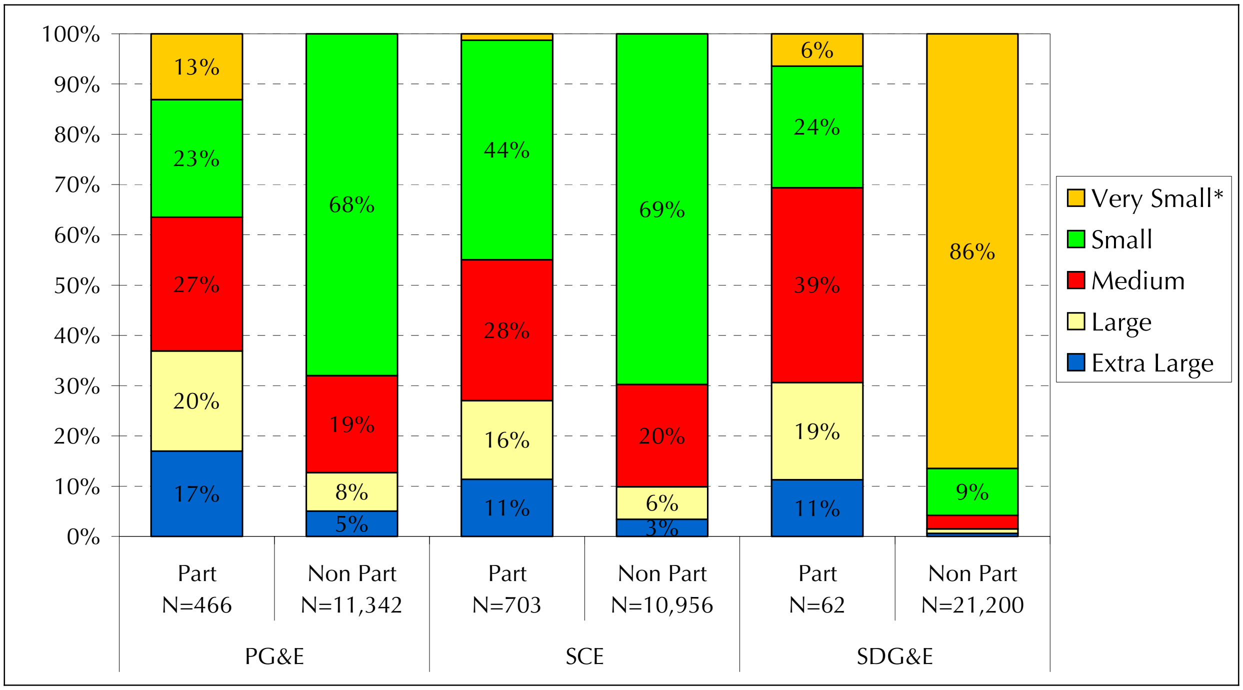
[7] Note that the available population data did not allow an accurate framing of Very Small and Extra Small customers that are eligible to participate in DBP via aggregation in PG&E and SCE, and therefore Exhibit 4-38 excludes such customers.

Exhibit 4-38
DBP Participants and Eligible Non-Participants by Customers Size in each Utility



* Extra Small customers shown aggregated with Very Small customers

Exhibits 4-39 and 4-40 present the distribution of business types and customer sizes among current participants in the DRP program and eligible non-participants in each utility.[8] These Exhibits demonstrate two unique aspects of DRP participants relative to CPP and DBP participants. First, as Exhibit 4-39 shows, Commercial customers account for a larger share of current DRP participants – over 80% of current DRP participants in all three utilities – than exists among eligible non-participants. Similarly, Industrial and Institutional customers account for only very small shares of current DRP participants. The second unique aspect of current DRP participants is that, as Exhibit 4-40 shows, they are distributed across customer size in a manner nearly identical to that of the eligible non-participant population, with customers having annual peak demands below 500 kW making up the vast majority of both the participant and eligible non-participant population.

[8] Note that the available population data did not allow an accurate framing of Very Small and Extra Small customers in PG&E and SCE that are eligible to participate in DRP, and therefore Exhibit 4-40 excludes such customers.

Exhibit 4-39
DRP Participants and Eligible Non-Participants by Business Type in each Utility

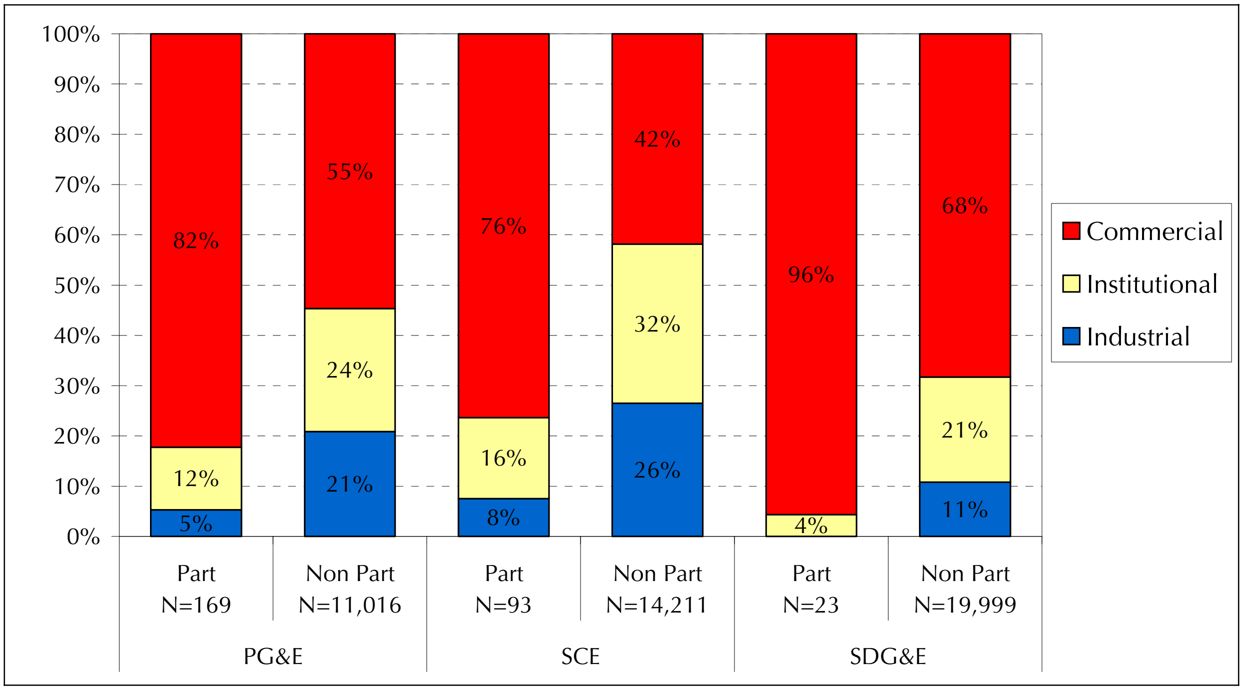
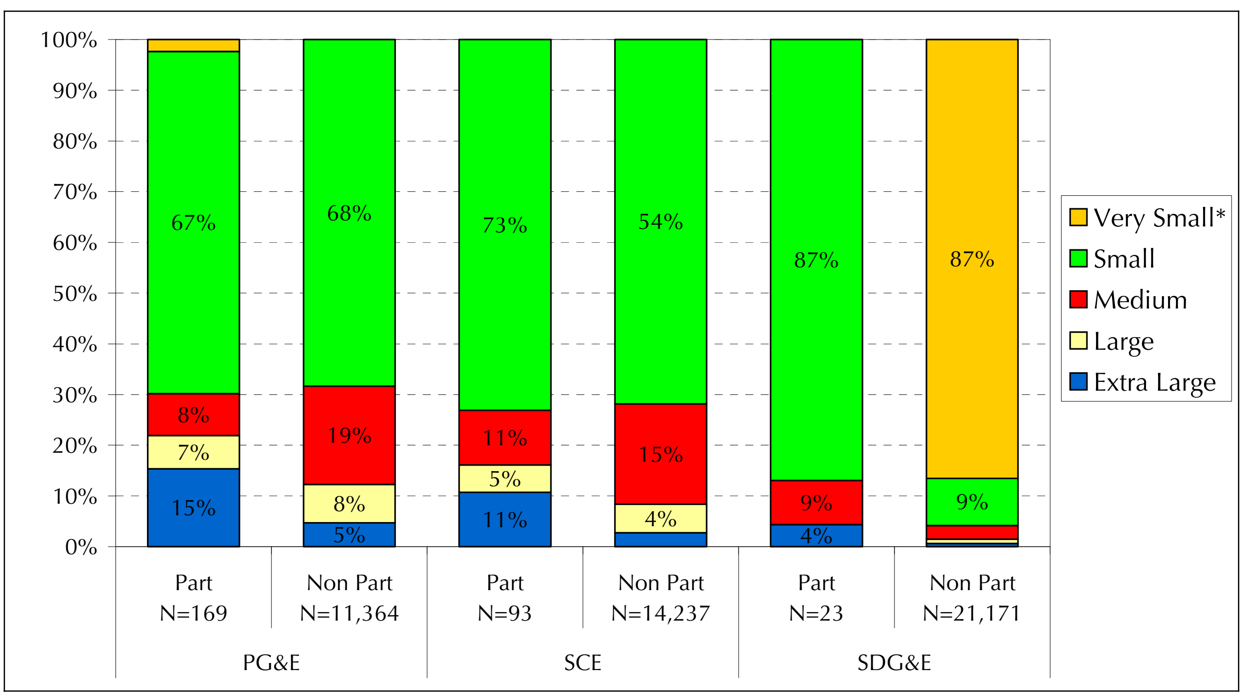


Exhibit 4-40
DRP Participants and Eligible Non-Participants by Customers Size in each Utility



* Extra Small customers shown aggregated with Very Small customers

4.5 SUMMARY AND KEY FINDINGS

Large Customers in PG&E and SCE Account for the Majority of Enrolled Load in Both Day-Ahead and Reliability Programs

Statewide enrollment in reliability programs currently stands at 767 customer accounts, representing 2,325 MW of non-coincident peak load. Large customers (i.e., those with annual peak demands of at least 1 MW) make up two-thirds of these enrolled accounts and over 90 percent of enrolled load statewide. In particular, large customers that take service on traditional interruptible tariffs in PG&E and SCE account for more than 70 percent of the total non-coincident peak load enrolled in reliability programs.

Statewide enrollment in day-ahead programs currently stands at 1,838 customer accounts, representing 2,822 MW of non-coincident peak load. In contrast to reliability programs, large customers make up less than a third of all accounts enrolled in day-ahead programs. However, on an enrolled load basis, large customers in PG&E and SCE again make up more than 70 percent of non-coincident peak load enrolled in day-ahead programs statewide.

Significant Overlap between DBP Participants and Interruptible Customers

Participants in the DBP program and traditional interruptible tariffs make up the majority of total participants in statewide day-ahead and reliability programs, respectively. DBP participants make up 67 percent of all accounts and 57 percent of all non-coincident peak load enrolled in day-ahead programs, and traditional interruptible customers make up 81 percent of all accounts and 77 percent of all non-coincident load enrolled in reliability programs.

However, these two programs share a significant pool of customers that participate in both programs. Traditional interruptible customers represent 14 percent of enrolled DBP accounts and about 34 percent of enrolled DBP load. Conversely, interruptible customers that also participate in DBP represent 27 percent of accounts and 30 percent of non-coincident load enrolled in interruptible tariffs. Interruptible customers that also participate in DBP are fairly representative of the total population of interruptible customers, both in terms of business type and customer size. Compared to the rest of the DBP participant population, however, interruptible customers that also participate in DBP are clearly much larger on average and tend to be Industrial customers rather than Commercial or Institutional customers.

This overlap is important to note and understand not only because customers in reliability programs tend to be larger customers but also because customers in reliability programs, in particular interruptible customers, tend to have larger and more developed load reduction capabilities compared to other customers. The influence of traditional interruptible customers on the total load reduction impacts from 2005 DBP participants is treated explicitly in Chapter 7.

This finding indicates two important but conflicting participation trends. First, a significant portion of reliability customers have adapted their curtailment planning and actions from the infrequent, compliance-driven framework of reliability programs to the more frequent, voluntary framework of day-ahead programs. From this perspective, the utilities and the state are now able to get more flexible and more frequent DR out of the existing reliability resource. However, the fact that a significant portion of participation in day-ahead programs is coming from existing reliability customers also indicates that the level and growth of day-ahead program participation from customers who had not previously participated in any DR program is significantly less that it would otherwise appear. In addition, as discussed further in Chapter 7, although DBP bidding rates are higher for reliability participants, they are still not particularly high.

Active CPP and DBP Participants Tend to be Industrial and Institutional Customers

Comparing the business type and size attributes between day-ahead participants who actively provide significant load reductions and participants who are enrolled but have yet to actively provide significant load reductions reveals some important differences. Specifically, "active" CPP participants (i.e., those who have reduced their load by at least 5 percent on average during critical peak events) are made up of disproportionately higher shares of Industrial and Institutional customers compared to "non-active" CPP participants. [9] Similarly, DBP "bidders" (i.e., those that have submitted at least one load reduction for DBP events) are also made up of disproportionately higher shares of Industrial and Institutional customers compared to DBP "non-bidders". The one exception to these trends is DBP participants in SDG&E, where Institutional customers actually make up a smaller share of DBP bidders compared to non-bidders.

Industrial and Institutional customers already account for 65 percent of load enrolled in CPP and 71 percent of load enrolled in DBP. The findings above, however, indicate that Industrial and Institutional customers account for even higher shares of the enrolled load that actively delivers program-induced load reductions. Indeed, Industrial and Institutional customers account for 75 percent of "active" load enrolled in CPP and 83 percent of "active" load enrolled in DBP.

Total Penetration of All In-Scope DR Programs on an Enrolled Load Basis is about One Fifth of the Eligible Market

Measured relative to the eligible market, current penetration rates of day-ahead programs are modest, ranging from 2.7 percent for DBP, 1.1 percent for CPP, and 0.6 percent for DRP on an account basis. Penetration rates of reliability programs are slightly lower in comparison, again on an account basis. On a non-coincident peak load basis, current penetration rates are comparatively higher for all in-scope programs, ranging from 8.8 percent for traditional interruptible tariffs, 8.0 percent for DBP, 5.3 percent for DRP, and 2.9 percent for CPP. Taking into account customers that participate in more than one program, the combined penetration rate of day-ahead programs on a non-coincident peak load basis is 18 percent or approximately one-fifth of the eligible non-coincident peak load. It is important to note that for DBP, these penetration rates should be interpreted with caution, due to the large number of customers enrolled who do not make load reduction bids.[10] If only bidders are counted, the MW penetration rate for DBP drops from 8.0 percent to 2.4 percent. Additionally for DRP, it is important to note that twelve large pumping facilities associated with one customer account for roughly 600 MW of the enrolled load. The MW penetration for DRP would otherwise be approximately 2 percent.

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[9] This load reduction is measured relative to each customer's 10-day adjusted baseline (see Chapter 6).

[10] The issue of DBP non-bidders is addressed in more detail in Chapter 7.

At the business type and customer size level, there are two overall penetration trends of note. First, overall program penetration levels tend to be much lower among customers with annual peak demands below 500 kW, both on an account basis and a MW basis. Indeed, with the exception of CPP, all of the in-scope programs exhibit their highest penetration rates amongst customers whose annual peak demands exceed 2 MW. Second, program penetration levels tend to be higher among Industrial customers compared to Commercial and Institutional customers. This difference is more pronounced in the penetration of reliability programs compared to day-ahead programs. The highest penetration rates among both day-ahead and reliability programs occurs in the Mining, Metals, Stone, Clay, Glass, and Concrete sector, with 20 percent of eligible peak load enrolled in DBP and over 50 percent of "eligible" peak load enrolled in traditional interruptible tariffs.[11]

Enrollment in Day-Ahead Programs Grew Significantly During the 2005 Program Season; Reliability Program Enrollment Remained Relatively Unchanged

The number of accounts enrolled in day-ahead programs grew substantially during the 2005 program season. By the end of the 2005 program season, the number of accounts enrolled in day-ahead programs had more than doubled for CPP, nearly doubled for DBP, and more than tripled for DRP. On a MW basis, growth in enrollment was less dramatic, but still significant, growing by over 60 percent over the course of the 2005 program season. For CPP, PG&E customers accounted for most of the growth in statewide program enrollment, although a significant portion of this growth (~30% of 2005 enrollment) occurred after the last CPP event of the summer. For DBP, PG&E customers again accounted for most of the growth in statewide program enrollment, with SCE customers also accounting for a significant portion of the increase in statewide participation.

One factor that clearly contributed to DBP enrollment trends during the 2005 program season was the modification to the 2005 DBP programs allowing Direct Access (DA) customers to participate. In PG&E, DA customers accounted for 31 percent of all accounts that enrolled in DBP during the 2005 program season. Similarly in SCE, DA customers accounted for 24 percent of all accounts that enrolled in DBP during the 2005 program season. In SDG&E, however, none of the accounts that joined the DBP in 2005 were DA customers.

In contrast to these trends in day-ahead program enrollment, enrollment in reliability programs remained essentially unchanged during the 2005 program season, with the sole exception of marginal increases in BIP enrollment, mostly in SCE. Overall, however, enrollment in the BIP and OBMC programs remains low relative to interruptible tariffs and day-ahead programs.

Higher Shares of Commercial Customers Signed up for Day-Ahead Programs in 2005 Compared to 2004

Comparing the basic size and business type characteristics of customers that enrolled during the 2005 program season and those that enrolled in 2004 reveals some important trends going forward. Specifically for CPP, Commercial customers account for a significantly larger share of

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[11] The penetration rates calculated for traditional interruptible tariffs use a denominator that describes all accounts that would be eligible if these interruptible tariffs were open for new enrollment (which is not the case currently).

2005 sign-ups compared to 2004 sign-ups. In PG&E, where most of the statewide 2005 CPP sign-ups occurred, the share of Commercial customers in new enrollment increased from 26 percent to 38 percent between 2004 and 2005. In SDG&E, the share of Commercial customers in new enrollment increased from less than half in 2004 to more than two thirds of new CPP enrollment in 2005. Additionally, customers with annual peak demands below 500 kW accounted for an increasing share of CPP sign-ups in 2005 compared to 2004.

Similar trends also appear among recent DBP sign-ups. In general, Commercial customers account for an increasing share of new sign-ups for the DBP program and now account for the vast majority of new participants in both PG&E and SDG&E. This shift away from Industrial and Institutional customers and towards Commercial customers signing up for DBP translates to a shift away from larger customers and towards smaller customers in terms of new participants going forward.

These trends indicate that future growth in day-ahead program participation is likely to come from a more diverse set of Commercial customers with lower peak demand associated with each account. These trends also indicate that most large customers who are willing and capable of providing day-ahead demand response at current incentive levels may already be participating. Together these findings imply that future incremental growth in enrolled load will likely necessitate, on average, higher relative incremental growth in enrolled accounts than has been experienced to date.

5. NON-PARTICIPANT MARKET SURVEY

This chapter presents a market assessment of the current population of customers eligible for, but not participating in, demand response programs. The first section provides an overview of the research context and objectives. The second section describes the survey methodology. The third section presents the key survey results, and the fourth section summarizes the key findings of the non-participant market assessment.

5.1 EVALUATION GOALS AND SCOPE

One of the core tasks of the 2005 Working Group 2 (WG2) Demand Response Evaluation is to carry out a general market assessment that focuses on demand response familiarity, receptivity, barriers, opportunities, and potential among current non-participants. Three key research objectives underlie this task: 1) to improve understanding of customer costs and barriers associated with implementing demand response, 2) to evaluate the impact of recent changes in program features on customer awareness, familiarity, and perception of participation barriers, and 3) to identify unmet informational needs from a customer perspective both for current programs and with respect to any future rollout of default CPP rates should that occur.

To accomplish these objectives, Quantum Consulting conducted a telephone survey of 573 commercial and industrial (C&I) customers from the PG&E, SCE, and SDG&E, service territories who were eligible to participate in the 2005 Demand Bidding Program (DBP), the 2005 voluntary Critical Peak Pricing (CPP) Program, the 2005 Demand Reserves Partnership Program (DRP), or the 2005 Base Interruptible Program (BIP) but not signed up to participate in any of these programs as of fall 2005. The survey was designed to supplement and validate, where appropriate, the findings from a similar survey conducted by Quantum Consulting for the 2004 WG2 Demand Response Evaluation and identify any significant changes in awareness, familiarity, and perception of barriers that have occurred among non-participants since 2004. The results of the survey were aggregated using an energy-weighted analysis. These energy-weighted results were then analyzed, and key findings developed as presented below. Complete energy-weighted results, as well as premise-weighted and un-weighted results, are presented in Appendix C.

Note that the population of eligible customers for this survey did not include customers on traditional interruptible tariffs, which represents an important difference from the population frame used for the 2004 market survey. The relevant comparative caveats that result from this difference are discussed on a case-by-case basis.

5.2 METHODOLOGY

This section describes the methods used to conduct the Non-Participant Market Survey for the 2005 WG2 Demand Response Evaluation. It begins with a brief overview of the objectives of the survey and the design of the survey instrument. It is followed by a discussion of the sample design, which includes details on the construction of the population frame, sampling plan, and weighting scheme used to aggregate the results.

5.2.1 Overview

The main objectives of the Non-Participant Market Survey were to obtain statistically reliable data on the characteristics, knowledge, and infrastructure of the non-participating customer population and to evaluate the impact of recent program changes on customer awareness, familiarity, and perceived barriers to participation. Additionally, the survey sought to identify unmet informational needs from a customer perspective for both current demand response programs and any future rollout of default CPP rates.

To this end, Quantum Consulting developed a telephone survey instrument with guidance from the WG2 oversight committee and additional input from the PIER Demand Response Research Center. The survey questions explored the following topics:

- Demand response program familiarity and awareness
- Barriers to participation, including any impacts of 2005 program changes on perceived barriers to participation
- Technical and economic demand response potential
- Ownership of key enabling and automation technologies
- Recent trends in automation investments
- Awareness and perspectives relative to public appeals programs and default CPP
- General perceptions about energy markets
- Firmographic characteristics

In order to enable valid assessments of changes in customer awareness, perceptions, and investments since 2004, a number of survey questions were carried over from the 2004 market survey. These questions covered program awareness, barriers to participation, technical and economic demand response potential, automation investments, and general perceptions about energy markets. Topics that were new to the 2005 market survey included impacts of 2005 program changes, ownership of key enabling and automation technologies, and awareness and perspectives regarding pubic appeals programs and default CPP. The final instrument developed for the 2005 Non-Participant Market Survey is presented in Appendix B.

5.2.2 Data Sources

Data for the WG2 Demand Response Evaluation was provided to Quantum Consulting from each of the three investor-owned utilities (PG&E, SCE, and SDG&E). The utilities provided the following types of data:

- Demand Response Participant Tracking Data. The participant tracking data was used to identify accounts that had signed up to participate in the CPP, DBP, DRP, or BIP programs.

- Commercial Population Data. Customer Information System (CIS) data was used to determine whether an account was eligible for the CPP, DBP, DRP, or BIP programs. It also was used to create the size and business type classifications for each account. Premise and Customer identifiers from the CIS were used to identify unique premises (across multiple accounts at a site) and customers (across multiple accounts and premises), and classification variables associated with these aggregated units.

- Customer Contact Information. Contact information (names and phone numbers) for both participants and non-participants were provided to Quantum from Customer Representative tracking databases, as opposed to the CIS. Where applicable, this helped ensure the customer we contacted was the same individual the utility account representative spoke with while marketing the DR programs. These contacts were provided on an as needed basis after samples had been selected.

5.2.3 Population Frame

Quantum Consulting created a population frame containing all PG&E, SCE and SDG&E accounts that were eligible for, but did not participate in, the 2005 CPP, DBP, DRP, or BIP programs. Eligibility for these programs was primarily based upon the account having a maximum annual demand greater than 200kW (20kW for SDG&E). CPP had an additional requirement that the account not be participating in a conflicting load management program (such as BIP, OBMC, SLRP, etc.).

Accounts in the population frame were assigned flags indicating their size and business type. These flags were created on an account level, a premise level and a customer level. The premise level flags were selected based on the largest account at that premise. In a similar manner the customer level flags were selected based on the largest account for that customer. The size flags were defined based on an account's annual maximum demand as follows:

- Extra Small customers are defined as those having a max demand between 20 kW and 100 kW (applicable only to SDG&E customers)

- Very Small customers are defined as those having a max demand between 100 kW and 200 kW (applicable only to PG&E and SDG&E customers)

- Small customers are those with max demand between 200 kW and 500 kW

- Medium customers are those with max demand between 500 kW and 1000 kW

- Large customers are those with max demand between 1000 kW and 2000 kW

- Extra Large customers are those with max demand greater than 2000 kW

The business type flags were defined based on SIC code for SCE and SDG&E and a mapping of NAICS to SIC codes for PG&E. The nine business types used for this evaluation were:

- Office

- Retail/Grocery

- Institutional
- Other Commercial
- Transportation/Communication/Utility (TCU)
- Petroleum/Plastic/Rubber/Chemicals (PPRC)
- Mining/Metals/Stone/Glass/Concrete (MMSGC)
- Electronic/Machinery/Fabricated Metals (EMFM)
- Other Industrial/Agricultural (OIA)

The size and business type distributions of the accounts in the population frame, along with the sum of their non-coincident demand (in MW) and energy consumption (in GWh) are presented in Exhibit 5-1. This exhibit also displays the breakdown of accounts eligible for CPP, DBP, DRP, or BIP across the four sizes and nine business types. Note that the customer demand coincident with utility system peaks will be significantly less than the non-coincident figures shown in Exhibit 5-1.

Exhibit 5-1
Population Frame of WG2 Eligible Population
(Note: "Extra Small" and "Very Small" represent only SDG&E)

3 IOUs	Total Eligible Accounts	Total Eligible MW Sum*	Total Eligible GWh Sum	Accounts Eligible for CPP	Accounts Eligible for DBP	Accounts Eligible for DRP	Accounts Eligible for BIP
Size							
Extra Small (20-100 kW)**	15,397	704	2,063	14,512	15,397	15,394	0
Very Small (100-200 kW)**	2,938	406	1,237	2,611	2,938	2,926	2,938
Small (200-500 kW)	18,016	5,532	18,606	14,250	17,673	17,556	17,111
Medium (500-1000 kW)	5,356	3,674	13,237	4,005	5,315	4,890	5,216
Large (1000-2000 kW)	2,010	2,740	10,505	1,341	1,974	1,656	1,944
Extra Large (2000+ kW)	1,283	7,876	28,997	623	1,243	984	1,262
Unknown	283	7	139	234	235	277	24
Business Type							
Commercial and TCU							
Office	9,168	2,751	8,750	7,830	8,403	8,937	4,448
Retail/Grocery	7,632	1,911	8,546	5,246	7,122	7,447	4,419
Institutional	7,723	3,337	11,037	6,159	6,921	7,595	5,060
Other Commercial	9,682	3,026	9,960	7,263	9,125	9,464	4,894
Transportation/Communication/Utility	4,013	2,944	8,526	2,840	3,685	3,809	2,960
Industrial and Agricultural							
Petroleum, Plastic, Rubber and Chemicals	1,177	1,389	5,318	751	1,002	1,050	902
Mining, Metals, Stone, Glass, Concrete	974	1,349	5,859	620	803	817	758
Electronic, Machinery, Fabricated Metals	2,677	1,713	7,543	2,048	2,363	2,504	1,862
Other Industrial and Agriculture	4,128	2,458	9,230	3,247	3,728	3,872	2,883
Unclassified							
Unknown	1,826	320	775	1,702	1,812	1,823	459
Totals	45,283	20,939	74,786	37,576	44,775	43,683	28,495
Utility Breakdown							
PG&E	12,073	9,094	29,364	8,415	11,808	11,547	10,910
SCE	11,856	8,320	32,808	9,448	11,540	10,790	11,682
SDG&E	21,520	3,535	12,640	19,715	21,497	21,429	5,912

* Non-coincident peak load
** Data reflect SDG&E only

5.2.4 Sample Selection

Preparing the survey sample dataset began by creating a statewide database of premises eligible to participate in the DR Programs, but not currently enrolled. The sample design targeted 600 eligible non-participating premise decision-makers across the three utilities (PG&E, SCE and SDG&E). Primary quotas were assigned based upon four customer sizes and nine business types with roughly equal points allocated to each category to ensure comprehensive representation. Quotas were further specified by IOU service territory (200 completes for each IOU). [1] The sample was then reduced to ensure multiple premises with the same decision maker would not be contacted more than once. The final sample frame included decision-makers who may be responsible for one or more accounts and/or premises. Section 5.2.6 describes how weights were calculated to account for decision-makers that were responsible for multiple accounts and/or premises.

[1] Quotas for SDG&E eligible customers were based upon six customer sizes and nine business types.

5.2.5 Data Collection

Telephone interviews were conducted with a representative group of customers eligible for the WG2 DR programs but not participating as of October 2005. The survey was implemented by Quantum Consulting's Computer Aided Telephone Interview (CATI) center. A disposition of the results from the interviews is provide in Appendix C. As mentioned in Section 5.2.4, customers were assigned to one of 117 strata based on their utility, business type and size. Quotas were then set for each of the 117 strata. Exhibit 5-2 presents the final distribution of the completed non-participant surveys by size, business type and utility.

Exhibit 5-2
Final Distribution of Completes by Industry, Size, and Utility

	All			Small (20/200-500 kW)			Medium (500-1000 kW)			Large (1000-2000 kW)			Extra Large (2000+ kW)		
Industry	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Office	28	23	20	7	7	13	7	7	5	7	7	1	7	2	1
Retail/Grocery	15	14	17	7	7	13	4	5	4	3	2	0	1	0	0
Institutional	27	28	26	8	7	14	7	7	6	6	7	2	6	7	4
Other Commercial	29	26	28	6	7	13	8	7	6	7	7	6	8	5	3
Transportation, Communication, Utility	28	16	14	7	6	12	7	7	0	7	1	1	7	2	1
Petroleum, Plastic, Rubber and Chemicals	16	22	14	4	7	11	7	7	3	2	7	0	3	1	0
Mining, Metals, Stone, Glass, Concrete	22	16	6	7	7	5	8	7	1	3	0	0	4	2	0
Electronic, Machinery, and Fabricated Metals	19	19	29	7	7	14	6	7	6	2	4	5	4	1	4
Other Industrial and Agriculture	28	28	15	7	7	12	6	7	3	7	7	0	8	7	0
Total	212	192	169	60	62	107	60	61	34	44	42	15	48	27	13

5.2.6 Weighting

The responses to the non-participant quantitative survey results were aggregated using two distinct weighting schemes. The primary weighting scheme is based on energy usage. This weight is calculated based on the ratio of the energy use represented by the surveyed population relative to the respective energy use in the eligible population for each size, business type and utility stratum. These weights were then adjusted according to the usage associated with each decision-maker within the cell. These adjustments are necessary in order to properly weight the survey responses from survey decision-makers that are responsible for more than one facility in the same IOU service territory. Within the survey, decision-makers were asked how many facilities in the same IOU service territory they were responsible for. They were also asked how many of these facilities their survey responses were applicable to. CIS data were used to corroborate self-reported responses. The additional energy usage of other similar facilities under the decision-makers management is then used to adjust the survey weight. By associating survey responses with more than one facility, a measurable variance in the relative importance of surveys within a cell is introduced. Thus, the weight assigned to surveys within a given cell was allocated proportionally according to the energy usage represented by each survey respondent.

The second weight used in the analysis was the premise weight, which is similar to the energy weight just described except that it is based on the number of facilities rather than energy consumption. The detailed steps used to calculate these energy weights are provided in Appendix C.

5.3 NON-PARTICIPANT MARKET SURVEY RESULTS

This section presents the final results of the Non-Participant Market Survey conducted for the 2005 WG2 Demand Response Evaluation. The alphanumeric series in parentheses in each section heading correspond to the question numbers from the survey instrument (see Appendix B). The key survey results are presented below and shown on an energy-weighted basis. Complete energy-weighted, premise-weighted, and un-weighted results are shown in Appendix C.

5.3.1 Business Demographics (EC1-EC9)

Each of the customers interviewed were asked to describe some basic characteristics of their organization's operations relevant to electricity use and management. These characteristics included the number of employees, floor area, largest end uses of electricity, whether energy management is a formal staff responsibility, and estimates of the energy cost share of total annual operating costs. The key findings relevant to assessing the motivations, opportunities, and barriers to participation in demand response programs among the eligible customer population are presented below.

As shown in Exhibit 5-3, sixty-three percent of the market of eligible non-participants reported owning their facility, and 26 percent reported that they lease their facility.

Exhibit 5-3
Renter/Owner Distribution in California

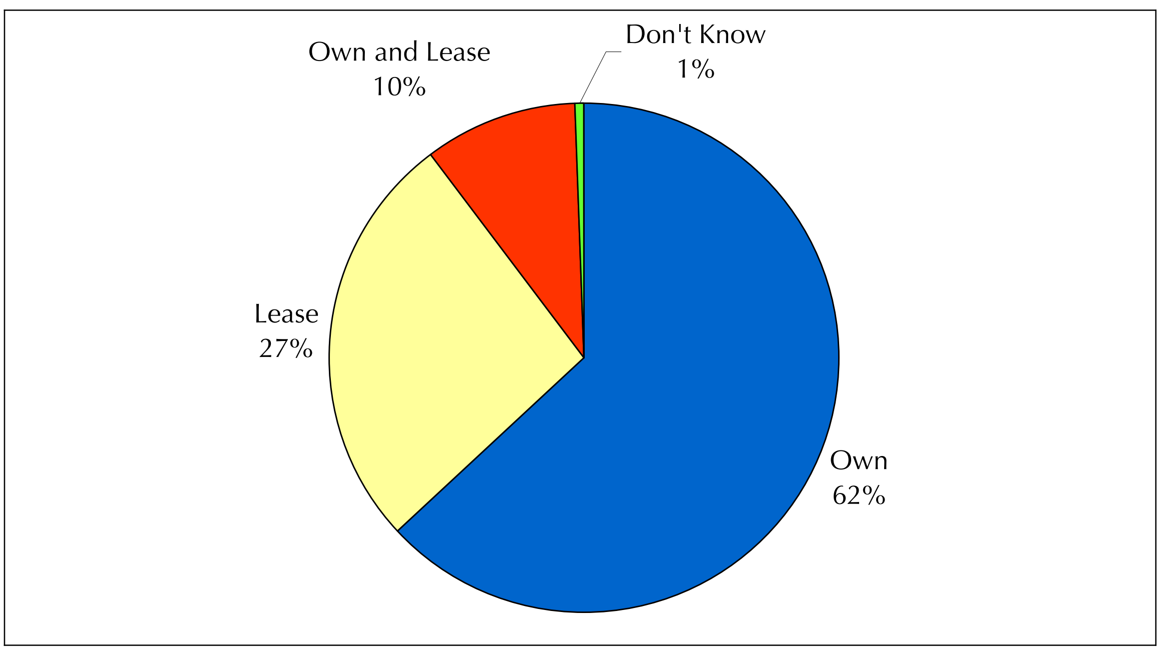
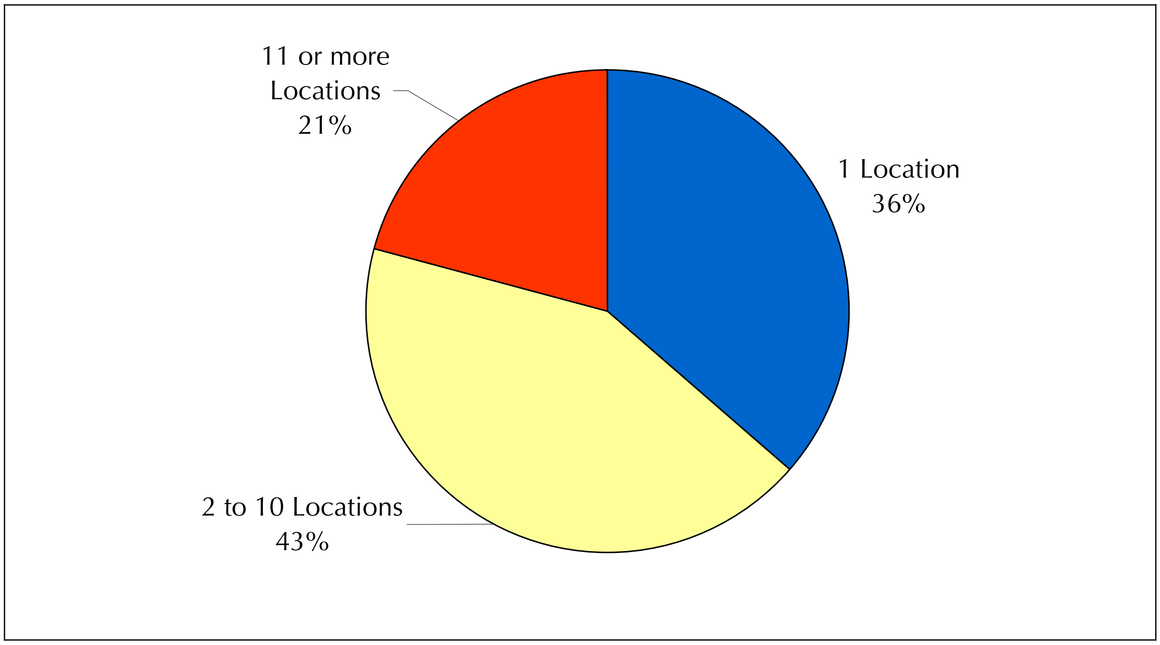


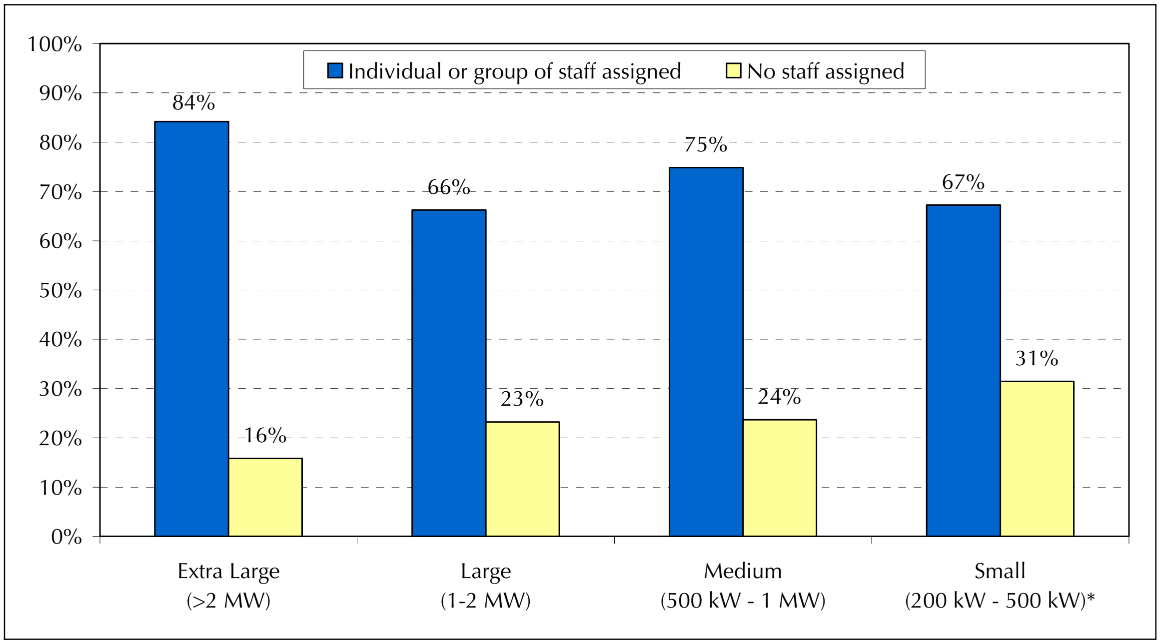
Exhibit 5-4 shows that approximately two-thirds of the market reported having more than one facility in California, with slightly over a third reporting having only one location.

Exhibit 5-4
Multi Location Distribution in California



Seventy-five percent of the market of eligible non-participants reported having assigned responsibility for controlling energy use and costs to either an individual in-house staff person or a group of staff. Across business types, the highest frequencies of having staff formally assigned to energy management were reported in the Institutional sector (85%) and the Mining/Metals/Stone/Glass/Concrete (MMSGC) sector (94%), while the lowest frequencies were reported in the Transportation/Communication/Utility (TCU) sector (51%). As might be expected, the formal assignment of staff to energy management is correlated to customer size, as shown in Exhibit 5-5, with Small customers reporting the largest share of having "no one" assigned to manage energy use and costs.

Exhibit 5-5
Shares of Customers with Dedicated Energy Management Staff

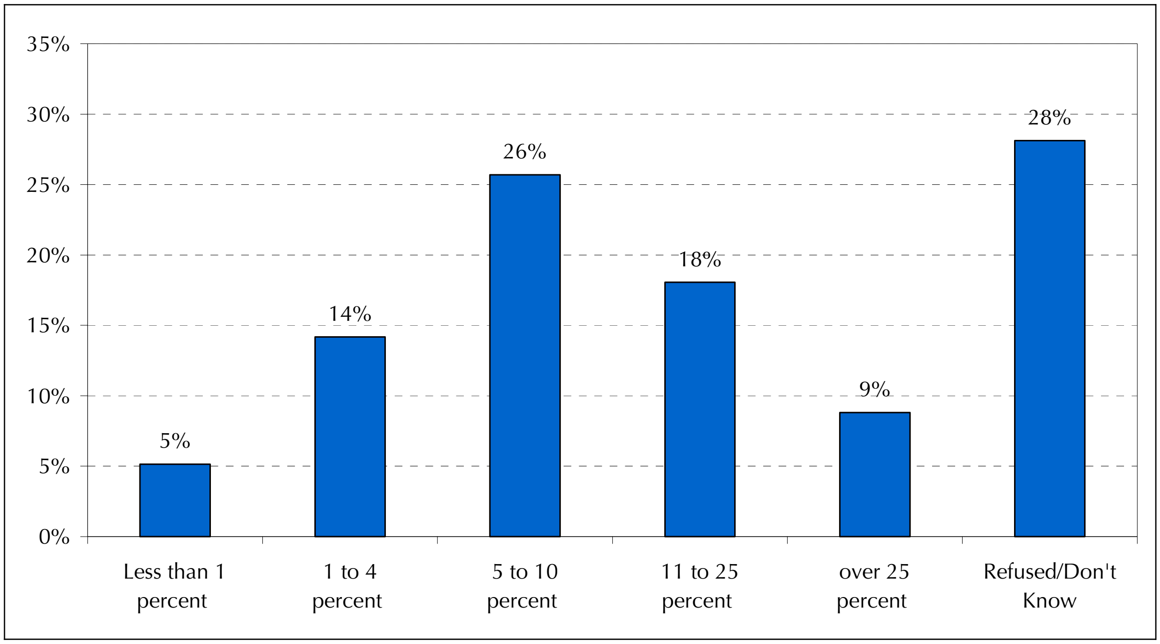


* Very Small and Extra Small customers shown aggregated with Small customers

As Exhibit 5-6 shows, twenty-seven percent of the market reported that their energy costs represent more than 10 percent of their total operating costs. On average for the entire eligible non-participant population, energy costs were reported to represent 12 percent of annual operating expenditures. Compared to the 2004 survey results, these values represent a fairly significant decline in energy cost share of annual operating expenditures. However, this apparent decline is due in large part to the exclusion of traditional interruptible customers from the population frame, where energy costs are typically greater than 10 percent of total operating costs.

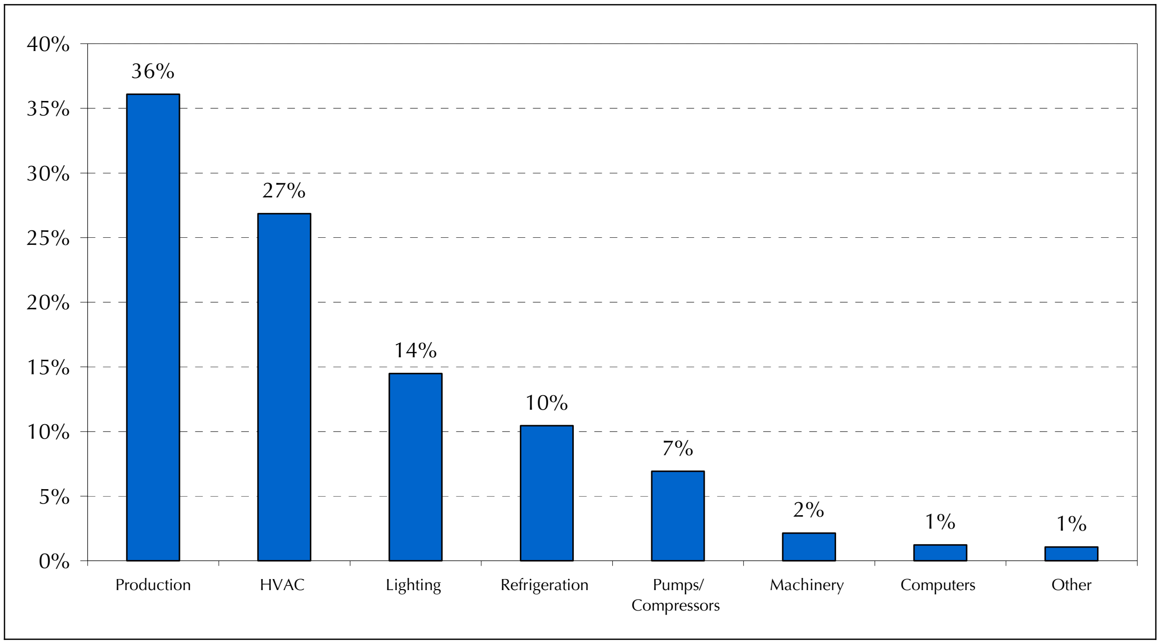
Customers in the MMSGC sector reported the highest energy cost shares, with 73 percent of the MMSGC market reporting that their energy costs exceed 10 percent of total operating costs. The average energy cost share reported in the MMSGC sector was 17 percent.

Exhibit 5-6
Energy Costs as a Percentage of Total Operating Costs in California



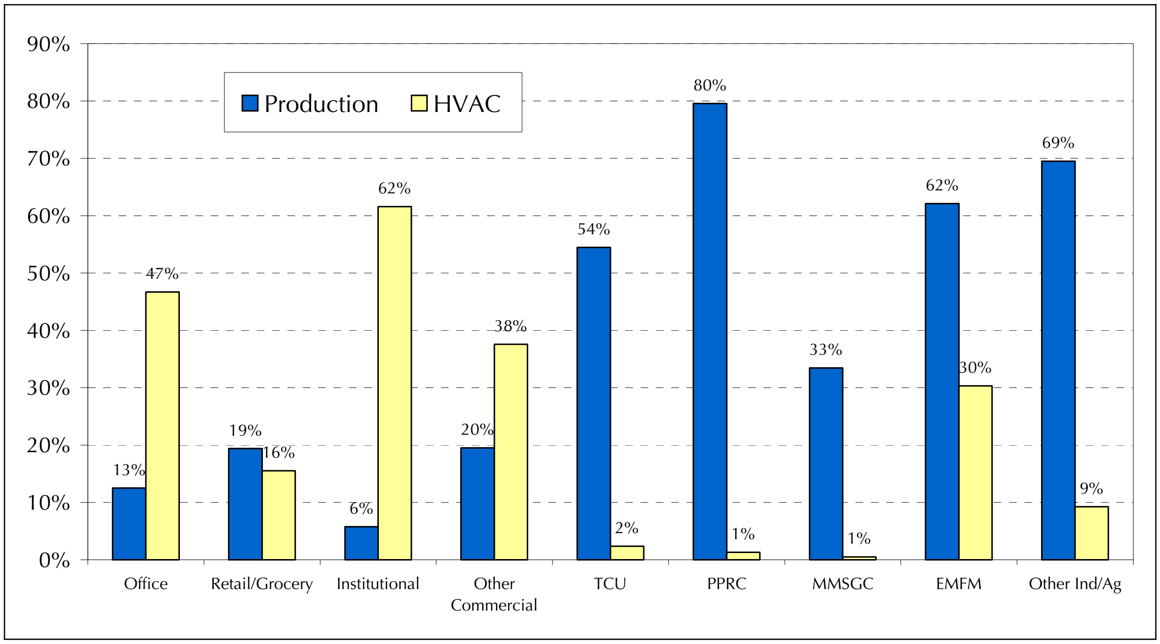
Thirty-six percent of the market reported that their largest end use of electricity was their production process (including both continuous and batch processing) and 27 percent reported that heating, ventilation, and air conditioning (HVAC) was their largest end use of electricity, as shown below in Exhibit 5-7.

Exhibit 5-7
Self-Reported Largest End Uses of Electricity



Looking across business types, there is a clear relationship between the largest self-reported end use of electricity and business type. As Exhibit 5-8 shows, the majority of customers in the manufacturing and industrial sectors reported that their production processes were their most important electric end use, whereas customers in the commercial services sectors reported that HVAC services were their largest single electric end use. The notable exceptions to these trends were in the MMSGC sector, where 58 percent of MMSGC customers reported that pumps and compressors were their largest electric end use, and the Retail/Grocery sector, where 32 percent reported that refrigeration was their largest end use.

Exhibit 5-8
Self-Reported Largest End Uses of Electricity by Business Type



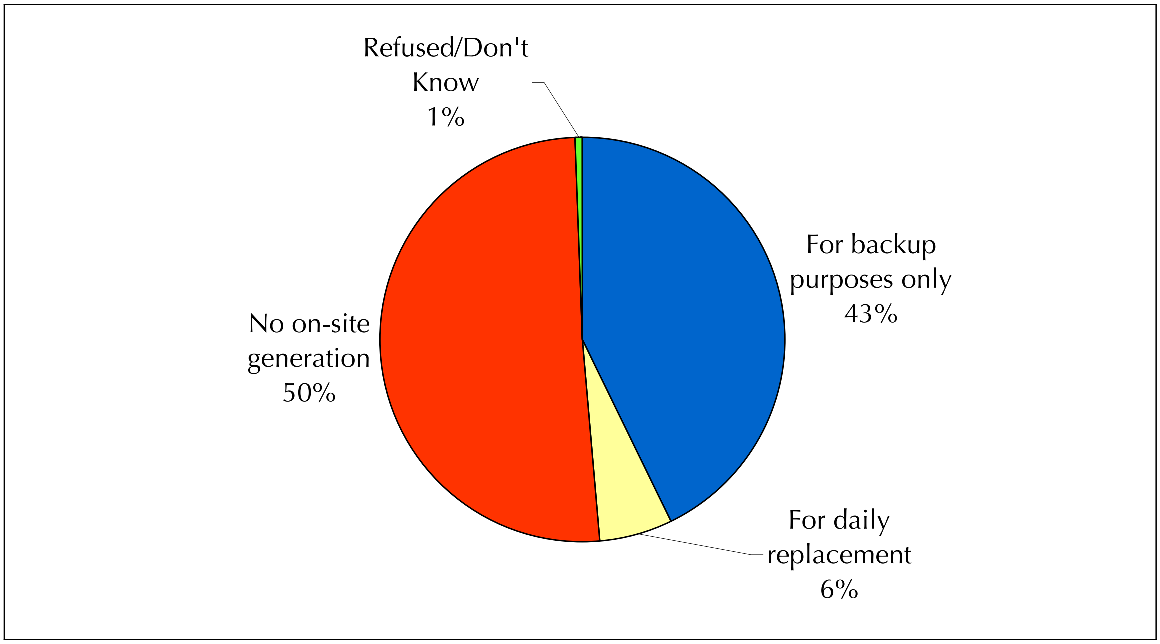
Forty-three percent of the market reported that lighting was their second largest electric end use, and 20 percent reported that HVAC was their second largest electric end use.

5.3.2 DR-Enabling and Automation Technologies (EC10, CA3, AT1-AT2)

To supplement the basic demographic information shown above, customers were also asked a battery of questions about their ownership of three key demand-response enabling and automation technologies – on-site generators, energy information systems, and energy management and control systems. The results from these questions allow examination of the structure of the installed base of enabling technologies and how ownership of these technologies correlates with customer perceptions of demand response barriers, opportunities, and potential. The key results describing the structure of the installed technology base are summarized below.

In total, forty-nine percent of the eligible non-participant market reported having on-site electricity generation, as shown in Exhibit 5-9. Sixty-eight percent of these customers, however, reported facing legal restrictions on the operation of their generators during the summer months.

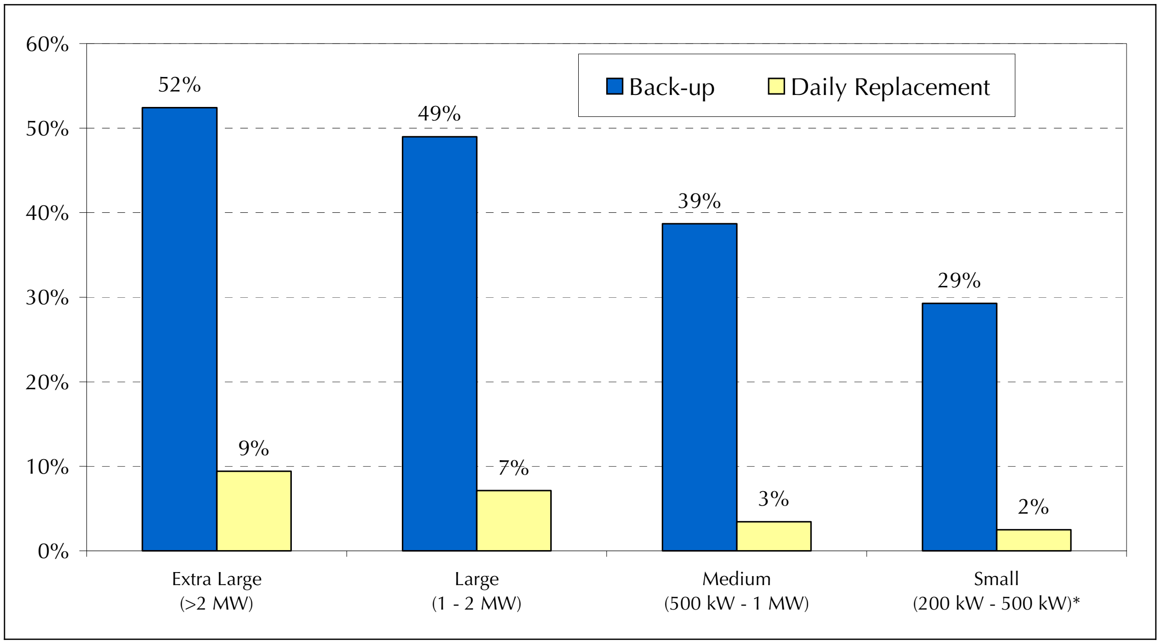
Exhibit 5-9
On-Site Generator Ownership in California



On-site generation ownership varied only slightly across business types, with the only the notable exceptions being the very low reported ownership rates in two sectors – the Petroleum/Plastic/Rubber/Chemicals (PPRC) sector (15%) and the MMSGC sector (19%). The reported on-site generation ownership in the PPRC sector is in line with that reported in the 2004 survey, but that reported in the MMSGC sector is significantly lower than in 2004 (19% compared to 68%). This difference is again largely due to the exclusion of traditional interruptible customers from the population frame but should also be treated with caution.

In contrast, as Exhibit 5-10 shows, ownership of on-site generation varied significantly with customer size among eligible non-participants, with larger customers reporting much higher ownership rates of both emergency back-up generation and daily replacement generation compared to smaller customers.

Exhibit 5-10
On-Site Generator Ownership by Customer Size

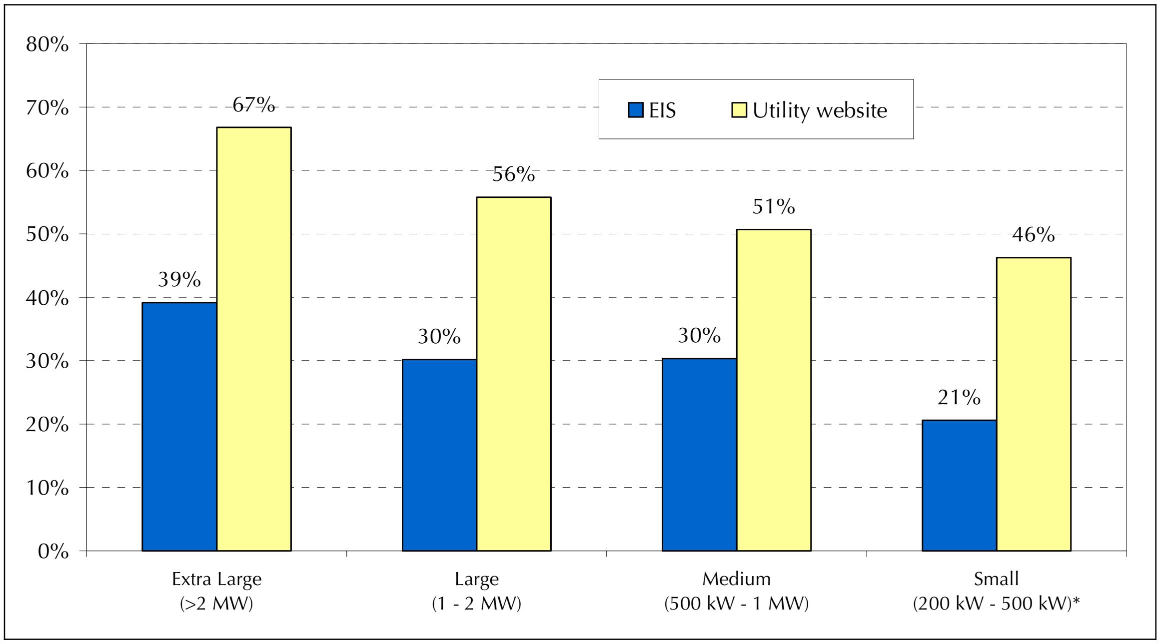


* Very Small and Extra Small customers shown aggregated with Small customers

Nearly half of on-site generation owners stated that their generators could meet up to 25 percent of their total peak load, about a quarter claimed their generators could meet 25 to 75 percent of their peak load, and about a quarter claimed their generators could meet more than 75 percent of their total peak load. On average, customers with on-site generation reported that they could meet approximately 50 percent of their non-coincident peak load with their on-site generators.

Thirty-one percent of the eligible non-participant market reported having the ability to view their facility's hourly demand on an in-house Energy Information System (EIS), while 56 percent reported being able to view their facility's hourly demand on a utility-provided website. Exhibit 5-11 shows how reported EIS ownership varies with customer size, with 39 percent of Extra Large customers reporting having an EIS compared to only 21 percent EIS ownership among Small customers. Exhibit 5-11 also shows a similar trend regarding the reported ability to view a customer's hourly demand on a utility-provided website – 67 percent of Extra Large customers reported having this ability compared to only 46 percent of Small customers reporting to have this ability.

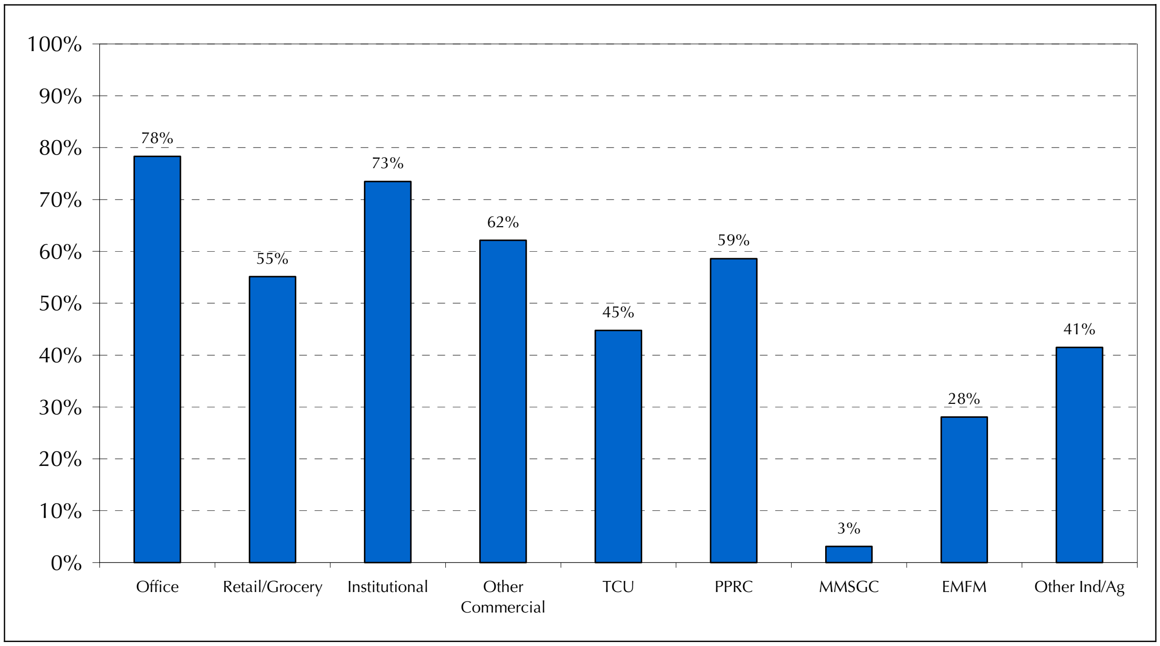
Exhibit 5-11
Ownership of Energy Information Systems and Access to Hourly Demand Data via Utility Websites by Customer Size



* Very Small and Extra Small customers shown aggregated with Small customers

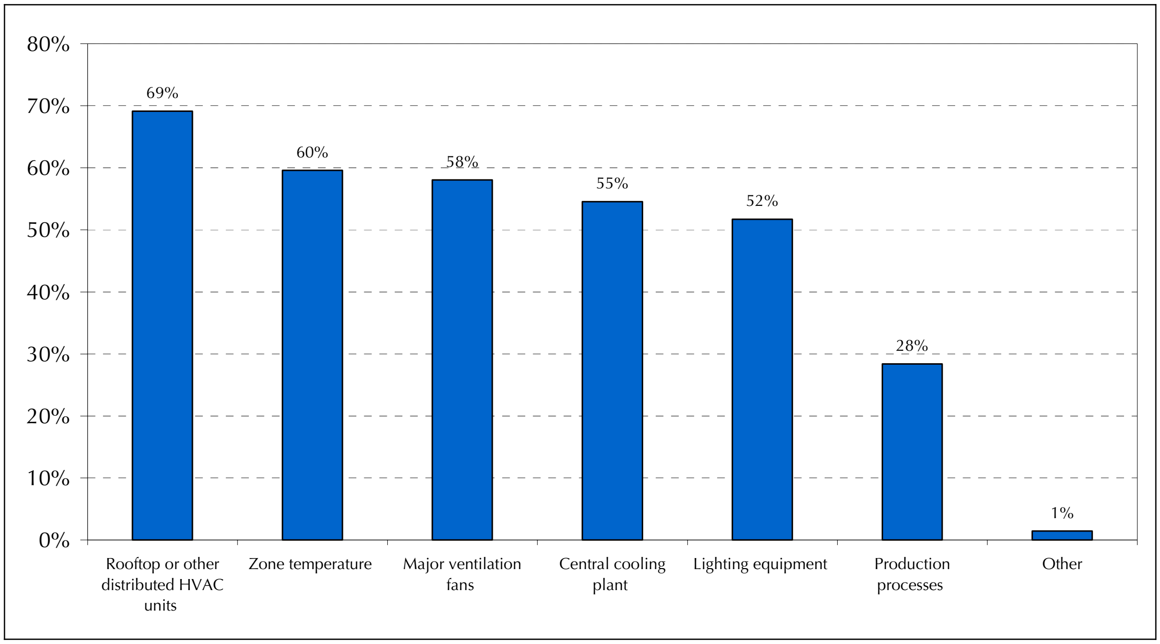
Fifty-two percent of the eligible non-participant market reported using an Energy Management and Control System (EMCS) to centrally control some or all of their HVAC or other energy-using equipment. Unlike the reported ownership of on-site generators or EIS, EMCS ownership does not appear to vary significantly by customer size. As Exhibit 5-12 shows, however, reported EMCS ownership varied significantly by business type. For example, 78 percent and 73 percent of Office and Institutional customers, respectively, reported using an EMCS compared to only 3 percent of customers in the MMSCG sector and 28 percent of customers in the EMFM sector.

Exhibit 5-12
Ownership of Energy Management and Control Systems by Business Type



Customers who reported using an EMCS system were asked to identify the equipment types controlled by their EMCS system. As Exhibit 5-13 shows, the most common types of equipment controlled by EMCS were rooftop or distributed HVAC systems followed by zone temperature, major ventilation fans, central cooling plants, and lighting equipment.

Exhibit 5-13
Main Equipment Types Controlled by EMCS Systems

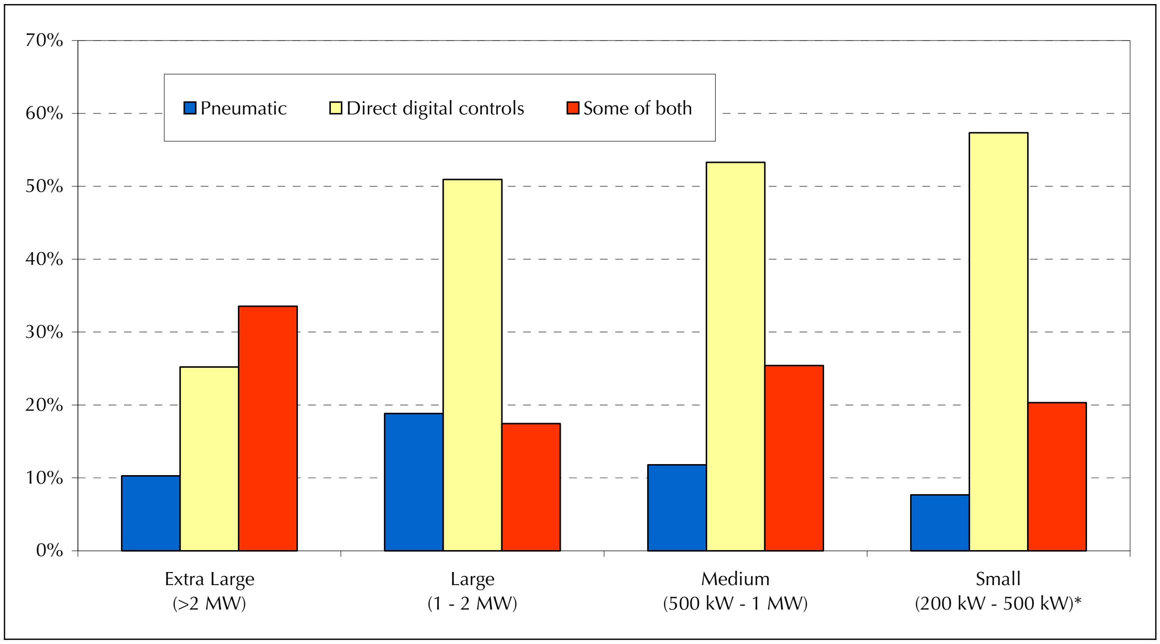


Customers who reported using an EMCS system were also asked about the extent of their ability to control zone temperatures. Sixty-three percent of these customers (33% of the total market) reported being able to control zone temperatures individually, while 51 percent (27% of the total market) reported being able to control zone temperatures globally via a simple screen or other centralized action.

All customers were asked about the characteristics of their space temperature control systems. Forty-three percent reported that their control system was primarily direct digital controls (DDC), 11 percent reported that their control system was primarily pneumatic, and 26 percent indicated that their controls were a mix of both DDC and pneumatic. The highest frequency of DDC systems was reported in Retail/Grocery (76%) and Other Commercial sectors (61%). The highest frequency of primarily pneumatic controls was reported in the Office sector (25%). The highest frequency of having a mix of both pneumatic and DDC controls was reported in the Institutional sector (51%).

As Exhibit 5-14 shows, the frequency of pneumatic versus DDC controls appears to be correlated with size, with the highest frequency of primarily DDC controls reported among Small customers, the highest frequency of primarily pneumatic controls reported among Large customers, and the highest frequency of having a mix of both systems reported among Extra Large customers.

Exhibit 5-14
Space Temperature Control System by Customer Size



* Very Small and Extra Small customers shown aggregated with Small customers

5.3.3 Automation Investments (EA8-EA11)

Customers were asked a series of questions about recent investment activity related to automation and control measures. The results of these questions provide important perspectives on how the installed base of control technologies has been changing in the eligible non-participant population and what trends to expect over the near-term.

Fifty-six percent of the market reported that they had considered investments in automation and control technology in order to better manage their facility's energy use in the past two years. Of those customers that considered automation and control investments, the vast majority stated that they did so in an effort to save on energy costs (74%), upgrade old equipment (27%), and increase flexibility of their control systems (25%). Contrary to the findings in the 2004 survey, larger customers reported a higher frequency of having recently considered automation investments compared to smaller customers. This difference is not likely due to the exclusion of interruptible customers from the 2005 survey (which would tend to produce the opposite result) and suggests that larger customers are relatively better positioned to consider these types of investments due to the scale of their operations and finances.

Thirty-five percent of the eligible non-participant market reported having actually installed automation and control upgrades in the past two years. Overall, the frequency of recent automation and control investments is positively correlated with customer size, with 46 percent of Extra Large customers reporting recent investments in automation compared to only 30% of Medium customers and 26% of Small customers. By business type, the highest frequency of having installed recent automation and control upgrades was reported in MMSGC sector (61%) while the lowest frequencies were reported in the TCU and PPRC sectors (11% each).

Among the different automation and control upgrades reported, controls and EMCS systems were the most common upgrade installed in the past two years (52%). These upgrades occurred mostly in the Institutional and Office sectors, with 77% of customers that considered automation/control investments in those sectors choosing to install controls and EMCS. Exhibit 5-15 shows the distribution of reported upgrades recently installed by type.

Exhibit 5-15
Distribution of Automation and Control Upgrades Installed in the Past Two Years
(Of those who Reported Installing Upgrades, N=145)

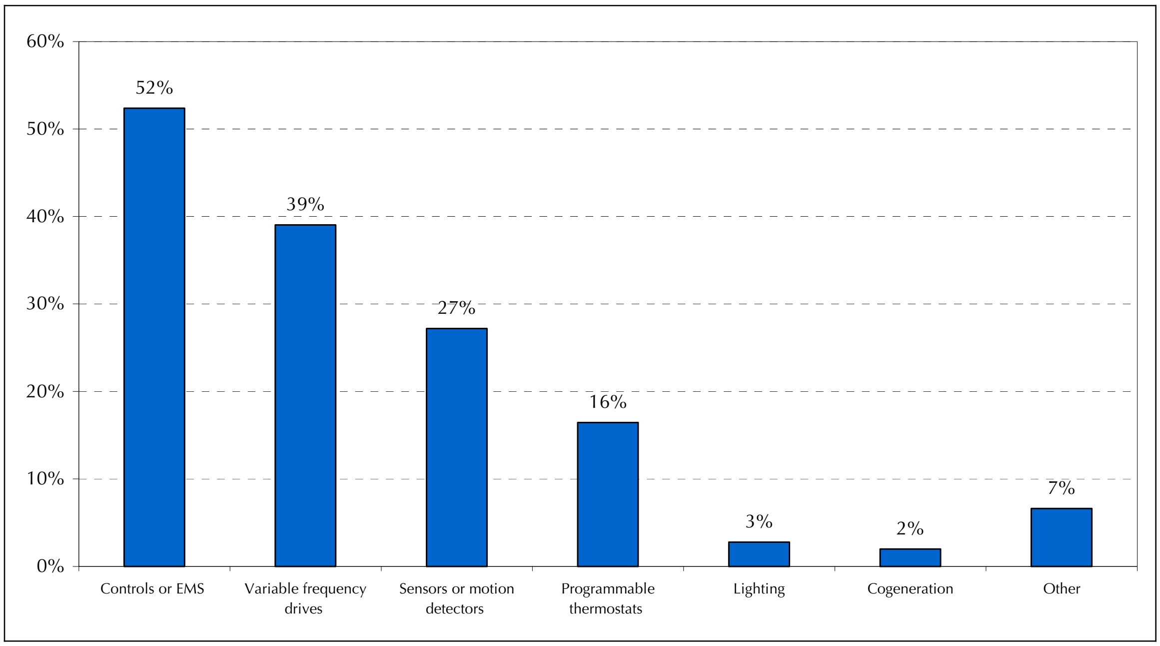


Exhibit 5-15 reveals some important differences from the findings of the 2004 survey. Namely, the results above show an approximate doubling in the reported frequency of recent investments in variable frequency drives (VFD), sensors and motion detectors, and programmable thermostats compared to the 2004 results. Although it is possible that this result reflects a true increase in VFD investments, it more likely reflects significant under-reporting of VFD investments in the 2004 survey. Examining these results reveals that the vast majority of VFD investments were reported primarily in the Institutional, Office, and Other Commercial sectors, and the bulk of investments in programmable thermostats and sensors/motion detectors were reported in the Institutional sector. These results are unlikely to be the result of excluding traditional interruptible customers from the population frame and may reflect an emerging trend in investments to better manage energy use among eligible non-participants. However, it should be noted that the measures presented above only reflect investment trends and do not necessarily reflect the extent to which these technologies are used to improve energy efficiency or enable demand response.

5.3.4 General Energy Market Perceptions (EM4-EM5)

Non-participants were asked a short series of questions about their current perceptions of the California electricity market going forward over the near term. The key findings from these questions were:

- Seventy-seven percent of the market expects wholesale electricity prices to increase over the next three years. This represent a substantial increase from the 2004 result when 53 percent of the market expected electricity prices to increase over the next three years.

- Sixty-six percent of the market believes that it is highly or somewhat likely that California's power supplies will not be adequate to meet expected power demand over the next three years. This is consistent with the results of the 2004 survey.

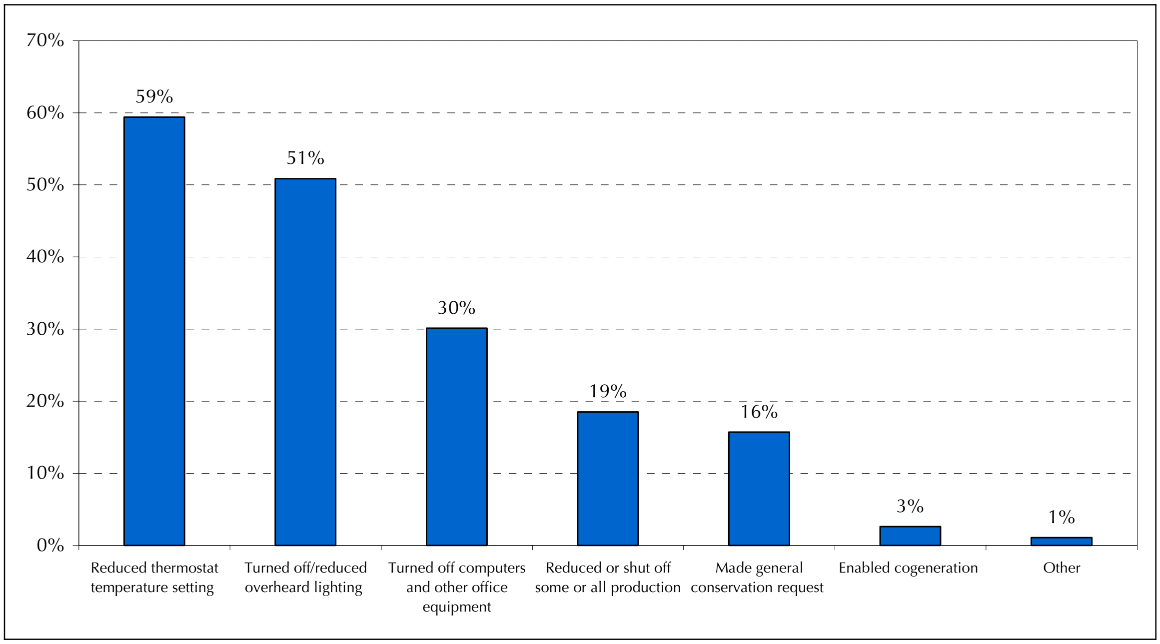
5.3.5 Public Appeals Program Awareness (AP1)

Outside of the WG2 demand response programs, the establishment of public appeal-based, voluntary demand response programs in California – such as Flex Your Power Now! and the CAISO's Voluntary Load Reduction Program – represents another avenue for increasing customer awareness about peak power issues and demand response. As part of the 2005 Market Baseline Survey, customers were asked a series of questions regarding their awareness and familiarity with these "public appeals" programs and the extent to which customers took voluntary demand response actions during the summer of 2005.

Forty-one percent of the eligible non-participant market recalled receiving alerts or notices to temporarily reduce their electricity demand during the summer of 2005. More than half of these customers reported receiving the notices via email, while a third reported receiving the notices via television or radio. Of all customers who reported receiving demand response notices, one third associated them with the Flex Your Power Now! Program.

Forty-six percent of those that recalled receiving public appeals alerts (i.e., 19 percent of the total eligible non-participant population) took action to temporarily reduce their demand. The most common actions cited were reducing thermostat temperature settings (59%), turning off or reducing overhead lighting (51%), turning off computers or other office equipment (30%), turning off some or all production equipment (18%), and making general conservation requests/announcements to facility staff (16%).

Exhibit 5-16
Voluntary Demand Reduction Actions Taken as a Result of Public Appeals Notices
(Of those who Recalled Receiving Notices and Took Action, N=102)



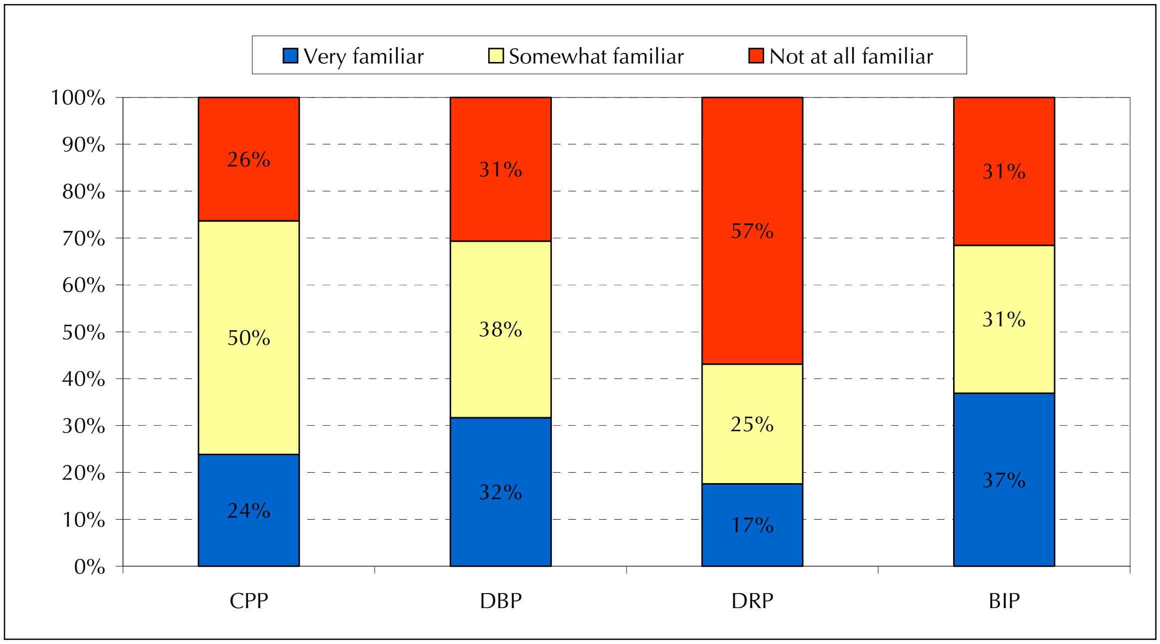
5.3.6 Demand Response Awareness and Familiarity (F1-F7, CH1-CH3)

One of the central objectives of the 2005 Market Baseline Survey was to assess the extent of non-participant customer awareness and familiarity with WG2 demand response programs and track any significant changes that have occurred since 2004. To this end, customers were asked a battery of questions designed to gauge overall customer familiarity with demand response programs and specific familiarity with the Critical Peak Pricing (CPP) Program, the Demand Bidding Program (DBP), the Demand Reserves Partnership Program (DRP), and the Base Interruptible Program.

The battery began with an unaided question asking whether customers had heard about specific programs developed in California to promote demand response. Seventy-nine percent of the eligible non-participant market indicated that they had heard about specific demand response programs. Half of those customers that indicated they had heard about specific programs were able to identify a specific program by name. The most frequently identified program was DBP (28%), followed by CPP (24%), BIP (10%), and DRP (9%). Other common programs identified were the 20/20 and other energy efficiency programs (7%) and interruptible service tariffs (8%).

Customers were then asked a series of familiarity questions specific to the CPP, DBP, DRP, and BIP programs. These familiarity questions were all aided questions where a one or two sentence program description was read prior to the customer being asked to state their level of familiarity. Exhibit 5-17 shows the reported familiarity levels with each program.

Exhibit 5-17
Familiarity with WG2 Demand Response Programs Among Non-Participants



Seventy-three percent of the eligible non-participant market indicated that they were very or somewhat familiar with CPP, compared to 69 percent for DBP, 68 percent for BIP, and 43 percent for DRP. At this aggregate level, these values represent significant increases in familiarity with CPP, DBP, and DRP among non-participating customers compared to the values reported in the 2004 survey (64%, 61%, and 32%, respectively). The increases in familiarity with the DBP and DRP programs were largely due to significantly more customers reporting to be "very familiar" with these programs, with only small increases in customers reporting to be "somewhat familiar". The overall increase in familiarity with CPP, however, was driven entirely by more customers reporting to be "somewhat familiar" with CPP compared to the 2004 results. In this sense, therefore, the reported increase in familiarity with CPP at the aggregate level should be treated with caution.

Given these high and steady, if not increasing, levels of familiarity with CPP and DBP, it is informative to take a closer look at self-reported unfamiliarity. Exhibit 5-18 shows the frequencies of customers who reported to be "not at all familiar" with CPP and DBP by business type. As the Exhibit shows, customers in the Other Commercial sector reported the highest levels of unfamiliarity with both CPP (36%) and DBP (47%). Exhibit 5-18 also shows a significant correlation between business type and overall level of unfamiliarity, with customers in service-based business sectors reporting a significantly higher level of unfamiliarity with CPP and DBP compared to manufacturing and industrial customers.

Exhibit 5-18
Unfamiliarity with CPP and DBP Among Non-Participants by Business Type

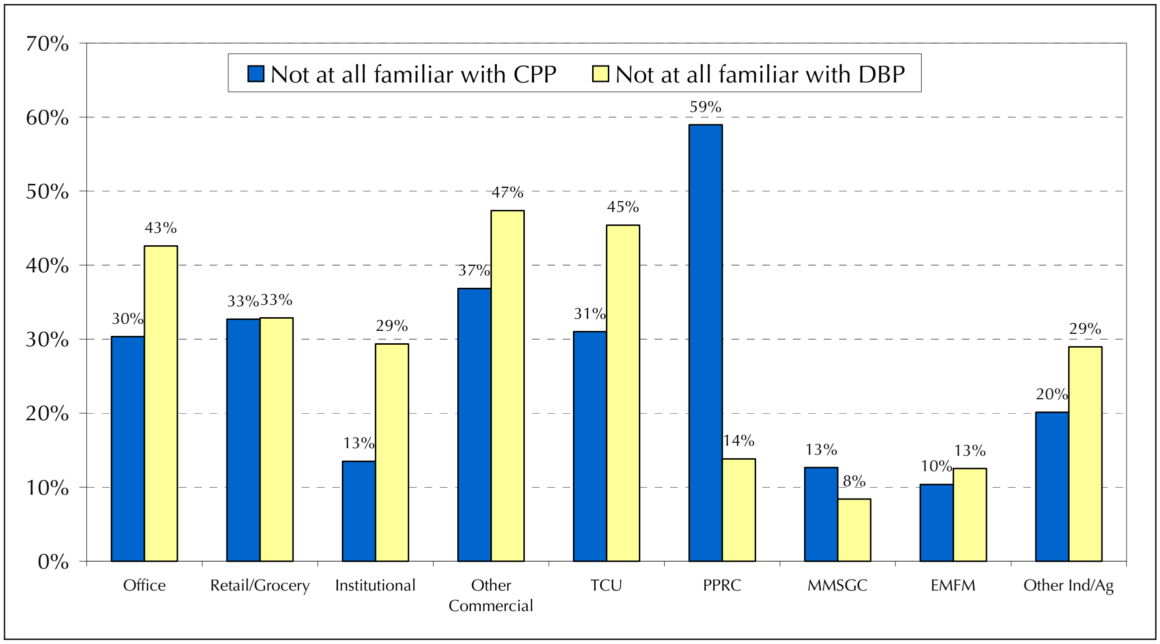
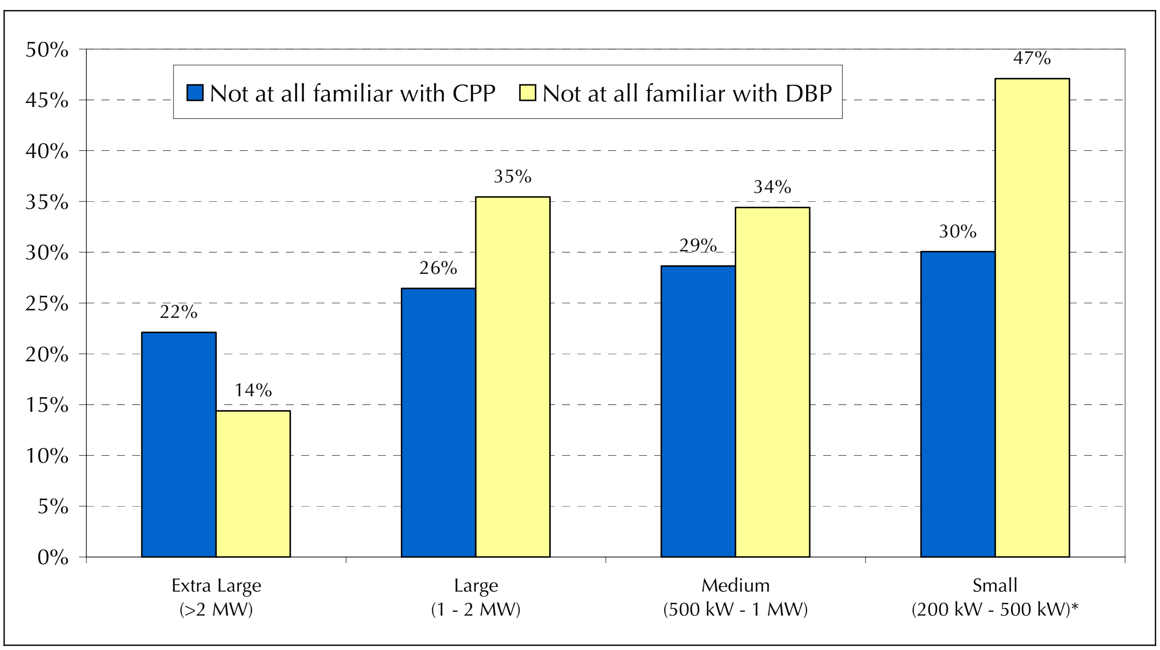


Exhibit 5-19 shows, as might be expected, how self-reported unfamiliarity with CPP and DBP is also negatively correlated to customer size, although the correlation appears less significant for CPP than for DBP.

Exhibit 5-19
Unfamiliarity with CPP and DBP Among Non-Participants by Customer Size

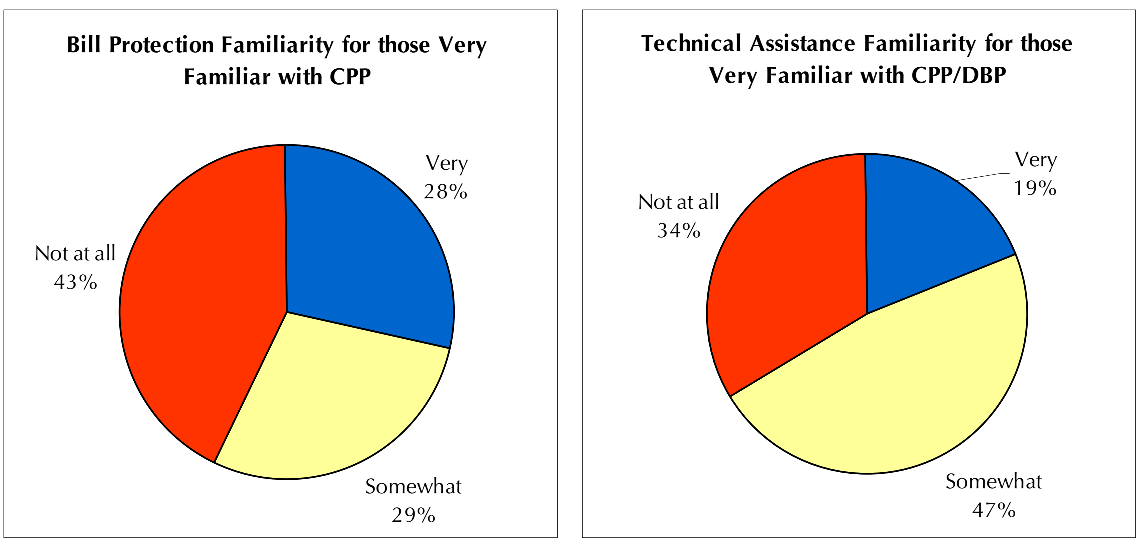


* Very Small and Extra Small customers shown aggregated with Small customers

Similar relationships also hold between customer size and familiarity with the DRP and BIP programs. Familiarity with BIP also exhibits a similar correlation with business type as that shown in Exhibit 5-18 for CPP and DBP. That is, self-reported familiarity is highest in the manufacturing and industrial sectors and self-reported unfamiliarity is highest in the service-oriented business sectors. In the case of DRP, however, customer familiarity does not appear to vary significantly between the service-oriented sectors and the manufacturing and industrial sectors.

Customers were also asked a series of questions gauging their familiarity with two incentive programs associated with WG2 demand response programs – the Bill Protection Incentive for CPP and the Technical Assistance Incentive Program. Overall, forty-four percent of the eligible non-participant market indicated that they were either somewhat or very familiar with the Bill Protection Incentive, and 40 percent indicated that they were somewhat or very familiar with the Technical Assistance Incentive Program. Among customers who reported to be very familiar with the CPP or DBP programs, familiarity with these incentive programs was markedly higher. As Exhibit 5-20 shows, 57 percent of these customers reported to be very or somewhat familiar with the Bill Protection Incentive and 66 percent reported to be very or somewhat familiar with the Technical Assistance Incentive Program.

Exhibit 5-20
Familiarity with Demand Response Incentives for those Very Familiar with CPP/DBP



While familiarity with demand response incentives are moderately high among those very familiar with CPP or DBP, these levels represent a significant decline compared to those reported in 2004. In particular, familiarity with the Technical Assistance Incentive Program fell by more than a factor of two, due entirely to a large decrease in customers reporting to be very familiar with the incentive.

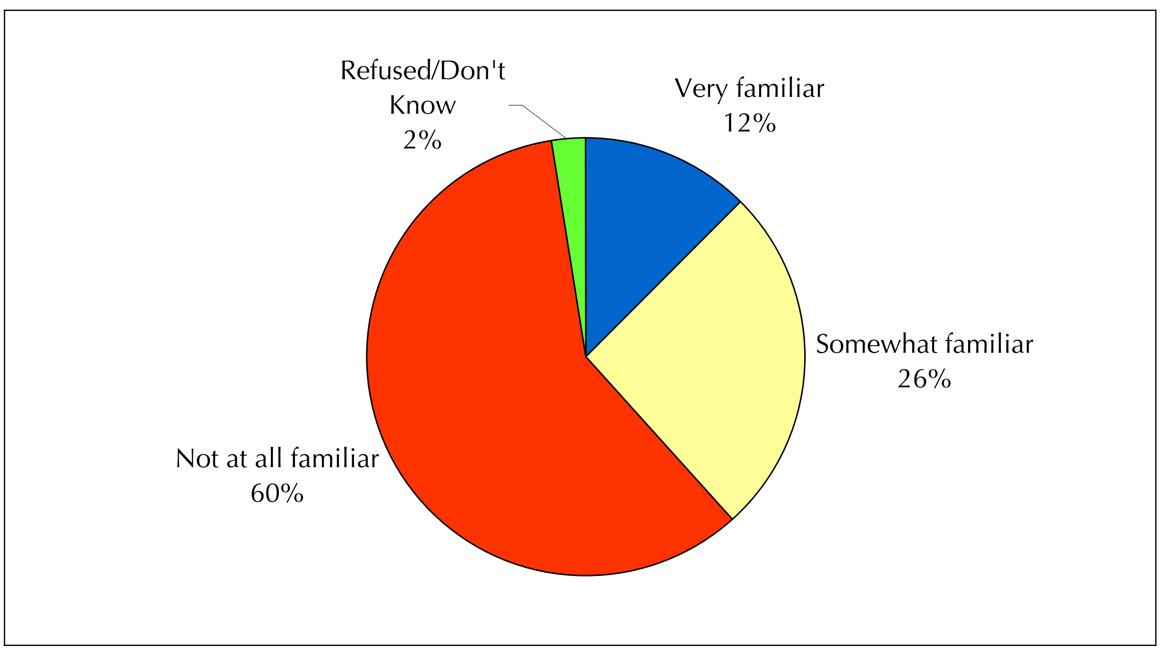
Finally, in order to gauge the impact of program marketing efforts on customer awareness levels, customers were asked a series of questions about the types and usefulness of marketing materials that they had received in the past year. Fifty-nine percent of the non-participant market recalled having a general discussion with their utility representative about demand response program features, and 64 percent recalled receiving brochures or other printed materials about demand response programs. However, only 28 percent of the market recalled receiving a specific analysis of the financial impacts of participation from their utility representative. Overall, 35 percent of the non-participant market recalled receiving some type of program information in the past year that they considered very useful and 24 percent recalled receiving information that they considered somewhat helpful. For the most part, these results are in line with those from the 2004 survey. One exception is a decline in the reported recall of having specific rate analyses provided by utility representatives (34% in 2004 compared to 28% in 2005). This difference is likely due to the exclusion of traditional interruptible customers from the population frame but also likely reflects a natural drop-off in customer recall relative to the 2004 survey, since the timing of last year's survey overlapped with the rollout of utility marketing efforts.

5.3.7 Default CPP Awareness and Bill Impact Perceptions (DE1-DE6)

In light of the anticipated rollout of default CPP tariffs for the summer of 2006, customers were asked a series of questions designed to gauge their level of familiarity with proposed default CPP rates, the perceived bill impacts of these rates, and the main types of informational needs customers consider necessary in order make informed decisions about staying on or opting out of default CPP.

As Exhibit 5-21 shows below, only 12 percent of the eligible non-participant market reported to be very familiar, and 26 percent reported to be somewhat familiar with their utility's proposed default CPP tariff.

Exhibit 5-21
Familiarity with Proposed Default CPP Tariffs



In order to better understand the depth of self-reported familiarity, customers that reported to be either very or somewhat familiar with the proposed default CPP rates were asked to estimate the potential bill impacts of default CPP. Of the customers reporting to be familiar with the proposed rates, 42 percent estimated that, on average, most customers' annual electricity bills would increase as a result of taking service on default CPP, while 8 percent estimated that most customers' bills would decrease, and 39 percent estimated that most customers' bills would stay about the same. Approximately a third of the customers who anticipate net bill increases estimate increases in annual bills on the order of 1-5 percent, another third estimate increases on the order of 6-10 percent, and another third estimate bill increases greater than 10 percent. For customers who anticipate net bill decreases, approximately half estimate decreases in annual bills on the order of 1 to 5 percent, about a fifth estimate decreases on the order of 6 to 10 percent, and a third estimate decreases of greater than 10 percent. The average perceived impact of default CPP on most customers' annual electricity bills was a 3.1 percent increase.

Customers who reported to be familiar with the proposed default CPP rates were also asked to estimate the potential bill impacts for their particular facility. Fifty-eight percent estimated that their specific annual electricity bill would increase as a result of taking service on default CPP, while 11 percent estimated that their annual bill would decrease, and 25 percent estimated that their annual bill would stay about the same. The average perceived impact of default CPP on customers' individual electricity bills was a 3.9 percent increase.

Finally, all customers were asked an open ended question about what kinds of information they would need in order to make a sound decision about whether or not to stay on default CPP if default service were indeed changed to a CPP tariff. As Exhibit 5-22 shows, the most common responses entailed pricing information (29%), detailed program information (21%), and estimates of impacts on electricity bills and/or production (13%).

Pricing information responses included specific answers such as:

- "How much are we going to charged and why is it so high?"
- "How much will rates increase on critical days?"
- "How much the tariff is and under what conditions does the tariff kick in?"
- "I would need to know the price differentials based on my historical data."

Detailed program information responses included specific answers such as:

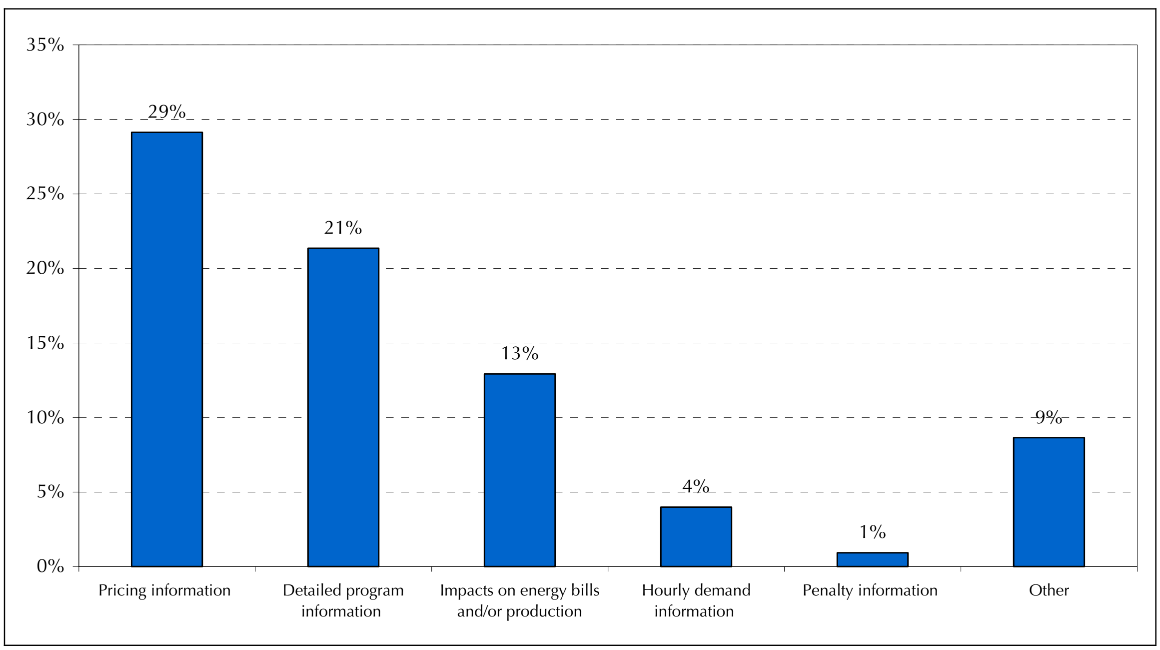
- "All the info I could get."
- "All of the details, complete, nothing left out, a rep who could tell me everything and who I could ask questions to."
- "A complete explanation."
- "Further documentation and reading materials."

Estimates of impacts on electricity bills and/or production information included specific answers such as:

- "Any information that would clearly show me if it is costing me more money or not."
- "Based on the same use, what the difference in my bills would be."
- "The cost difference would have to be discussed and how it would affect our provided healthcare."
- "How does this affect me financially?"
- "How is it going to affect me – time wise, cost wise, customer wise?"

While program information and bill/production impacts, were cited fairly evenly across customer sizes and business types, pricing information was cited most frequently among larger customers and customers in the manufacturing and industrial sectors.

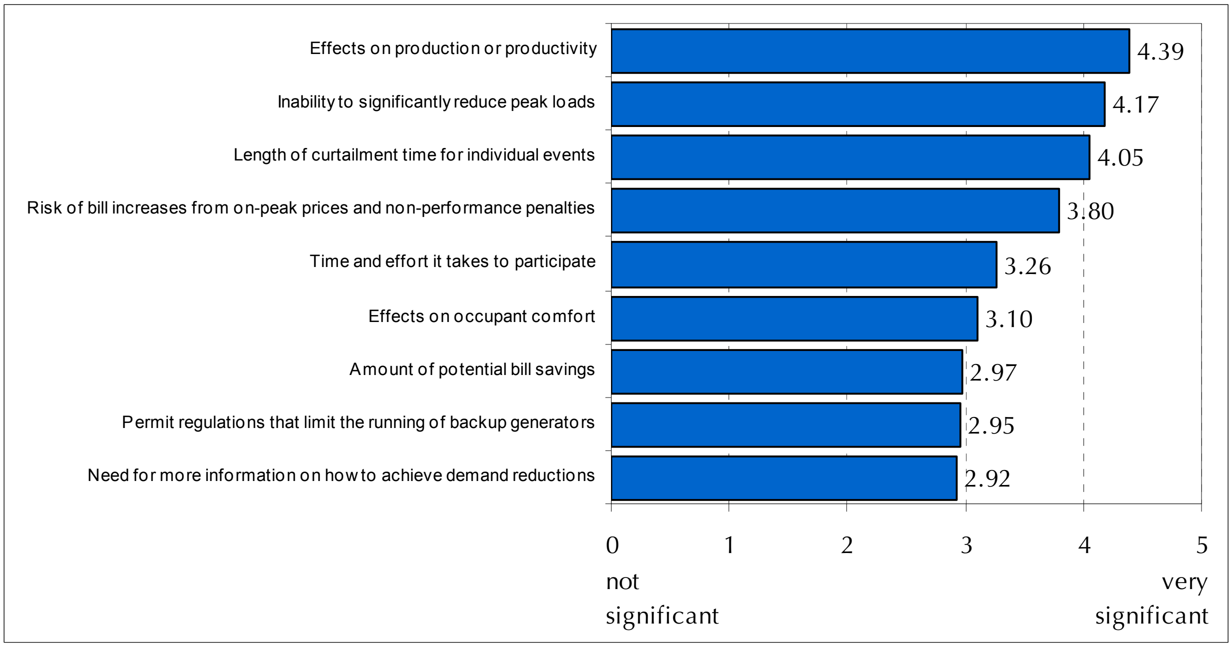
Exhibit 5-22
Information Types Cited as Necessary for Decision-Making on Default CPP



5.3.8 Barriers to Participation in DR Programs (BA1-BA9)

As in the 2004 survey, customers were asked about a number of potential barriers to implementing demand response. Eligible non-participants were read nine concerns that customers often view as barriers to participating in demand response programs and asked to rank the significance of each concern on a scale from 1 (not significant) to 5 (very significant). The mean response given for each barrier described is shown below in Exhibit 5-23. As the Exhibit shows, the highest ranked concern across the entire non-participant population was "effects on production or productivity" (4.4), followed by "inability to significantly reduce peak loads" (4.2), "length of curtailment time for individual events" (4.0), and "risk of bill increases" (3.8).

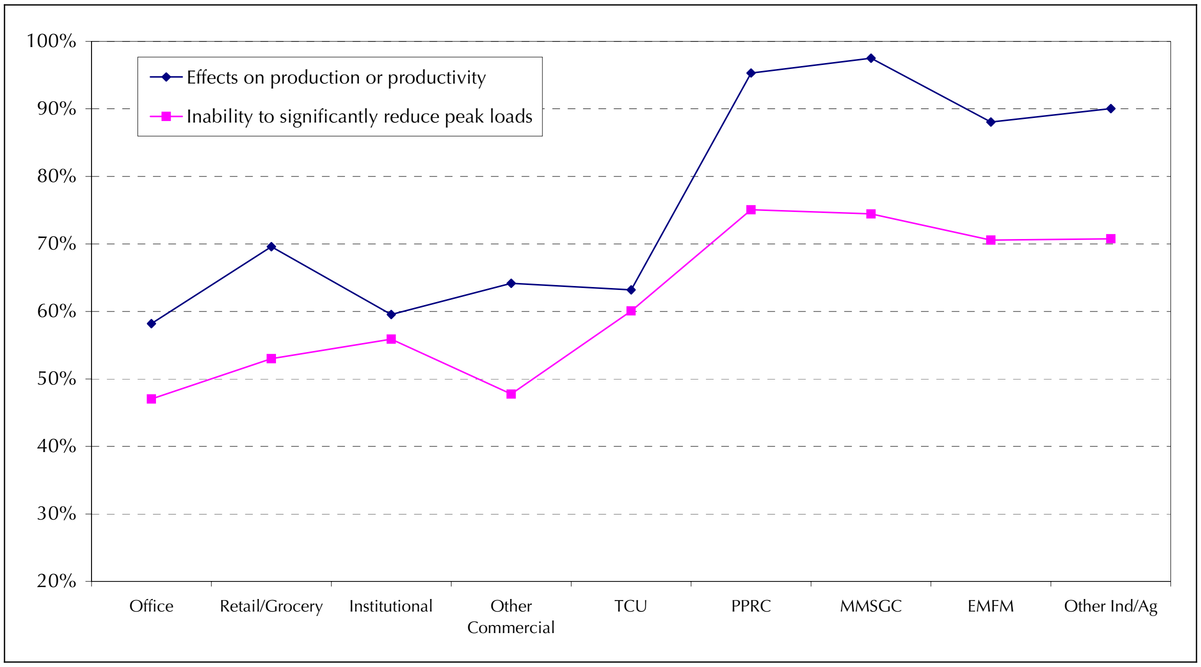
Exhibit 5-23
Customer Ranking of Participation Concerns (Mean Ranking = 3.5)



Looking at the results for each barrier more closely reveals some important variations between business types and customer sizes. As Exhibit 5-24 shows below, significantly higher shares of manufacturing and industrial customers ranked "effects on production or productivity" and "inability to significantly reduce peak loads" as a 5 compared to customers in service-oriented sectors. Higher shares of larger customers also ranked these two barriers as very significant compared to smaller customers. These results imply that the primary concerns among large manufacturing and industrial customers are related to the structure of their electricity consumption and the opportunity costs of temporary demand reductions. This finding is consistent with the fact that large manufacturing and industrial customers tend to have high load factors and load profiles that are dominated by process and production end uses.

One would expect that owners of on-site generation would rank "effect on productivity" or "inability to reduce peak loads" significantly lower than those without on-site generation. Interestingly, however, self-reported ownership of on-site generation capacity did not correlate significantly with customer rankings of these two barriers, nor did the ownership of other enabling technologies such as energy information systems or energy management and control systems. This finding suggests that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response. In this respect, the installed base of enabling technologies, as shown in Exhibits 5-10, 5-11, and 5-12, can be viewed as a significant but mostly dormant demand response resource in the non-participant population in California.

Exhibit 5-24
Share of Customers Ranking "Effects on Production or Productivity" and "Inability to Reduce Peak Loads" as Very Significant Concerns by Business Type

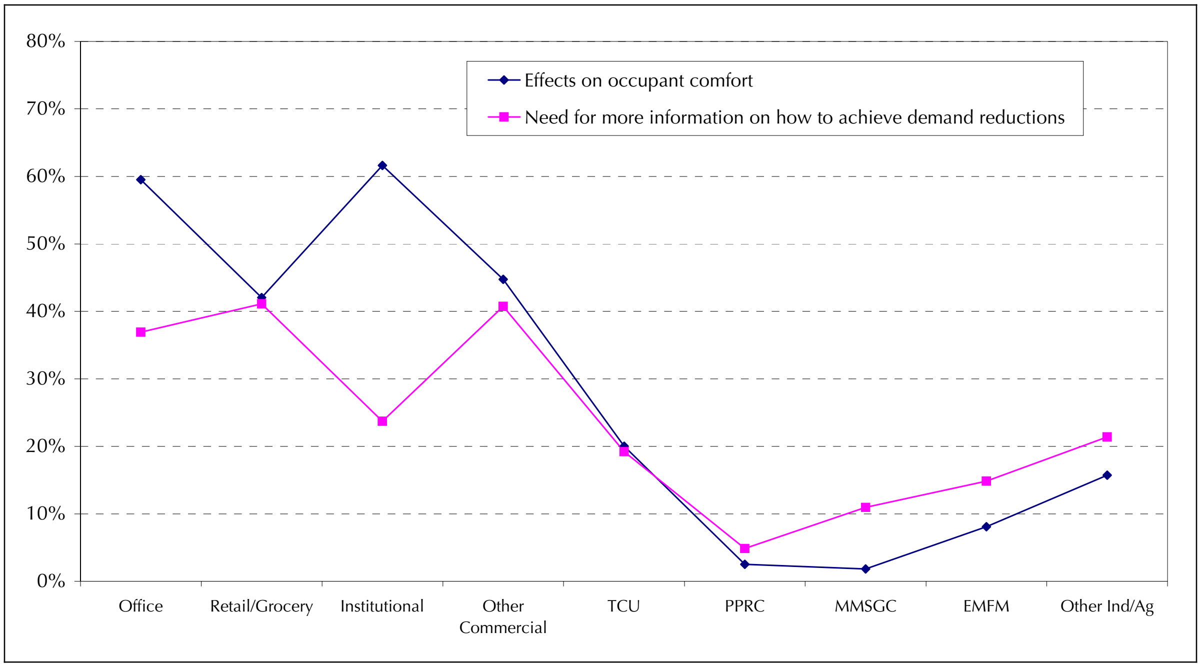


A higher share of smaller customers ranked bill impacts – "risk of bill increases" and "amount of potential bill savings" – as very significant participation concerns compared to larger customers. This result implies that even though smaller customers reported smaller energy cost shares than larger customers, the scale of their operations makes them much more sensitive to changes in their energy bills. It also indicates that the costs associated with temporary demand reductions are perhaps less detrimental to small business operations compared to larger businesses.

Exhibit 5-25 shows how the shares of customers ranking "effects on occupant comfort" and "need for more information on how to achieve demand reductions" as barriers varied by business type. As the Exhibit shows, significantly higher shares of customers in the Institutional, Office, Other Commercial, and Retail/Grocery sectors ranked these two barriers as very significant relative to manufacturing and industrial customers. The results for the Institutional sector reflect a similar level of concern with occupant comfort as that in the Office sector, as one would expect, but a lower need for information compared to other service-oriented sectors, reflecting relatively higher levels of knowledge about peak load management and demand response among Institutional customers.

A significantly higher share of Small customers also ranked "need for more information on how to achieve demand reductions" as a very significant barriers compared to the rest of the market. This result is consistent with smaller customers reporting a higher share of "no one assigned responsibility for controlling energy usage and costs" (see Exhibit 5-5).

Exhibit 5-25
Share of Customers Ranking "Effects on Occupant Comfort" and "Need for More Information on How to Achieve Demand Reductions" as Very Significant Concerns by Business Type



For the most part, the results presented above are in line with those from the 2004 survey with three key exceptions. "Amount of potential bill savings", "effects on occupant comfort", and "permit regulations that limit the running of backup generation" all were ranked significantly lower compared to the 2004 survey results. Looking closely at the differences reveals that customer ranking of "effects on occupant comfort" fell most among Extra Large customers and manufacturing and industrial customers. This change suggests an increased willingness to curtail HVAC services among large manufacturing and industrial customers.

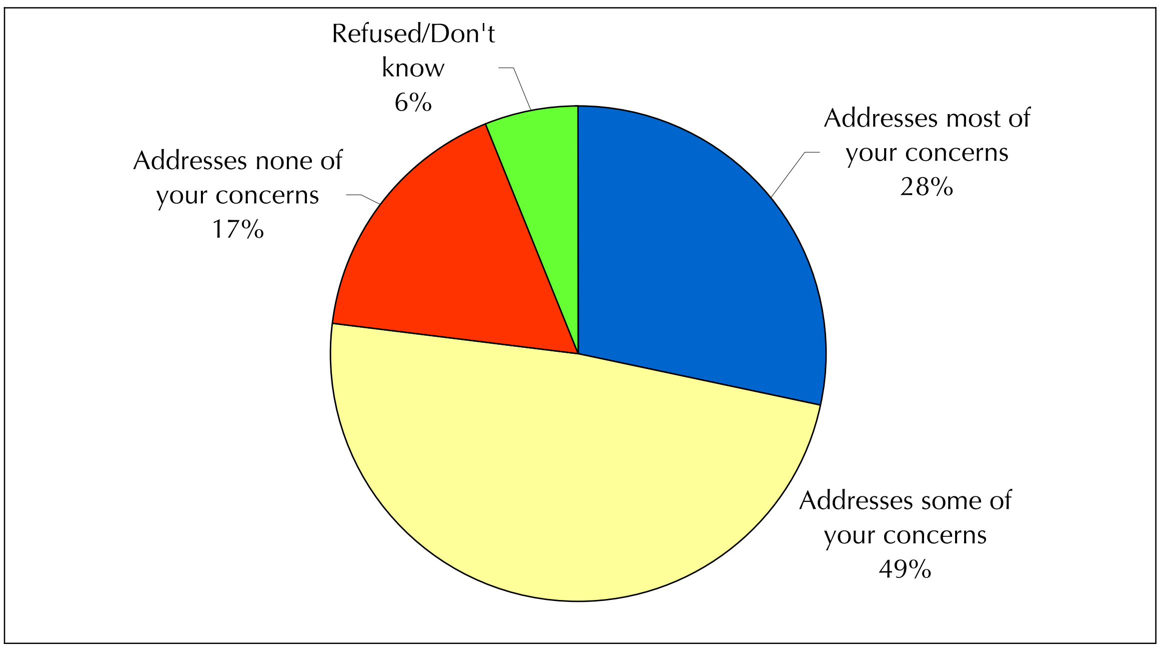
Similarly, manufacturing and industrial customers ranked of "amount of bill savings" much lower than in the previous survey. This trend suggests that other participation concerns are becoming more important relative to incentive levels, e.g. inability to shift load or effects on production and productivity from temporary load reductions. It should be noted, however, that this result could also reflect the exclusion of traditional interruptible customers from the 2005 survey, since these customers face the most risk and receive significantly larger incentives compared to customers in other demand response programs.

5.3.9 Impacts of 2005 Program Changes on Perceived Barriers to Participation (CH1-CH3)

Prior to summer 2005, several changes were made to WG2 demand response programs in order to address certain perceived barriers to participation identified in the 2004 Evaluation. For CPP, the most important changes were modifications to program eligibility criteria (SDG&E only) and continuation of the Bill Protection Incentive for new participants. For DBP, important changes included lower minimum load reduction bids and allowing customers with the same tax ID number to submit aggregated load reduction bids. Overall, only 39 percent of the market reported to be very or somewhat familiar with these changes. Additionally, the Technical Assistance Incentive Program was also modified to provide free on-site audits to identify load reduction opportunities and financial incentives for equipment-enabled load reductions.

In order to assess the impact of these program changes on the perceived barriers to participation among the eligible non-participant population, customers were asked a series of questions related to specific barriers and the extent to which the 2005 program changes addressed these concerns. Customers who cited "risk of bill increases from level of on-peak prices or non-performance penalties" as a significant participation concern were read a brief description of the Bill Protection Incentive and asked to evaluate the extent to which the Bill Protection Incentive addressed their concerns about participating in CPP. As Exhibit 5-26 shows, 28 percent responded that the Bill Protection Incentive addressed most of their concerns about bill risk, while 49 percent responded that the Bill Protection Incentive addressed some of their concerns about bill risk.

Exhibit 5-26
Extent to Which the Bill Protection Incentive Addresses Concerns About the Risk of Bill Increases from Participating in CPP (N=442)



Across business types, significantly more customers in the Retail/Grocery sector (66%) responded that the Bill Protection Incentive addressed most of their concerns about bill risk compared to customers in other sectors. Across customer sizes, slightly higher shares of Medium and Small customers responded that the Bill Protection Incentive addressed most of their bill risk concerns compared to Large and Extra Large customers.

Customers who responded that the Bill Protection Incentive addressed "some" or "none" of their concerns were asked to provide an open-ended explanation for their answers. The most frequent reasons given to explain "some" or "none" responses were an inability to shift or reduce peak load (31%), uncertainty over the non-energy cost impacts versus the energy bill benefits of participating in CPP (19%), and longer-term concerns related to uncertainty and risks faced after the Bill Protection Incentive expires (17%).

Responses categorized as an inability to shift or reduce peak load include:

- “We are a 5-star resort and occupancy drives my energy consumption - guest comfort is of the utmost importance.”
- “At this point we can't reduce anything without jeopardizing our license for day care.”
- “Basically the emphasis has to be on maintaining the equipment and maintaining the electrical input for that equipment. The problem is not shutting off for 1/2 hour but any amount of time above 1/2 hour could create critical problems with freezers and other lab equipment.”
- “Because it doesn't really address variables we have limited control over. Like ships needing power - I can't just go and pull the plug on them.”
- “It’s just that we can’t reduce in middle of the day – once the kilns are on, they can’t stop.”

Responses representing uncertainty over non-energy costs and energy bill benefits of CPP include:

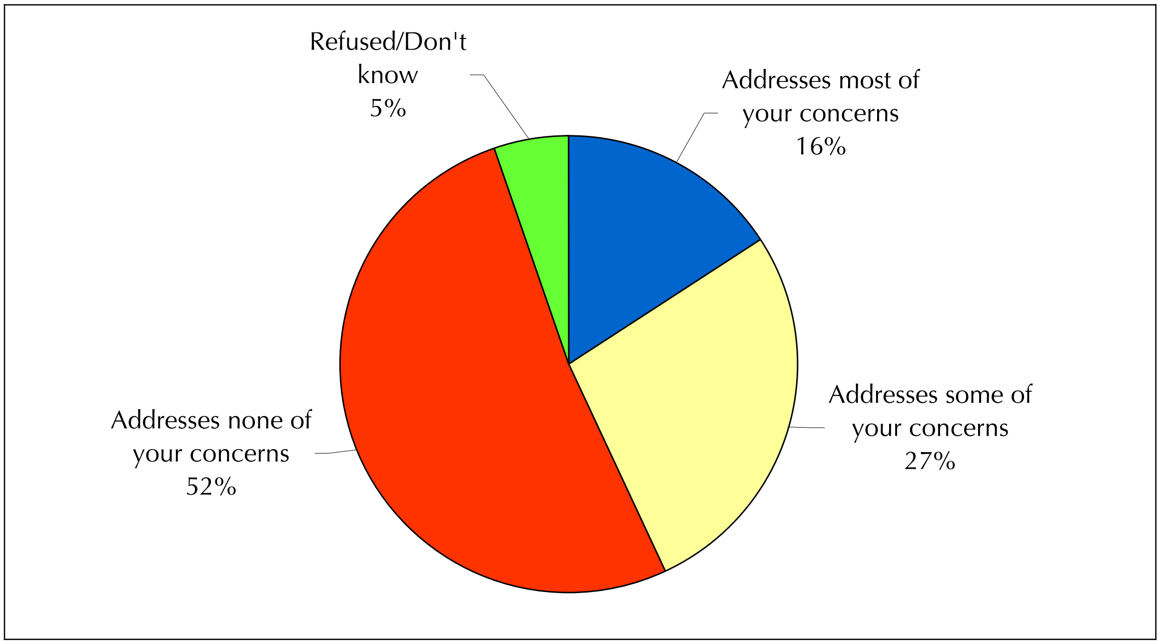
- “We are concerned that we might get shut down during the peak times.”
- “Well if prices go up significantly, it impacts our business because costs have to be passed on to customers.”
- “We want to know how much to decrease usage in order to get some savings.”

Responses representing long-term concerns related to risks faced after the expiration of Bill Protection include:

- “Well, I’m hearing the financial guarantee, but still we're left with the inability to carry it out – seems like little results possible.”
- “We want our business to last longer than one year so that's really not going to help us.”
- “Well, it is good for the first 12 months, and I can’t reduce my load, so it would only be useful for the first 12 months.”
- “You need more of a long-term solution.”

Customers who cited “inability to significantly reduce peak loads” as a significant participation concern were read a brief description of the revised minimum load reduction requirements and aggregation allowances for DBP and asked to evaluate the extent to which these recent program changes addressed their concerns about participating in DBP. As Exhibit 5-27 shows, 16 percent responded that the recent DBP changes addressed most of their concerns about inability to significantly reduce peak load and 28 percent responded that the DBP changes addressed some of their concerns.

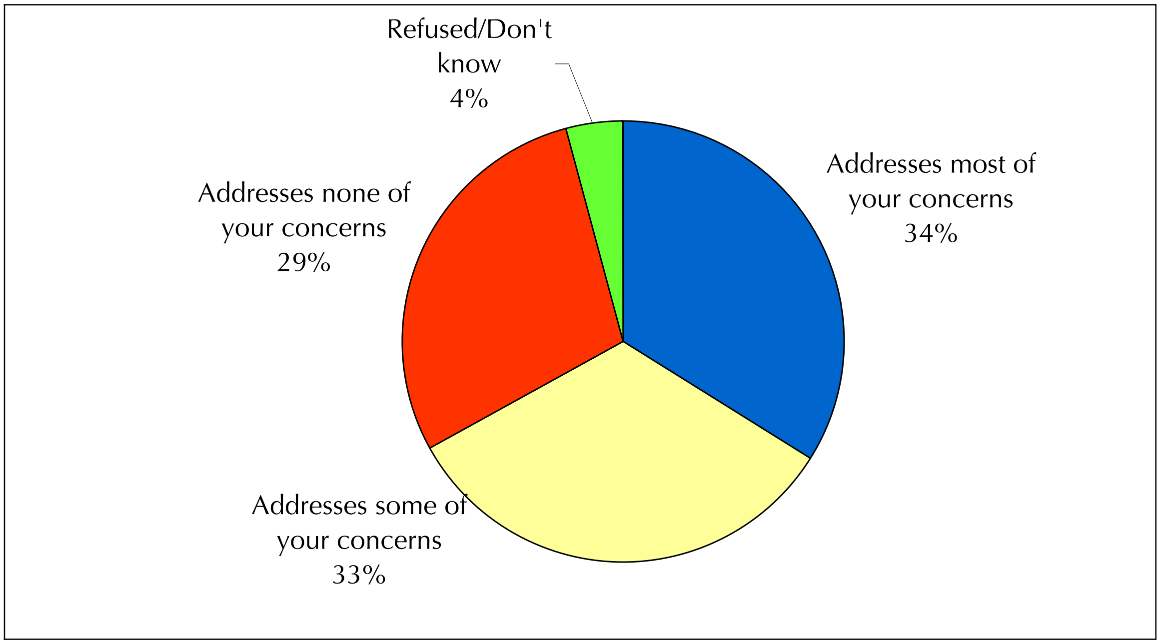
Exhibit 5-27
Extent to Which Changes to DBP Address Concerns About Inability to Reduce Peak Loads (N=473)



The results shown above did not vary significantly by business type or customer size outside of higher relative shares of Extra Large customers and customers in the MMSGC sector responding that the DBP program changes addressed none of their concerns related to an inability to reduce significantly peak loads. Similarly, the majority of explanations given to explain "some" or "none" responses were reiterations of their organization's inability to shift or reduce peak loads.

Customers who cited "need for more information on how to achieve demand reductions" or "time and effort it takes to participate" as a significant participation concern were read a brief description of the Technical Assistance and Incentive Program and asked to evaluate the extent to which the TA/TI program addressed their concerns about lacking the time and knowledge necessary to temporarily reduce peak load at their facility. As Exhibit 5-28 shows, 34 percent responded that the TA/TI program addressed most of their concerns about a lack of time and knowledge regarding temporary load reductions and 33 percent responded that the TA/TI program addressed some of their concerns.

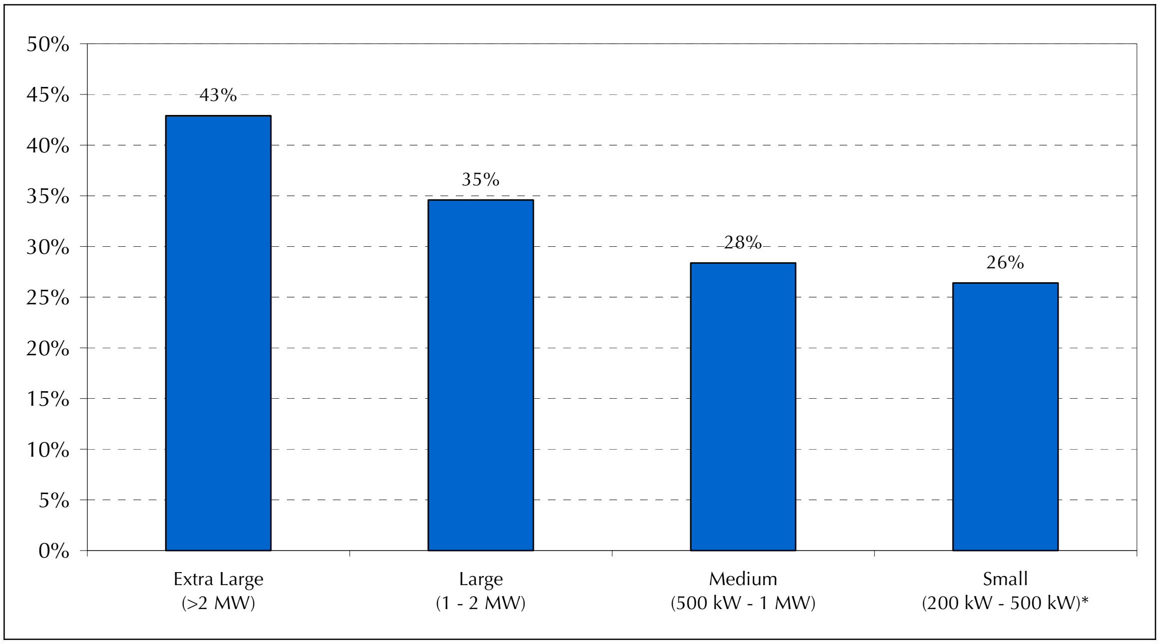
Exhibit 5-28
Extent to Which TA/TI Addresses Concerns About Time and Knowledge Barriers (N=448)



Looking at these results across business types, higher shares of Institutional (66%) and EMFM customers (47%) responded that the TA/TI program addressed most of their concerns with lacking the time & knowledge necessary to temporarily reduce peak load. Conversely, the sectors that most frequently responded that TA/TI did not address any of their concerns were Retail/Grocery (43%), TCU (37%), and PPRC sectors (65%). Again, the most frequent explanations given to explain "some" or "none" responses were reiterations of their organization's inability to shift or reduce peak loads.

One surprising result, as Exhibit 5-29 shows below, is that TA/TI appears to be more attractive to larger customers as opposed to smaller customers, despite a higher frequency among larger customers of having dedicated energy management staff.

Exhibit 5-29
Customers Reporting that TA/TI Addresses Most of Their Concerns about a Lack of Time and Knowledge Necessary to Reduce Peak Loads (N=143)



* Very Small and Extra Small customers shown aggregated with Small customers

5.3.10 Technical and Economic DR Potential (CA1, SA2)

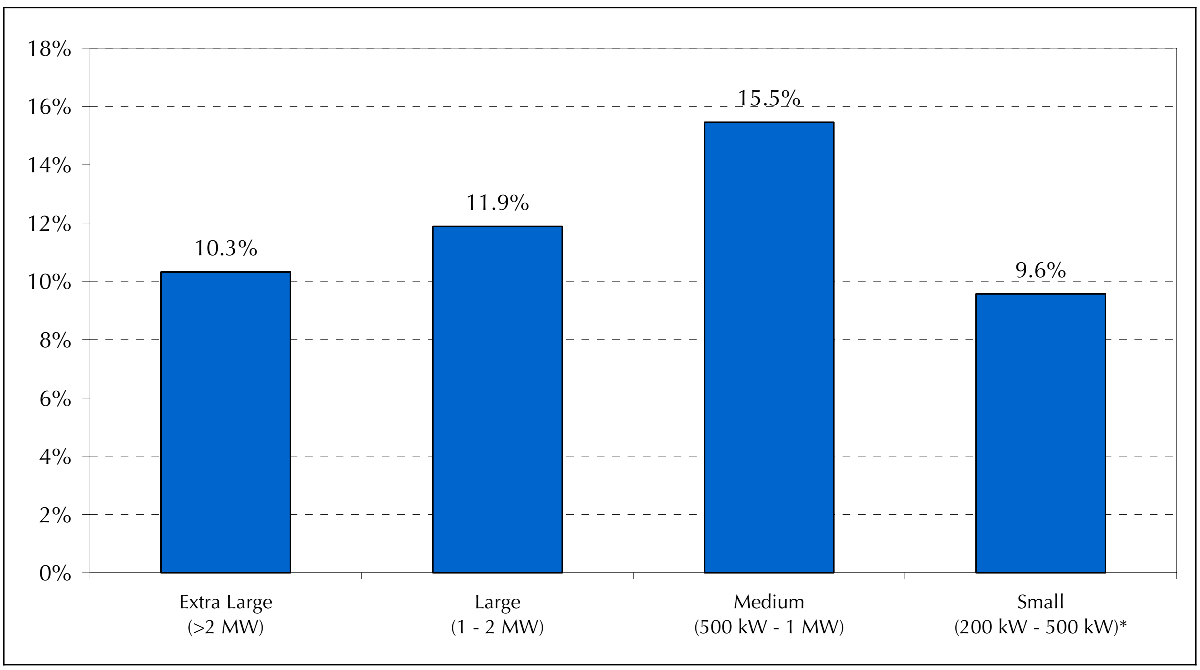
In order to develop estimates of the potential demand response resource that currently exists in the current eligible, non-participant population, customers were asked a hypothetical question asking what percent of their afternoon peak demand they could potentially reduce for a few hours on twelve of the hottest summer days, provided that they were notified the day before and given sufficient financial motivation to do so. The responses to this question form the basis of our estimate of the technical potential of WG2 demand response programs, i.e. the potential demand response resource available from customers eligible for WG2 programs assuming that programs paid what the market demanded.

The estimates presented below were calculated using the mid-points of the stated reduction ranges and should be considered as the upper bound of near-term technical potential since there may be a tendency to over-estimate self-reported demand reduction ability. However, because knowledge of and experience with demand response is still relatively nascent in this customer population, one would expect the longer-term potential demand response resource to be higher as knowledge and enabling technologies diffuse and mature.

The average technical potential reported in the eligible non-participant market was 11 percent. This value is slightly lower but compares well to the value calculated from the 2004 survey results (13%) for the same customer population. Based on an estimate of the coincident peak demand for eligible non-participant customers (~12,000 MW), the total MW demand response resource is thus likely to be approximately 1,340 MW.

The average load reduction potential varied considerably both by customer size and business type. Exhibit 5-30 shows that Medium customers reported the highest average technical potential (15.5%), whereas Small customers reported the lowest average technical potential (9.6%). The average load reduction potential reported by Large and Extra Large customers represent significantly lower values than those reported in the 2004 survey (12% and 10% compared to 15% and 17%, respectively). These differences are again mostly due to the exclusion of traditional interruptible customers from the population frame and should not be interpreted as a downward trend in the technical potential of larger-sized non-participants. However, these differences serve to highlight an important point – that large customers with large relative demand reduction capabilities in California tend to already be enrolled in traditional interruptible programs. This clearly impacts the size and structure of the potential demand response resource available to programs like CPP and DBP because of the low likelihood that traditional interruptible customers will migrate to price-responsive programs (see Chapter 9).

Exhibit 5-30
Average Technical Potential by Customer Size



* Very Small and Extra Small customers shown aggregated with Small customers

Exhibit 5-31 shows how average reported technical potential varied by business type. With the exception of PPRC and Other Commercial customers, customers in the manufacturing and industrial sectors reported higher average technical demand reduction potentials compared to customers in service-oriented business sectors. Customers in the MMSGC sector reported by far the highest average technical potential (22%), while customers in the Office sector reported the lowest load reduction potential (7%). Compared to the values reported in the 2004 survey, the most significant differences in average reported technical potential occurred in the TCU sector (drop from 35% to 11%), the PPRC sector (drop from 19% to 8%), and the MMSGC sector (increase from 14% to 22%). The differences for the TCU and PPRC sectors are consistent with the exclusion of traditional interruptible customers from the population frame. The difference for the MMSGC sector, however, reflects a large share of the MMSGC customers surveyed reporting being capable of reducing more than 50% of their peak load given sufficient financial motivation (11 out of 37 MMSGC customers surveyed). This result, while potentially accurate, should nonetheless be treated with caution.

Exhibit 5-31
Average Technical Potential by Business Type

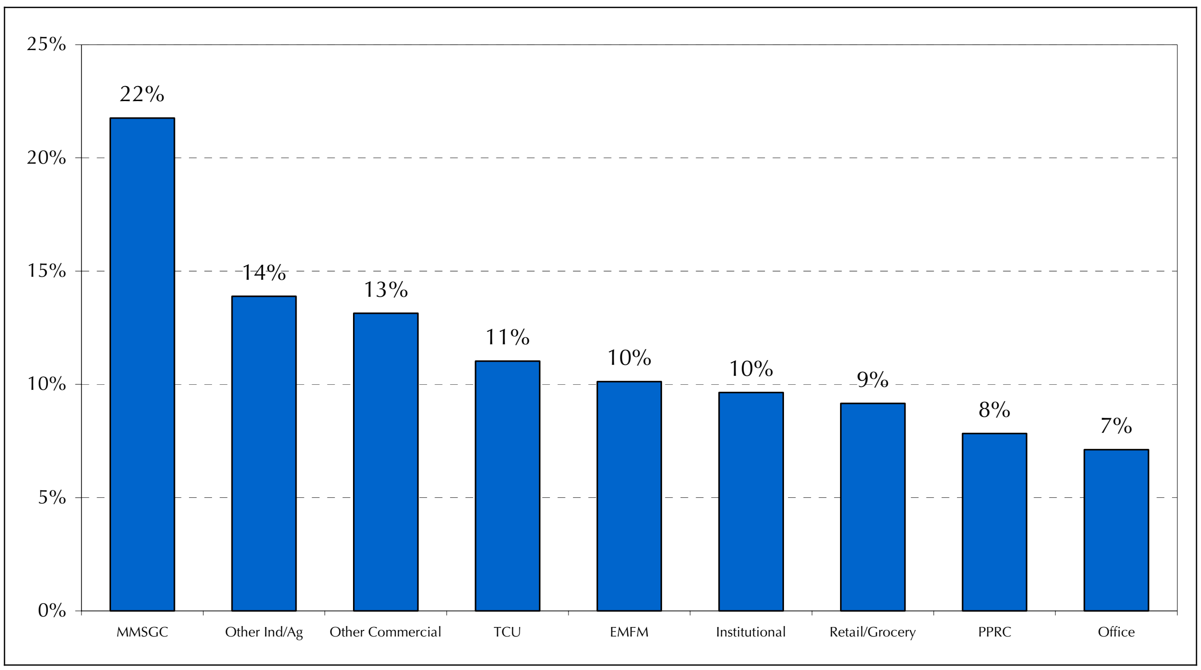


Exhibit 5-32 combines customer self-reports of energy cost shares with self-reported technical potential. The results show that energy costs, as a share of total operating costs, are only weakly correlated with technical potential. In contrast, the results from the 2004 survey demonstrated a strong positive correlation between energy cost share and technical potential. This difference is again largely due to the exclusion of traditional interruptible customers, whose energy cost shares and technical potentials are comparatively large, from the population frame.

Exhibit 5-32
Average Technical Potential versus Energy Costs as a Share of Total Annual Operating Costs

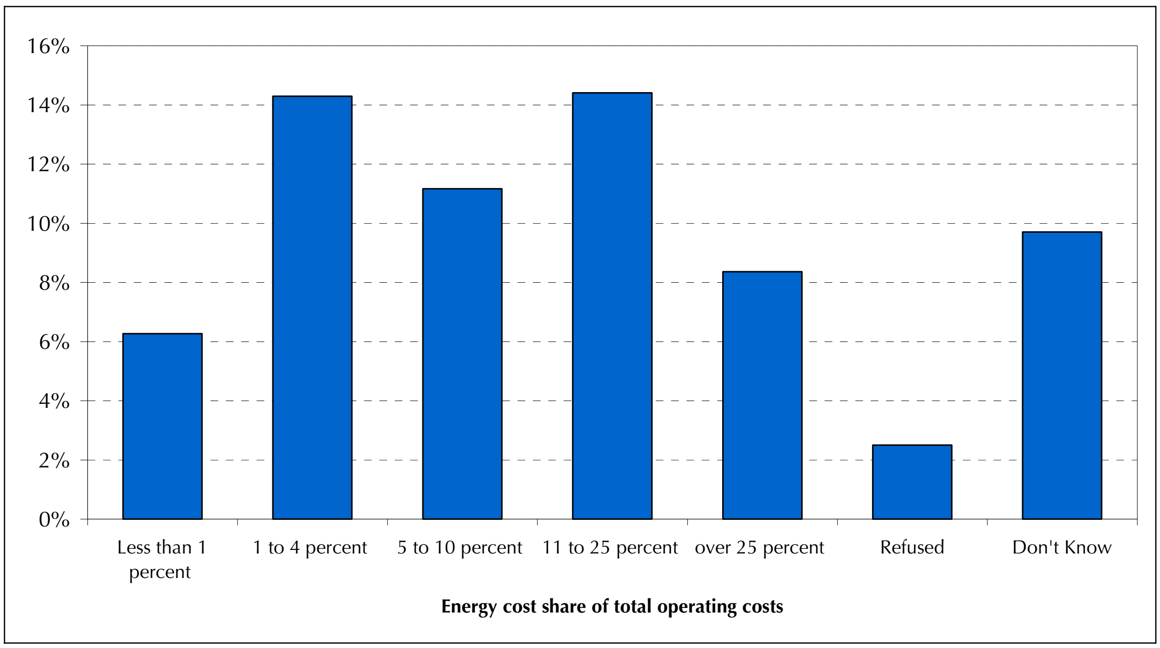
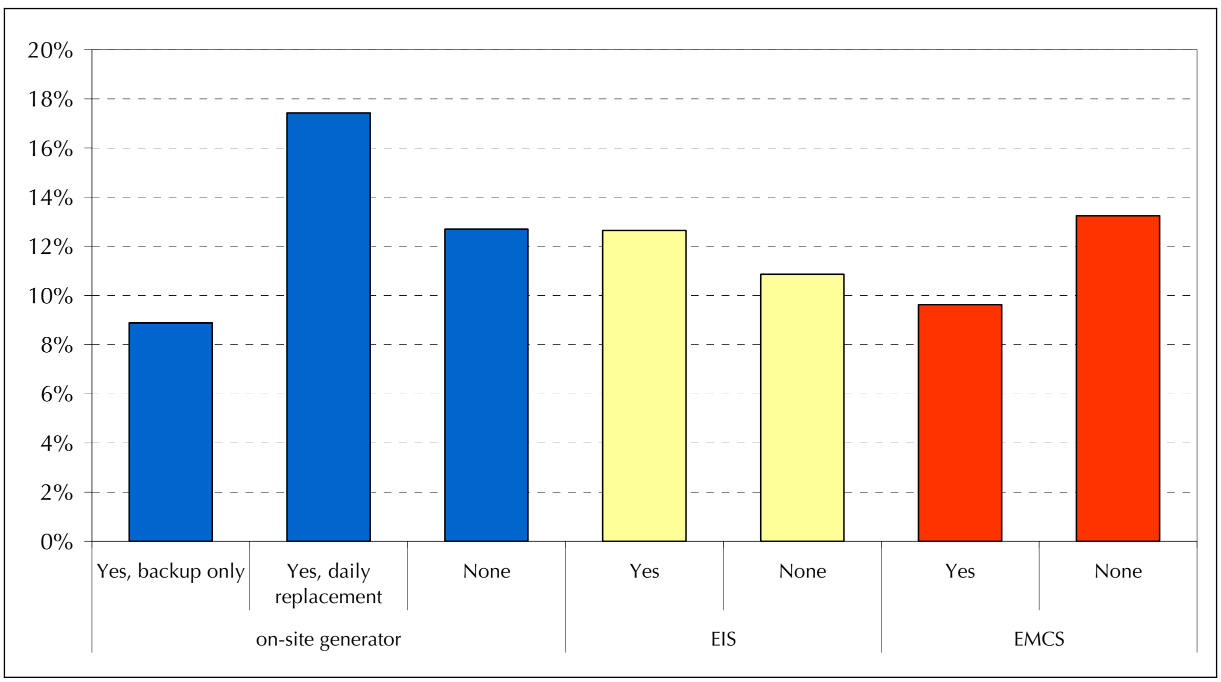


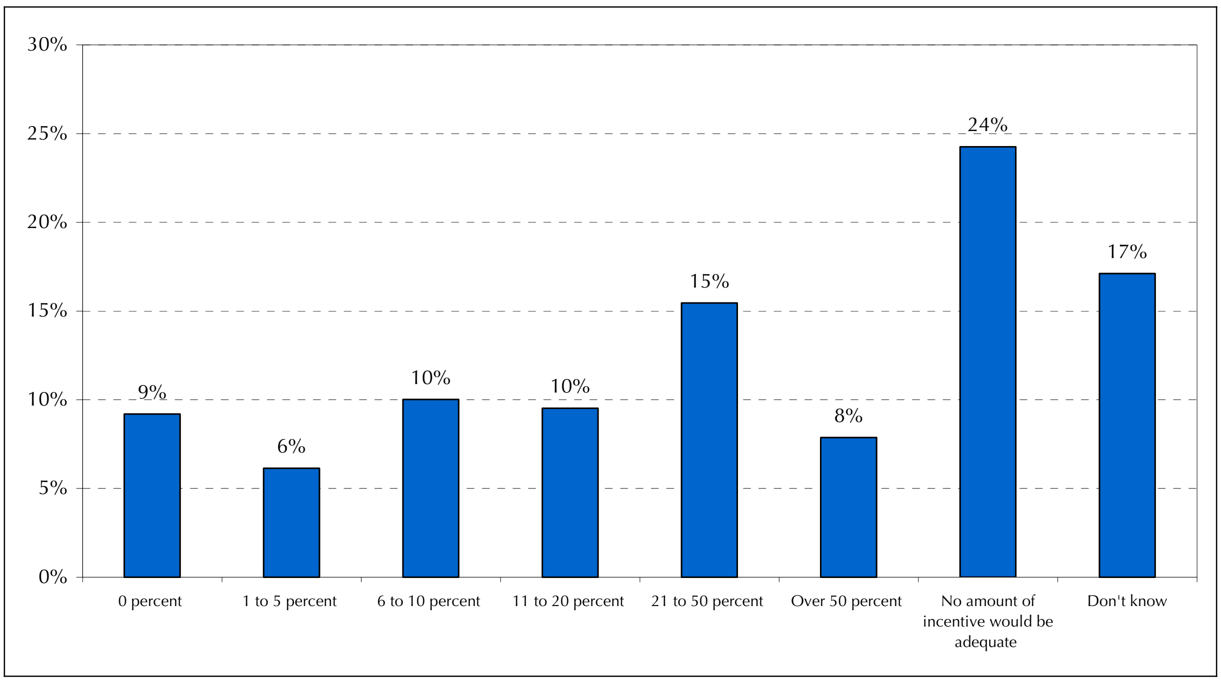
Exhibit 5-33 combines customer self-reports of enabling technology ownership with self-reported technical potential. The results show a significant positive correlation between reported ownership of on-site generators used for daily replacement and self-reported technical potential. Interestingly, however, the results show only a weak positive correlation between EIS ownership and technical potential and negative correlations between the ownership of back-up generation or EMCS systems and self-reported technical potential. The relationship between EMCS ownership and technical potential is partially explained by the fact that EMCS ownership tends to be higher among customers in service-oriented business sectors (see Exhibit 5-12) but self-reported technical potential tends to be higher in the manufacturing and industrial sectors (see Exhibit 5-31). Overall, these results, while perhaps surprising, are consistent with the hypothesis developed earlier – that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response.

Exhibit 5-33
Average Technical Potential versus DR-Enabling Technology Ownership



To benchmark these technical potential results, customers were also asked a question that sought to establish how much financial motivation customers would need in order to achieve specific levels of demand reduction. Specifically, customers were asked what percentage of their annual electricity bill they would need to save as an incentive to reduce their demand by 15 percent for a few hours on roughly twelve of the hottest summer weekdays. Exhibit 5-34 shows the distribution of responses over the market. By taking the midpoints of the stated incentive ranges, the average self-reported annual bill savings required to reduce demand by 15 percent was estimated to be 20 percent. As with our estimate of aggregate technical potential, this value compares well to the value calculated from the 2004 survey results (19%) for the same customer population.

Exhibit 5-34
Percent Bill Savings Required to Reduce Demand by 15% on Four Summer Weekday Afternoons



Confining the analysis to the compensation ranges of current programs (5% or less) allows us to estimate the economic potential associated with WG2 demand response programs – that is, the demand response resource realistically available under current incentive levels. To calculate economic potential, the share of eligible customers who indicated they would be willing to reduce demand by 15 percent for 5 percent or less annual bill savings is multiplied by the associated load reduction (15%). This yields an estimate of economic potential of 2.3 percent among eligible non-participant customers, which compared well to the overall economic potential estimated from the 2004 survey results (1.8%). Again, based on an estimate of the coincident peak demand of the eligible non-participant population (~12,000 MW), the total demand response resource potentially available at current incentive levels is thus approximately 280 MW.

5.4 SUMMARY & KEY FINDINGS

General Market is Increasingly Familiar with DR Programs but not DR Incentives

The majority of the non-participant market reports to have some familiarity with day-ahead and reliability programs. Overall, 73 percent of the eligible non-participant market indicated that they were either "very" or "somewhat" familiar with CPP, compared to 69 percent for DBP, 68 percent for BIP, and 43 percent for DRP. At this aggregate level, these values represent significant increases in familiarity with CPP, DBP, and DRP among non-participating customers compared to the values reported in the 2004 survey (64 percent, 61 percent, and 32 percent, respectively). Remaining unfamiliarity with day-ahead programs and BIP is concentrated among smaller customers in service-oriented business sectors.

General familiarity with the Bill Protection Incentive also increased slightly from 2004 levels, with 44 percent of eligible non-participants reporting to be "very" or "somewhat" familiar with the incentive. In contrast, however, general familiarity with the Technical Assistance and Technology Incentive (TA/TI) Program declined slightly from 2004 levels, with 40 percent of eligible non-participants reporting to be either "very" or "somewhat" familiar with the program. Among customers who reported to be very familiar with the CPP or DBP programs, familiarity with these incentive programs was markedly higher. However, these levels again represent a significant decline compared to those reported in 2004. In particular, familiarity with the TA/TI Program fell by more than a factor of two, due entirely to a large decrease in customers reporting to be "very" familiar with the incentive.

Non-participants Continue to Perceive Significant Barriers to Participating in DR Programs; Self-Reported Barriers Vary Significantly Across Market Segments

Non-participants ranked "effects on production or productivity" and "inability to significantly reduce peak loads" as the two most important barriers to participating in day-ahead programs, as they did in 2004. Significantly higher shares of manufacturing and industrial customers ranked these two barriers as "very significant" compared to customers in service-oriented sectors. Higher shares of larger customers also ranked these two barriers as "very significant" compared to smaller customers. These results imply that the primary concerns among large manufacturing and industrial non-participants are related to the structure of their electricity consumption and the opportunity costs of temporary demand reductions. This finding is consistent with the fact that large manufacturing and industrial customers tend to have high load factors and load profiles that are dominated by process and production end uses.

Customers in the service-oriented sectors also ranked "effects on occupant comfort" and "need for more information on how to achieve demand reductions" as very significant barriers to participation in day-ahead programs. The results for the Institutional sector reflect a similar level of concern with occupant comfort as in other service sectors, as one would expect, but a lower need for information, reflecting relatively higher levels of knowledge about peak load management and demand response among Institutional customers. Higher shares of smaller customers consistently ranked "need for more information on how to achieve demand reductions" as an important barrier compared to the rest of the market. This result is consistent with smaller customers also reporting a high share of "no one assigned responsibility for controlling energy usage and costs".

Ownership of DR-Enabling Technologies Does Not Yet Influence Perception of Key Barriers

Self-reported ownership of select enabling technologies (specifically on-site generation, energy information systems, and energy management and control systems) did not correlate significantly with perceptions of key barriers to demand response among non-participants, in particular "inability to reduce peak load" and "effects on productivity". This result suggests that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response. In this respect, the installed base of enabling technologies can be viewed as a significant, but mostly dormant, demand response resource in the eligible non-participant population in California. Because of the potentially important ramifications of this finding in terms of demand response program and incentive design, further investigation into customer perceptions of the costs and feasibility of using such technologies for demand response is clearly warranted.

2005 Program Changes Appear to Address Important Barriers for a Significant Number of Non-Participants

Prior to summer 2005, several changes were made to day-ahead programs in order to address certain perceived barriers to participation identified in the 2004 evaluation. When asked to evaluate the extent to which the changes address these barriers, twenty-eight percent of the market judged that the 2005 Bill Protection Incentive addresses "most" of their concerns about the risk of bill increases from participating in CPP. Similarly, sixteen percent the market judged that the lower DBP bid minimums and aggregation allowances of the 2005 DBP program address "most" of their concerns about being unable to significantly reduce peak loads. Finally, thirty-four percent of the market judged that the free on-site audits and financial incentives of the revised TA/TI program address "most" of their concerns about the time, effort, and knowledge required to participate in demand response programs. The majority of customers who judged that these program changes addressed only "some" or "none" of the relevant participation concerns offered that these program changes, including TA/TI, did not seem to adequately address their inability to reduce peak loads.

Taken together, these results indicate that the changes made to the 2005 day-ahead programs significantly mitigate customer concerns related to bill risk, peak load reduction capability, and time and knowledge barriers, but only for modest *shares* of the non-participant market. However, given the size of the non-participant population relative to the number of current participants, these shares represent a significant *number* of customers for whom the 2005 program changes, at face value, significantly mitigate important perceived barriers to participation. Given that the overall awareness of these recent program changes is rather low (e.g. less than 9 percent of the non-participant market reported to be "very" familiar with the DBP program changes), these results therefore indicate that education and marketing efforts highlighting these program changes could potentially yield a significant number of new participants in day-ahead programs.

Perceptions of Default CPP

In light of the possible rollout of default CPP tariffs for the summer of 2006, customers were asked a series of questions designed to gauge their level of familiarity with proposed default CPP rates, the perceived bill impacts of these rates, and the main types of informational needs customers consider necessary in order to make informed decisions about staying on or opting out of default CPP. Only 12 percent of the eligible non-participant market reported to be "very" familiar, and 26 percent reported to be "somewhat" familiar with their utility's proposed default CPP tariff. Of the customers reporting to be "very" or "somewhat" familiar with the proposed rates, 58 percent estimated that their specific annual electricity bill would increase as a result of taking service on default CPP, while 11 percent estimated that their annual bill would decrease, and 25 percent estimated that their annual bill would stay about the same. The average perceived impact of default CPP on customers' individual electricity bills was a 3.9 percent increase.

These results should be viewed relative to the utilities' estimated bill impacts of default CPP that were filed with the CPUC in fall 2005. According to PG&E's rate analysis, more than 50 percent of eligible customers would experience net bill decreases from default CPP without reducing summer peak loads, and only 5 percent would experience net bill increases greater than 1 percent. According to SCE's rate analysis, 39 percent of eligible customers would experience net bill decreases from default CPP without reducing summer peak loads, 43 percent would experience net bill increases of less than 2 percent, and 18 percent would experience net bill increases greater than 2 percent.[2] In the absence of customer-specific rate analyses, it is difficult to determine the extent to which customer perceptions of default CPP bill impacts diverge from these utility estimates. However, on the whole, it appears that the majority of customers perceive default CPP as negatively affecting their annual electricity bills, whereas utility rate analyses indicate that approximately half of eligible customers would benefit from proposed default CPP rates without taking any action to reduce summer peak loads.

All customers were asked an open ended question about what kinds of information they would need in order to make a sound decision about whether or not to stay on default CPP if default service were indeed changed to a CPP tariff. The most common responses entailed pricing information (29 percent), detailed program information (21 percent), and estimates of impacts on electricity bills and/or production (13 percent). While program information and bill/production impacts were cited fairly evenly across customer sizes and business types, pricing information was cited most frequently among larger customers and customers in the manufacturing and industrial sectors.

Short-Term Market Potential Among Non-Participants Continues to be Moderate and Unaffected by Ownership of DR-Enabling Technologies

Based on self-reported estimates of load reduction potential (given "sufficient financial motivation"), the average technical DR potential across the eligible non-participant market was estimated to be 11 percent. This average technical DR potential is slightly lower but compares well to the value estimated from the 2004 market survey (13%). Based on an estimate of the coincident peak demand for eligible non-participants (~12,000 MW), we estimate the total technical DR potential resource to be approximately 1,340 MW.

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[2] According to SDG&E's rate analysis, more than 90 percent of eligible customers would experience net bill decreases from default CPP, and only 3 percent would experience net bill increases greater than 1 percent. However, SDG&E's analysis assumes customers reduced peak demand by 50 percent on CPP event days, thus their estimated bill impacts are not strictly comparable to those presented above.

Importantly, self-reported technical potential does not correlate significantly with ownership of either back-up generators or energy management and control systems. These results, while perhaps surprising, are consistent with the finding presented earlier – that customers currently view these technologies primarily in terms of their energy efficiency and operations benefits rather than in terms of their potential to enable demand response.

To benchmark the technical potential estimates, customers were asked what percentage of their annual electricity bill they would need to save as an incentive to reduce their peak demand by 15 percent for a few hours on roughly twelve of the hottest summer weekdays. Taking the share of customers who indicated compensation in the range of current day-ahead programs (5 percent or less) and multiplying by the associated load reduction (15 percent) provides a rough estimate of the economic potential associated with current DR programs – that is, the DR resource realistically available under current incentive levels. The results of the 2005 market survey yield an estimated economic DR potential of 2.3 percent, which is again similar to the economic potential estimated from 2004 market survey results (1.8 percent). Again, based on an estimate of the coincident peak demand of eligible non-participants, the total additional DR resource potentially available at current incentive levels is approximately 280 MW.

These market potential results reveal two important findings regarding the potential demand response resource available in California going forward. First, the potential DR resource available through current programs at current incentive levels appears to be only a fraction of the CPUC's price-responsive DR resource goals. Furthermore, although there appears to be significant opportunities to achieve this market potential (notably through mobilizing the existing infrastructure of DR-enabling technologies and marketing efforts to increase awareness of program features designed to mitigate key perceived barriers to participation), future increases in program participation are likely to be gradual in the absence of significant increases in program incentives. Second, our estimated technical DR potential estimate equates to roughly 3 percent of system peak (based on 43,500 MW) and is of the same order of magnitude as the CPUC's price-responsive resource goals. However, it is important to consider this technical potential estimate only from a long-term perspective and that only a portion of this potential DR resource is likely to be cost-effective. In the absence of accepted estimates of both the value and costs of DR resources and programs, it is difficult to estimate exactly how much of the technical DR potential could be captured cost-effectively. Regardless of cost-effectiveness, however, achieving technical potential is necessarily a long-term process extends well beyond current policy and planning timelines.

6. IMPACT EVALUATION DATA AND METHODOLOGY

This section presents the data requirements and methodology used to evaluate the impacts resulting from the 2005 WG2 Price Responsive and Reliability programs (PRRP). The following four subsections explain the scope, data and systematic methods applied to complete the impact evaluation:

- Objectives and Scope Of Impact Evaluation
- Summary of Data Sources for Impact Evaluation
- Summary of Evaluation Population and 2005 Events
- Summary of Methods used for the Estimation of Impacts
  - Representative Day Approach
  - Multivariate Statistical Models

6.1 OBJECTIVES AND SCOPE OF IMPACT EVALUATION

The purpose of the impact assessment is to provide evaluation-based estimates of the peak load reductions associated with the CPP, DBP, DRP and Interruptible programs for events occurring during the summer of 2005. A challenge in conducting the impact assessment is the relatively small number of active participants in the programs (DBP Bidders, CPP non-structural benefitters) making the impact results highly sensitive to the baseline method selected (3-Day baseline versus 10-Day Adjusted baseline, etc.), the relative size of the active participants and the attributes of the event days (such as Monday events versus Friday events). As a result, when considering what analyses to conduct, it is important to consider the application needs and value of the information that would be produced by different types of analyses. The approach taken in this evaluation is to use multiple methods to estimate and illustrate the 2005 impacts. For the 2005 impact evaluation, formal models are developed to forecast impacts of the CPP and DBP programs under various different conditions.

6.2 SUMMARY OF DATA SOURCES FOR IMPACT EVALUATION

The impact evaluation for the 2005 WG2 Price Responsive and Reliability programs uses data from four primary data sources for each of the three utilities. These data sources include: interval meter billing data, program specific event data, weather data, and participation data. Additionally, telephone survey data elements may be used to supplement the data provided by the three utilities when appropriate and available. The development of an analysis-ready dataset was achieved by merging the data from these primary sources into one file and applying a series of validation procedures to identify and correct for any missing or erroneous data that may be present. A summary of the data elements available for use in the impact assessment is presented below.

6.2.1 Interval Meter Billing Data

Each of the three utilities provided Quantum Consulting (QC) with a series of datasets containing interval meter data for CPP, DBP, DRP and Interruptible participants. QC merged these datasets together to create a unique interval meter database for each utility. These databases include 15-minute interval meter billing data from May through October of 2005 along with various account and meter identifiers used to link to the other data sources. For each of the utilities there were a few participants missing from the interval meter datasets. Since all participants are required to have interval meters installed in order to be eligible to participate, it is assumed that this missing data is a result of either an error in the files used by the utilities to identify participants, or due to transmission difficulties between an individual interval meter and the utility. It was necessary to exclude these few participants for whom we were missing valid load data from the impact analysis. Each of the impact tables presented in Appendices D1 and D2 contain two columns which indicate the difference between the number of participants enrolled in the programs as of individual event dates (N) and the number for which interval data were available for the impact analysis (n). On average across the CPP and DBP programs less than 5 percent of participant interval data were missing.

6.2.2 Program Event Data

For each CPP and DBP event, a dataset was created by each of the utilities and delivered to QC. These datasets contain event information such as confirmation of the notification process, the event type (CPP or DBP), the time period for which the event was called, the event trigger (temperature, price, system emergency, etc.), the hourly prices customers are paid for program reductions (DBP) or are charged for electrical consumption (CPP) during the event, the utility estimated load reductions resulting from the event[1] and the payments made to the customers for their DBP curtailments. The program event datasets were also used to validate that the 3-Day baselines calculated by QC for use in the Representative Day impact analysis were equal to the utility calculated 3-Daybaselines.

For the DRP program the necessary event data were downloaded from the DRP website, since the utilities do not have access to all of the necessary DRP data elements. In researching the availability of the DRP data, we found that the utilities had access to approximately 90 percent of the interval meter data for DRP participants. The missing data tended to be from the largest participants who are direct access customers and have a Meter Data Management Agent (MDNA) other than the utility. Because of this, their interval meter data were not provided to the utility. Data on the DRP website are provided at the facility level (as opposed to the individual account level) and includes load data, monthly and daily nomination data, details on the specific event periods by utility and program block type (1-8 hr, 1-5 hr and 1-3 hr program blocks) and the DRP curtailment payment information.

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[1] The estimated load reductions provided to QC from each of the utilities were based on the difference between the utility calculated baseline (based on the 3-day baseline methodology which is what each of the utilities uses for DBP program settlement and CPP rate protection) and actual event day load.

6.2.3 Weather Data

The hourly temperature and humidity data for each of the utility's load research weather sites were collected and appended to the interval meter databases using a weather station identifier. These weather data were used in the impact evaluation to identify weather sensitive accounts and to evaluate potential impacts in light of the day's climate conditions. For PG&E there were 25 unique weather sites, for SCE there were 24 unique weather sites, and for SDG&E there were 10 unique weather sites.

6.2.4 Participation Data

Each of the three utilities sent QC a series of datasets containing the most recent population of customers participating in the each of the in-scope programs. These datasets contained the names and customer identifiers for each participant, the date the customer became effective in or dropped out of the program, and flags indicating whether a customer had enrolled in either the Technical Assistance Incentive or Bill Protection (for CPP only) programs. Additional customer characteristics, such as size and business type, were determined from the participation data provided (based on the accounts' maximum demand in 2004 and NAICS code). The participation datasets were provided by each of the three utilities in early August, however the PG&E file was updated in late October due to the large number of additional program signups in August, September, and October.

6.2.5 Telephone Survey Data

A subset of the available telephone survey data collected during the Post-Event and End-of-Summer surveys was used in the impact evaluation. The two telephone surveys resulted in completed surveys for a total of 298 unique customers. The data collected in the telephone surveys supplied general information on a customer's bidding and curtailment activity for 2005 summer events (unlike the 2004 evaluation for which information was collected about specific event days). It may also be possible to utilize the information gathered on the surveys such as their level of automation or their end-uses having the largest consumption. This information could help estimate their response to program events.

For a detailed discussion of the telephone survey and the final sample disposition, see Section 8: CPP/DBP Process Evaluation. The final frequency tables for the Post-Event and Final Evaluation telephone surveys can be found in Appendix C.

6.3 SUMMARY OF EVALUATION POPULATION AND 2005 EVENTS

The impact assessment for each program encompassed all participants who were enrolled in the program as of the particular event day and had an interval meter installed such that the interval meter data could be provided by the utilities to the evaluation team. The 2005 participant population by utility is the following:

- For PG&E, the population of participants as of the final 2005 CPP event on September 29th was 279 accounts for CPP (up from 130 accounts from the last event of 2004) and as of the August 8th DBP event was 412 accounts (up from 78 accounts last year). An additional 13 CPP participants and 54 DBP participants signed up between the final summer 2005 event and the end of October. Sixty-five accounts were signed up for both the CPP and DBP program. PG&E had 157 accounts signed up for the DRP program and 95 accounts enrolled in one of the non-firm tariffs as of the end of October. Roughly 7 percent of the DBP participants were also enrolled in a non-firm tariff.

- In 2005 SCE continued to have 8 accounts enrolled in the CPP program and the participant population for DBP has grown to 703 accounts (from 558 accounts in 2004). SCE had 89 accounts signed up for the DRP program and 497 accounts enrolled in the I-6 Traditional Interruptible program. Nearly 20 percent of SCE's DBP participants are also enrolled in the I-6 Interruptible program.

- The 2005 population of participants for SDG&E consisted of 110 accounts signed up for CPP (double that of 2004 at which time there were 48 accounts enrolled) and 62 accounts for DBP (up from 37 accounts). SDG&E had 12 accounts singed up for the DRP program and 25 accounts enrolled in the AL-TOU-CP tariff.

A complete discussion of the eligible market, the participants and the program events is discussed in Chapter 4: Program Participation and Tracking.

Impacts were calculated for all CPP and DBP events for which there existed a complete set of interval data, however the impacts associated with a few of the events are flagged due to extenuating circumstances surrounding the events which could affect the resulting impacts (such as late or ineffective notification or lost bids) for some events. Exhibits 6-1 through 6-4 present the summer 2005 events for the CPP, DBP, DRP and Interruptible programs, respectively, by utility. There were no Interruptible events called within PG&E service territory during the summer of 2005.

Exhibit 6-1 illustrates that the majority of the 2005 CPP events were called based on the temperature triggers set for each of the utilities. The exception to this is two events within SCE territory that were called for Measurement and Verification reasons, thus ensuring that the maximum number of summer events (12) occurred. The first PG&E CPP event was not billed as a CPP event due to the delay in notification to a subset of the CPP participants.

Exhibit 6-1
2005 CPP Events by Utility

Utility	Event	CPP Event Trigger	Event Date	Event Hours	Zone	Participants
SDG&E	CPP #1	High Demand/Temperature	07/21/05	11-6 pm	n/a	87
	CPP #2	High Demand/Temperature	07/22/05	11-6 pm	n/a	88
	CPP #3	High Demand/Temperature	08/26/05	11-6 pm	n/a	110
	CPP #4	High Demand/Temperature	09/29/05	11-6 pm	n/a	110
	CPP #5	High Demand/Temperature	09/30/05	11-6 pm	n/a	110
SCE	CPP #1	Temperature	07/22/05	12-6 pm	n/a	8
	CPP #2	Temperature	07/25/05	12-6 pm	n/a	8
	CPP #3	Temperature	08/26/05	12-6 pm	n/a	8
	CPP #4	Temperature	08/29/05	12-6 pm	n/a	8
	CPP #5	Temperature	08/30/05	12-6 pm	n/a	8
	CPP #6	Temperature	08/31/05	12-6 pm	n/a	8
	CPP #7	Temperature	09/15/05	12-6 pm	n/a	8
	CPP #8	Temperature	09/20/05	12-6 pm	n/a	8
	CPP #9	Measurement and Verification	09/22/05	12-6 pm	n/a	8
	CPP #10	Measurement and Verification	09/28/05	12-6 pm	n/a	8
	CPP #11	Temperature	09/29/05	12-6 pm	n/a	8
	CPP #12	Temperature	09/29/05	12-6 pm	n/a	8
PG&E	*CPP #1* [a]	*Temperature*	*07/12/05*	*12-6 pm*	*1*	*180*
	CPP #2	Temperature	07/13/05	12-6 pm	1	193
	CPP #3	Temperature	07/14/05	12-6 pm	1&2	225
	CPP #4	Temperature	07/15/05	12-6 pm	1	193
	CPP #5	Temperature	07/18/05	12-6 pm	1	193
	CPP #6	Temperature	08/05/05	12-6 pm	1	194
	CPP #7	Temperature	08/08/05	12-6 pm	1	209
	CPP #8	Temperature	09/29/05	12-6 pm	1	214
	CPP #9	Temperature	09/29/05	12-6 pm	1&2	279

[a] *The first PG&E CPP Event was not billed since customers received late notification of the event.*

Exhibit 6-2
2005 DBP Events by Utility

Utility	Event	DBP Event Trigger	Event Date	Event Hours	Participants	Bidders
SDG&E	DBP #1	ISO Forecast	07/12/05	2-6 pm	60	12
	DBP #2	ISO Forecast	07/13/05	2-6 pm	60	13
	DBP #3	ISO Forecast	07/14/05	2-6 pm	60	11
	DBP #4	ISO Forecast	07/15/05	2-5 pm	60	11
	DBP #5	ISO Forecast	07/19/05	1-6 pm	60	8
	DBP #6	ISO Forecast	07/20/05	2-5 pm	60	8
	DBP #7	ISO Forecast	07/21/05	2-5 pm	60	6
	DBP #8	ISO Forecast	07/22/05	1-6 pm	60	8
	DBP #9	ISO Forecast	07/26/05	2-5 pm	60	7
	DBP #10	ISO Forecast	07/27/05	2-4 pm	61	7
	DBP #11	ISO Forecast	08/04/05	3-5 pm	62	8
	DBP #12	ISO Forecast	08/05/05	2-5 pm	62	4
SCE	DBP #1[a]	ISO Forecast	07/13/05	12-8 pm	703	21
	DBP #2	ISO Forecast	07/14/05	12-8 pm	703	21
	DBP #3[b]	*ISO Forecast*	*07/19/05*	*12-8 pm*	*703*	*32*
	DBP #4	ISO Forecast	07/20/05	12-8 pm	703	37
	DBP #5	ISO Forecast	07/21/05	12-8 pm	703	42
	DBP #6	ISO Forecast	07/22/05	12-8 pm	703	37
	DBP #7	ISO Forecast	07/25/05	12-8 pm	703	24
	DBP #8	ISO Forecast	07/26/05	12-8 pm	703	36
	DBP #9	ISO Forecast	07/27/05	12-8 pm	703	38
	DBP #10	ISO Forecast	07/29/05	12-8 pm	703	38
	DBP #11	ISO Forecast	08/04/05	12-8 pm	703	39
	DBP #12	ISO Forecast	08/05/05	12-8 pm	703	40
	DBP #13	ISO Forecast	07/21/05	12-8 pm	703	40
PG&E	*DBP #1*[c]	*ISO Forecast*	*07/13/05*	*12-8 pm*	*375*	*46*
	DBP #2[c]	*ISO Forecast*	*07/14/05*	*12-8 pm*	*375*	*29*
	DBP #3[c]	*ISO Forecast*	*07/15/05*	*12-8 pm*	*375*	*38*
	DBP #4[c]	*ISO Forecast*	*07/18/05*	*12-8 pm*	*375*	*9*
	DBP #5[c]	*ISO Forecast*	*07/19/05*	*12-8 pm*	*382*	*35*
	DBP #6[c]	*ISO Forecast*	*07/20/05*	*12-8 pm*	*383*	*22*
	DBP #7[c]	*ISO Forecast*	*07/21/05*	*12-8 pm*	*387*	*28*
	DBP #8	ISO Forecast	07/22/05	12-8 pm	387	39
	DBP #9	ISO Forecast	07/25/05	12-8 pm	402	9
	DBP #10	ISO Forecast	07/26/05	12-8 pm	402	36
	DBP #11	ISO Forecast	07/27/05	12-8 pm	404	26
	DBP #12	ISO Forecast	07/29/05	12-8 pm	404	37
	DBP #13	ISO Forecast	08/01/05	12-8 pm	407	18
	DBP #14	ISO Forecast	08/04/05	12-8 pm	407	38
	DBP #15	ISO Forecast	08/05/05	12-8 pm	409	35
	DBP #16	ISO Forecast	08/08/05	12-8 pm	412	17
	DBP #17	ISO Forecast	07/01/05	12-8 pm	412	17

[a] *Bids were lost for the first SCE DBP event.*

[b] *The third SCE DBP event was cancelled due to software issues.*

[c] *Bids were lost for the first 7 PG&E DBP events due to DBP bidding software issues.*

Exhibit 6-3
2005 DRP Events by Utility
(All Events Called based on CAISO discretion)

Utility	Event	Event Date	Event Duration						Event Hours						Total Participants
	Product Type		1-3 hr		1-5 hr		1-8 hr		1-3 hr		1-5 hr		1-8 hr		
SDG&E	Cal-DRP #1[a]	06/30/05	-		1 hr		-		-		2 - 3pm		-		25
	Cal-DRP #2	07/14/05	-		2 hrs		-		-		2 - 4pm		-		25
	Cal-DRP #3	07/20/05	-		2 hrs		-		-		3 - 5pm		-		25
	Cal-DRP #4	07/21/05	-		3 hrs		-		-		2 - 5pm		-		25
	Cal-DRP #5	07/22/05	-		4 hrs		-		-		1 - 5pm		-		25
	Cal-DRP #6[a]	08/26/06	-		4 hrs		-		-		1 - 6pm		-		25
	Cal-DRP #7	08/29/05	-		4 hrs		-		-		1 - 6pm		-		25
SCE	Cal-DRP #1	06/21/05	2 hrs		3 hrs		3 hrs		3 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #2	06/22/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #3	06/23/05	3 hrs		5 hrs		5 hrs		2 - 5pm		1 - 6pm		1 - 6pm		93
	Cal-DRP #4	07/13/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #5	07/14/05	3 hrs		5 hrs		7 hrs		3 - 6pm		1 - 6pm		12 - 7pm		93
	Cal-DRP #6	07/19/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #7	07/20/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #8	07/21/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #9	07/22/05	1 hr		1 hr		1 hr		4 - 5pm		4 - 5pm		4 - 5pm		93
	Cal-DRP #10	07/29/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #11	08/17/05	3 hrs		4 hrs		4 hrs		2 - 5pm		2 - 6pm		2 - 6pm		93
	Cal-DRP #12	08/23/05	3 hrs		5 hrs		7 hrs		2 - 5pm		1 - 6pm		12 - 7pm		93
	Cal-DRP #13	08/25/05	2 hrs		2 hrs		2 hrs		3 - 5pm		3 - 5pm		3 - 5pm		93
	Cal-DRP #14	08/26/05	3 hrs		3 hrs		3 hrs		2 - 5pm		2 - 5pm		2 - 5pm		93
	Cal-DRP #15	09/01/05	3 hrs		5 hrs		7 hrs		2 - 5pm		1 - 6pm		12 - 7pm		93
	Cal-DRP #16	09/06/05	3 hrs		5 hrs		8 hrs		2 - 5pm		1 - 6pm		11am - 7pm		93
	Cal-DRP #17	09/21/05	3 hrs		5 hrs		7 hrs		3 - 6pm		1 - 6pm		12 - 7pm		93
	Cal-DRP #18	09/22/05	3 hrs		5 hrs		2 hrs		2 - 5pm		1 - 6pm		2 - 5pm		93
	Cal-DRP #19	09/30/05	3 hrs		4 hrs		-		2 - 5pm		2 - 6pm		-		93
PG&E	PG&E Zone		zone 3	zone 4	zone 3	zone 4	zone 3	zone 4	zone 3	zone 4	zone 3	zone 4	zone 3	zone 4	zone3/zone4
	Cal-DRP #1	06/30/05	1 hr	1 hr	1 hr	1 hr	4 hrs	1 hr	3 - 4pm	3 - 4pm	3 - 4pm	3 - 4pm	2 - 6pm	3 - 4pm	172 / 24
	Cal-DRP #2	07/12/05	3 hrs	3 hrs	4 hrs	4 hrs	4 hrs	4 hrs	3 - 5pm	3 - 5pm	2 - 6pm	2 - 6pm	2 - 6pm	2 - 6pm	172 / 24
	Cal-DRP #3	07/13/05	2 hrs	2 hrs	2 hrs	2 hrs	2 hrs	2 hrs	3 - 5pm	3 - 5pm	3 - 5pm	3 - 5pm	3 - 5pm	3 - 5pm	172 / 24
	Cal-DRP #4	07/14/05	2 hrs	2 hrs	3 hrs	3 hrs	4 hrs	4 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	1 - 5pm	1 - 5pm	172 / 24
	Cal-DRP #5	07/15/05	2 hrs	2 hrs	3 hrs	3 hrs	3 hrs	3 hrs	3 - 5pm	3 - 5pm	3 - 6pm	3 - 6pm	3 - 6pm	3 - 6pm	172 / 24
	Cal-DRP #6	07/18/05	3 hrs	3 hrs	4 hrs	4 hrs	4 hrs	4 hrs	3 - 6pm	3 - 6pm	2 - 6pm	2 - 6pm	2 - 6pm	2 - 6pm	172 / 24
	Cal-DRP #7	07/25/05	3 hrs	3 hrs	4 hrs	4 hrs	4 hrs	4 hrs	3 - 6pm	3 - 6pm	2 - 6pm	2 - 6pm	2 - 6pm	2 - 6pm	172 / 24
	Cal-DRP #8	07/26/05	3 hrs	3 hrs	3 hrs	3 hrs	3 hrs	3 hrs	3 - 6pm	3 - 6pm	3 - 6pm	3 - 6pm	3 - 6pm	3 - 6pm	172 / 24
	Cal-DRP #9	08/08/05	3 hrs	-	4 hrs	-	4 hrs	-	3 - 6pm	-	2 - 6pm	-	2 - 6pm	-	172 / 24
	Cal-DRP #10	08/10/05	3 hrs	-	3 hrs	-	3 hrs	-	3 - 6pm	-	3 - 6pm	-	3 - 6pm	-	172 / 24
	Cal-DRP #11	08/11/05	3 hrs	-	3 hrs	-	3 hrs	-	3 - 6pm	-	3 - 6pm	-	3 - 6pm	-	172 / 24
	Cal-DRP #12	08/12/05	2 hrs	-	3 hrs	-	3 hrs	-	3 - 5pm	-	2 - 5pm	-	2 - 5pm	-	172 / 24
	Cal-DRP #13	08/17/05	2 hrs	-	3 hrs	-	3 hrs	-	3 - 5pm	-	2 - 5pm	-	2 - 5pm	-	172 / 24
	Cal-DRP #14	08/18/05	2 hrs	-	3 hrs	-	3 hrs	-	3 - 5pm	-	2 - 5pm	-	2 - 5pm	-	172 / 24
	Cal-DRP #15	08/23/05	2 hrs	2 hrs	3 hrs	3 hrs	3 hrs	3 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	2 - 5pm	2 - 5pm	172 / 24
	Cal-DRP #16	08/25/05	3 hrs	3 hrs	2 hrs	3 hrs	2 hrs	3 hrs	3 - 6pm	3 - 6pm	3 - 5pm	3 - 6pm	3 - 5pm	3 - 6pm	172 / 24
	Cal-DRP #17	08/26/05	3 hrs	-	-	-	-	-	3 - 6pm	-	-	-	-	-	172 / 24
	Cal-DRP #18	09/06/05	3 hrs	-	3 hrs	-	3 hrs	-	3 - 6pm	-	3 - 6pm	-	3 - 6pm	-	172 / 24
	Cal-DRP #19	09/19/05	2 hrs	2 hrs	3 hrs	3 hrs	3 hrs	3 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	2 - 5pm	2 - 5pm	172 / 24
	Cal-DRP #20	09/20/05	2 hrs	2 hrs	3 hrs	3 hrs	4 hrs	4 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	1 - 5pm	1 - 5pm	172 / 24
	Cal-DRP #21	09/21/05	2 hrs	2 hrs	3 hrs	3 hrs	4 hrs	3 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	1 - 5pm	2 - 5pm	172 / 24
	Cal-DRP #22	09/22/05	2 hrs	2 hrs	3 hrs	3 hrs	4 hrs	4 hrs	3 - 5pm	3 - 5pm	2 - 5pm	2 - 5pm	1 - 5pm	1 - 5pm	172 / 24
	Cal-DRP #23	09/28/05	3 hrs	3 hrs	5 hrs	5 hrs	6 hrs	6 hrs	3 - 6pm	3 - 6pm	2 - 7pm	2 - 7pm	1 - 7pm	1 - 7pm	172 / 24
	Cal-DRP #24	09/29/05	3 hrs	3 hrs	3 hrs	5 hrs	3 hrs	4 hrs	3 - 6pm	3 - 6pm	2 - 5pm	2 - 7pm	2 - 5pm	2 - 6pm	172 / 24

[a] *Two of the SDG&E DRP events were not included in the monthly report to the CPUC*

Exhibit 6-4
2005 Interruptible Events by Utility

Utility	Event	DRP Event Trigger	Event Date	Start Time	End Time	Participants
SDG&E	AL-TOU-CP #1	Stage 2 Emergency	07/21/05	14:32 PM	16:12 PM	31
	AL-TOU-CP #2	Stage 2 Emergency	07/22/05	13:28 PM	18:00 PM	31
	AL-TOU-CP #3	Stage 2 Emergency	08/26/05	15:31 PM	16:55 PM	31
	AL-TOU-CP #4	Stage 2 Emergency	08/29/05	15:19 PM	17:31 PM	31
SCE	I-6 #1	Transmission System	08/25/05	3:51 PM	5:08 PM	501
	BIP #1	Transmission System	08/25/05	3:51 PM	5:08 PM	78
	OBMC #1	Transmission System	08/25/05	4:14 PM	4:40 PM	12

Exhibits 6-5 through 6-7 below present the distribution of day-ahead and reliability events in a calendar format for each of the utilities across the summer of 2005. These exhibits illustrate the frequency of back-to-back events that occurred throughout the summer.

Exhibit 6-5
PG&E 2005 Summer Day-Ahead and Reliability Events

July	27	28	29	30 DRP	1 CPP
	4	5	6	7	8
	11	12 DBP/CPP/DRP	13 DBP/CPP/DRP	14 DBP/CPP/DRP	15 DBP/CPP/DRP
	18 DBP/CPP/DRP	19 DBP	20 DBP	21 DBP	22 DBP
	25 DBP/DRP	26 DBP/DRP	27 DBP	28	29 DBP
August	1 DBP	2	3	4 DBP	5 DBP/CPP
	8 DBP/CPP/DRP	9	10 DRP	11 DRP	12 DRP
	15	16	17 DRP	18 DRP	19
	22	23 DRP	24	25 DRP	26 DRP
	29	30	31	1	2
September	5	6 DRP	7	8	9
	12	13	14	15	16
	19 DRP	20 DRP	21 DRP	22 DRP	23
	26	27	28 DRP	29 CPP/DRP	30

Exhibit 6-6
SCE 2005 Summer Day-Ahead and Reliability Events

June	20	21 DRP	22 DRP	23 DRP	24
July	27	28	29	30	1 CPP
	4	5	6	7	8
	11	12 DBP	13 DBP/DRP	14 DBP/DRP	15
	18	19 DBP/DRP	20 DBP/DRP	21 DBP/CPP/DRP	22 DBP/CPP/DRP
	25 DBP/CPP	26 DBP	27 DBP	28	29 DBP/DRP
August	1	2	3	4 DBP	5 DBP
	8	9	10	11	12
	15	16	17 DRP	18	19
	22	23	24	25 I-6/BIP	26 CPP/DRP
	29 CPP	30 CPP	31 CPP	1 DRP	2
September	5	6 DRP	7	8	9
	12	13	14	15 CPP	16
	19	20 CPP	21 DRP	22 CPP/DRP	23
	26	27	28	29 CPP	30 CPP/DRP

Exhibit 6-7
SDG&E 2005 Summer Day-Ahead and Reliability Events

July	27	28	29	**30** DRP	1
	4	5	6	7	8
	11	**12** DBP	**13** DBP	**14** DBP/DRP	**15** DBP
	18	**19** DBP	**20** DBP/DRP	**21** AL-TOU-CP DBP/CPP/DRP	**22** AL-TOU-CP DBP/CPP/DRP
	25	**26** DBP	**27** DBP	28	29
August	1	2	3	**4** DBP	**5** DBP
	8	9	10	11	12
	15	16	17	18	19
	22	23	24	25	**26** AL-TOU-CP CPP/DRP
	29 AL-TOU-CP/DRP	30	31	1	2
September	5	6	7	8	9
	12	13	14	15	16
	19	20	21	22	23
	26	27	28	**29** CPP	**30** CPP

6.4 SUMMARY OF METHODS USED FOR THE ESTIMATION OF IMPACTS

Both Representative Day and statistical methods were employed in the 2005 PRRP evaluation to calculate the program impacts. This next section summarizes the Representative Day approach, which requires calculating baselines for each event based on a series of recent "similar" days[2], and the following section describes the multivariate statistical regression models developed to estimate impacts based on a series of customer characteristics.

[2] Similar days exclude weekends, holidays, and any additional days during which a customer was paid to curtail their load.

6.4.1 Representative Day Baselines Assessed

One of the two primary impact analysis methodologies employed is referred to as the *Representative Day Approach*. The *Representative Day Approach* constructs a "typical day" or baseline using load and/or weather data from the days preceding the event day. The baselines used for the Representative Day Approach analysis included the 3-Day Baseline, the 10-Day Adjusted Baseline, the Utility Coincident 3-Day Baseline, the 8-Day Adjusted Baseline, and the DRP 8-Day Baseline. Each of these baselines is described below. Not all of these baselines were used to evaluate each of the Price Responsive and Reliability programs; rather a subset of these Representative Day baselines was selected based on the specific program and the baselines that are currently being employed for program settlement.

Visual representations of the difference between each of these methods can be seen in Chapter 7, Exhibits 7-14 through 7-15 (for CPP) and Exhibits 7-14dbp through 7-16dbp (for DBP). These exhibits compare the average estimated daily load shapes predicted with each of these baseline methods to the actual load shapes during event and non-event hours for the 2005 event days.

3-Day Baseline

The current baseline methodology being used for settlement at each of the three utilities for the CPP and DBP programs is referred to as the ***3-Day Baseline***. This baseline is calculated by first selecting a series of days that represent the most recent 10 similar days that occurred prior to the event day. Similar days exclude weekends, holidays, and any additional days during which a customer was paid to curtail their load. From this series of 10 similar days, the three days with the highest overall energy consumption during the curtailment hours were selected and the load for each hour of these three days was averaged (by hour) to calculate an hourly 3-Day baseline estimate. The 3-Day baselines differ for CPP and DBP due to the fact that the curtailment hours for these programs differ (see analysis hours section below for details). Impacts were calculated for all program participants using the 3-Day Baseline and compared to the individual participant impacts calculated by each of the utilities for validation purposes. This validation confirmed that the baselines used by each of the utilities for settlement or incentive purposes were being calculated in accordance with the program tariff definitions.

10-Day Adjusted Baseline

The first alternative baseline methodology used to calculate program impacts was the ***10-Day Adjusted Baseline***. This baseline is similar to the 3-Day baseline in that it also selects a series of the last 10 similar days. However, as opposed to selecting the three highest days from the last 10 days, this approach calculates a 10-Day baseline for each hour by averaging the hourly load over all of the last 10 similar days. Once this 10-Day baseline has been calculated for each hour, a scalar adjustment is applied based on a series of calibration hours (the hours of noon to 3 p.m. on the most recent similar day), which essentially scales the 10-Day baseline to the customer's recent operating level during the calibration hours. The scalar adjustment factor was calculated by computing the ratio of the average load over the three calibration hours to the average load for the same three hours from the last 10 similar days. The calibration hours used for this analysis were the hours from noon until 3pm on the most recent similar day[3]. The calibration ratio is calculated in the following manner:

$$\textit{10-Day Adjusted Baseline} = \textbf{Calibration Ratio} * \textit{10-Day Baseline}$$

where,

$$\textbf{Calibration Ratio} = \frac{\text{Average Load during Calibration Hours}}{\text{Average Load during same hours from the last 10 similar days}}$$

The calibration ratio is capped in such a way that it can never take a value greater than 2 or less than 0.5 so that it can never increase or decrease the baseline to non-feasible levels. This baseline was used to estimate the final program impacts for the CPP, DBP, DRP and Interruptible programs.

Utility Coincident 3-Day Baseline

The second alternative baseline methodology used to calculate program impacts was the ***Utility Coincident 3-Day Baseline***. This baseline is similar to the 3-Day baseline in that it also based on the average of 3 days from the last 10 similar days. However, as opposed to selecting the three highest days for each customer based on their individual specific usage, the three highest days are selected based on the coincident load for all program participants and thus are required to be the same days for each customer. The individual customer baselines are then calculated as the average hourly load for these three utility selected days. This baseline method was used to estimate program impacts for the CPP and DBP programs, however is not the recommended Representative Day baseline for the programs being evaluated. The impact estimates associated with this baseline are included in Appendix D.

8-Day Adjusted Baseline

The third alternative baseline methodology used to calculate program impacts was an ***8-Day Adjusted Baseline***. This baseline is similar to the 3-Day baseline except that it is the average of the mid 8 days from the last 10 similar days (the highest and lowest days have been dropped.) This average of the mid 8-days is adjusted similarly to the 10-Day Adjusted baseline where the calibration ratio is the average load on the notification date between 12pm and 3pm divided by the average load during those same three hours from the 8-Day baseline. This baseline is modified slightly from the DRP 8-Day baseline (described below) in that it requires the 10 days selected to be "similar" days and thus events, holidays, and recent event days are excluded from the selection of the set of 10 days. This modification ensures that the baseline is always based on an average of 8 days. This baseline method was used to estimate program impacts for all programs in this evaluation; however it is not the recommended Representative Day baseline for the programs being evaluated. The impact estimates associated with this baseline are included in Appendix D.

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[3] The time interval from noon to 3pm is the three-hour period immediately prior to event notification on the prior day assuming the prior day was not an event, a holiday or a weekend day.

DRP 8-Day Baseline

The fourth and final baseline methodology used to calculate program impacts was the ***DRP 8-Day Baseline***. This baseline is calculated as the average of the mid 8-days from the last 10 non-holiday, non-weekend days. As mentioned above, the difference between these two 8-Day baselines, as well as the other baselines described earlier, is that the set of 10 days selected for this baseline does not exclude recent event days. However, since these recent event days are dropped prior to calculating the average, it is possible (and for this past summer most certain) that the average used for the baseline is based upon fewer than 8-Days. The average of the days selected is also adjusted similarly to the 8-Day Adjusted baseline described above. This baseline method was only used to evaluate the DRP program. According to APX, the current administrator of the program, this baseline will be replaced in the next program year by a high-5 day baseline similar to what is currently being used by the NYISO.

6.4.2 Representative Day Approach Impact Methodology

As mentioned above, one of the two primary impact analysis methodologies employed is referred to as the *Representative Day Approach*. The *Representative Day Approach* constructs a "typical day" or baseline using load and/or weather data from the days preceding the event day. This impact evaluation approach involves computing an hourly baseline for all program participants for each of the event days and then calculating the difference between the baseline and the actual load for each hour of the event day. The overall participant difference (or delta) for a given event hour is then simply the sum of the hourly differences across the program participants:

$$Difference_t = \sum_n \left(k\hat{W}_{n,t} - kW_{n,t} \right)$$

where,

$Difference_t$ = Difference between the estimated baseline load and the actual load at time t,

$k\hat{W}_{n,t}$ = Estimated baseline load of customer n at time t, and

$kW_{n,t}$ = Actual load of customer n at time t.

For the 2005 Price Responsive and Reliability Program Evaluation four primary sets of baselines were selected to calculate the summer 2005 program impacts. The first type of baselines used to calculate the event impacts was a 3-Day baseline. This baseline was selected since it is the baseline currently used for settlement in the existing CPP and DBP programs at each of the three utilities. The second type of baseline used for the impact calculations was a 10-Day Adjusted baseline (using a prior-day adjustment). This baseline was selected since it was found to most accurately[4] represent the customer load shapes based on the baseline analysis performed as part of the 2004 WG2 DR program evaluation[5]. The third baseline type used to

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[4] When compared to the 3-Day, the 10-Day and the Previous Day baselines.

[5] *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

calculate program impacts was the 3-Day Utility Coincident baseline. This baseline, while similar to the 3-Day baseline used for settlement, is less likely to overstate the actual impacts since the same 3 days are selected for all program participants based on the program participant coincident peak demand as opposed to each account utilizing separate days to represent their individual high 3 days. And finally for the calculation of DRP program impacts, a mid 8-Day baseline was utilized. This method was selected since it is the baseline currently used to determine the DRP impact estimates for participant settlement.

Counting Estimated Load Differences

One determinant that can affect the final program impact calculation under the Representative Day approach is which of the load differences should be attributed to the program. Based on the results of the baseline analysis completed in the 2004 Demand Response Program Evaluation, it was evident that a moderate amount of uncertainty exists, both positive and negative, surrounding the baseline estimates. Errors in the baseline estimates will, of course, lead to errors in the corresponding impact estimates. A baseline with a positive bias, (relative hourly error) on average over-states the load for a "typical day" and thus is likely to overestimate the resulting load impacts. In other words, the difference between the estimated load and actual load may be positive even when the customer takes no action. Conversely, a baseline with a negative bias tends to underestimate the load in the absence of an event and thus will often underestimate the load impact. In this 2005 effort, we have conducted further analysis of the variation in impacts resulting from alternative methods of counting load differences in order to help to create more consistency and understanding of DR accounting methods across utilities and between the programs and the evaluation.

Small random errors from the baseline methods should generally cancel each other. Of more concern are potentially biased baseline estimates that are systematically high or low. However, there are several aspects of the program and our analysis that make isolation of program effects tractable:

- many of the load shape changes are quite large and obvious for those program participants that do take action,
- DBP program bids are required which provide a strong indication of whether customer's load shape changes are intentional[6],
- for a sample of program participants, we have obtained through the Post-Event and End of Summer surveys customer reports of whether they intentionally took action for any of the summer 2005 events, and
- an analysis of baseline methods was conducted as part of the 2004 DR evaluation on a range of day-types (high demand, low demand, and consecutively high demand) for non-participants during the summer of 2003. For these customers the actual load shapes were known, thus allowing for an investigation into whether alternative estimation methods are systematically biased and, if so, to what extent.

[6] Baseline bids were lost for the first 7 of PG&E's 17 DBP events due to bidding software issues.

The current accounting methods used by each of the utilities in the monthly report of their program impact estimates to the CPUC are provided in Exhibit 6-8.

Exhibit 6-8
Utility Specific Impact Accounting Methods

Utility	Program	Impact Reporting Method to CPUC
PG&E	CPP	Sum of Positive and Negative Impacts
	DBP	Sum of Positive and Negative Impacts from Event Bidders
	Cal-DRP	Based on Average Hourly Nomination from APX Website
	Non-Firm	n/a
SCE	CPP	Maximum Hourly Load Reduction Compared to a 10-Day Rolling Average
	DBP	
	Cal-DRP	Based on Highest Hourly Nomination from APX Website
	I-6	Difference Between Demand at the Beginning of the Event and the Single Highest Hourly Load Reduction during the Event
	BIP	
	OBMC	
SDG&E	CPP	Sum of Positive and Negative Impacts through August, Changed to Positive Only in September
	DBP	
	Cal-DRP	Based on Average of Hourly Impacts from APX Website
	AL-TOU-CP	TBD

There are a variety of alternative strategies to deal with the small random errors that can be employed to differentiate the true program impacts from the noise surrounding the baseline. There were a total of three types of alternatives examined to determine the variation and sensitivity in program impacts resulting from the impact accounting alternative utilized. The main categories of alternatives examined included the following:

- Count All Load Shape Changes (positive and negative regardless of size),
- Count Positive Load Shape Changes Only
  - Analysis examined counting all positives (>0 kW), positives greater than 10 kW, positives greater than 50 kW, and positives greater than 5 percent of the baseline value.
- Count All Load Shape Changes beyond a Tolerance Threshold
  - Differences greater +/- 5 percent of the baseline value.

Each of these alternatives is described in further detail below.

Alternative 1: Include All Differences

The first alternative that can be used to calculate the total program impact over all customers is to include all differences that exist between the baseline and the event day for all customers. The advantage of this strategy is, assuming the baseline is unbiased, that the small positive and negative differences (that are not necessarily attributable to the program) tend to cancel each other out. However, if the baseline is shown to be slightly biased (either over- or under-stated) then the majority of the small errors will be either positive or negative and thus the overall program impact may also be over- or understated. This alternative was used to count load reductions for the CPP impact analysis in the 2004 evaluation and is recommended in the 2005 evaluation for both the CPP and DBP impact estimates.

Alternative 2: Include All Positive Differences

A "positive" difference in this discussion refers to a reduction in the customer's load during an event hour as compared to the calculated baseline (i.e., savings are defined as positive). Under this alternative a series of different positive thresholds were used to examine the resulting impact estimates. The first threshold evaluated was counting all hourly customer impacts greater than zero. This approach can be viewed as calculating the upper bound for the actual event impact since it includes what may be either small random positive changes or small systematically biased positive changes between the baseline and the actual load, but excludes any small negative changes that may also exist. The second type of threshold analyzed included counting all impacts greater than a set kW level. For this evaluation 10kW and 50kW were both tested. These two thresholds excluded small impacts that could be conceived of as "noise," independent of a customer's size. These set kW levels are somewhat imprecise since for a smaller customer with an average demand of 100 kW, a 50 kW reduction is a 50 percent reduction in load, whereas for a 3 MW customer, a 50 kW reduction is less than a 2 percent drop in average load. To account for this, the third type of threshold analyzed counted all impacts greater than a set percentage of a customer's baseline load level. For this evaluation, 5 percent was tested. This final threshold attempted to isolate small random impacts for each customer relative to its size. These final two counting approaches led to insignificant differences in the overall program impacts of individual events and thus were excluded from the final impact estimation tables.

Although counting all positive differences greater than zero was used to estimate the load reductions in the 2004 evaluation for DBP participants who bid for a particular event, it is not recommended for use in the 2005 evaluation due to additional analysis, which confirmed its tendency to overstate the overall impact of the DBP participant population. It is included in the impact tables in Appendix D1 for informational purposes only.

Alternative 3: Include All Differences Greater than a Minimum Difference Tolerance

A third alternative that can be used when calculating the impact of an event is to include all differences that are greater than a pre-determined "tolerance". "Tolerance" is the minimum difference that must exist in order for the difference to be attributable to the program. There are a number of ways the tolerance can be set, however in the 2005 Price Responsive and Reliability Program (PRRP) an approach was used that set a unique tolerance for each participant based on 5 percent of their baseline estimate. The impact estimates resulting from this alternative were very similar to the results from alternative 1 above (counting all impacts). This indicates that positive and negative impacts below the tolerance level are similarly distributed and thus when this approach is used the excluded impacts tend to cancel each other out. Due to the similarity between the overall program impacts based on this alternative and those calculated using Alternative 1, they were excluded from the final impact estimation tables.

Illustration of the Different Alternatives

Exhibit 6-9 compares the effect of the different methods of counting estimated load differences for 10 hypothetical accounts. For individual accounts, the choice of treatment can result in a large impact (e.g., Accounts 5 and 10). In this example the total differences for the 10 hypothetical accounts examined in aggregate are small (e.g., a difference of 2 percent). Differences in these accounting approaches for the actual 2005 participants will be developed and compared in the results section.

Exhibit 6-9
Hypothetical Effects of Load Difference Accounting Alternatives

Account	Baseline (kW)	5% Tolerance (kW)	Actual Load (kW)	Load Reduction (kW)	Percent Reduction	Alternative 1: All Differences	Alternative 2: All Positive Differences	Alternative 3: Differences > 5% Tolerance
Account 1	600	30	550	50	8%	50	50	50
Account 2	3,000	150	3120	-120	-4%	-120	0	0
Account 3	400	20	300	100	25%	100	100	100
Account 4	3,000	150	2,860	140	5%	140	140	0
Account 5	200	10	5	195	98%	195	195	195
Account 6	1,200	60	800	400	33%	400	400	400
Account 7	800	40	835	-35	-4%	-35	0	0
Account 8	4,000	200	3805	195	5%	195	195	0
Account 9	600	30	300	300	50%	300	300	300
Account 10	1,300	65	1,210	90	7%	90	90	90
Total	15,100	--	13,785	1,315	9%	1,315	1,470	1,135
% Reduction	--	--	--	--	--	9%	10%	8%

6.4.3 Multivariate Statistical Models to Assess Customer Response Patterns

The second of the two primary impact analysis methods uses multivariate statistical models to determine individual CPP and DBP customer's event responses. Using a representative day approach or a customer-by-customer baseline method can hide patterns of customer response that are linked to weather, price regimes, and customer specific factors. In addition, these approaches can be significantly affected by short-term (day-to-day) fluctuations in a customer's load. Using a statistical model allows us to develop information on how customers respond to program events across event days that may have different weather, as well as to understand the determinants of different responses across customers. It is important to understand the factors that drive impacts across events, programs, and customers. This data analysis will examine these factors by using a set of methods that use calculated impacts as a dependent variable and examine relationships between this variable and a small set of potential "influential variables."

Using multivariate statistical models in this year's evaluation of the California PRRP is an approach that was not used in the 2004 WG2 evaluation for a number of reasons. Besides providing an alternative method of assessing program impacts, these models allow us to explore the technical issues associated with implementing regression models to calculate hourly price response, bid realization rates, and other impacts for large C&I customers in these types of programs. Regression modeling techniques have been applied more often in mass-market applications, with relatively well-behaved load shapes; and less often with large C&I customers whose load shapes can be very heterogeneous and difficult to predict on any particular day.

Using 2004 and 2005 WG2 DR program data for this analysis provides WG2 with an opportunity to better understand the strengths, weaknesses, and challenges of these models when applied to large C&I in California. This could be critically important if default CPP is ultimately implemented and the CPUC requires an ex post analysis of impacts. Additionally, this analysis may also allow us to develop a tangible model that could be used by utility procurement staff to run various scenarios to estimate future program impacts. While we feel this analysis can improve planning estimates of future demand response impacts and provide more flexibility than the Representative Day methods, it is important to note that we are reluctant to justify this task based on the objective of developing a model for extrapolation. The validity of such extrapolations will be tied to the extent to which characteristics that are predictive of load impacts in the current program cohorts are also characteristics that drive load impacts in the remaining population or at least the next cohort. This depends on a number of factors such as self-selection bias and simply how much customer characteristic variation exists in the current cohort. Because of the potential data limitations resulting from limited variation in participating customers, it is feasible that the final results will hold only for the cohort of participants currently enrolled in the programs regardless of the additional segmentation variables included in the model. The data limitations are illustrated in Exhibit 6-10 below, which provides both the distribution of the eligible population and the distributions of the current CPP and DBP participant populations across size and business type on a customer level.

Exhibit 6-10
Eligible and Participant Population Distributions Across Size and Business Type on a Customer Level

	Eligible Population		2005 CPP & DBP Participant Population						
3 IOUs	CPP & DBP Eligible Customers	Customer Distribution	CPP Customers	CPP Customer Distribution	DBP Bidding Customers	DBP Bidders Distribution	DBP Non-Bidding Customers	DBP Non-Bidders Distribution	DBP Bid Rate* by Segment
Size*									
Extra Small (20-100 kW)	7,226	33%	0	0%	0	0%	0	0%	0%
Very Small (100-200 kW)	1,566	7%	2	1%	1	1%	0	0%	100%
Small (200-500 kW)	7,968	37%	36	20%	9	8%	64	14%	12%
Medium (500-1000 kW)	2,806	13%	68	38%	34	28%	151	33%	18%
Large (1000-2000 kW)	1,304	6%	44	24%	33	28%	130	29%	20%
Extra Large (2000+ kW)	949	4%	31	17%	43	36%	107	24%	29%
Unknown	100		26		3		23		
Business Type									
Commercial and TCU									
Office	4,652	22%	20	11%	10	8%	79	18%	11%
Retail/Grocery	2,488	12%	6	3%	2	2%	17	4%	11%
Institutional	2,149	10%	28	15%	15	13%	35	8%	30%
Other Commercial	5,200	25%	37	20%	23	19%	89	20%	21%
Transportation/Communication/Utility	1,219	6%	25	14%	13	11%	28	6%	32%
Industrial and Agricultural									
Petroleum, Plastic, Rubber and Chemicals	665	3%	8	4%	7	6%	31	7%	18%
Mining, Metals, Stone, Glass, Concrete	514	2%	7	4%	10	8%	36	8%	22%
Electronic, Machinery, Fabricated Metals	1,517	7%	22	12%	15	13%	56	12%	21%
Other Industrial and Agriculture	2,650	13%	28	15%	25	21%	79	18%	24%
Unclassified									
Unknown	865		26		3		25		
Totals	21,919		207		123		475		21%

*DBP Bidders divided by the DBP participant population

Time-Series Model

The foundation of the multivariate analysis is the development of a time-series model that is specific to each customer. By using an individualized approach, it becomes possible to eliminate the problems associated with aggregating across diverse customers.[7] An additional benefit of using this type of analysis to estimate load impacts in conjunction with the Representative Day approach, is that it allows us to better identify potential biases that may exist in any one of the methods. As originally proposed, this triangulation of results increases confidence in, and improves understanding of, the impact estimates.

In general, a time-series model is any regression model that combines data over time. This is contrasted with a cross-sectional model that combines data across firms for a given time period. Use of the time-series model structure may require the researcher to address two key estimation issues – autocorrelation and heteroskedasticity. Autocorrelation arises when the variation in one period is correlated with the variation in a previous period (i.e. consumption in hour 14 is related to consumption in hour 13) and thus the variance of error terms are correlated over time. In this case, a time-series model can be used to estimate separate autocorrelation effects for each customer such that, for example, a customer that uses a temperature set back program will have a different autocorrelation scheme than a customer who runs their AC all the time. The second estimation issue, heteroskedasticity, arises in situations where the scale of a customers' load (the dependant variable) varies across observations, thus causing the error terms to have a non-uniform variance. By estimating models that are unique to each customer, heteroskedasticity is no longer a possibility.

CPP Impact Estimates

In order to understand both load and energy impacts of a time differentiated rate such as CPP a direct modeling approach was used where hourly electricity use is linearly related to the CPP event and weather conditions.[8] Algebraically, the time-series regression model developed to determine load impacts can be described as follows:

$$kW_{i,t} = \alpha_i + \beta_i' W_{it} + \delta_i CPP_t + \varepsilon_{i,t}$$

where:

- $\mathbf{kW}_{i,t}$ = is the average metered electricity load for customer *i* during hour *t*
- α_i = a constant term unique to customer *i*

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[7] The use of a pooled time-series/cross sectional model was investigated, and it was determined that the variability in the general shape of each customer's load curve as well as the variation in their response to weather conditions and the programs limited the usefulness of pooled models. The theoretical benefit to a pooled model is that it is a more efficient use of the data, thus pooling is preferred when customers are similar.

[8] A log-log specification was investigated where the dependent variable is the natural log of hourly electricity use and the key independent variable was the natural log of the price of electricity for both CPP and non-CPP days. Deriving the impact of the CPP event from this type of model was problematic because it only produces percentage change, and to derive electricity impacts, a baseline must be developed. A linear model was therefore used so that the impact of the CPP event is directly estimated.

ß = a vector of estimated coefficients unique to each customer i

$\mathbf{W}_{i,t}$ = a vector of variables that represent current and lagged average weather conditions for customer *i* during hour *t* (such as temperature and humidity)

δ_i = an estimated coefficient that denotes the effect of the critical peak event on load for customer *i*

$\mathbf{CPP}_t$ = a binary variable that indicates hour *t* is during a CPP event

$\varepsilon_{i,t}$ = the error term for customer *i* during hour *t*.

This model will produce estimates of the load impact associated with CPP that are specific for each customer. The individual effects are summed to determine the total program effect. In order to determine if it is possible to classify the different responses based on different customer types (such as customer size, maximum yearly demand, and business type), a second stage model is estimated to relate the estimated program effect to observable characteristics of the customers. Further details on this expanded model are provided below in the Model Specification of the Response Variable section below.

DBP Impact Estimates

The multivariate statistical analysis used for the DBP program is similar in nature to the analysis of the CPP program. The underlying statistical models are essentially the same, with the CPP variable changed to denote the customers' bid amount during that period.

The regression model developed to determine load impacts (Bid Realization Rates) for the DBP can be expressed as:

$$kW_{i,t} = \alpha_i + \beta_i' W_{i,t} + \varphi_i BD_{i,t} + \varepsilon_{i,t}$$

where:

$\mathbf{kW}_{i,t}$ = the average metered electricity load for customer *i* during hour *t*

α_i = a constant term unique to customer *i*

$\mathbf{ß}_i$ = a vector of estimated coefficients specific to customer *i*

$\mathbf{W}_{i,t}$ = a vector of variables that represent current and lagged average weather conditions for customer *i* during hour *t* (such as temperature and humidity)

φ_i = an estimated coefficient that denotes the extent to which the customer's bid was realized (i.e. the bid realization rate)

$\mathbf{BD}_{i,t}$ **=** the i^{th} customer's average load reduction bid for hour *t*

$\varepsilon_{i,t}$ = the error term for customer *i* during hour *t*.

Model Specification of the Response Variable

Since a non-homogeneous C&I population is being analyzed for this evaluation, it is necessary to expand the specification of the response variable to capture the different responses associated with different groups of customers (such as customer size, maximum yearly demand, and business type.) This can easily be accomplished through the use of a second-stage regression equation. For example, one likely characteristic that influences elasticity is the size of the firm, say small, medium and large. The model will then have three different terms, one for each size:

$$\delta_i = \alpha + \delta_1 Small_i + \delta_2 Med_i + \delta_3 Large_i + \varepsilon_i$$

where:

δ_i	= the estimated coefficient that denotes the program effect found for customer *i*
α	= a constant term
δ_x	= an estimated coefficient that denotes the affect of the program for customer *i* with characteristic *x* (in this case size),
ε_i	= the error term for customer *i*

Small, Med, and Large are indicator variables that equal 1 if that customer is a small, medium, or large customer, respectively, and zero otherwise. The coefficients on these variables represent the response, as a group, to the program in question.

This model clearly contains heteroskedasticity. However, a natural estimate of the difference in the error terms across customers is readily available – namely the standard error of the estimated response coefficient. By utilizing weighted ordinary least squares, it is possible to eliminate the effect of heteroskedasticity.

One benefit of this approach is that it allows for the estimation of total impacts associated with different groups of customers. For example, if program participants in one year are heavily weighted towards large customers and program participants in the next year are weighted more towards small customers, then the effect of the program can be approximated by using the relative impacts of each group found from the above equation. Thus, the participant group in one year need not be representative of participant groups in later years so long as the model captures those differences[9].

In addition to size, there are a number of other characteristics that may influence a customers' response to the program. These have been segmented into two categories based upon the availability of the data. Possible segmentation characteristics that are currently available include:

- Size - based on the maximum customer demand within a specified period,
- Business Type - based on the SIC or NAICS code assigned to a customer,
- Event Day-of-Week – indicating the day of week on which the event occurs,

[9] The issue QC faces in this analysis arises from the limited participant data that exist. Because of the limited participant data, it may not be feasible to create models that can accurately (with a high level of certainty) capture these differences.

- Seasonality Factor – based on the month in which the event occurs, and
- Weather Factors – using temperature and humidity variables.

Segmentation characteristics for which the data is not currently available, and thus would have to be gathered through a customer survey or collaboration with customer account representatives, include:

- Production Type - Batch versus continuous processing,
- Automation Level - Use of a building EMS,
- HVAC ownership, and
- Back Up Generation capacity.

This information may be useful for future analysis.

7. IMPACT EVALUATION RESULTS

The purpose of the impact assessment is to provide evaluation-based estimates of the peak load reductions associated with the day-ahead notification programs (CPP, DBP and DRP) and reliability-triggered programs (including the traditional interruptible programs, BIP and OBMC) for events occurring during the summer of 2005. This chapter presents the impact estimates for the 2005 evaluation using the approaches and procedures described previously in *Chapter 6 Impact Evaluation Data and Methodology*.

Two general methods are employed in this evaluation to calculate program impacts: the Representative Day approach and multivariate statistical models. As described in Chapter 6, the Representative Day approach requires calculating baselines for each event based on a series of recent "similar" days that are proximate to the event day in question. The multivariate statistical regression models estimate program impacts based on all days included in the model plus a series of weather, customer, and other characteristics.

The baselines analyzed within the Representative Day Approach for the impact evaluation include the 3-Day Baseline, the 10-Day Adjusted Baseline, the Utility Coincident 3-Day Baseline, the 8-Day Adjusted Baseline, and the DRP 8-Day Baseline. Each of these baselines is described in detail in Section 6. Results from each of these methods are presented in the impact tables included in Appendices D1 and D2. The following impact estimates presented in this chapter provide results based on the 10-Day Adjusted baseline, which was shown in 2004 baseline analysis[1] to be the most accurate and least biased of the representative day methods analyzed. Analysis of the 2005 participant data also indicates that the 10-Day Adjusted baseline method is the best of the representative day methods investigated.

One additional factor that can affect the final program impacts estimated using the Representative Day approach is whether impacts should be calculated based on the differences between the estimated baselines and the actual loads for each event day or whether restrictions should be imposed, such as counting only positive differences or differences of a certain magnitude. This issue is discussed in Chapter 6 where we conclude that the most appropriate approach is to count all differences. This approach is used to calculate the impacts presented in this chapter. Impact results based on the "Count Positive Impacts" alternative are included along with the preferred "Count All Impacts" alternative in the hourly tables in Appendix D1; however, these should be recognized as being biased upward significantly. The average daily impact tables included in Appendix D2 contain the results from all counting alternatives presented in Chapter 6.

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[1] The 2004 baseline analysis results are presented in the *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report*. Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December 2004. The findings presented in this report were also consistent with the results of CEC protocol report (*Protocol Development For Demand Response Calculations – Findings and Recommendations*. Prepared by KEMA-XENERGY, February 2003).

The complete results for the CPP Representative Day impact analysis are presented first, followed by the impact results for the DBP Program, the DRP program, and the reliability-triggered programs (for SCE and SDG&E only since no reliability program events were called during the summer of 2005 within PG&E service territory). The regression modeling analysis is presented for the CPP and DBP programs following the Representative Day impact analysis for the day-ahead and reliability-triggered programs.

For the Representative Day methods, the following impact results are presented for each of the four programs analyzed:

- Relationship Between Baseline Method and Program Impacts
- Average Hourly Program Impacts
- Complete Hourly Program Impacts
- Distribution of Impacts Across Customers
- Analysis of Impact Estimates for High Load-High Variance Customers
- Analysis of DBP Bidding Trends
- Analysis of Overlap Between DBP and Traditional Interruptible Participants
- Impact Spillover Beyond Program Event Hours
- Impacts over 48 Hours[2]

Following the results from the Representative Day approach for each of the four programs we present a discussion of issues associated with selecting baselines for program settlement. This chapter concludes with the program impact results from the regression modeling analysis for the CPP and DBP programs only. The regression methods provide an interesting point of comparison because they use a baseline constructed from both pre-event and post-event days. The use of pre-event day information only may be required for determining financial settlements with participants to allow them to know their baseline in advance of bidding or curtailing load. However, from an evaluation perspective, actual estimates of program impacts may benefit from a baseline that uses proximate day information both before and after an event.

7.1 REPRESENTATIVE DAY IMPACT RESULTS

In this section, estimates of peak load reductions for the CPP, DBP, DRP and Traditional Interruptible programs resulting from the Representative Day methods are presented. The final impacts estimates are based upon the 10-Day Adjusted Baseline and counting all differences

[2] In Decision 04-10-035 the CEC proposed that "DR resources should be available at least 48 hours each summer season to count as a qualifying capacity", however this proposal was not adopted in Decision 05-10-042 stating "discussion should take place in future RAR proceedings before additional restrictions on DR are adopted." *Opinion on Resource Adequacy Requirements*, Decision of ALJ Cooke, Decision 05-10-042, October 27, 2005.

between the baseline estimates and actual event day loads as impacts (both positive and negative impacts), as noted above. Impact estimates resulting from other baselines and/or counting alternatives are included in Appendices D1 and D2.

7.1.1 CPP Impact Results

The peak load reduction impact results presented in this section for the CPP program are calculated as the sum of individual customer level hourly impacts for all CPP participants who are signed up for the CPP tariff as of the day prior to the event (since the events have day-ahead notification). Each individual customer's hourly impact is calculated as the difference between the estimated customer specific representative day baseline and the customer's actual load during the event hours.

Over the course of the summer, the number of customers enrolled in PG&E and SDG&E CPP tariff grew steadily. Hence, the impacts calculated in this section are based on an increasing number of participants for each event. This variation in the number of customers participating in a particular event is one factor, along with weather and other seasonality factors that can lead to fluctuations in the estimated program impacts. Exhibit 7-1 below shows the number of CPP events called in 2005, along with the maximum and minimum number of CPP participants participating for a single 2005 event. Across all three utilities, there were 26 events called in 2005. This compares to 23 events in 2004. Again in 2005, SCE was the only utility to call 12 events, the program maximum, over the course of the summer. The number of CPP participants increased by 55 percent for PG&E and by 26 percent for SDG&E between the first and the last event of the summer. The large increase in PG&E service territory is attributable to both new program signups (PG&E had a 28 percent increase in program participants over the course of the summer) and the zone for which the events were called. PG&E, unlike the other two utilities, segmented their CPP participants into two zones, one composed of participants in the San Francisco Bay Area and the other composed of participants in the remainder of their service territory, so that events could be called for portions of their total participant population. SCE has had eight customers enrolled in the CPP program during the past two summers.

Exhibit 7-1
2005 CPP Participation Statistics

2005 CPP Event Participation Statistics	Utility		
	PG&E	SCE	SDG&E
Number of 2005 CPP Events	9	12	5
Minimum Participants per Event	180*	8	87
Maximum Participants per Event	279	8	110
Percent Increase in Participants	55%**	0%	26%

* Minimum for PG&E is based on zone 1 only, Max is based on zones 1&2
** Percent Increase in zones 1&2 across summer events ~ 28%

Relationship Between the Baseline Method and Program Impacts for CPP

As discussed in Section 6.4.1, the program impacts resulting from a Representative Day analysis approach are a function of the baseline method selected for the analysis. If the baseline method is biased, so too will be the resulting impact estimates. Exhibits 7-2 through 7-4 show the range in average hourly impacts for the CPP program across the 3-Day, 3-Day Coincident, 10-Day, 10-Day Adjusted and 8-Day baselines methods for each of the three utilities. When reviewing the results presented in these exhibits it is important to keep in mind that the averages presented here are simple averages of the impacts across all of the events. These results have not been adjusted based on how recently the event occurred, how many participants were active at the time of the event, or whether the event was called in zone 1 and/or zone 2 (for the PG&E CPP program).

For each of the utilities, these exhibits illustrate the extent to which the peak load reduction estimates based on the 3-Day baseline methodology are significantly higher than those resulting from the alternative baselines calculations. This is consistent with the results of the baseline analysis conducted as part of the 2004 WG2 DR evaluation[3] which found that the 3-Day baseline methodology had the most significant upward bias of all the baseline methodologies analyzed. Also similar to last year, the 10-Day unadjusted baseline produces the smallest program impacts due to the nature of when program events are called. Event days tend to be higher load/higher temperature than normal and thus an average of 10 recent "similar" days results in an underestimation of the actual load on an event day. The 10-Day Adjusted baseline, which was found to be the most accurate based on the baseline analysis performed in 2004, produces impacts that fall almost exactly in the middle of the range of impacts stemming from the five methods analyzed. Overall, the 3-Day baseline tends to estimate impacts that were on average 50 percent higher for the SDG&E events, 30 percent higher across the SCE events, and 60 percent higher for the PG&E events than those calculated using the 10-Day Adjusted baseline method. Because we continue to believe that the 10-Day Adjusted baseline is the most accurate of the Representative Day methods analyzed, the impacts presented in the remainder of this chapter are based on the 10-Day Adjusted baseline.

Exhibit 7-2 below illustrates that for the PG&E CPP, the 10-Day Adjusted baseline tends to estimate impacts that are on average (across all event hours) close to 40 percent lower than the estimated impacts based on the 3-Day baseline method and nearly eight times larger than the 10-Day unadjusted baseline. This exhibit also shows that the impacts across the six event hours remain fairly constant, with only a slight increase in impacts occurring for the start of the CPP High Price period (3PM to 6PM).

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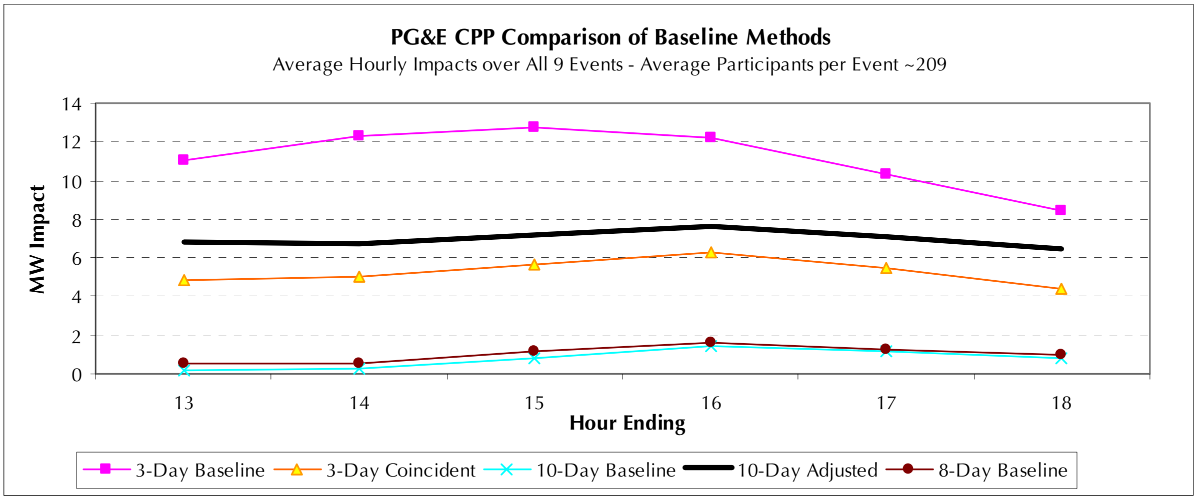
[3] *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

Exhibit 7-2
Relationship Between Baseline Method and Program Impact PG&E CPP Participants
Hourly Impacts Averaged over All Events



The hourly impacts presented in Exhibit 7-3 below are based on the eight customers currently enrolled in SCE's CPP program. Across these eight customers the majority of the program impacts are the result of one customer's curtailment[4]. The exhibit below shows that across these 8 customers, the impacts based on the 3-Day baseline are roughly 20 percent higher than those based on the 10-Day Adjusted baseline. The impact estimates from the other methods are all very similar to the 10-Day Adjusted impacts, which may be attributable to the fact that the one customer who accounts for most of the program impact does not appear to be very weather sensitive. This exhibit also shows that the impact across the six event hours remains fairly constant until the last hour of the event (5-6PM).

[4] One of SCE's eight CPP customers on average dropped about 750 kW (90 percent of their load), which accounted for the majority of the SCE CPP program impacts.

Exhibit 7-3
Relationship Between Baseline Method and Program Impact SCE CPP Participants
Hourly Impacts Averaged over All Events

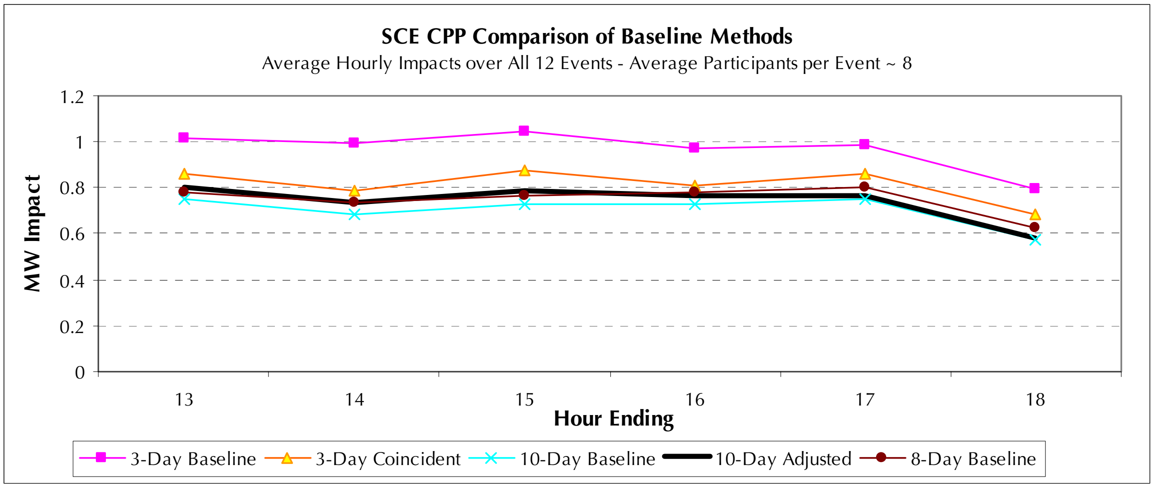
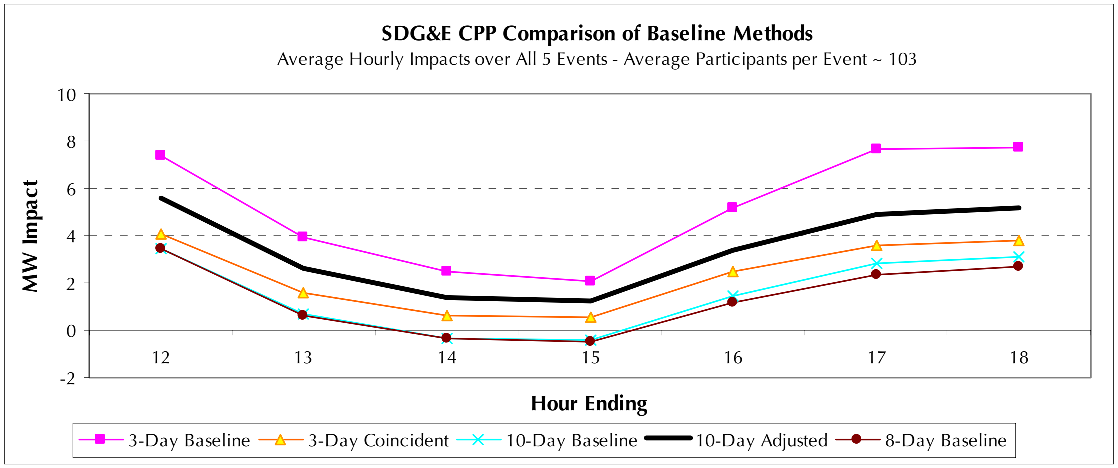


Exhibit 7-4 shows that the estimated peak load reduction for the SDG&E CPP program based on the 10-Day Adjusted baseline are, on average across all event hours, 34 percent lower than those estimated based on the 3-Day baseline method and approximately double those based on the 10-Day unadjusted baseline. The shape of the SDG&E CPP impacts across the seven event hours is very U-shaped with the largest impacts occurring during the first and last two hours of the event. Exhibit 7-23, presented later in this chapter, provides the average daily load shape for the SDG&E CPP participants. That exhibit illustrates the unique load shape of the customers signed up for the SDG&E CPP program on non-event days. These participants tend to have load shapes that gradually decrease between 11AM and 3PM, and then gradually increase over the next three hours. This type of load shape most likely makes the CPP program more attractive to these organizations, and thus results in impacts in the shape presented below. This shape indicates that on an event day, customers with this natural U-shape load reduce their load all at once, as opposed to gradually reducing it over a few hours, and do not ramp back up until the event is over.

Exhibit 7-4
Relationship Between Baseline Method and Program Impact SDG&E CPP Participants
Hourly Impacts Averaged over All Events



Average Hourly Program Impacts for CPP

To ascertain how the CPP program performed over the course of the entire summer, we calculated the average hourly program impact across all CPP participants within a given service territory for each event. Exhibits 7-5, 7-7 and 7-9 present these average hourly program impacts by utility and event based on the 10-Day Adjusted baseline (expressed as both the total MW reduction, as well as the percent load reduction). For PG&E it is interesting to note that the impacts from the first CPP event (July 1st) were two to four times higher than the impacts for the remaining eight events despite the fact that this event was cancelled (thus customers were not billed the higher critical peak period rate) due to late event notification. One hypothesis for the large reduction during this initial event is that the event fell on July 1st, which happened to be the Friday proceeding the 4th of July holiday weekend. It is conceivable that some customers were either already planning on shutting down early for the holiday weekend or decided to do so after finding out a CPP event was being called for that day.

Immediately following each of the average hourly CPP program impact exhibits are Exhibits 7-6, 7-8 and 7-10, which present the average temperature for the CPP participants during the event hours in parallel with the average hourly impacts for the 2005 events. These exhibits display the range of average temperatures across the 2005 summer and the correspondence between the average temperature during the event hours and the daily impact resulting from the CPP program.

Exhibit 7-5 below shows the difference between the first CPP event and subsequent CPP events. Despite the apparent increases in program impacts on consecutive event days, the overall program impacts across the summer events did not increase even though the number of participants increased. The number of customers participating in the last CPP event was 55 percent higher than the number participating in the first CPP event. This is attributable in part to the 61 new participants who enrolled in the program between the first and last CPP event, but is also a function of the first event only being called in zone 1 and the last event being called in both zones 1 and 2. It is interesting that the level of program impacts for PG&E CPP did not seem to increase for the July 13th (5.6 MW) or September 29th (3.6 MW) events which were the only two events called in both zones[5]. This would seem to indicate that participants in zone 1 deliver only a fraction of the overall program impacts.

Exhibit 7-5
PG&E CPP Average Hourly Program Impacts Across the 2005 Events (9 Events)
Impacts Expressed as the Total MW Reduction and as a Percentage of Load Reduced

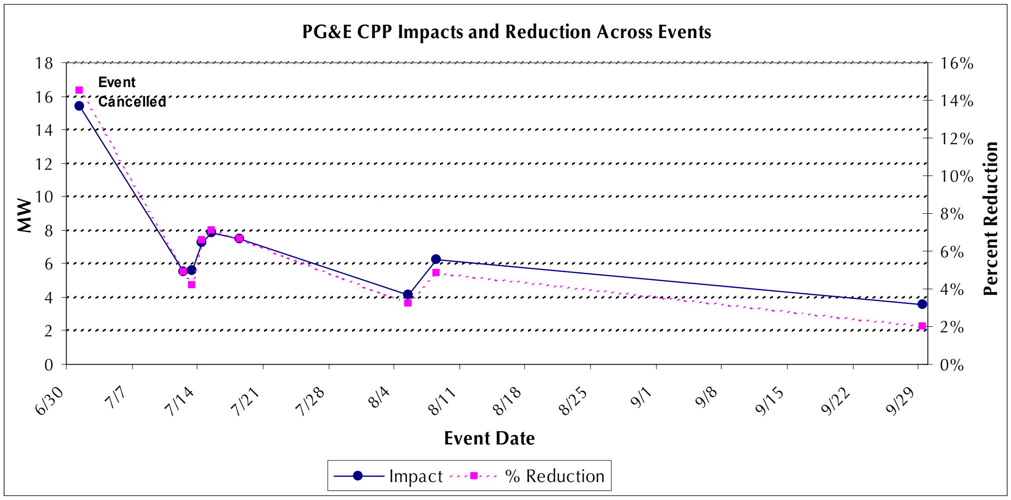


Exhibit 7-6 shows little correlation between the estimated impact for an individual CPP program event and the average temperature across the CPP participants on that event day. It does show that for the string of consecutive events that occurred in early July, the estimated impacts increased day after day despite the rise in temperature.

[5] All other events were called in Zone 2 only which consists of the PG&E territory outside of the immediate San Francisco Bay Area. The majority of PG&E CPP participants reside in Zone 2 (~85 percent of program participants).

Exhibit 7-6
PG&E Average Hourly CPP MW Impacts versus the Average Temperature across CPP Participants during the Event Hours

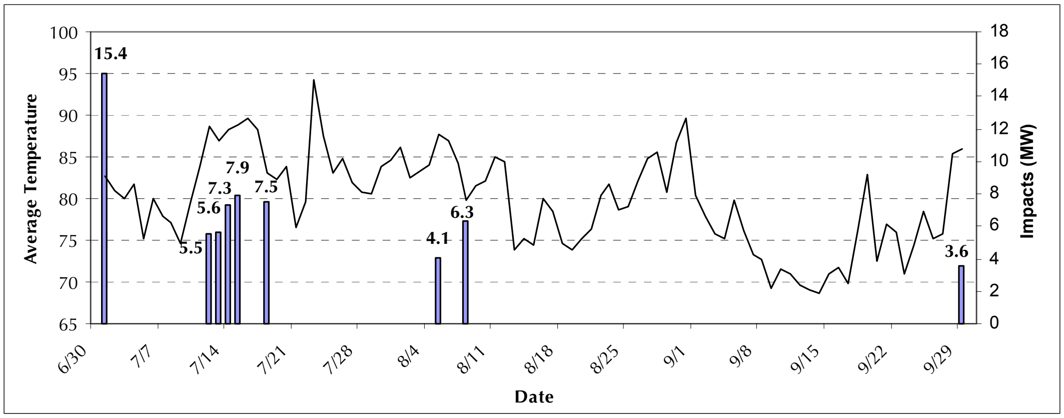
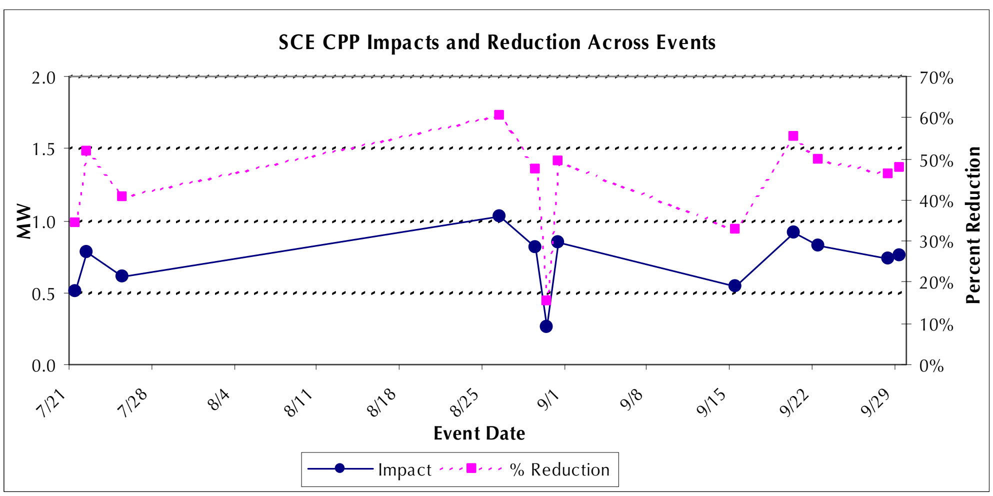


Exhibit 7-7 below shows that with the exception of the September 1st event, the peak load reductions resulting from SCE's eight CPP program participants consistently range between 0.5 to 1 MW.

Exhibit 7-7
SCE CPP Average Hourly Program Impacts Across the 2005 Events (12 Events)
Impacts Expressed as the Total MW Reduction and as a Percentage of Load Reduced[6]



6 As was the case in 2004, a single customer in the 2005 program is primarily driving the SCE CPP percent reduction reported in this exhibit. As mentioned earlier, SCE had only eight accounts signed up for the CPP program, one of which is the primary driver of the overall results, who had an average load just under 1 MW and regularly shed 80-90 percent of this load for the CPP events. The other 7 participants had an average load around 100kW and on average shed only 1 percent of their load.

Exhibit 7-8 below shows the variation in program impacts on event days, in parallel with the average temperature experienced by the few SCE CPP program participants across the summer.

Exhibit 7-8
SCE Average Hourly CPP MW Impacts versus the Average Temperature across CPP Participants during the Event Hours

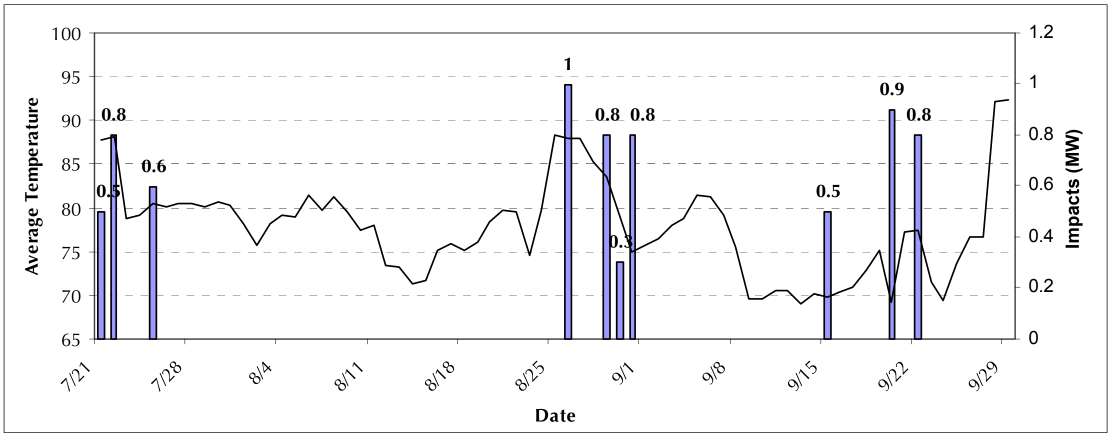


Exhibit 7-9 shows a slight increase in SDG&E CPP program impacts after the first two events. Similar to PG&E, program participation increased throughout the summer from 87 CPP participants for the first event to 105 participants for the final event (a 21 percent increase in participation over the course of the summer events).

Exhibit 7-9
SDG&E CPP Average Hourly Program Impacts Across the 2005 Events (5 Events)
Impacts Expressed as the Total MW Reduction and as a Percentage of Load Reduced

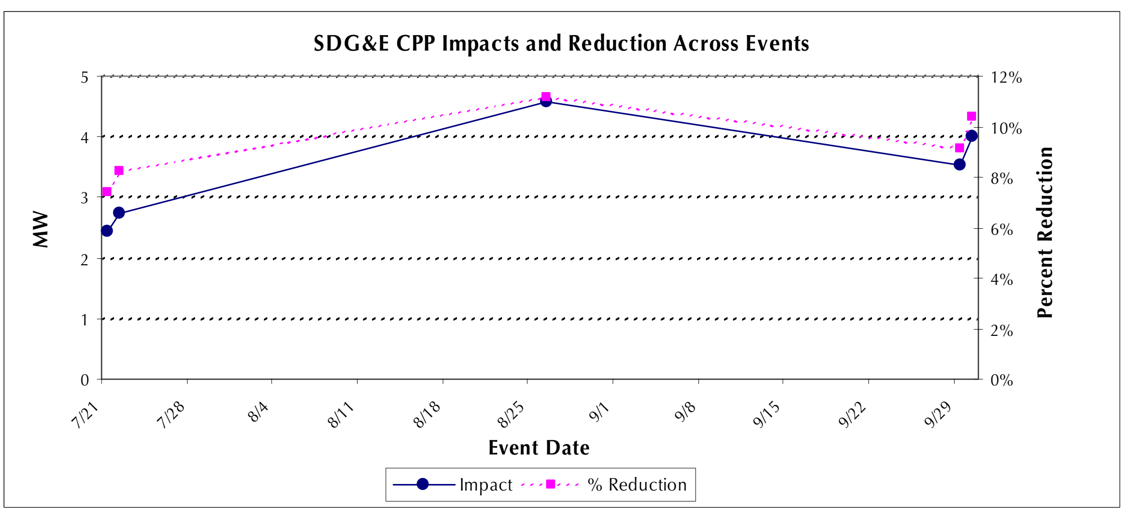
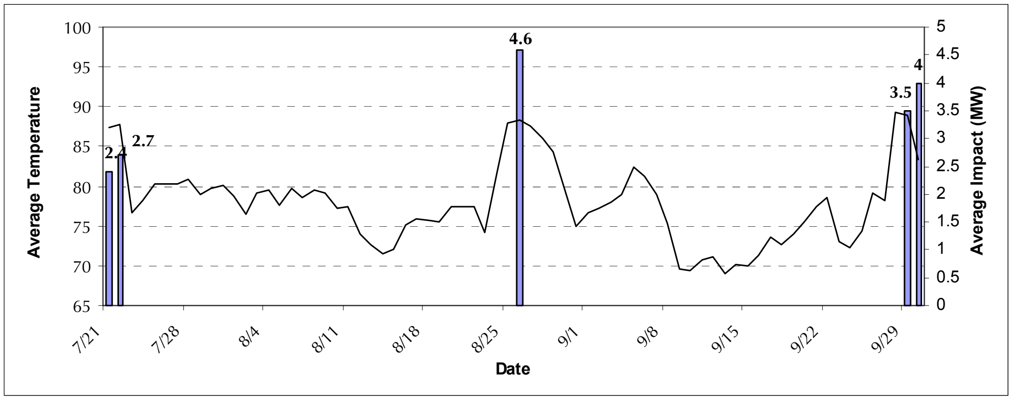


Exhibit 7-10 also shows little correlation between the estimated impact for an individual CPP program event and the average temperature across the CPP participants on that event day. It does show that SDG&E's current CPP event trigger (forecasted temperature at Miramar Marine Corps Air Station >= 84 degrees) coincides with the hottest summer days for CPP participants.

Exhibit 7-10
SDG&E Average Hourly CPP MW Impacts versus the Average Temperature across CPP Participants during the Event Hours



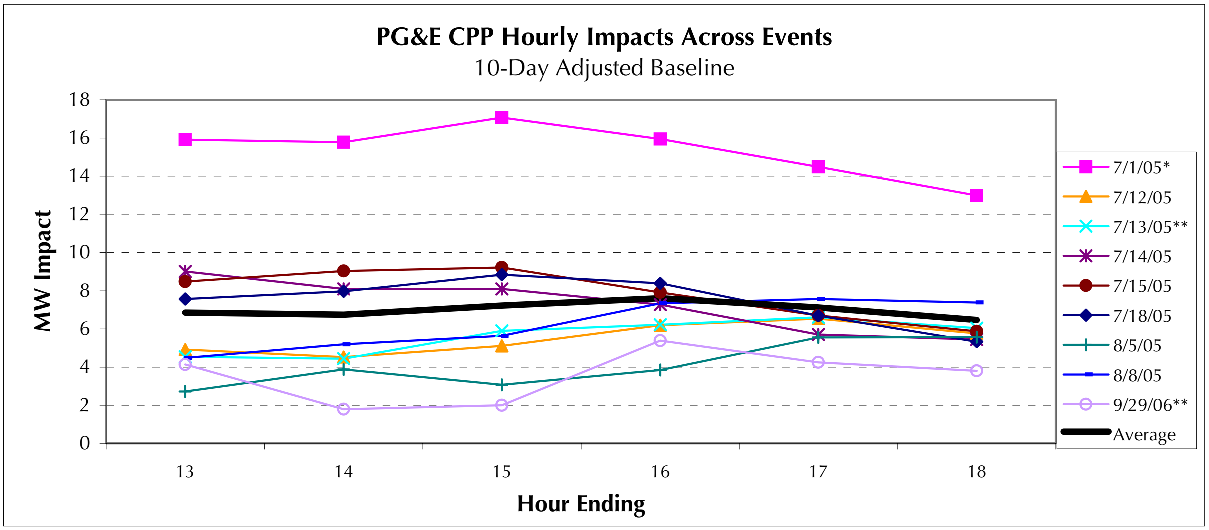
Complete Hourly Program Impacts for CPP

We also wanted to examine how, on average, the CPP program performed over the course of the six (PG&E and SCE) or seven (SDG&E) event hours. This provides information on whether it takes customers time to curtail their load at the start of an event, and whether or not they are able to maintain their load reductions over the entire event period. Exhibits 7-11 though 7-13 present the estimated hourly impacts for each CPP event occurring throughout the summer of 2005, and the average hourly impact across all summer events, based on the 10-Day Adjusted baseline. These exhibits illustrate that for PG&E and SCE, the hourly impacts remain fairly steady across the six hour event period (from noon until 6PM), but for SDG&E the impacts tend to steadily decrease during the first four event hours (11AM until 3PM) and then steadily increase during the remaining three event hours (from 3PM until 6PM)[7]. A complete table of the hour-by-hour MW impacts for each event across the three utilities is included in Appendix D1.

Exhibit 7-11 below provides the estimated hourly impacts for each of the nine PG&E 2005 CPP events. This exhibit illustrates the wide range of estimated program impacts resulting from PG&E's CPP program. The first CPP event within PG&E territory, called on July 1st, was clearly an outlier compared to the remaining CPP events. We believe this is attributable primarily to the fact that this first event was called on the Friday preceding the 4th of July holiday weekend.

[7] Based upon the non-event day load shapes of the CPP participants within SDG&E territory. Exhibit 7-20 provides an illustration of the relationship between the event and non-event day load shapes that lead to these U-shaped impacts.

Exhibit 7-11
PG&E CPP Hourly Program MW Impacts for each of the 2005 Events (9 Events)



* The 7/1/05 event was cancelled due to late notification
** The 7/13 and 9/29 events were the only two events called in Zones 1&2 (all other events were in Zone 1 only)

Exhibit 7-12 below shows the range of hourly impacts across the 12 SCE CPP events based on the 10-Day Adjusted baseline methodology. The impact for one of the event hours during the August 30th event was less than zero indicating that the total energy consumption across the CPP participants during this hour increased over the predicted baseline.

Exhibit 7-12
SCE CPP Hourly Program Impacts for Each of the 2005 Events (12 Events)

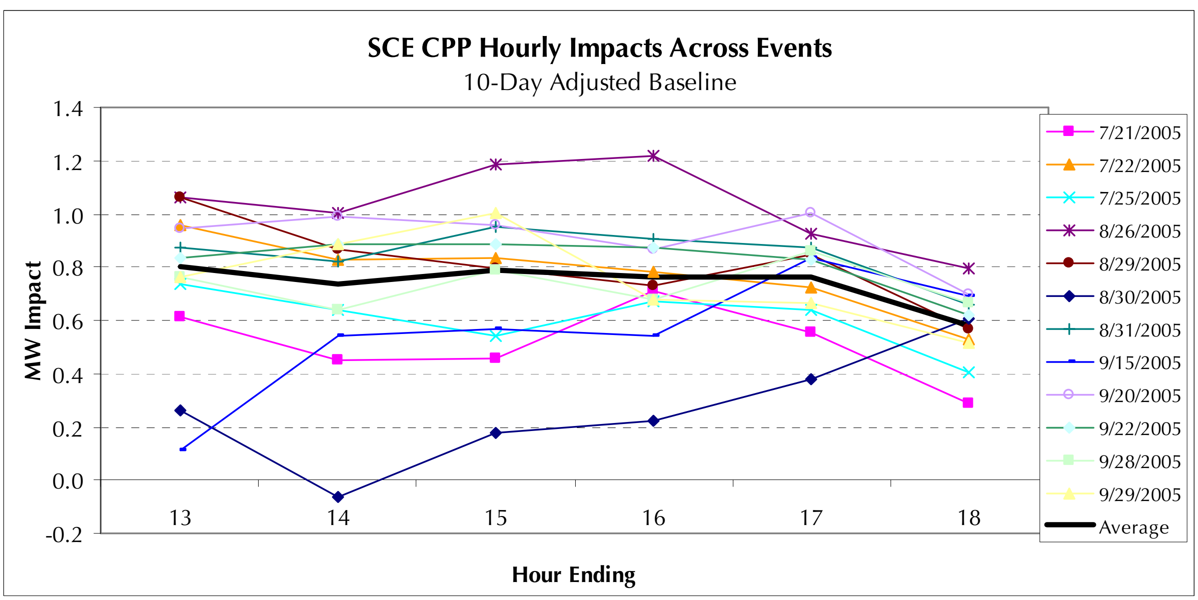
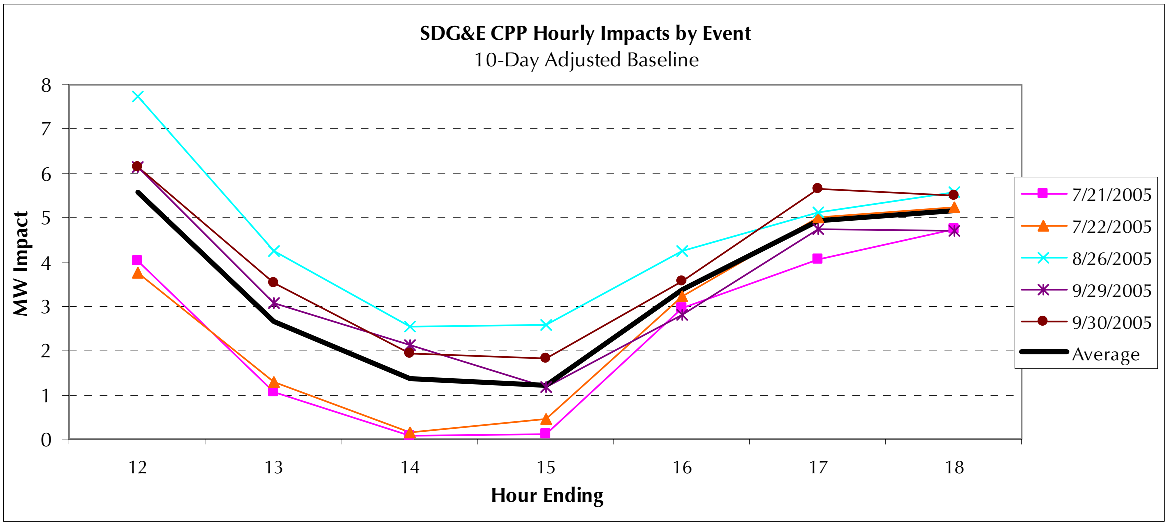


Exhibit 7-13 below shows that for the first two SDG&E CPP events (July 21st and 22nd) the impacts during the first four event hours are quite a bit lower than those same hours during the subsequent events. However, as stated earlier, these initial two events are based upon approximately 20 percent fewer participants.

Exhibit 7-13
SDG&E CPP Hourly Program Impacts for Each of the 2005 Events (5 Events Total)



Exhibits 7-14 and 7-15 below present the average hourly program impacts, in terms of MW and percent reductions, for each utility over all 2005 CPP event hours (161 hours in total across all three utilities). One finding from our analysis is that the estimated hourly impacts vary widely across events. Due to the wide range of estimated impacts across event days and, for some utilities, event hours, the exhibits below also provides the estimated impacts falling at the 25th and 75th percentiles of all summer 2005 event hours. This shows that 50 percent of the summer event hours achieved load reduction impacts between 8 and 14 MW, and the average over all event hours was approximately 11 MW. These MW impacts correspond to an average drop in load of 6 percent for PG&E, 44 percent for SCE (based on eight participants), and 9 percent for SDG&E.

Exhibit 7-14
Average MW Impact Estimates Across All 2005 CPP Event Hours

Program Impacts Across All CPP Events (MW)				
Utility	**Total Event Hours**	**Average Impact**	**75th Pct Impact**	**25th Pct Impact**
PG&E	54	7.0	8.1	5.1
SCE	72	0.7	0.9	0.6
SDG&E	35	3.5	5.1	2.1
Statewide*	161	11.2	14.1	7.8

* Non-Coincident Statewide Impacts

Exhibit 7-15
Average Percent Load Reductions Across All 2005 CPP Event Hours

Estimated Percent Load Reduction Across All CPP Events				
Utility	Total Event Hours	Average Percent Reduction	75th Pct Percent Reduction	25th Pct Percent Reduction
PG&E	54	6%	7%	4%
SCE	72	44%	53%	40%
SDG&E	35	9%	14%	6%
Statewide*	161	7%	9%	5%

* Non-Coincident Statewide Impacts

Distribution of Impacts Across Customers for CPP

We next examined the estimated program impacts for individual customers at each of the utilities. Exhibit 7-16 presents the percentage of CPP participants achieving various levels of demand reduction for at least one event during the summer of 2005. The load reduction percent is calculated as the ratio of the estimated load drop divided by the estimated base load using the 10-Day Adjusted baseline. This exhibit shows that more than 50 percent of CPP participants across the three utilities were able to achieve a 5 percent load reduction during at least one of the CPP events in 2005 and about a third of the PG&E and SDG&E CPP participants were able to drop 25 percent or more of their load during at least one event. For SCE, only eight customers were signed up for the CPP program and thus these results should be viewed within the context of this limited population.

Exhibit 7-16
Percent of Participants Reaching Various Load Reduction Levels
for at Least One Event in 2005

Load Reduction	Percent of Participants		
	PG&E	SDG&E	SCE*
5%	74%	57%	100%
10%	55%	44%	100%
25%	34%	37%	100%
50%	18%	26%	50%

* Based on 8 CPP Participants

The analysis performed found that within both PG&E and SDG&E service territories, roughly one quarter of CPP participants were able to reduce their load by more than 100 kW during at least one event. Within SCE territory, three of the eight CPP participants (38 percent) achieved this level of load reduction at least once during 2005.

Exhibit 7-17 below displays the levels of load reductions CPP customers averaged over all 2005 events during which they were participants. The comparison of Exhibit 7-16 and 7-17 illustrates that while large portions of the CPP participants were able to make various levels of load reductions for a particular event, the levels of contributions presented in Exhibit 7-16 cannot generally be relied upon for an entire summer of events.

Exhibit 7-17
Percent of Participants Reaching Various Average Load Reduction Levels for All 2005 Events

Load Reduction	Percent of Participants		
	PG&E	SDG&E	SCE*
5%	38%	30%	63%
10%	24%	28%	50%
25%	9%	22%	13%
50%	2%	13%	13%

* Based on 8 CPP Participants

The average peak load reduction for CPP participants over all of 2005 events ranged from a high of 44 percent for SCE participants (only eight participants) to a low of 5.6 percent for PG&E participants. SDG&E participants had an average reduction of 9.4 percent.

Exhibits 7-18 through 7-20 below present the distribution of CPP participants' average hourly impacts across all CPP events based on the 10-Day Adjusted baseline. These exhibits show the percentage of customers that make up various percentages of the *positive* impacts observed. The denominator for these percentages was based on the sum of the positive impacts, so that the percentage all the positive impacts would not be greater than 100 percent. Exhibit 7-18 shows that on average over the nine summer 2005 PG&E CPP events, 5 percent of participants contributed roughly half of the overall *positive* program impacts and 18 percent contributed nearly 80 percent of these impacts. Approximately one-third of the CPP participants contributed negative impacts, which means they actually increased their consumption during the event hours. Within PG&E service territory, 9 percent of the CPP program participants were able to reduce their load by 100 kW or more on average over all of the 2005 events; Fifty percent of PG&E CPP participants averaged less than a 5 kW reduction per event.

Exhibit 7-18
Distribution of Average PG&E CPP Participant Impact Contributions
Based on Average Hourly Impact per CPP Participant across All 9 Events

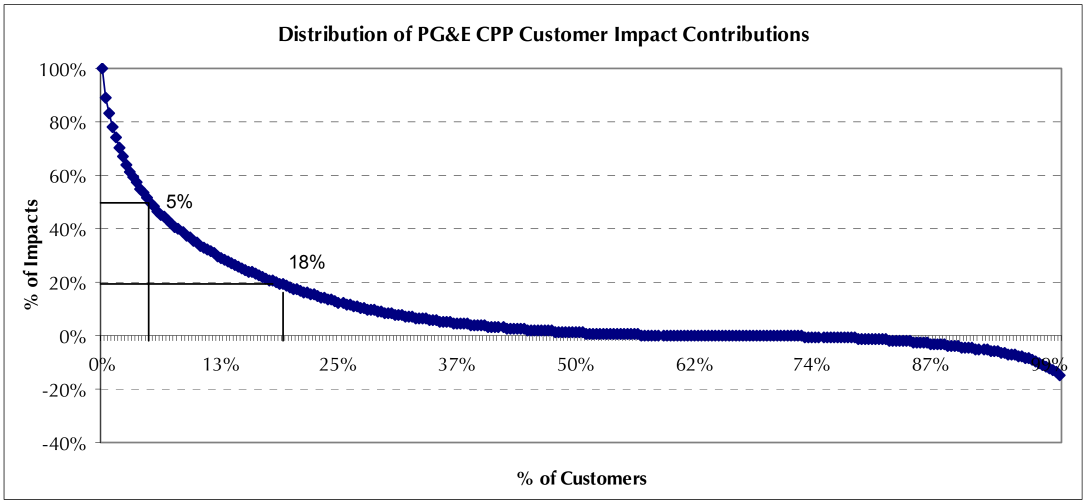
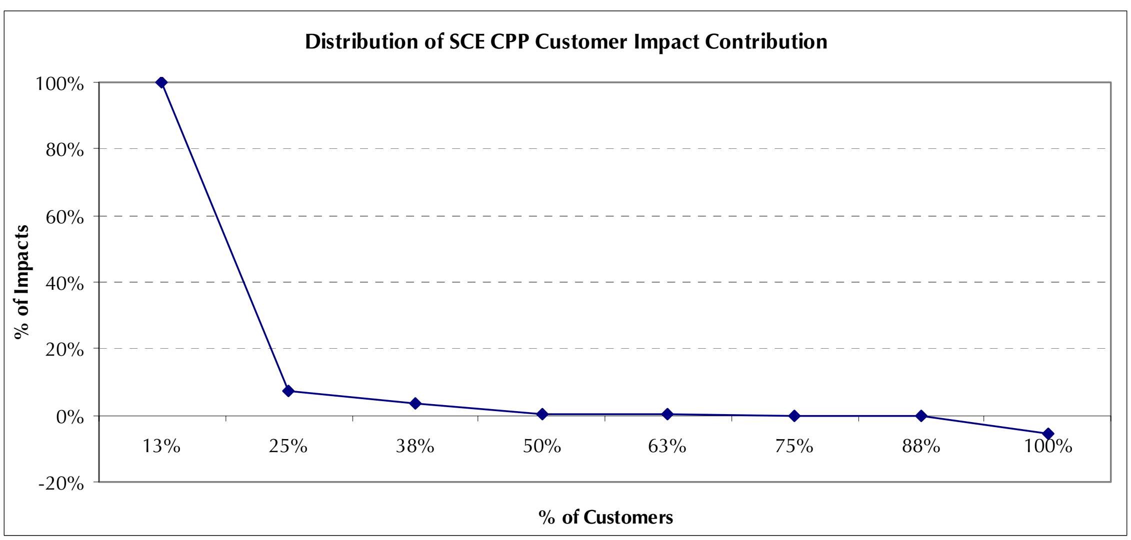


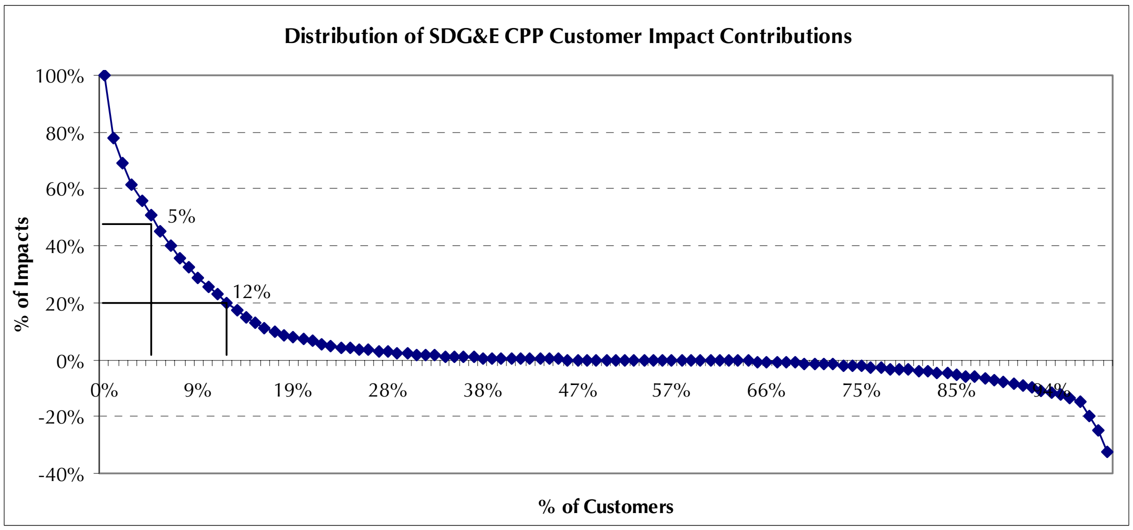
Exhibit 7-19 illustrates that for SCE, one CPP participant accounted for the majority of program impacts during this past summer. This one CPP participant was able to reduce its load by at least 100 kW on average over all 12 events; five participants averaged less than a 5 kW reduction per event.

Exhibit 7-19
Distribution of Average SCE CPP Participant Impact Contributions
Based on Average Hourly Impact per CPP Participant across All 12 Events



The distribution of SDG&E CPP participant impact contributions, shown in Exhibit 7-20, is similar to that of PG&E CPP participants. Across the five SDG&E CPP events, 5 percent of the participants contributed more than 50 percent of the program impacts and 80 percent of the overall impacts were contributed by 12 percent of the participants. Half of the CPP participants contributed negative impacts. Fifteen percent of the SDG&E CPP participants reduced their load by at least 100 kW on average over all events, while 62 percent averaged less than a 5 kW reduction per event.

Exhibit 7-20
Distribution of Average SDG&E CPP Participant Impact Contributions Based on Average Hourly Impact per CPP Participant across All 5 Events



Analysis of Impact Estimates for High-Load High-Variance Customers for CPP

As mentioned previously, the baseline analysis completed for the 2004 WG2 DR Evaluation[8] determined that the 10-Day Adjusted baseline was the most accurate baseline with the smallest bias and error magnitude. The analysis completed in 2004 also identified a series of High-Load High-Variance (HLHV) customers for which none of the baseline methods could accurately predict the customers' usage for a given event day. For the 2005 evaluation, these customers who displayed a high amount of variability in either their day-to-day load shape or their average daily demand were analyzed further. This analysis sought to determine if there is an accurate way of identifying these HLHV customers and quantifying their effect on the overall program impact estimates. Before presenting the analysis result of these HLHV customers, it is helpful to understand how well the baselines predict the daily load shapes on average for event days. Exhibits 7-21 through 7-23 present both the average daily-predicted load shape for each of the five baselines evaluated, and the average event day load shape over the 2005 CPP events for PG&E, SCE, and SDG&E. Although the average daily customer load shape is presented here for SCE CPP participants, they were excluded from the HLHV customer analysis due to the small number of customers enrolled in the CPP program within SCE service territory. The vertical bars displayed in these exhibits indicate the event start and end times. Events ran from

[8] Reference last years report again.

12PM - 6PM within PG&E and SCE service territory, and from 11AM – 6PM within SDG&E service territory.

Exhibit 7-21 shows that on average for PG&E CPP participants, the 10-Day Adjusted baseline slightly over-predicts the actual load in the hours leading up to the event start (12PM start = Hour Ending 13) and following event, whereas the 3-Day Coincident baseline matches the actual load shape closely in the pre- and post-event periods (excluding one hour on either side of the event where some spillover is apparent[9]). Despite this difference between the 10-Day Adjusted and the actual load during the non-event period (which is somewhat expected due to the nature of the scalar adjustment which shifts the entire curve up or down based on the consumption during the calibration hours), the 10-Day Adjusted baseline is very close to the 3-Day Coincident baseline during the program event hours. Similar graphs of the average daily load shape for each of the event days are included in Appendix D3.

Exhibit 7-21
Daily Load Shapes for All 2005 PG&E CPP Event Days
All Baselines versus Actual Load

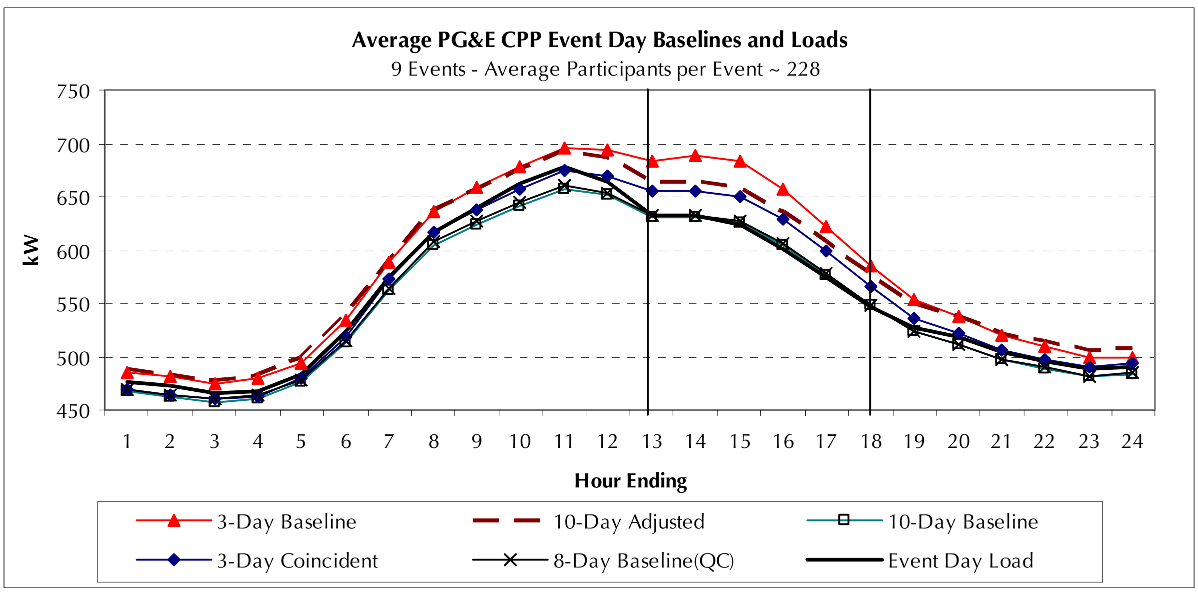
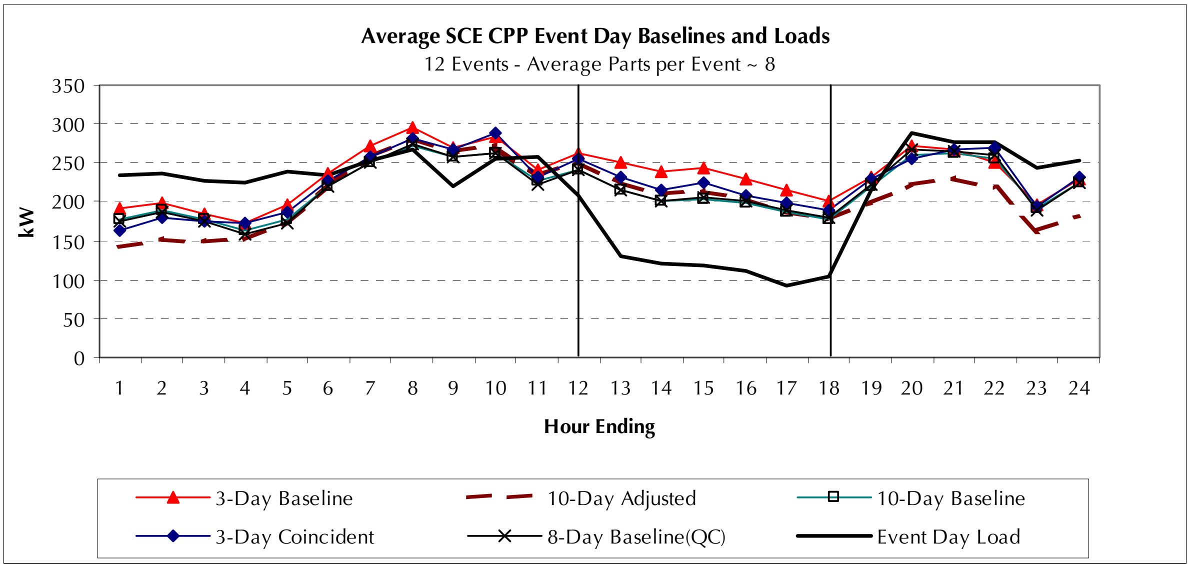


Exhibit 7-22 presents the average daily load shape for the eight SCE CPP participants currently enrolled in the CPP program, across all 12 of the 2005 events. The average load reduction for this population of CPP participants is clearly visible in this exhibit.

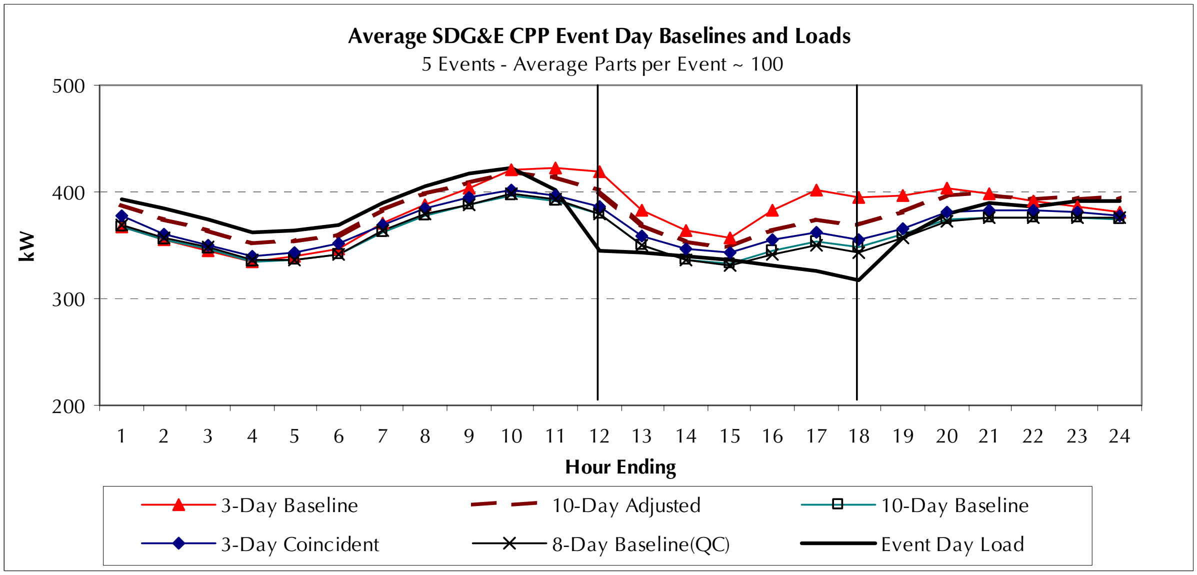
[9] The spillover apparent in this exhibit is addressed later in this section.

Exhibit 7-22
Daily Load Shapes for All 2005 SCE CPP Event Days
All Baselines versus Actual Load



For SDG&E CPP participants, Exhibit 7-23 shows that on average the 10-Day Adjusted baseline predicts the actual load in the hours leading up to the event start (11AM start = Hour Ending 12) and following the event quite closely. For this population, the 3-Day Coincident baseline slightly under-predicts the actual load shape in the pre- and post-event periods and the 3-Day baseline over-predicts the actual load during the entire event period. As this exhibit illustrates, SDG&E customers enrolled in the CPP program tend to have load shapes that dip down for a few afternoon hours before the event on non-event days. It appears the CPP events encourage these participants to decrease their usage to this reduced level a few hours earlier than normal on event days and to maintain this level of consumption until the CPP event is over.

Exhibit 7-23
Daily Load Shapes for All 2005 SDG&E CPP Event Days
All Baselines versus Actual Load



Identification Algorithms for High-Load High-Variance Customers

To determine whether there is a systematic way of identifying any CPP participants for whom the 10-Day Adjusted baseline does not perform well, a series of algorithms was analyzed. The first algorithm analyzed is based on calculating a coefficient of variation (CoV)[10] for each customer's estimated average hourly load. The CoV normalized the variations around each customer's mean load so comparisons across different sized customers could be easily made. The distribution of the CoV statistics was examined across participants within a given service territory. Any customer whose CoV statistic exceeded a tolerance level[11] determined by the analysis was flagged as a HLHV customer. This method did not perform as well as anticipated since the normalization resulted in flagging some customers whose estimated base load was small, thus making their CoV sensitive to the standard deviation of their base load estimate. The base load fluctuations from this population of participants resulted in only minimal changes to overall estimated program impacts. A group of much larger customers, who were not flagged as HLHV customers, had relatively smaller degrees of volatility in their base load; however, their volatility had more significant implications for the overall program impact estimates. To help adjust for this issue, an additional criterion was added to the algorithm. This criterion excluded accounts from being flagged as HLHV if their maximum base load over the summer was below a certain level. Excluding these smaller customers improved the

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[10] The coefficient of variation for this analysis was calculated as the standard deviation of the hourly baseline estimate divided by the mean hourly baseline estimate.

[11] Different tolerance levels were analyzed based on the distribution of the CoV for each of the participant populations at the three utilities.

algorithms ability to identify the HLHV population to a degree; however, this algorithm was not optimal since it was heavily dependant upon the tolerance and base load levels utilized in the algorithm.

The second algorithm flagged all participants for whom the difference between their estimated average hourly impact (based on the 3-Day and 10-Day baselines) for a particular event was greater than 50 percent of the average base load across all other CPP participants within the same service territory. Exhibit 7-24 below provides the average base load used in the algorithm for each of the utility service territories, as well the number of participants flagged as HLHV customers using this algorithm.

Exhibit 7-24
Specification Details and Population Identified by High-Load High-Variance Algorithm by Utility for CPP

High-Variance High-Load Algorithm Specification	Utility		
	PG&E	**SDG&E**	**SCE**
Mean Load 10-Day Baseline (kW)	600	354	197
Variation Allowed in Avg Hrly Impacts (kw)	300	175	100
High-Variance High-Load Customers Identified	9	7	1
% of CPP Participants Identified	3%	6%	13%

Samples of customers identified as HLHV participants and HLHV non-participants were manually reviewed to verify the accuracy of the algorithm's performance. Exhibits 7-25 and 7-26 present the daily load shapes of two example HLHV customers for each of the 10 days preceding a particular event, the actual event day load, and the 3-Day, 10-Day, and 10-Day Adjusted baseline estimates. Exhibit 7-25 shows a CPP participant identified as HLHV who appears to have a seemingly stable load shape on the whole. However, this participant's maximum daily demand fluctuates by 1.5 MW during the morning hours on the 10 "similar" days preceding the event; their production appears to shutdown around 11AM on some days and as late as 3PM on other days. These large fluctuations can lead to errors in impacts that are similar in magnitude to the entire estimated program impact for some events.

Exhibit 7-25
Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the September 29th CPP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

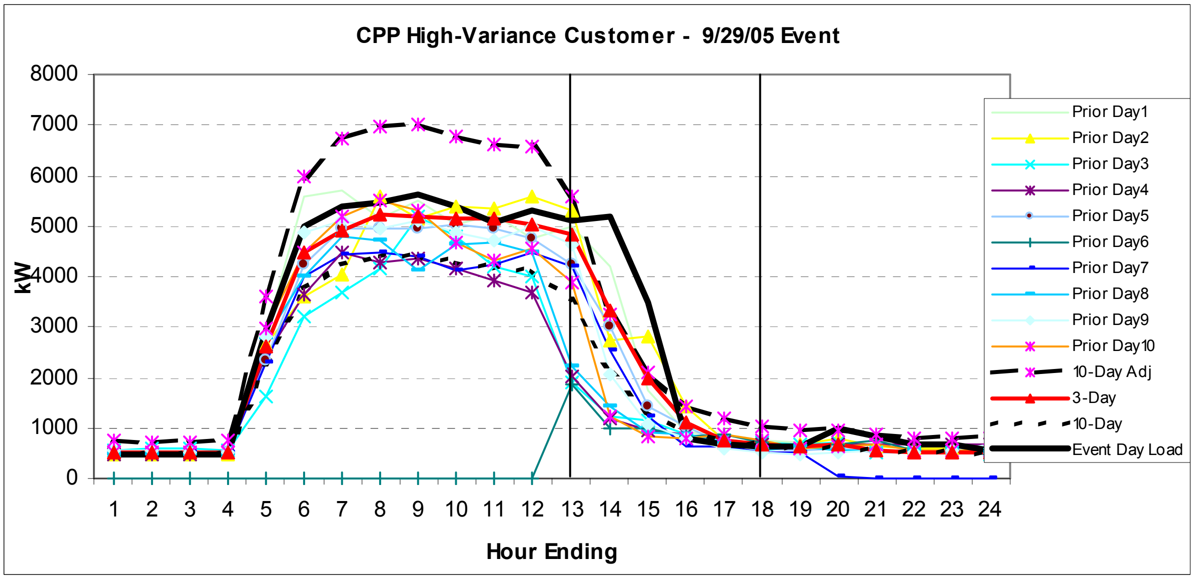


Exhibit 7-26 below provides an example of another HLHV CPP participant. Again the load shape of this participant is relatively stable, but their maximum daily demand fluctuates by 2 MW regularly during the event hours during the preceding 10 "similar" days. In this exhibit, all of the baselines under-predict the participant's actual load event day load and thus the participant's program impact is negative.

Exhibit 7-26
Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the September 29th CPP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

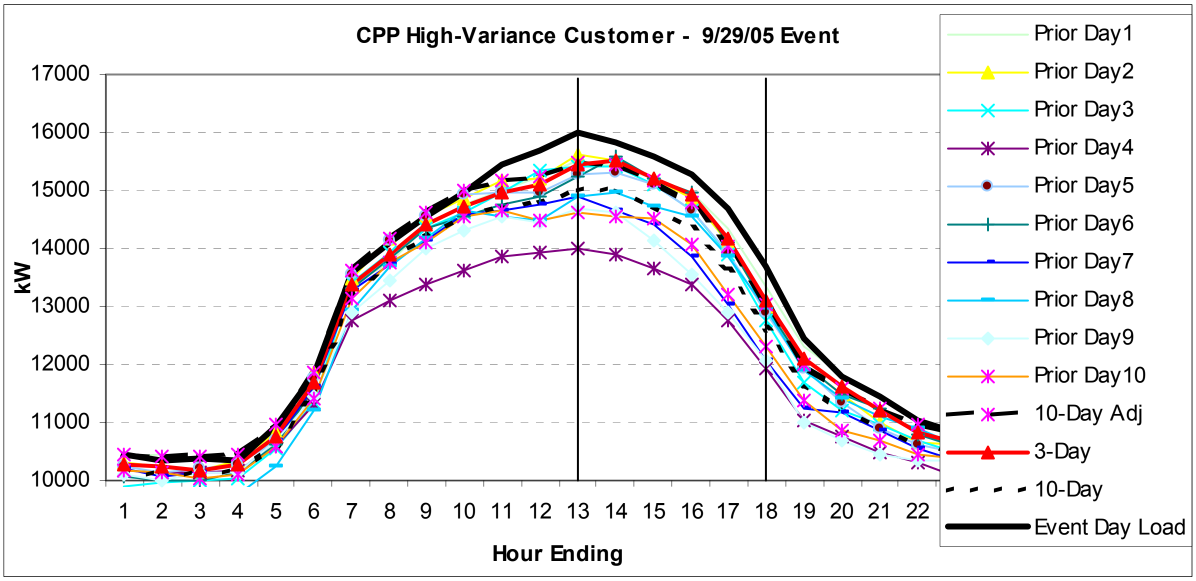


Exhibit 7-27 below presents utility-level data for those HLHV customers flagged using the algorithm. Included in this exhibit is the percentage of CPP participants identified as HLHV, total HLHV load for each utility, the average percent savings during CPP event hours of these customers versus those who are not HLHV, and the percent of impacts that the HLHV customers represent.

Exhibit 7-27
Effect of High-Load High-Variance Customers on Average and Daily Program Impact Estimates

High-Load High-Variance (HLHV) CPP Customers Across All Events*	Utility		
	PG&E	SDG&E	SCE**
Percentage of CPP Participants Identified as HLHV	4%	6%	13%
% of Base Load HLHV Participants Represent	31%	7%	53%
Avg Percent Savings of HLHV Participants	2%	53%	83%
Avg Percent Savings of Non HLHV Participants	7%	6%	1%
% of Overall CPP Impacts Delievered by HLHV Participants	8%	39%	99%

* HLHV customers in this exhibit are customers who were flagged as HLHV in one or more event in 2005
** One of the eight SCE CPP participants makes up the majority of SCE CPP impacts

Exhibits 7-28 and 7-30 displayed below are similar to Exhibits 7-21 and 7-23 except that they show the average daily-predicted and actual load shape for the HLHV participants *only*. Exhibits 7-29 and 7-31 provide the average load shapes for all participants *except* those flagged as HLHV.

Exhibit 7-28
Daily Load Shapes for All 2005 PG&E CPP Event Days
High-Variance High-Load Customers
All Baselines versus Actual Load

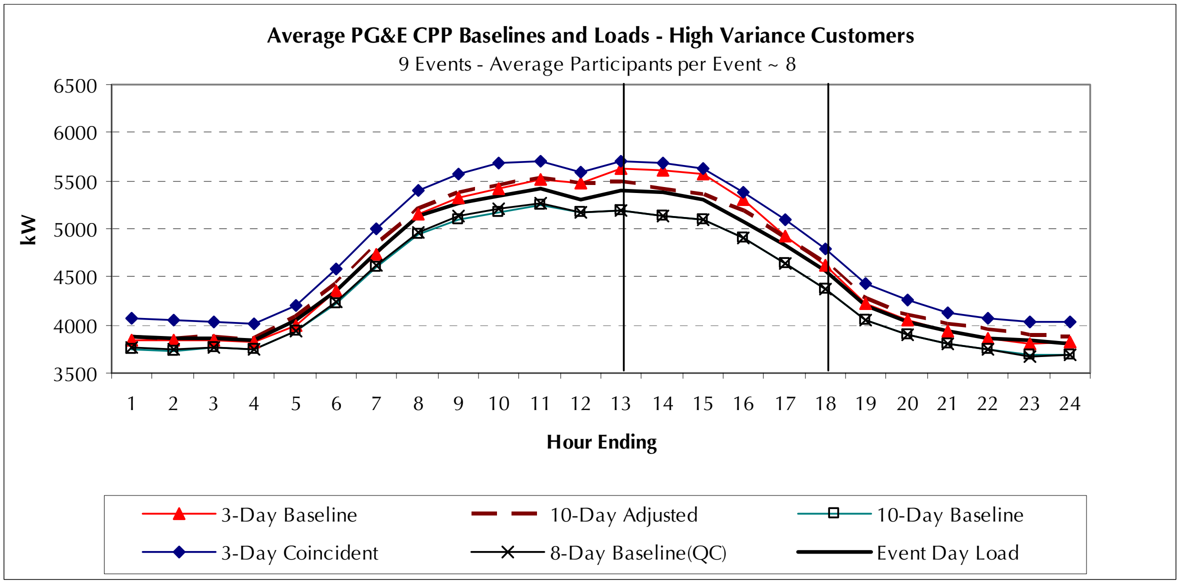


Exhibit 7-29
Daily Load Shapes for All 2005 PG&E CPP Event Days
Non High-Variance High-Load Customers
All Baselines versus Actual Load

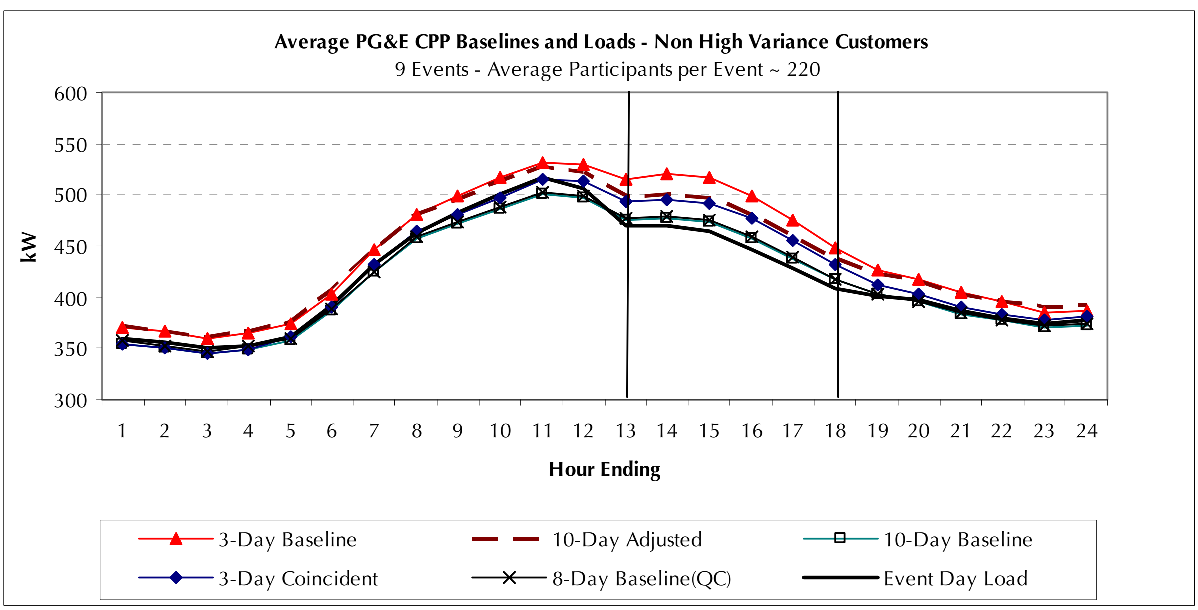


Exhibit 7-30
Daily Load Shapes for All 2005 SDG&E CPP Event Days
High-Variance High-Load Customers
All Baselines versus Actual Load

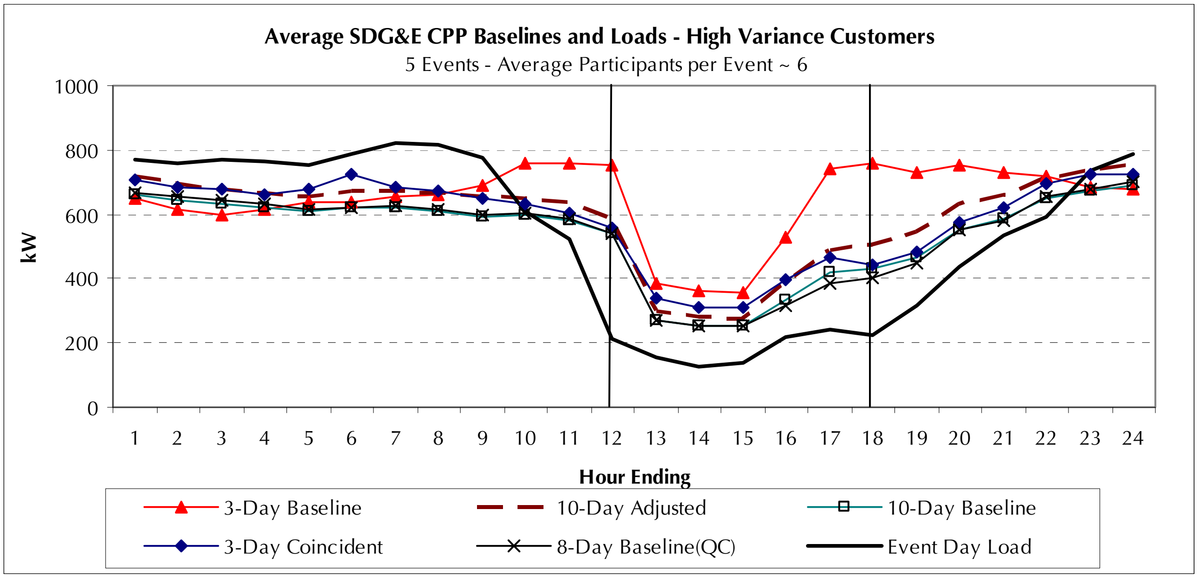
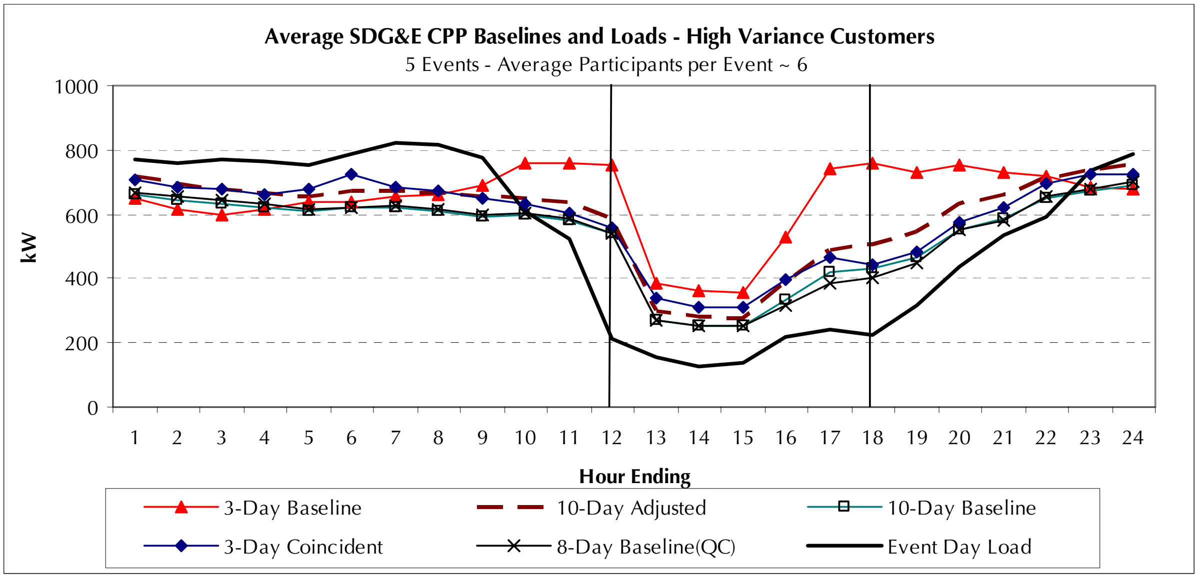


Exhibit 7-31
Daily Load Shapes for All 2005 SDG&E CPP Event Days
Non High-Variance High-Load Customers
All Baselines versus Actual Load



Impact Spillover Within and Beyond Program Event Hours for CPP

A spillover impact consists of the impacts occurring in the hours before or after an event is called. Spillover can result in positive or negative impacts depending on the type of actions participants take during these pre- and post-event hours. For instance, if a program participant is a large cold storage facility, their curtailment strategy may include lowering the set point for the refrigerated space during the one to two hours prior to an event. This is often referred to as "Pre-Cooling" and it may allow the facility to increase its set point, and thus reduce its load for this space during the event hours without causing any harm to the perishable goods being cooled. Once the event is over, it may be necessary for this facility to increase its consumption to a higher than normal level in order to return the facility to its desired temperature. This type of behavior would result in a negative spillover impact in the pre- and post- periods since their consumption outside the event hours has increased to make up for the load that was shed during the event curtailment hours. Other facilities, however, may begin to shut down extraneous load in the hours prior to the event to insure they achieve their desired load reduction. Such actions, during the pre- and post-event hours, result in a positive spillover impact.

Looking back to the daily load shape graphs presented in Exhibits 7-21 through 7-23 one can see that the CPP program in all utility service territories encourages some degree of positive spillover in both the pre- and post-event hours. This is evident in the exhibits by the ramping down and up that occur on either side of the event hours. Exhibit 7-32 below provides the average hourly impact for each of the utilities and the percent of this average hourly impact that is achieved in each of the two hours pre-event and post-event. The impacts presented in this exhibit are based on the 10-Day Adjusted baseline. This exhibit shows that the percent of average hourly impact achieved in the one hour immediately preceding the event ranges from one-third to two-thirds the average event hour impact. PG&E and SDG&E CPP participants show a higher tendency to contribute positive spillover, indicating they are ramping down for the events over a period of a few hours, whereas the single SCE CPP participant (who makes up 90 percent of SCE CPP program impacts) seems to make up for the curtailed load in the non-event hours. As one would expect, the hour immediately preceding and following the actual event hours show higher degrees of spillover than the hour that comes two hours prior or post event.

Exhibit 7-32
CPP Spillover Impacts as a Percent of Average Hourly Impact
Based on the 10-Day Adjusted Baseline

CPP Average Hourly Impact				
Average Hourly Impact (MW)		PG&E	SCE	SDG&E
		7.1	0.7	3.5
CPP Spillover as a Percent of Average Impact				
Spillover Period		PG&E	SCE	SDG&E
Pre-Event	2-hr pre	45%	-25%	-9%
	1-hr pre	69%	47%	36%
Post-Event	1-hr post	66%	-19%	68%
	2-hr post	58%	-74%	49%

In the process of evaluating the spillover occurring within the CPP program, the average net daily change in consumption (MWh) for a CPP event day was also evaluated. This analysis showed that across all PG&E CPP participants, the total daily consumption went down by an average of 105 MWh over the entire event day. Of this 105 MWh reduction, 42 MWh occurred during the 6 event hours, and the remaining 63 MWh occurred in the pre- and post-event hours (an average of 3.5 MW an hour was reduced). This seems to indicate the participants who shed load for a CPP event continued to operate at a lower level throughout the entire event day. For SCE, the total daily consumption went up by an average of 1 MWh over the event day. This indicates that slightly more than the average event curtailment of 4.3 MWh was made up for in the non-event hours. Within SDG&E service territory, the average total daily consumption went down by 24 MWh over the event day. The average event curtailment was 3.5 MW per hour, for the seven-hour event period, which amounted to a total reduction of 24 MWh over the entire event period. The decrease in the total daily consumption equaling the total event period reduction indicates that SDG&E CPP participants operated at normal levels on average over the non-event hours. The average hourly impact estimates across all event day hours for each of the utilities is provided in Appendix D4.

Impacts over 48 Hours for CPP

An opinion on draft resource adequacy requirements was written in November 2004 that proposed basing the level of a resource, such as the CPP program impacts, on the minimum amount the particular resource has been shown to deliver for at least 48 hours during the course of the summer[12]. Although this proposal was not adopted[13], Exhibits 7-33 through 7-35 present the distribution of the CPP hourly impacts delivered by each utility over all 2005 CPP event hours based on the 10-Day Adjusted Baseline. These exhibits indicate the available resource delivered for at least 48-hours for PG&E CPP was slightly less than 5 MW, for SCE it was approximately 0.5 MW. It was not possible to determine the 48-hour minimum level since they only had 35 CPP program hours during the summer of 2005.

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[12] In Decision 04-10-035 the CEC proposed "DR resources should be available at least 48 hours each summer season to count as a qualifying capacity".

[13] Decision 05-10-042 stated "discussion should take place in future RAR proceedings before additional restrictions on DR are adopted." *Opinion on Resource Adequacy Requirements*, Decision of ALJ Cooke, Decision 05-10-042, October 27, 2005

Exhibit 7-33
Distribution of Hourly Impacts for PG&E CPP Participants across All 2005 Events (9 Events, 6 Hours per Event, 54 Event Hours)

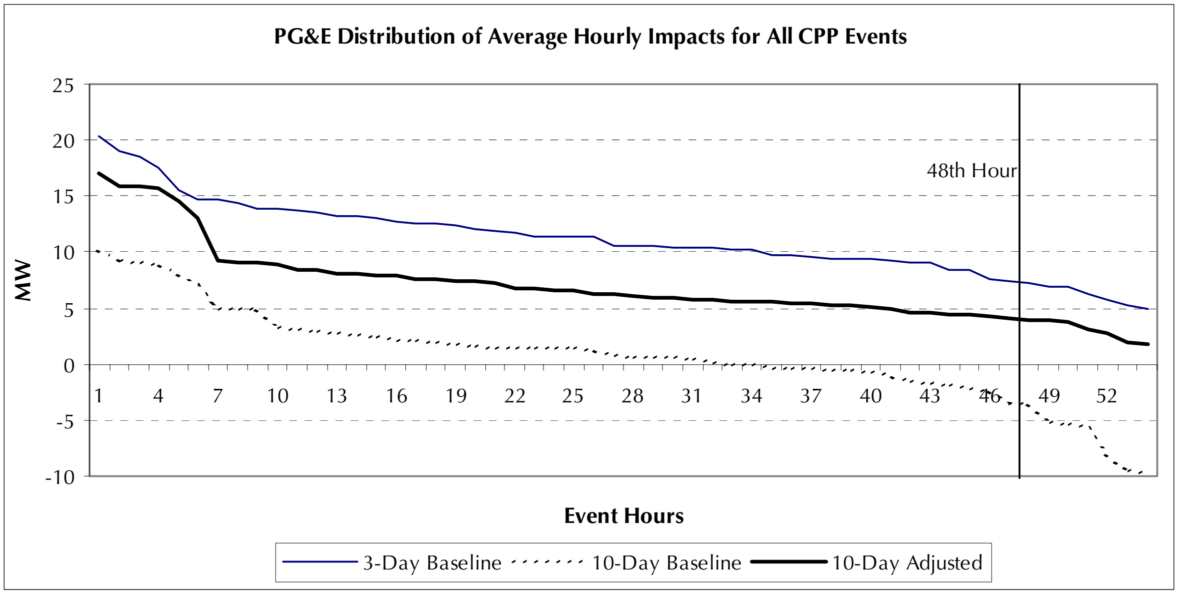


Exhibit 7-34
Distribution of Hourly Impacts for SCE CPP Participants across All 2005 Events (12 Events, 6 Hours per Event, 72 Event Hours)

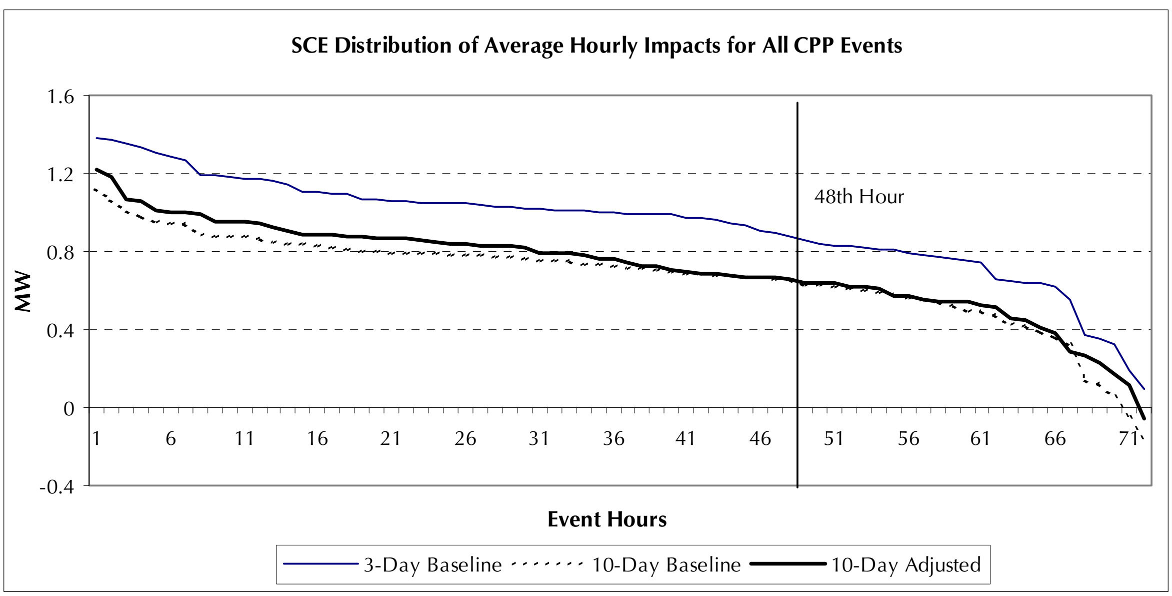
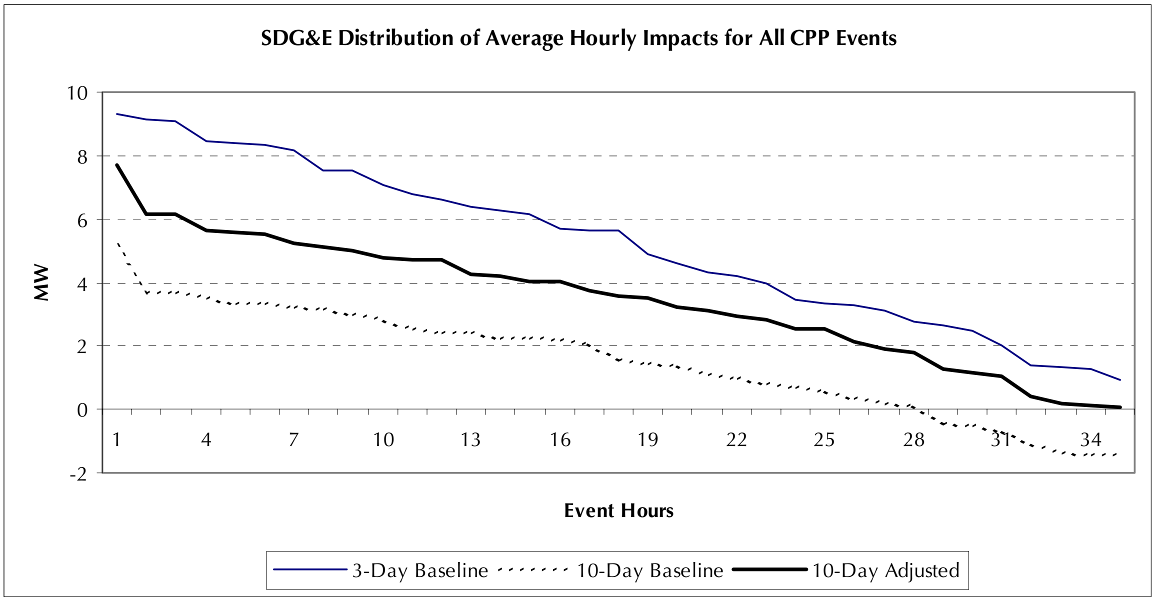


Exhibit 7-35
Distribution of Hourly Impacts for SDG&E CPP Participants across All 2005 Events (5 Events, 7 Hours per Event, 35 Event Hours)



7.1.2 DBP Impact Results

The overall impacts for the CPP program were based on the difference between the estimated and actual event day load across all participants and event hours. Impacts for the DBP program were calculated in a slightly different manner since this program required participants to bid on events for which they planned to take load reduction action. For each event, customers were allowed to place bids for all or a subset of the event hours subject to a few constraints[14], No penalty was associated with refraining from bidding for a particular event. This prior participation knowledge allowed DBP participants to be segmented into two populations for each event, Bidders and Non-Bidders[15], and impacts were then calculated by event for the bidding population only. Because the Bidder/Non-Bidder classification was completed on an event-by-event basis, customers who bid for a subset of the events were classified as DBP Bidders for some events and DBP Non-Bidders for other events.

Prior to the summer of 2005, a few changes were made to the Demand Bidding Programs across the state. One of the more significant changes had to do with the trigger used to activate the program. In 2004, DBP program events could be called when the forecasted day-ahead market

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14 DBP participants bidding for an event had to bid a minimum of 50 kW an hour for at least two consecutive hours.

15 A DBP Bidder is a customer who, for a particular event, logged on to their utility's website (after receiving notification that an event was to occur on the following business day) and placed a bid for two or more of the event hours. These Bidders may or may not have taken action after placing this bid; currently, no penalty exists for not taking action after a bid has been placed. Section 4.2.1 provides a characterization of Bidders versus Non-Bidders.

price equaled or exceeded $0.15 per kWh for four consecutive hours. Test events could also be called, subject to utility staff discretion, for a few days each summer to test the participants' responses to the program. This trigger, in combination with the relatively low summer 2004 market prices, caused the DBP program to be called infrequently in 2004. Within PG&E service territory, the only DBP event called throughout the summer was a test event. SCE called two test events and SDG&E called three events, one of which was a test event. The lack of non-test events limited the data available for analysis purposes and led to questions regarding whether participation for test events was suitable for predicting the true impact of the programs. It could be argued that some customers may not participate in events for which they do not believe the need is critical. In 2005 the DBP program trigger was changed so that events would be called on days where the CAISO day-ahead forecast exceeded 45,000 MW. This program change resulted in a significant increase in DBP events during 2005. However, the DBP events were called day after day throughout the month of July, and the weather accompanying the events was relatively moderate. Thus, there is still some question regarding the extent to which participants believed the 2005 DBP events were truly necessary.

Exhibit 7-36 below presents the average number of participants, bidders, and the corresponding average bid rate across the three utilities for the summer 2005 DBP events. This exhibit shows that in 2005 the percentage of DBP participants placing bids for events was only a fraction of those enrolled in the DBP program. The overall statewide average bid rate was 6 percent.

Exhibit 7-36
2005 DBP Participation Statistics – Participants, Bidders and Average Bidding Rate

2005 DBP Event Participation Statistics	Utility			Statewide
	PG&E	SCE	SDG&E	
Number of 2005 DBP Events	17	13	12	42
Average Participants per Event	394	703	60	1,157
Average Bids Placed per Event	29	34	9	71
Average Bid Rate per Event	7%	5%	14%	6%

One issue faced in calculating the load reduction impacts for this program was whether or not to count impacts delivered by the large DBP participant population that did not place bids for specific events, but reported delivering some load reductions on the events[16]. The low DBP bidding rate makes calculating impacts contributed by the Non-Bidders difficult since, on an event-by-event basis, the noise associated with the baseline estimates for Non-Bidders tends to overshadow the true program impacts of the Bidders. We acknowledge that calculating impacts for just the bidders potentially excludes some true program impacts from DBP participants who reportedly took curtailment actions despite not placing bids. However, without specific event day information identifying these DBP participants, quantifying this additional load reduction impact is difficult. Exhibits 7-37 through 7-39 below provide the

[16] During the Post-Event and End of Summer Surveys with DBP participants as many as 50 percent of those interviewed self-reported that they had, for at least one event this past summer, taken some level of demand reduction action despite not bidding for the event. See Section 8.4.3 *Participant Survey Results* for further details surrounding this survey.

average daily load shapes for DBP Bidders versus DBP Non-Bidders across all summer 2005 DBP events. Within each of these exhibits, the estimated base load (the expected load in the absence of the program based on the 10-Day Adjusted baseline) and the actual event day load are provided for both the DBP Bidder and Non-Bidder populations. The difference between the estimated base load and the actual event day load is estimated program impact. As these three exhibits show, a definite observable impact exists for the small bidding population, while no observable impact for the large non-bidding population can be seen. For this reason, the DBP program impact results presented in this chapter are calculated for DBP Bidders only unless otherwise specified.

Exhibit 7-37
PG&E DBP Bidder vs. Non-Bidder Average Event Day Load Shape

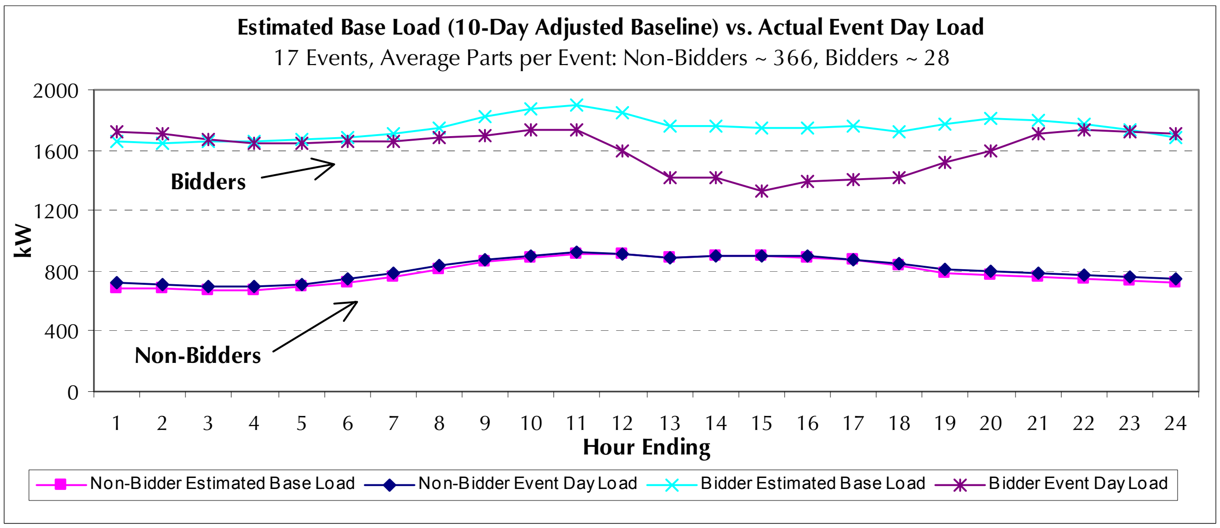


Exhibit 7-38
SCE DBP Bidder vs. Non-Bidder Average Event Day Load Shape

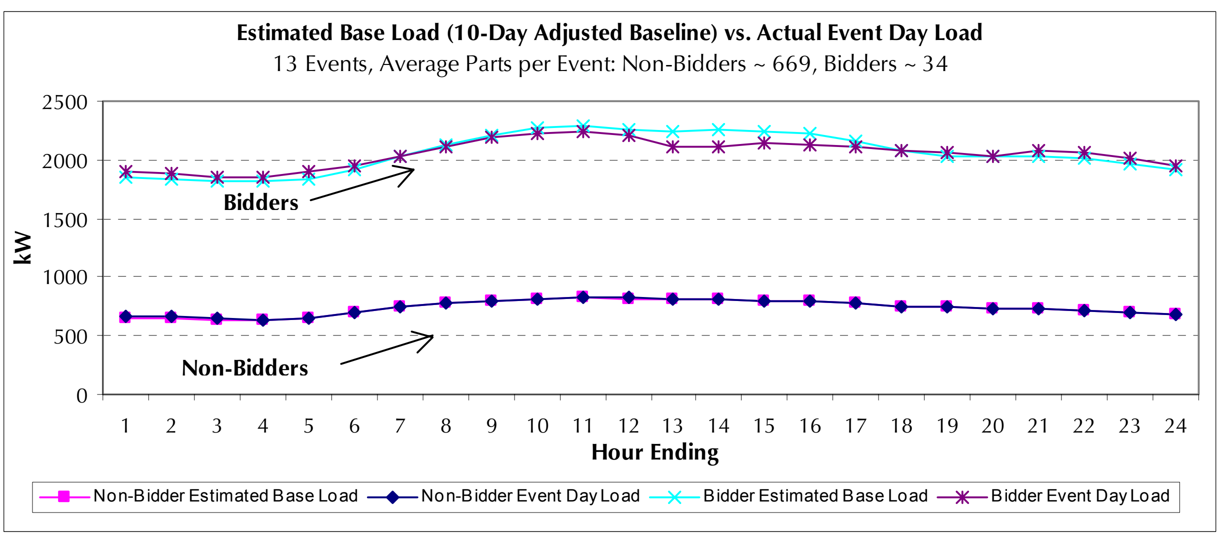
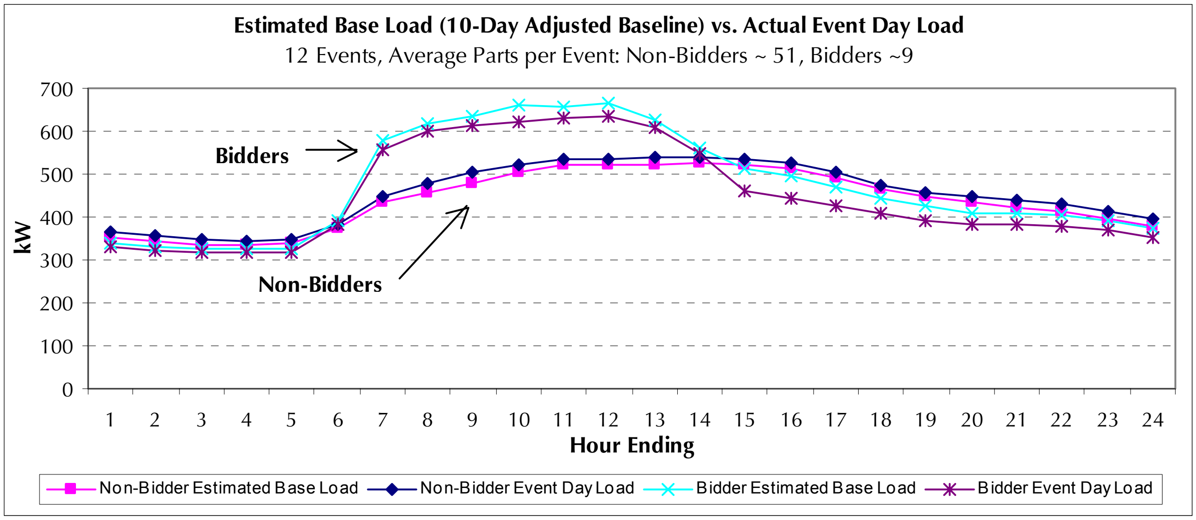


Exhibit 7-39
SDG&E Bidder vs. DBP Non-Bidder Average Event Day Load Shape



Relationship Between the Baseline Method and Program Impacts for DBP

As was shown previously in Section 7.1.1 with regards to the CPP program, impacts estimated using the Representative Day analysis approach are a function of the baseline method selected for the analysis. If the baseline method is biased, so too will be the resulting impact estimates. Exhibits 7-40 through 7-42 show the range in average hourly impacts for the DBP across the 3-Day, 3-Day Coincident, 10-Day, 10-Day Adjusted, and 8-Day baselines methods. These exhibits present averages of impacts across all of the DBP events during the summer 2005 events.

These exhibits illustrate the extent to which the 3-Day baseline estimates program impacts are significantly higher than those resulting from the alternative baselines calculations. This is consistent with the results of the 2004 WG2 DR evaluation[17] which found that the 3-Day Baseline methodology had the most significant upward bias of all the baseline methodologies analyzed. Overall, the 3-Day baseline tended to estimate impacts that were on average 50 percent higher for the 12 SDG&E events, 335 percent higher across the 13 SCE events, and 157 percent higher for the 17 PG&E events than those calculated using the 10-Day Adjusted baseline method. The 10-Day Adjusted baseline has been shown to be the most accurate of the Representative Day methods analyzed. Hence, the impacts presented in the remainder of this section are based on this baseline.

Exhibit 7-40 below illustrates that, for PG&E DBP, the 10-Day Adjusted baseline tends to estimate impacts that are on average (across all event hours) 62 percent lower than the estimated impacts based on the 3-Day baseline method and more than 20 percent lower than the 10-Day unadjusted baseline. This exhibit also shows that the impacts across the eight event

[17] *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

hours remain fairly constant during the first five hours and then start to taper off during the last three hours.

Exhibit 7-40
Comparison of Baseline Methods for PG&E DBP Participants
Hourly Impacts Averaged over All Events

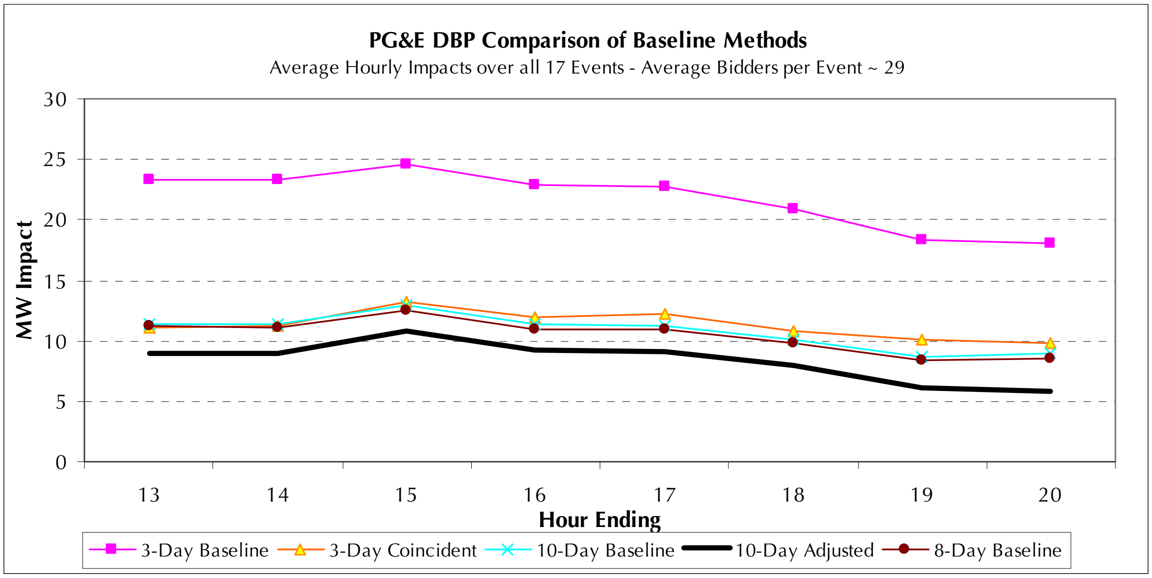
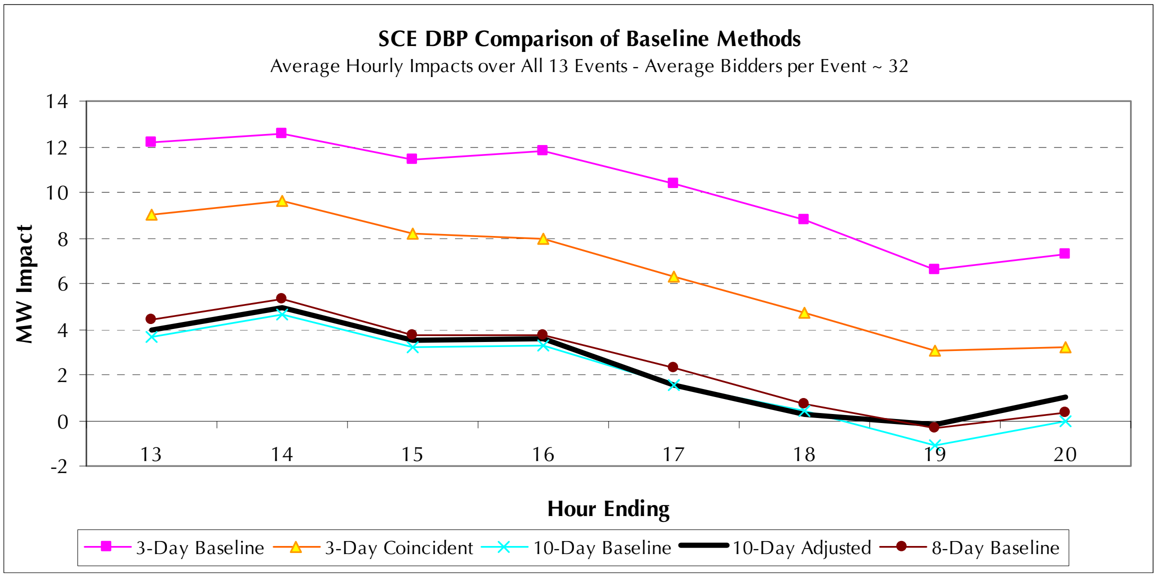


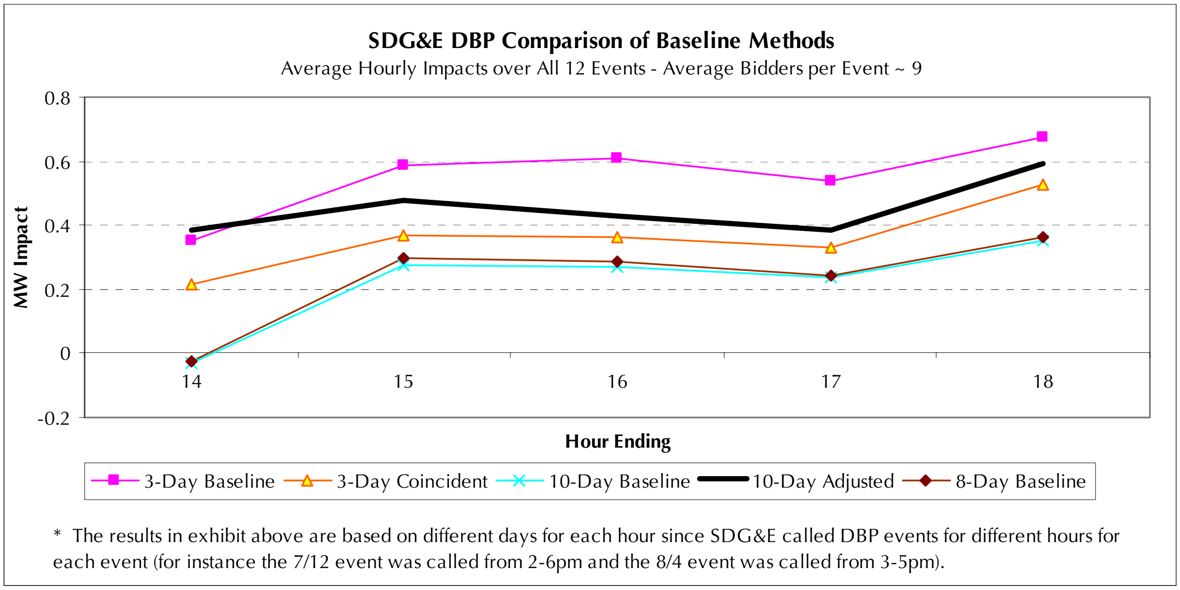
Exhibit 7-41 below illustrates that the average hourly impacts for the SCE DBP program do not seem to be as consistent across program hours as they are for the other two utilities, regardless of the baseline selected. This will be discussed in more detail in the *Complete Hourly Program Impacts for DBP* section that follows.

Exhibit 7-41
Comparison of Baseline Methods for SCE DBP Participants
Hourly Impacts Averaged over All Events



Although the impacts presented in Exhibit 7-42 below seem to increase across the event hours, this exhibit is a bit misleading since the event days included in each of the average hourly impacts change depending upon the hours for which an event was called. The SDG&E DBP program differed from the SCE and PG&E programs in that SDG&E called the DBP program for a different series of hours for each event. PG&E and SCE called all events for the same time period, noon to 8PM. Exhibit 7-51 presented in the next section provides the average hourly impacts for each SDG&E event, which illustrates that the impacts provided for an event tended to remain consistent across all event hours.

Exhibit 7-42
Comparison of Baseline Methods for SDG&E DBP Participants
Hourly Impacts Averaged over All Events



Average Hourly Program Impacts for DBP

To get an idea of how the DBP program performed over the course of the entire summer, we calculated the average hourly program impact across all DBP participants who placed a bid within a given service territory for each event. Exhibits 7-43, 7-45 and 7-47 present the average hourly DBP program impacts for each utility and each summer 2005 DBP event based on the 10-Day Adjusted baseline. These impacts are expressed as both as a total MW reduction and as a percent load reduction. These exhibits also present the average bid realization rate for each event, which is the average hourly impact for the event, divided by the average hourly bid.

Following each of the average hourly DBP program impact graphs are three exhibits, Exhibit 7-44, 7-46 and 7-48, which present the average temperature during the DBP event across all program participants, in parallel with the average hourly impacts for each of the event days. These exhibits display the range in average temperature across the DBP bidding participants during the summer of 2005, and the correspondence between this average temperature and the daily estimated impacts for the DBP program. The bid realization rate is missing for the first seven PG&E DBP events in Exhibit 7-43 due to a system issue that caused bids to be overwritten. Customers who placed bids for these initial events were paid based on the impacts they delivered to the program, calculated from their 3-Day baseline, regardless of what they had originally bid. This exhibit shows that for PG&E, the bid realization rate across the last 10 events remained fairly consistent between 70 and 85 percent. The associated MW and percent reductions, however, fluctuated drastically depending on the event day (from a low of 1.7 MW for the July 25th event to a high of 27.3 MW for the July 13th event).

Exhibit 7-43
PG&E DBP Average Hourly Program Impacts Across the 2005 Events (17 Events)
Impacts Expressed as Total MW Reductions and Percent of Load Reduced

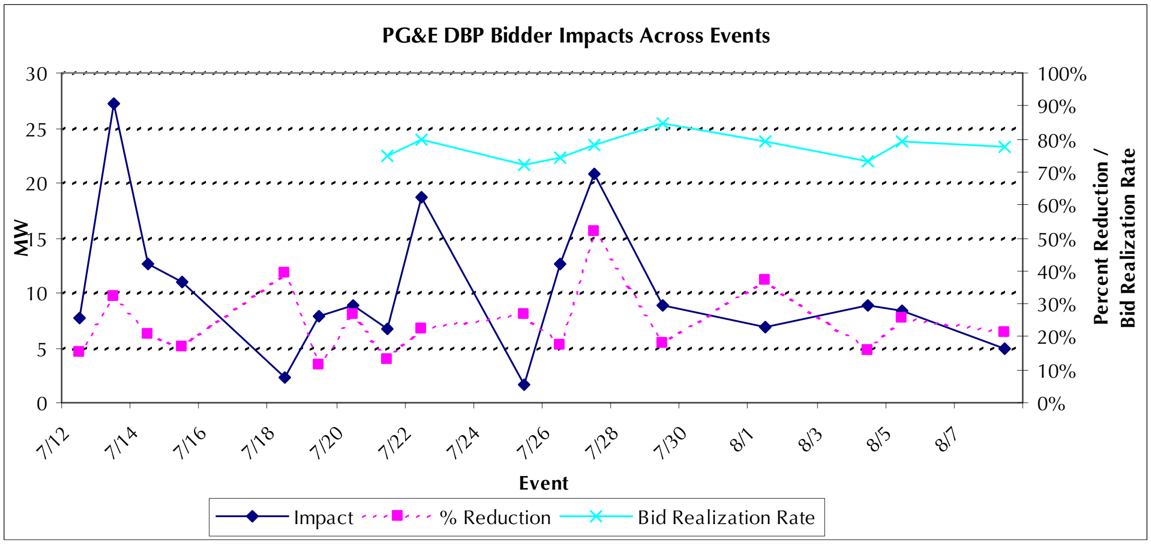


Exhibit 7-44
PG&E Average Hourly DBP Impacts versus Average Temperature
across DBP Participants (during Event Hours)

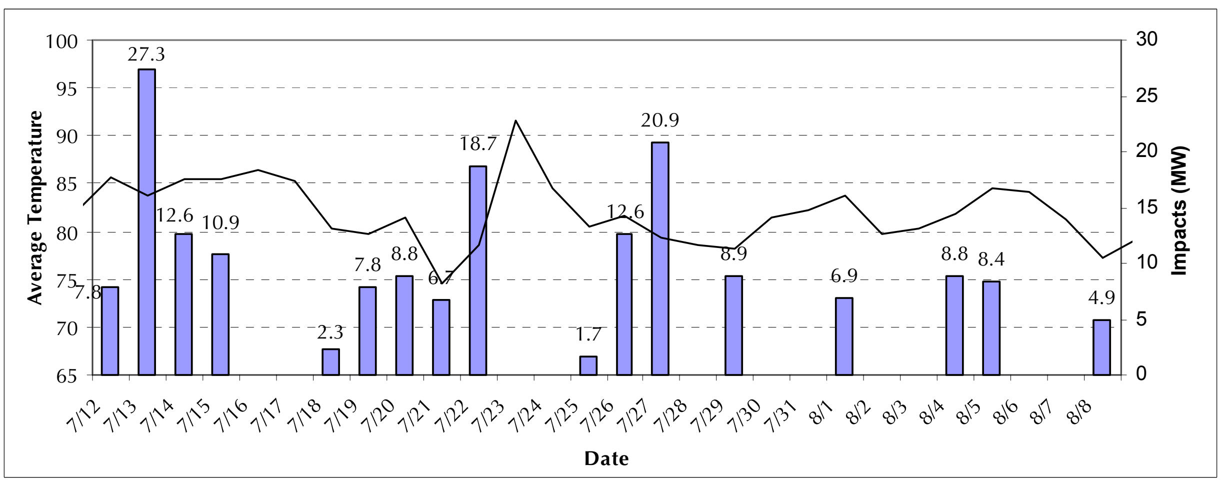
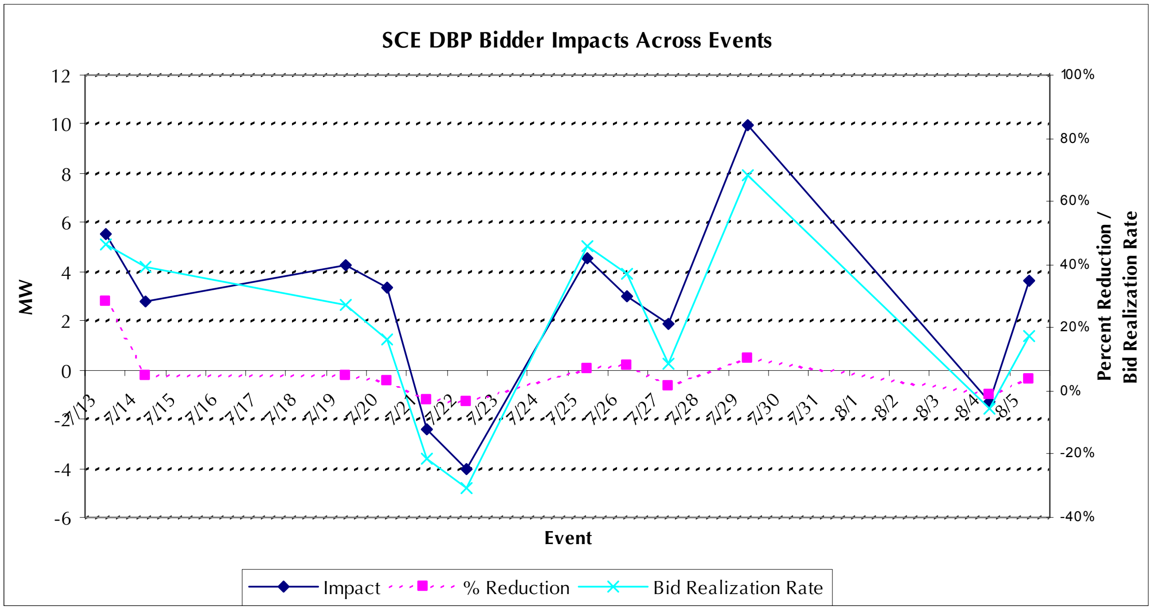


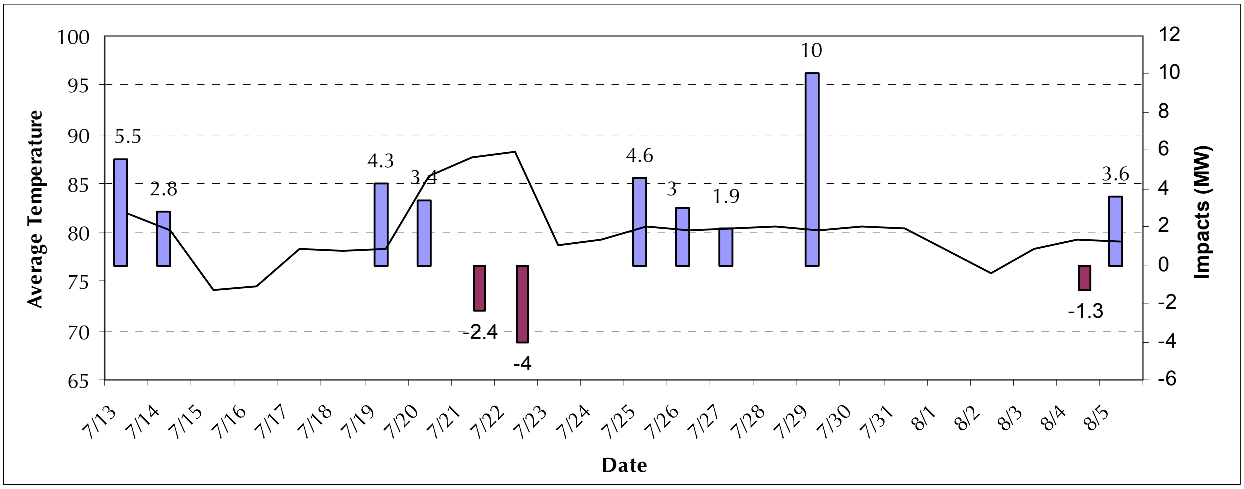
Exhibit 7-45 below shows that the DBP realization rate varied widely by event for SCE. The July 29th event for which there was 44 bidders achieved 68 percent of the submitted bids (the average hourly bid was 14.6MW); however the July 22nd, for which there were 27 bidders, achieved negative 31 percent of the 13MW bid. The percent load reduction achieved by the bidders across all DBP events ranged from a high of 28.4 percent to a low of negative 3.5 percent. The average load reduction across all events was 3.2 percent.

Exhibit 7-45
SCE DBP Average Hourly Program Impacts Across the 2005 Events (13 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced



Looking at Exhibit 7-46 one can see that the estimated impacts resulting from the consecutive events that occurred between July 19th and July 22nd decrease with each consecutive event. After looking closer at the baseline and actual load shape graphs for these event days (which are included in Appendix D3) it becomes obvious that all of the Representative Day methods seem to fail for this series of events. Over the course of these four days the average temperature amongst participants continued to rise, however because the events are consecutive, the baselines used for each event remained constant (the previous 10 "similar" days do not change for consecutive events). In addition, for this series of events the adjustment used for the 10-Day Adjusted baseline is based on the most recent similar day, which happens to be July 18th. The average temperature on this date was 10 degrees lower than the final two event days in the series.

Exhibit 7-46
SCE Average Hourly DBP Impacts versus Average Temperature across DBP Participants (during Event Hours)



Although Exhibit 7-47 below shows a high degree of inconsistency between the MW impacts delivered for the summer 2005 events, it is important to note the scale of the impacts. The ranges shown represent 1 MW fluctuations. The exhibit below also presents the bid realization rates for each of the DBP events, which ranged between 32 and negative 31 percent (the average across all events was 14 percent). The percent reduction in load across all of the events ranged from a high of 23 percent (which represented 0.7 MW) to a low of negative 9 percent for the July 21st event (representing a 0.1 MW increase in consumption). Exhibit 7-48 shows that this July 21st event occurred on one of the hottest days of the summer and was the 3rd event in a series of four consecutive events.

Exhibit 7-47
SDG&E DBP Average Hourly Program Impacts Across the 2005 Events (12 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced

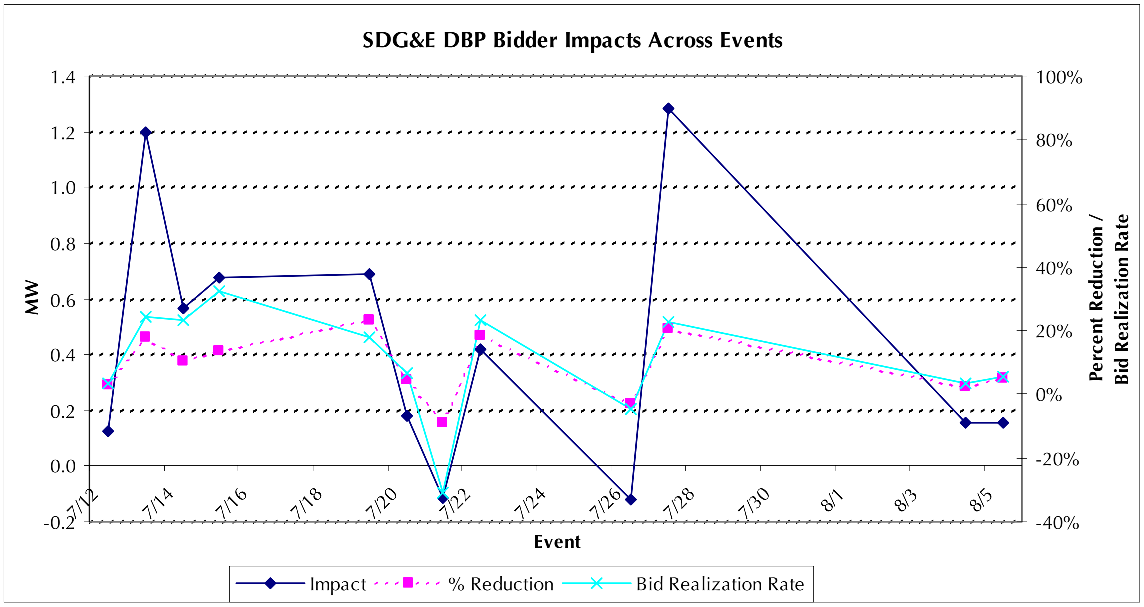
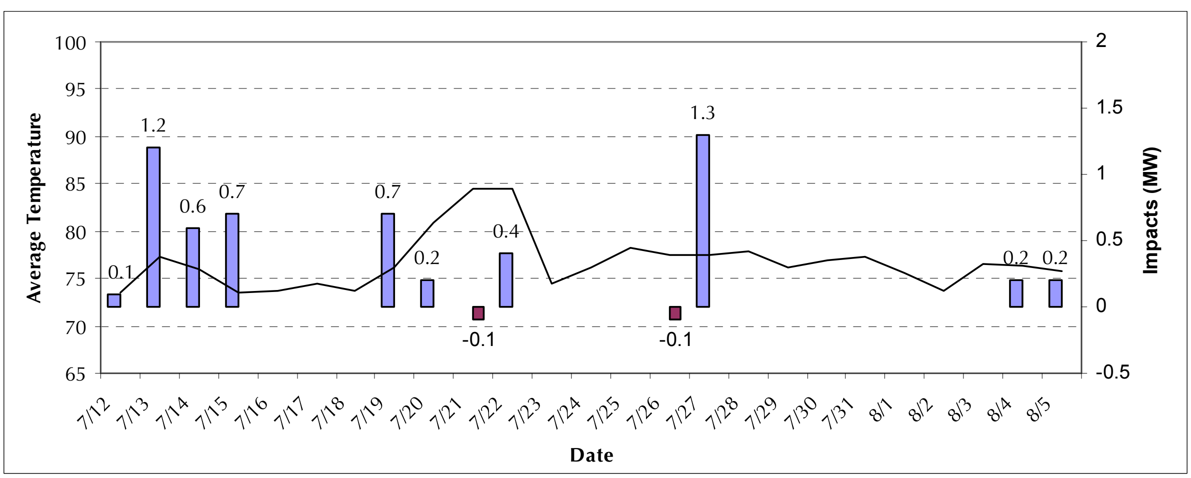


Exhibit 7-48
SDG&E Average Hourly DBP Impacts versus Average Temperature
across DBP Participants (during Event Hours)



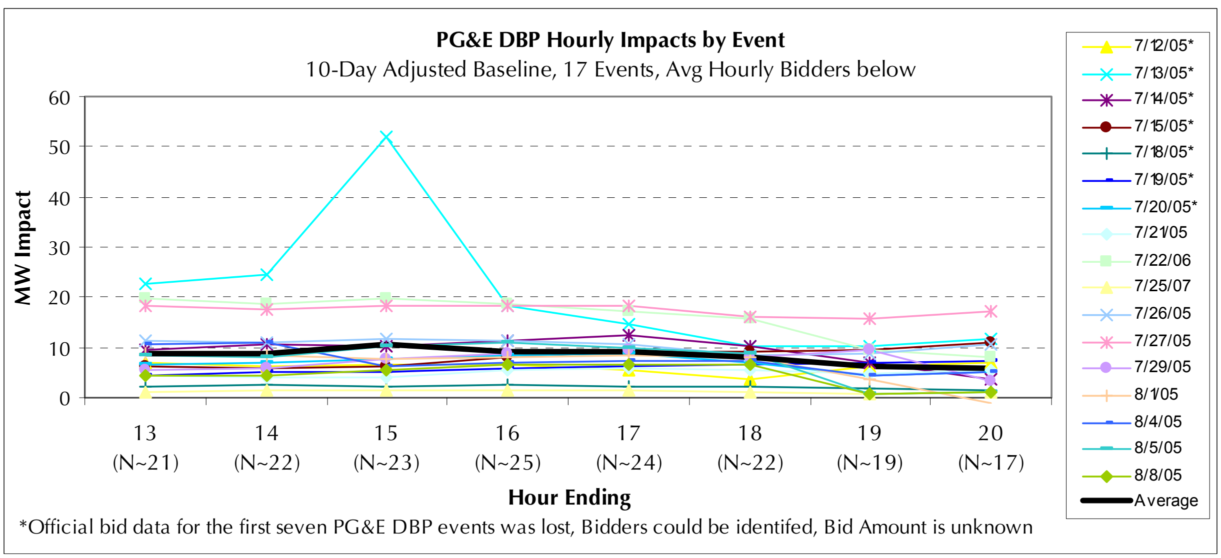
Complete Hourly Program Impacts for DBP

During the course of the impact evaluation we also looked at how the DBP program performed over the course of the event hours. Examining the overall hourly program impacts provides information on the time it takes customers to curtail their load at the start of an event, and whether or not they are able to maintain consistent load reductions over the entire event period.

Exhibits 7-49 though 7-51 present the hourly impacts for each of the DBP events occurring throughout the summer of 2005 based on the 10-Day Adjusted baseline, as well as the average hourly impact across all of the summer events. These exhibits illustrate that for PG&E and SDG&E the hourly impacts remain fairly steady across the event period (from noon until 8PM for PG&E and varied for SDG&E). For SCE, the DBP impacts tend to steadily decrease over the course of the eight event hours (noon until 8PM). A complete listing of the hour-by-hour MW impacts for each event across the three utilities can be found in Appendix D1.

The most striking characteristic of Exhibit 7-49 below is the huge spike in MW impact during the July 13th event for hour ending 15 (2-3PM). Because the bids were lost for this event due to a software issue, customers who placed bids[18] were paid based on their load reduction for any hour where their reduction exceeded 50 kW (the program minimum reduction for payment). This 30 MW is attributable to one customer whose daily load is consistently around 30 MW throughout the summer and who dropped their load to 0 MW for one hour during the July 13th event.

Exhibit 7-49
PG&E DBP Hourly Program Impacts for each of the 2005 Events (17 Events[19])
Based on the 10-Day Adjusted Baseline



The impact estimates for each of the SCE DBP events displayed in Exhibit 7-50 show slightly decreasing impacts across the series of event hours. The average impact across all events was close to 5 MW over the first three program hours and declined steadily to less than 1 MW for the last three event hours. This decline is correlated with the average number of DBP participants that bid in a particular hour. Hour ending 14 had on average the highest number

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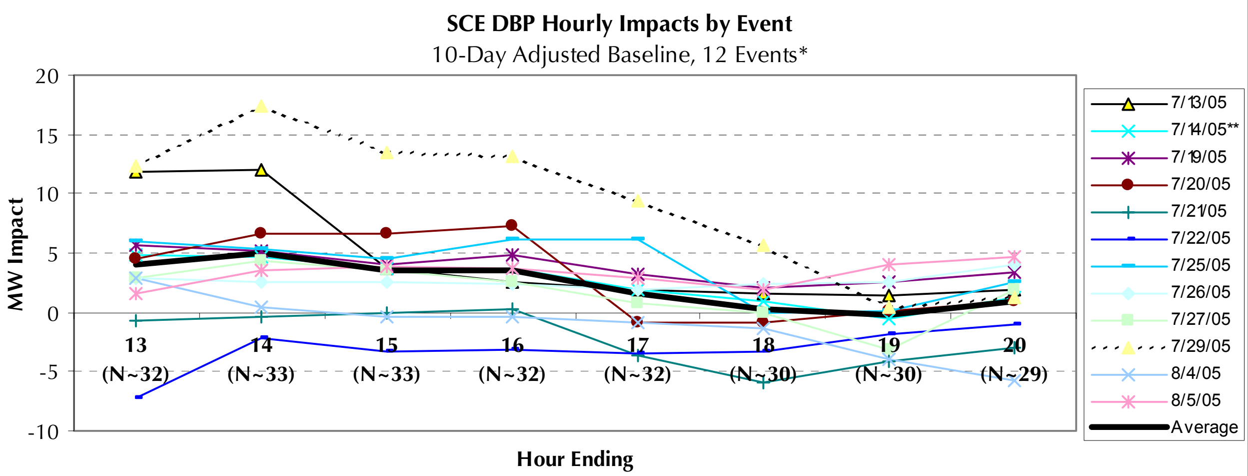
[18] Customers who placed bids could be identified, only the bid amount was lost.

[19] Actual bid data were lost for the first seven of PG&E's DBP events, however since PG&E was able to identify the participants who placed bids, just not the bid amount, there were included in the following exhibit.

of bidders per event (~33 bidders) and hour ending 20 had the fewest bidders (~29 bidders). One of the SCE DBP events (July 22nd) produced entirely negative impacts throughout the entire event and one outlying event on July 29th realized impacts greater than 10 MW for four of the eight event hours.

Exhibit 7-50
SCE DBP Hourly Program Impacts for Each of the 2005 Events (12 Events*)



*The first SCE DBP event (7/12) was excluded from the exhibit above since bid data was unavailable
** The third event (7/14) was included in the exhibit although it was officially cancelled due to software issues.

The impact estimates for each of the events displayed in Exhibit 7-51 show consistent impacts across all hours for each of the SDG&E DBP events. The average impact across all events was slightly less than a half a megawatt an hour. The highest hourly impact across the 2005 DBP events was around 1.2 MW and the lowest was slightly less than zero, indicating an increase in consumption for the DBP bidders during the event hours.

Exhibit 7-51
SDG&E DBP Hourly Program Impacts for Each of the 2005 Events (12 Events Total)

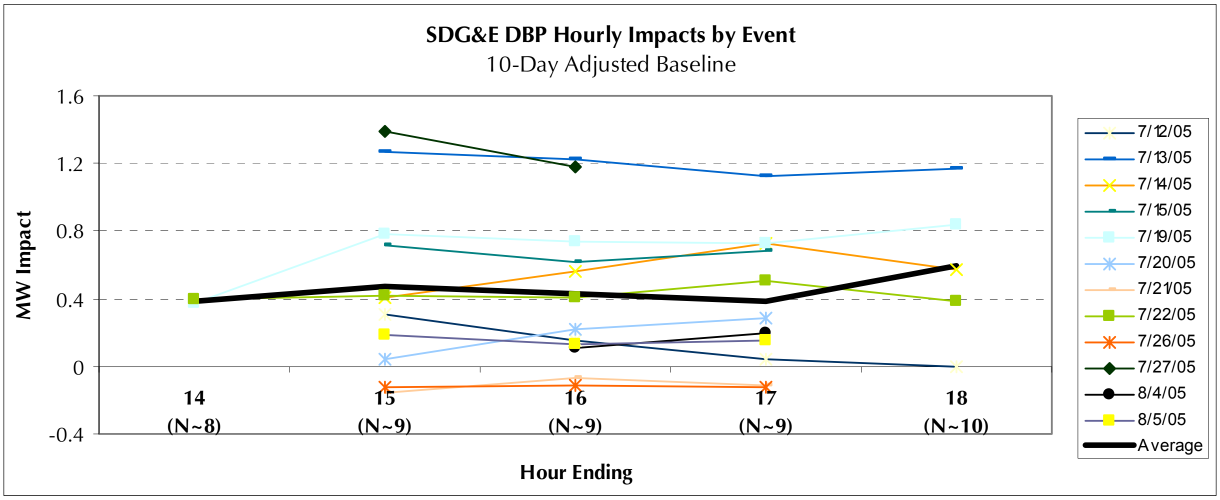


Exhibit 7-52 and 7-53 below present the average hourly program impacts, in terms of MW and percent reductions, by utility over all 2005 DBP event hours (273 hours in total across all three utilities). One finding from our analysis is that the estimated hourly impacts vary widely across events. Due to the high level of variation in estimated impacts that exist for each utility across the summer 2005 events, the exhibit below provides the mean and the impacts falling in the 25th and 75th percentiles ranges. The mean and percentile ranges correspond to the average impact over all event hours for DBP bidders. This produces slightly different results for PG&E and SCE than calculating the average impact over all bid hours, since on average PG&E and SCE bidders place bids for approximately 85 percent of the total event hours. This shows that 50 percent of the DBP summer event hours achieved load reduction impacts between 5 and 15 MW from the DBP bidding population, and the average impact over all event hours was approximately 11 MW. These MW impacts correspond to an average drop in load of 26 percent for PG&E, 5 percent for SCE, and 10 percent for SDG&E.

Exhibit 7-52
Average MW Impact Estimates Across All 2005 DBP Event Hours

Program Impact Ranges for DBP (MW)				
Utility	**Event Hours**	**Mean**	**75th Pct**	**25th Pct**
PG&E	136	8.4	10.3	5
SCE	96	2.3	4.3	-0.1
SDG&E	41	0.5	0.7	0.2
Statewide*	273	11.2	15.3	5.1

Exhibit 7-53
Average Percent Load Reductions Across All 2005 DBP Event Hours

Estimated Percent Load Reduction Across All DBP Events				
Utility	Total Event Hours	Average Percent Reduction	75th Pct Percent Reduction	25th Pct Percent Reduction
PG&E	136	26%	30%	15%
SCE	96	5%	8%	0%
SDG&E	41	10%	18%	6%
Statewide*	273	9%	12%	4%

* Non-Coincident Statewide Impacts

Distribution of Impacts Across Customer for DBP

For DBP, we also looked at the estimated program impacts for individual customers at each of the utilities. Exhibit 7-54 presents the percentage of DBP participants achieving various levels of percent load reduction for at least one event during the summer of 2005. The load reduction is calculated as the ratio of the estimated load drop divided by the estimated load based on the 10-Day Adjusted baseline. This exhibit shows that nearly 70 percent of DBP participants in SDG&E and SCE territory and over 90 percent of DBP participants in PG&E territory were able to able to attain a 5 percent load reduction for at least one event in 2005. About a third of the PG&E DBP Bidders and a quarter of the SCE and SDG&E Bidders were able to drop 50 percent of their load for at least one event.

Exhibit 7-54
Percent of DBP Participants Reaching Various Load Reduction Levels for at Least One Event in 2005

Load Reduction	Percent of DBP Bidders		
	PG&E	SDG&E	SCE
5%	94%	68%	70%
10%	81%	64%	59%
25%	53%	27%	43%
50%	36%	23%	27%

When analyzing load reduction on a MW basis we found that within PG&E service territory nearly 80 percent of DBP Bidders were able to reduce their load by more than 100 kW for at least one event. Within SCE and SDG&E service territories there were 45 percent and 27 percent of bidders, respectively, that were able to achieve this level of load reduction for at least one event.

Exhibit 7-55 below displays the levels of load reductions DBP bidding customers averaged over all events for which they placed a bid during the summer of 2005. The comparison of these two exhibits illustrates that a fairly high percentage of the PG&E bidders were able to maintain high levels of load reductions across all events for which they bid (the average DBP participant bid for 5.4 events[20]).

Exhibit 7-55
Percent of DBP Participants Reaching Various Load Reduction Levels on Average over All 2005 Events

Load Reduction	Percent of DBP Bidders		
	PG&E	SDG&E	SCE
5%	77%	45%	45%
10%	60%	41%	39%
25%	37%	18%	19%
50%	22%	5%	15%

The average load reduction for DBP participants over the entire summer of events ranged from a high of 22 percent for PG&E participants to a low of 3 percent for SCE. SDG&E participants had an average reduction of 10 percent across all events.

Exhibits 7-56 through 7-58 below present the distribution of DBP participants' average hourly impacts across all DBP events based on the 10-Day Adjusted baseline. These exhibits show the percentage of customers that make up various percentages of the *positive* impacts observed.

Exhibit 7-56 shows that on average over the 17 summer 2005 PG&E CPP events, 5 percent of participants contributed roughly half of the overall *positive* program impacts and 22 percent contributed nearly 80 percent of these impacts. One percent of DBP participants contributed negative impacts. Within PG&E territory, 78 percent of DBP participants who placed a bid were able to reduce their load by 100 kW or more on average for all of the 2005 events for which they placed a bid. Only 7 percent were not able to reduce by at least 5 kW on average over the events for which they bid.

[20] Additional information regarding DBP participants bidding habits and behaviors follows later in this section.

Exhibit 7-56
Distribution of Average PG&E DBP Participant Impact Contribution
Based on Average Hourly Impact per DBP Participant across All 17 Events

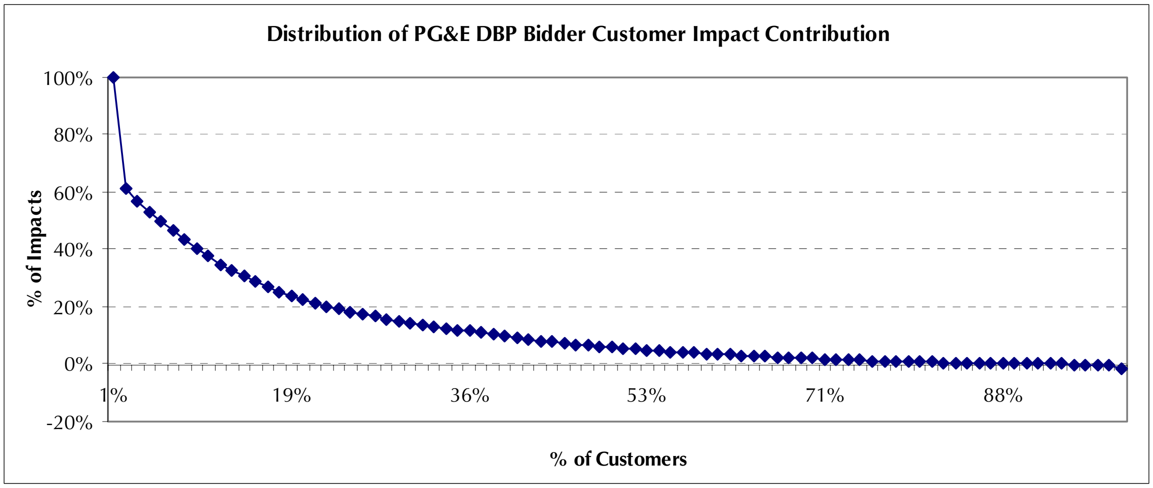


Exhibit 7-57 shows that for SCE, 5 percent of the DBP participant bidders contributed nearly 60 percent of the overall 2005 program impacts and 80 percent of the overall impacts are delivered by just 13 percent of the participants. Forty-five percent of SCE DBP Bidders were able to reduce their load by at least 100 kW on average over all events for which they bid.

Exhibit 7-57
Distribution of Average SCE DBP Participant Impact Contribution
Based on Average Hourly Impact per DBP Participant across All 13 Events

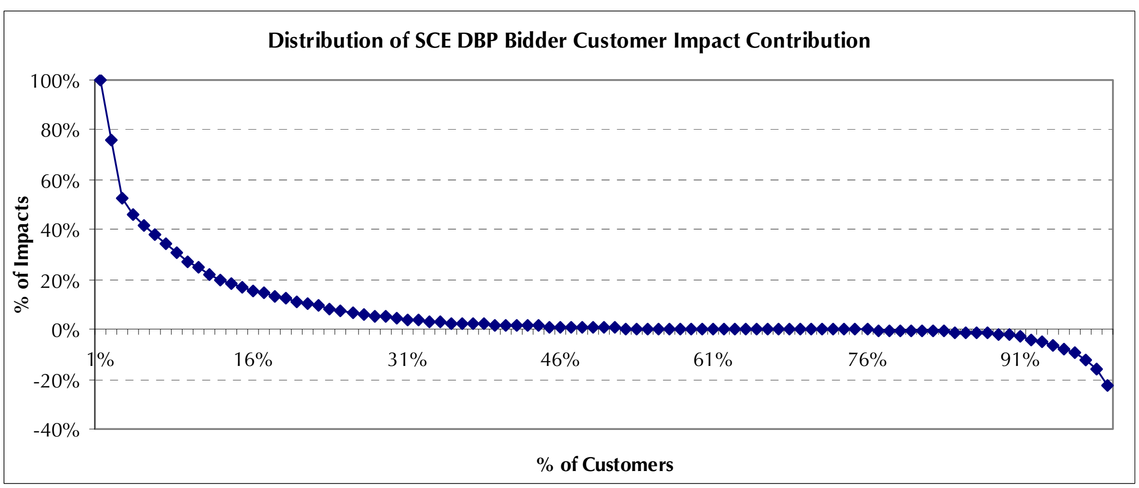
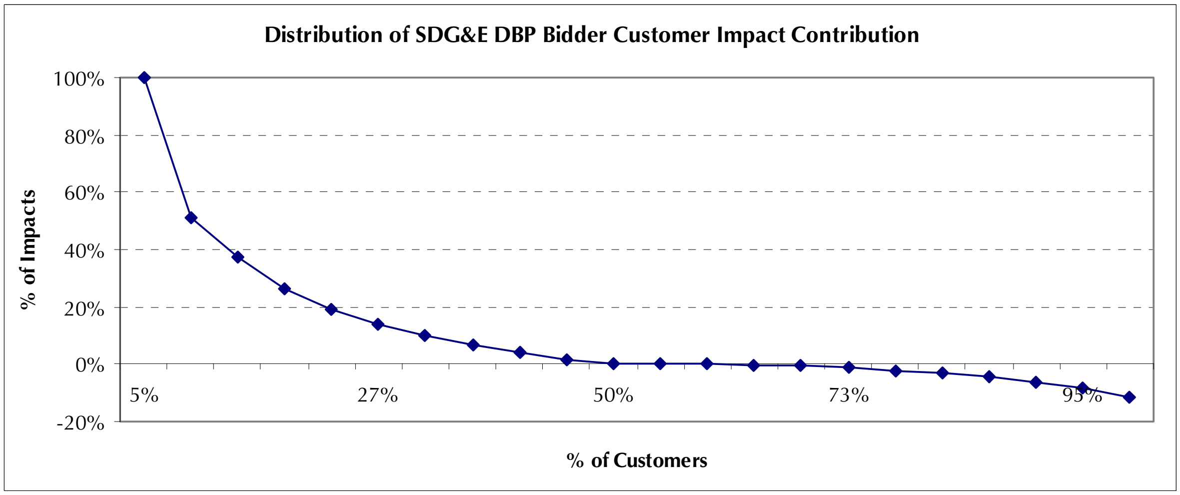


Exhibit 7-58 shows that similarly for SDG&E, 5 percent of the DBP participants contributed slightly less than 50 percent of the overall 2005 program impacts; while 80 percent of the overall DBP impacts were contributed by 23 percent of the participants. Within the SDG&E territory nearly half of the DBP participants contributed negative impacts (45 percent). Of the six customers who were able to attain a 100 kW load drop for at least one event, only one was unable to maintain it over all of the summer 2005 events for which they bid.

Exhibit 7-58
Distribution of Average SDG&E DBP Participant Impact Contribution
Based on Average Hourly Impact per DBP Participant across All 12 Events

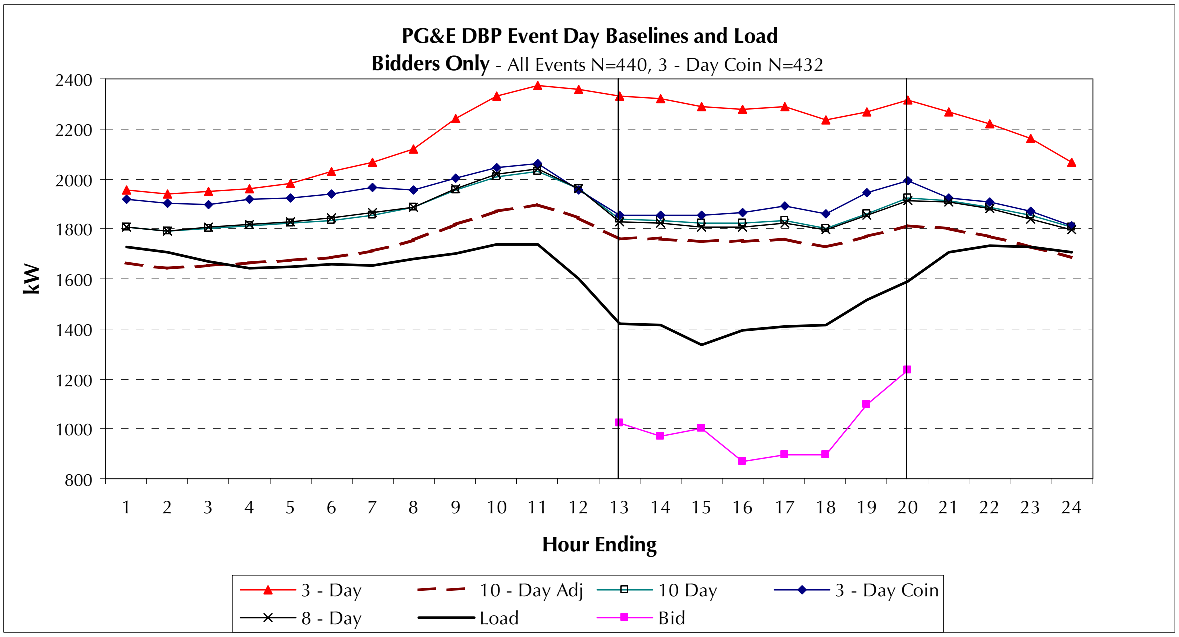


Analysis of Impact Estimates for High-Load High-Variance Customers for DBP

Analysis similar to what was described previously for CPP High-Load High-Variance (HLHV) customers was also completed for the DBP participant population to determine if there is there was an accurate way of identifying these customers and quantifying their effect on the overall program impact estimates. Exhibits 7-59 through 7-61 present both the average daily-predicted load shapes (using all 5 of the baselines evaluated) and the average actual load shape over the 2005 DBP events for each of the three utilities. The vertical bars in these exhibits indicate the DBP event start and finish times. All DBP events for PG&E and SCE were called from 12PM – 8PM, although customers could bid place bids for as few as two consecutive hours during this 8-hour period. For SDG&E, DBP events could have been called for any hours between noon and 8PM, however they were typically called for three to four hour blocks and they never were scheduled to start prior to 1PM or to end after 6PM. These exhibits illustrate how well the baselines predict the overall daily load shape of DBP participant bidders on event days.

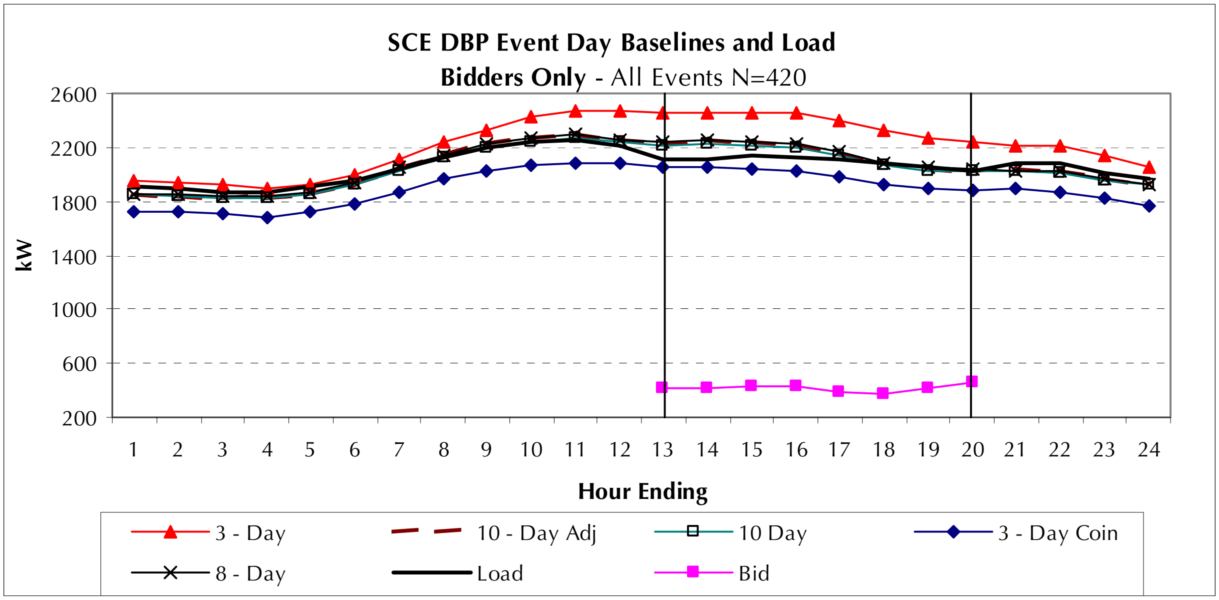
Exhibit 7-59 below shows that overall for PG&E DBP participants, the 10-Day Adjusted baseline is the best predictor of actual load in the hours leading up to the event start (12PM start = Hour Ending 13) and in the hours following the event. The 3-Day baseline significantly over-predicts the actual load during the entire pre-period (by as much as 800 kW in the hour preceding the event start). A moderate amount of spillover is apparent during the one to two hours before and after the event period. This will be addressed in an upcoming section. Similar graphs of the average daily load shape for each of the individual event days are included in Appendix D3. The average customer bid over all of the events is approximately 1MW an hour, which is roughly 70 percent of the average customers' 10-Day Adjusted baseline load during the event period. The pink "bid" line in the following exhibits represents the average bid amount over all participants who bid for a particular event hour. Unlike the daily load shapes, which are based on a constant number of participants over all 24 hours, the number of participants averaged for the "bid" line varies by the hour. This variation in the number of participants included in the hourly bid average causes some of the fluctuation in the average bid amount over the course of the event. The number of PG&E bidders on an hourly basis ranged from a high of 25 for hour ending 16 to a low of 17 for hour ending 20.

Exhibit 7-59
Daily Load Shapes for All 2005 PG&E DBP Event Days – Bidders Only
All Baselines versus Actual Load



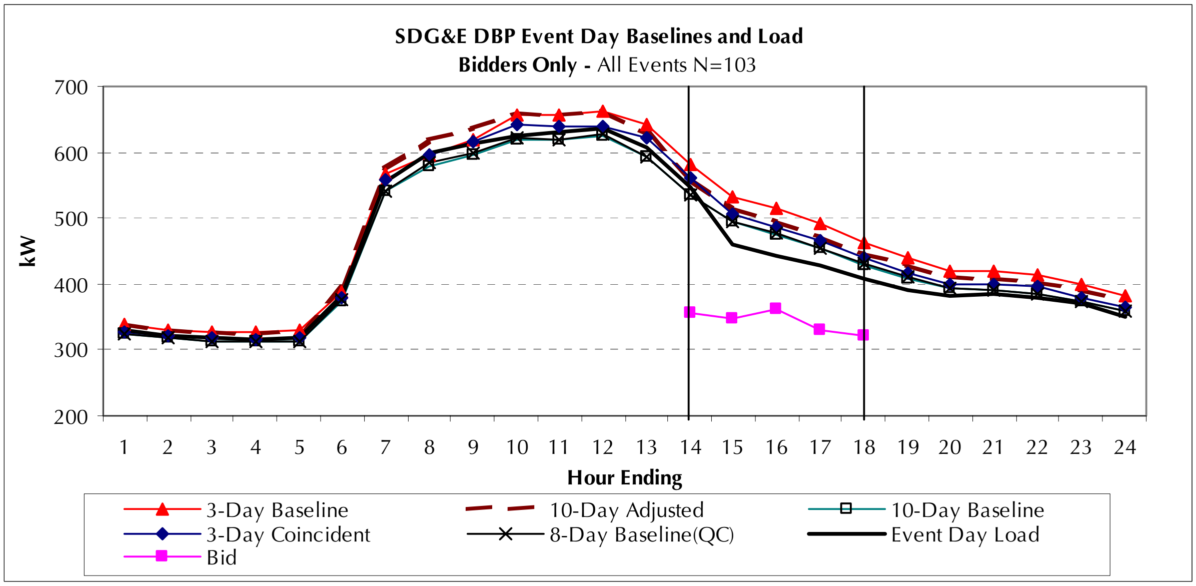
For SCE DBP participants, Exhibit 7-60 illustrates that on average the 10-Day Adjusted baseline accurately predicts the average load in the hours leading up to the event start (12PM start = Hour Ending 13). The 3-Day Coincident baseline consistently under-predicts the average actual load and the 3-Day baseline consistently over-predicts the average actual load. The exhibit below also shows that there is a slight increase in load following the 2-hours after the event possibly to make up for lost production during the event period. The average customer bid over all of the events is approximately 400 kW an hour, which is roughly 20 percent of the customers' 10-Day Adjusted baseline load during the event period. The number of bidders per hour for SCE ranged from a high of 33 for hours ending 14 and 15 to a low of 29 for hour ending 20.

Exhibit 7-60
Daily Load Shapes for All 2005 SCE DBP Event Days – Bidders Only
All Baselines versus Actual Load



For SDG&E DBP participants, Exhibit 7-61 shows that on average the 10-Day Adjusted baseline over-predicts the actual load in the early morning hours leading up to the event, but more accurately predicts the actual load for the hour immediately preceding the earliest event start (1PM start = Hour Ending 14). The average customer bid over all 12 of the events is approximately 350 kW an hour, which is roughly 75 percent of the customers' 10-Day Adjusted baseline load during the event period. The number of bidders per hour for SDG&E ranged from a high of 10 for hour ending 18 to a low of 8 for hour ending 14.

Exhibit 7-61
Daily Load Shapes for All 2005 SDG&E DBP Event Days – Bidders Only
All Baselines versus Actual Load



Identification Algorithms

The algorithms analyzed to determine if there was a systematic way of identifying HLHV DBP participant bidders for whom the 10-Day Adjusted baseline did not perform well were similar to those described above for the CPP participants. For the DBP population, we relied upon the algorithm that flagged participants whose difference between the estimated average hourly impact resulting from the 10-Day and 3-Day baselines exceeded a given threshold and did the best job of identifying the HLHV participants. The threshold based on the 10-Day baseline was altered to reflect the average load for all DBP participants within the same service territory. Exhibit 7-62 below shows the average 10-Day baseline load used in the algorithm for each utility as well the number of participants flagged as HLHV based on the algorithm. A sample of the customers identified as HLHV customers, as well as a sample of those not identified, was manually reviewed to verify the accuracy of the algorithms performance.

Exhibit 7-62
Specification Details and Population Identified by High-Load High-Variance Algorithm by Utility for DBP (as a percent of customer bid-events)

High-Variance High-Load Algorithm Specification	Utility					
	PG&E		SCE		SDG&E	
	Bidders	Non-Bidders	Bidders	Non-Bidders	Bidders	Non-Bidders
Mean Load 10-Day Baseline (kW)	884		802		498	
Variation Allowed in Avg Hrly Impacts	440		400		250	
High-Variance High-Load Customers Identified	16	20	9	21	0	0
% of DBP Participants Identified	18%	6%	10%	3%	0%	0%

Exhibit 7-63 provides an example of an HLHV customer whose load shape varies widely during the previous 10 "similar" days. On some days, this customer's usage remains fairly consistent over the whole day around 1.5 MW. On other days, it remains consistent but at levels closer to 3.5 MW. On the remaining days, it fluctuates between 1.5 and 3.5 MW. For this customer, the 10-Day Adjusted is about 1 MW lower than the 10-Day unadjusted which is a result of PriorDay10 (the most recent "similar" day – in this case August 3rd) which had a lower on average load during the 10-Day Adjusted calibration hours (noon - 3PM). This customer bid 2 MW per hour over the event period and it appears that its true program impact should be close to this hourly bid amount although the 10-Day Adjusted Representative Day approach calculates an impact that is half of that amount.

Exhibit 7-63
Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the August 4th DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

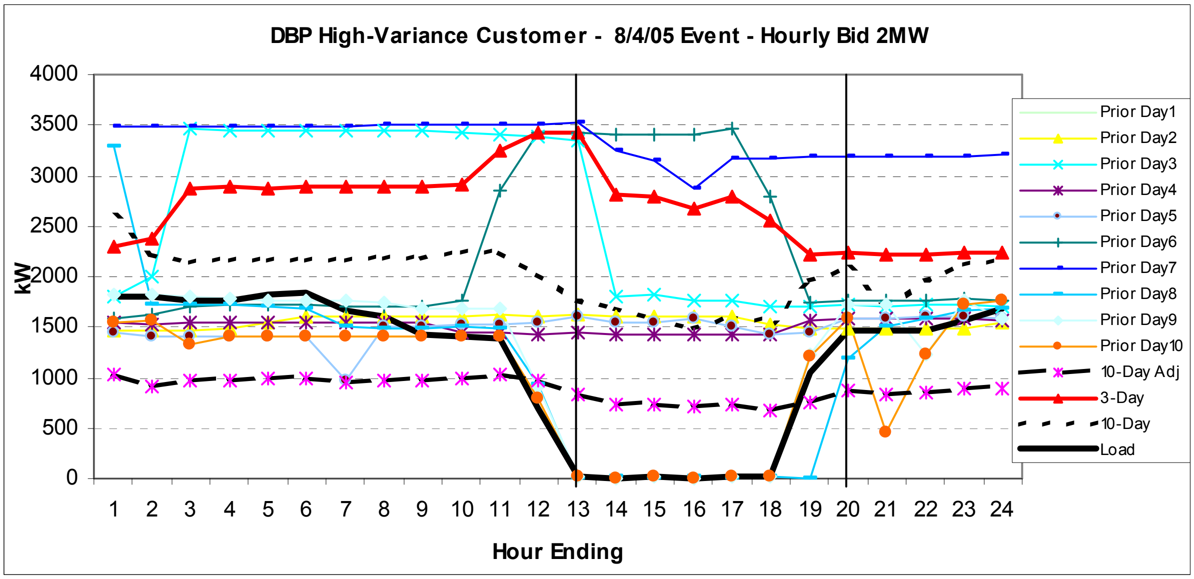


Exhibit 7-64 is another example of an HLHV customer. Again this customer's maximum daily demand regularly fluctuates by close to 15 MW during the preceding 10 "similar" days. The impact estimates for this customer range between an average of 3 MW per hour using the 10-Day Adjusted baseline, 8MW an hour using the 3-Day baseline, and 6 MW an hour using the 10-Day unadjusted baseline.

Exhibit 7-64
Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the August 4th DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

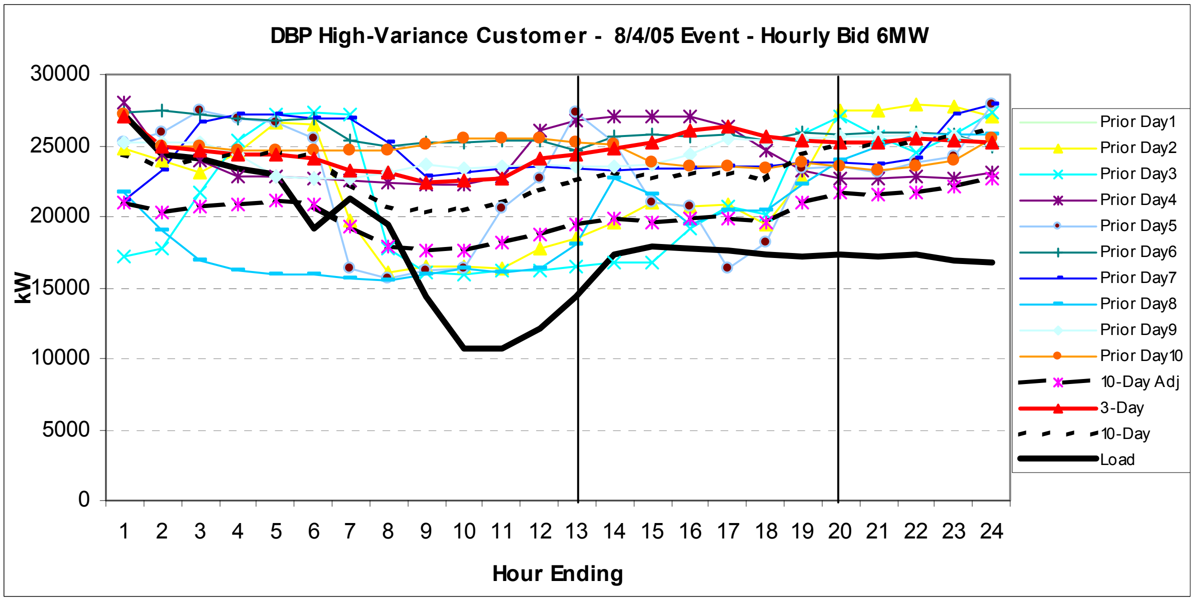


Exhibit 7-65 presents, for each utility, the percentage of DBP participant bidders and total DBP load attributed to HLHV customers for one or more events (this is different from Exhibit 7-62 which presents the percentage of customers flagged as HLHV on a bid-event level). This exhibit also presents the average percent savings during DBP event hours of these customers versus the non-HLHV customers, and the percent of all impacts over all events that these customers represent.

Exhibit 7-65
Effect of High-Load High-Variance DBP Customers on Average and Daily Program Impact Estimates

High-Load High-Variance (HLHV) DBP Customers Across All Events*	Utility		
	PG&E	**SDG&E**	**SCE**
Percentage of DBP Bidders Identified as HLHV	36%	0%	18%
% of Base Load HLHV Participants Represent	60%	-	64%
% of Total MW's Bid by HLHV Participants	82%	-	63%
Avg Percent Savings of HLHV Participants	26%	-	1%
Avg Percent Savings of Non HLHV Participants	17%	-	7%
Percent of Positive Impacts Over All Events	69%	-	19%

* HLHV customers in this exhibit are customers who were flagged as HLHV in one or more event in 2005

Exhibit 7-66 and 7-68 are similar to 7-59 and 7-60 except that they show the average daily-predicted and actual load shapes over the 2005 DBP events for HLHV DBP participants in

PG&E and SCE service territories. SDG&E DBP participants are not included in this section of analysis since none of the SDG&E DBP participants were identified as HLHV customers by the algorithm. Exhibit 7-67 and 7-69 are also similar but present the Non-HLHV DBP participants.

The exhibits below illustrate how much less stable the population of HLHV customers is compared to the remaining DBP participants. For both sets of participants the 10-Day Adjusted baseline appears to be the best predictor of the actual load during the non-event hours; however the variation between the predicted and actual load shape is a bit larger for the HLHV population. In all cases, the 3-Day baseline over-predicts the actual load.

Exhibit 7-66
PG&E DBP High-Variance High-Load Customers

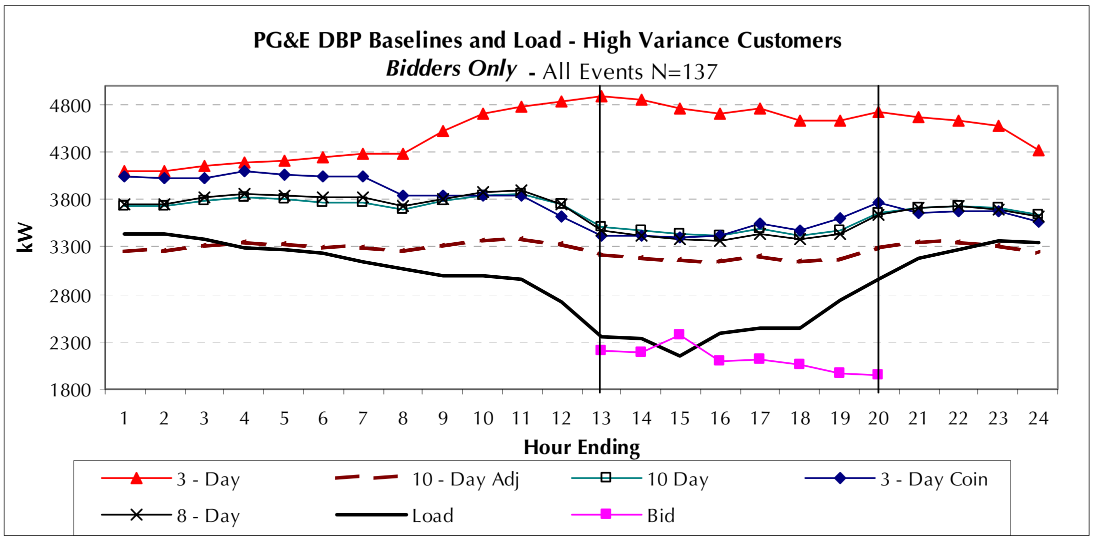


Exhibit 7-67
PG&E DBP Non High-Variance High-Load Customers

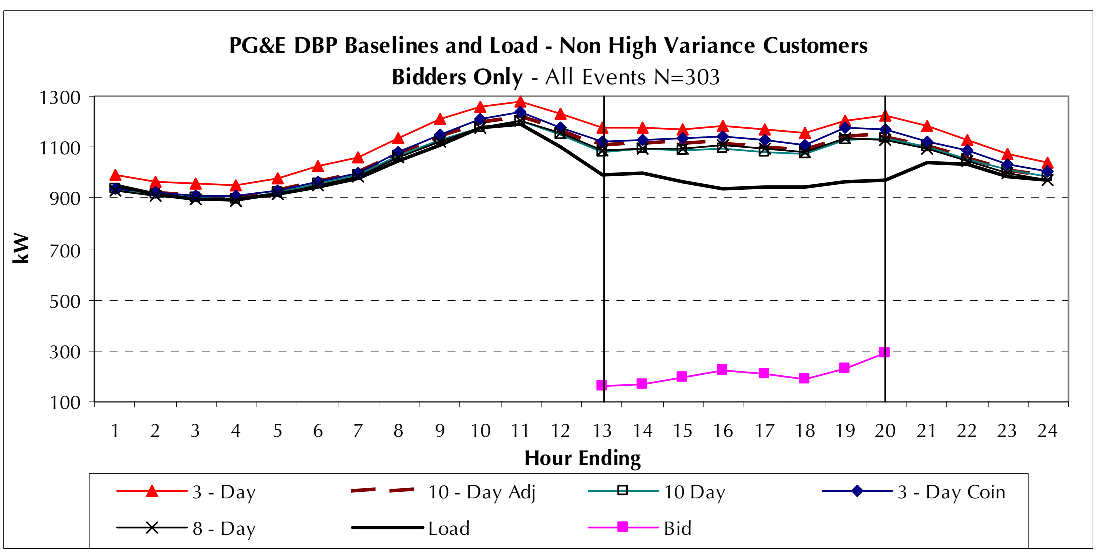


Exhibit 7-68
Daily Load Shapes for All 2005 SCE DBP Event Days – Bidders Only
High-Variance High-Load Customers
All Baselines versus Actual Load

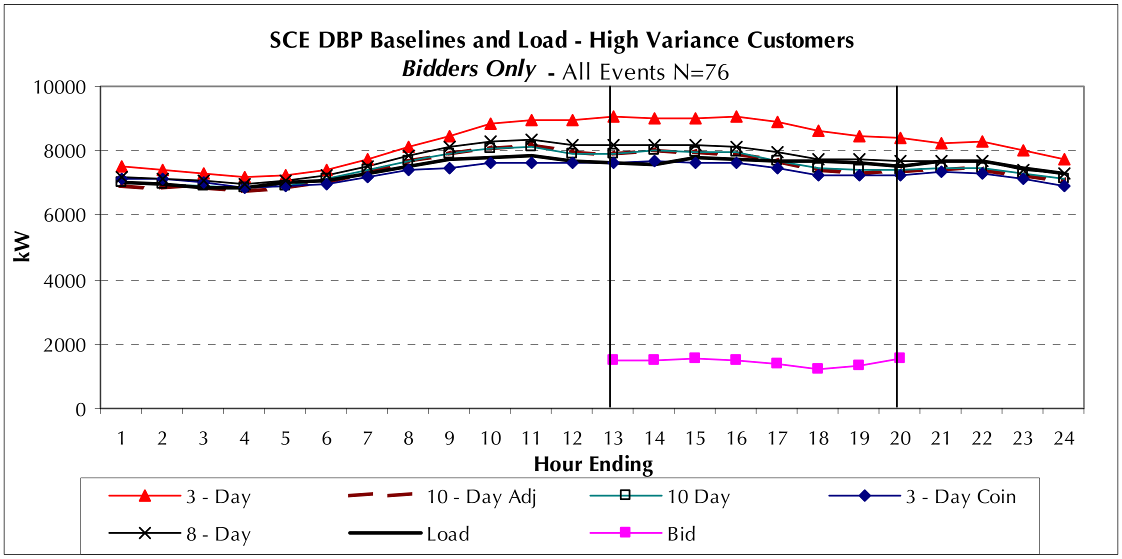
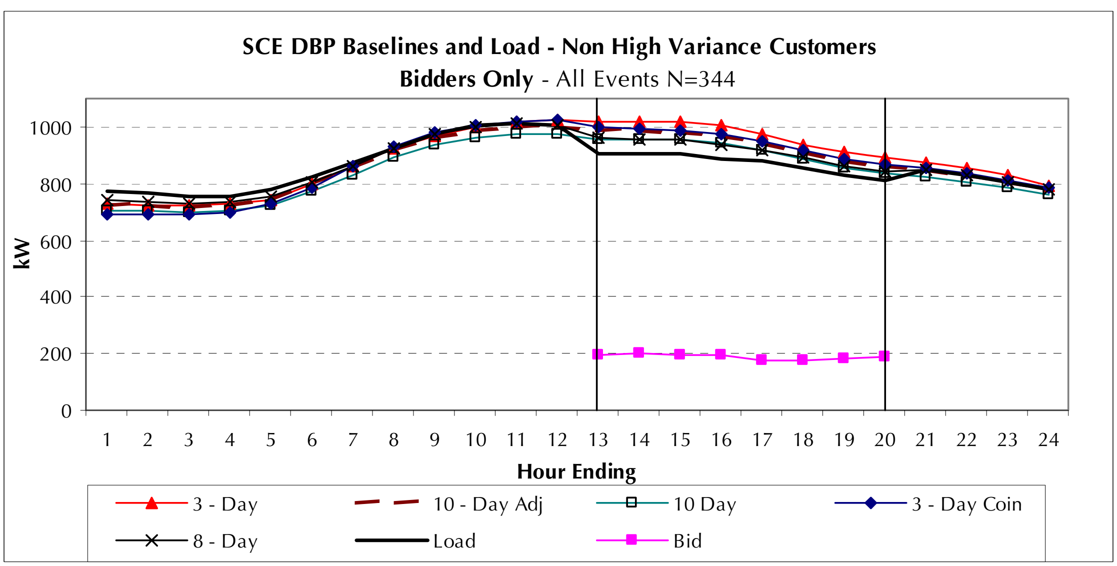


Exhibit 7-69
Daily Load Shapes for All 2005 SCE DBP Event Days – Bidders Only
Non High-Variance High-Load Customers
All Baselines versus Actual Load



Analysis of DBP Bidding Trends

Although DBP participation is relatively high, the number of DBP participants placing bids continued to be very low in 2005. Exhibit 7-70 provides a summary of some key DBP bidding statistics for 2005. This exhibit shows that in total 22 percent of PG&E, 37 percent of SDG&E and 14 percent of SCE DBP participants placed a bid for one or more of the 2005 events. The average bid amount for PG&E participants was more than twice that of SCE participants and approximately three times the size of the SDG&E participants' bids. The overall bid rate across all 2005 events was 7 percent for PG&E, 5 percent for SCE and 14 percent for SDG&E.

Exhibit 7-70
Summary of DBP Bid Statistics by Utilities

DBP Bid Analysis	Utility		
	PG&E	SCE	SDG&E
# DBP Events in 2005	17	13	12
Percent of DBP Participants who placed a bid in 2005	22%	14%	37%
Average Number of Bids Placed per Bidder	5.4	4.6	4.7
Average Bid Amount*	1,029	416	343
% of DBP Bidders who Bid for only 1 Event	20%	27%	32%
% of Events for which DBP Bidders placed Bids	32%	35%	39%
Overall Summer 2005 Bid Rate (Bids/Bid Opportunities)	7%	5%	14%

* For PG&E Average Bid Amount was over last 10 events where true bids were captured.

Exhibit 7-71 below presents the estimated hourly base load for DBP bidders based on the 10-Day Adjusted baseline, along with the average hourly bid across all bid hours. As this exhibit shows, SCE had the highest average estimated base load, nearly 50 percent larger than PG&E and 5 times larger than SDG&E. Despite this, the average hourly bid placed by SCE bidders was close to that of SDG&E bidders and approximately half the size of PG&E bidders. The average bid for PG&E DBP bidders was 128 percent of their estimated base load (using the 10-Day Adjusted baseline), which indicates that a large percentage of PG&E DBP bidders placed bids that were greater than their estimated base load[21]. For SDG&E bidders, the average bid was 96 percent of their estimated base load, and for SCE bidders it was 67 percent.

[21] A customer's estimated base load is calculated using one of the baseline methodologies and is an estimate of what their load would be in the absence of the program.

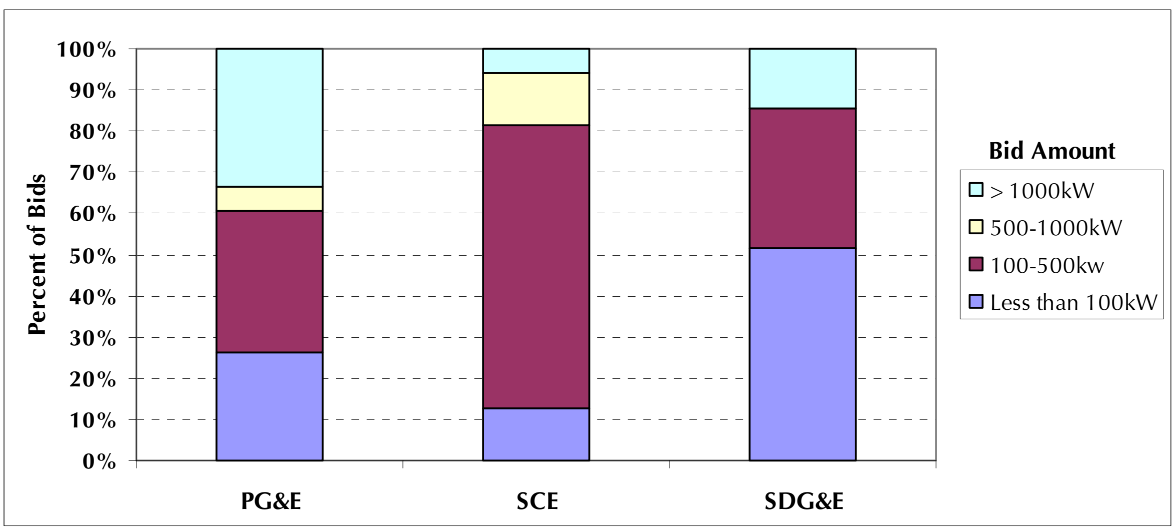
Exhibit 7-71
Analysis of Bids Placed for Summer 2005 Events by Utility

DBP Bid Amount Analysis over all Bid Hours	Utility		
	PG&E*	SCE	SDG&E
Average Estimated Base Load (10-Day Adjusted)	1,561	2,289	460
Average Bid Amount	1,029	416	343
Average Percent of Load Bid Overall	66%	18%	75%
Average Percent of Load Bid per Bidder	128%	67%	96%
% of Parts bidding more than Estimated Base Load (10-Day Adj)	36%	21%	47%
% of Parts bidding more than Estimated Base Load (3-Day)	7%	10%	30%

* For PG&E Analysis based on last 10 events where true bids were captured

Between the summer of 2004 and the summer of 2005 a change was made to the DBP program that lowered the minimum bid amount, previously 100 kW for all three utilities, to 50 kW for PG&E and SCE, and to 10 percent of the maximum demand for SDG&E. Exhibit 7-72 below provides the distribution of DBP hourly bid amounts for each of the three utilities across the entire summer. This exhibit shows a large percentage of the bids placed in PG&E and SDG&E service territories, 26 percent and 51 percent respectively, were for amounts less than 100 kW. PG&E had the largest percentage of DBP participants placing bids that were greater than 1 MW.

Exhibit 7-72
Distribution of Hourly Bid Amount Across Entire Summer by Utility



To determine the incremental program impacts resulting from this decrease in the minimum bid amount, an analysis was performed to determine how much of the bids and impacts came from the population of participants who bid less than 100kW an hour. Exhibit 7-73 below breaks down the total MWh bid across the entire summer, as well as the total estimated MWh impacts for program year 2005, for participants bidding less than 100kW versus those bidding 100kW or more. Again, the results presented below are based on the 10-Day Adjusted baseline.

As this exhibit shows, the percent of 2005 DBP MWh impacts contributed by participants bidding less than 100 kW an hour was 8 percent for PG&E, 3 percent for SCE and negative 4 percent for SDG&E. The negative estimated impact for the SDG&E less than 100kW bid population indicates that although this segment placed more than 50 percent of the total bids (186 bids out of 362 total bids placed) and the sum of these bids was nearly 10 percent of the total MWh bid, on average these participants did not contribute any savings to the program.

Exhibit 7-73
Distribution of Bids and Impacts With Respect to New Bid Minimum

DBP Bid Amount Analysis	Utility					
	PG&E*		SCE		SDG&E	
	Bid <100	Bid >=100	Bid <100	Bid >=100	Bid <100	Bid >=100
Sum of Bid Amount (MWh)	28	1,873	19	1,233	11	113
Percent of Bid Amount (MWh)	1%	99%	2%	98%	9%	91%
Sum of Estimated Impacts (MWh)	52	612	7	218	-1	19
Percent of Estimated Impacts	8%	92%	3%	97%	-4%	104%

* For PG&E, Analysis based on last 10 DBP events for which actual bids were captured.

A second change to the DBP program that was made for 2005 was to allow Direct Access (DA) customers to participate in this program. Chapter 4 presents results of an analysis regarding the percentage of DBP signups that were DA customers occurring after this program change took effect. SDG&E had no DA customers enrolled in the DBP program this past summer. Exhibit 7-74 below presents selected Direct Access analysis statistics including the percentage of DBP participants that are DA customers, the percentage of bids placed in 2005 by these customers, and the associated estimated load, bid, and impact results from the DA and Non-DA populations. This exhibit also shows that although DA customers in PG&E and SCE service territories have average loads that are five times larger than non-DA customers, their average bid, and load reduction, as a percent of their average load, are a fraction of what the non-DA customers' nominate and deliver.

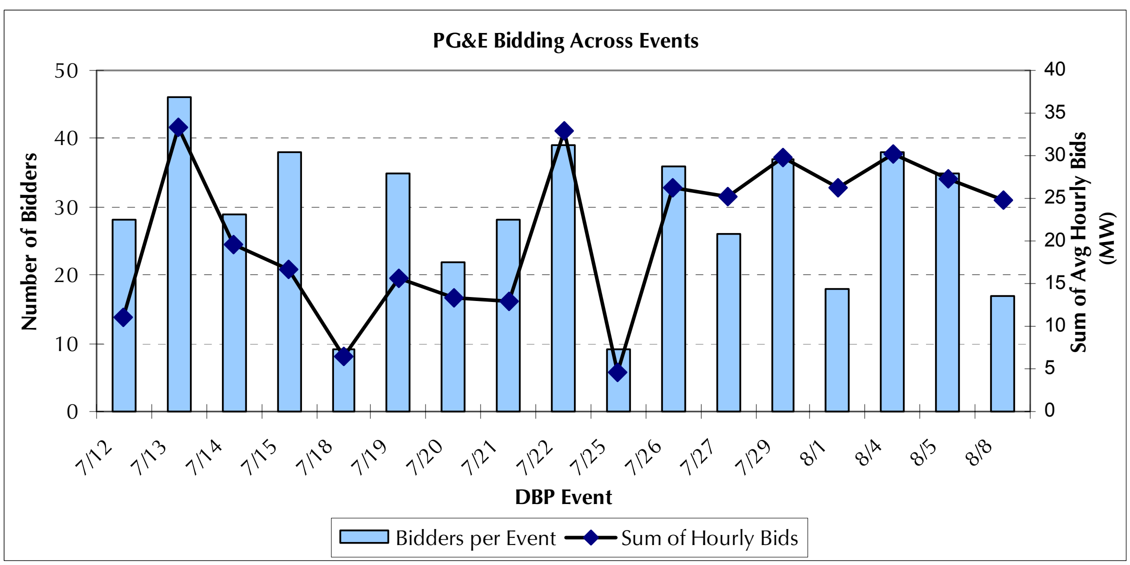
Exhibit 7-74
DBP Direct Access Bidding and Performance Results by Utility

DBP Direct Access (DA) Analysis (10-Day Adjusted Baseline)	Utility					
	PG&E*		SCE		SDG&E	
	DA	Non-DA	DA	Non-DA	DA	Non-DA
Distribution of DBP Participants	24%	76%	4%	96%	0%	100%
Distribution of DBP Bids (Hourly Level)	6%	94%	17%	83%	0%	100%
Average DBP Hourly Estimated Load (kW)	5,845	1,271	6,760	1,373	-	460
Average DBP Hourly Bid (kW)	1,001	1,030	253	449	-	343
Average Percent of Load Bid	17%	81%	4%	33%	-	75%
Average Hourly Impact (kW)	310	363	-8	92	-	51
Average Percent Load Reduction	5%	29%	0%	7%	-	11%

* For PG&E, Analysis based on last 10 DBP events for which actual bids were captured.

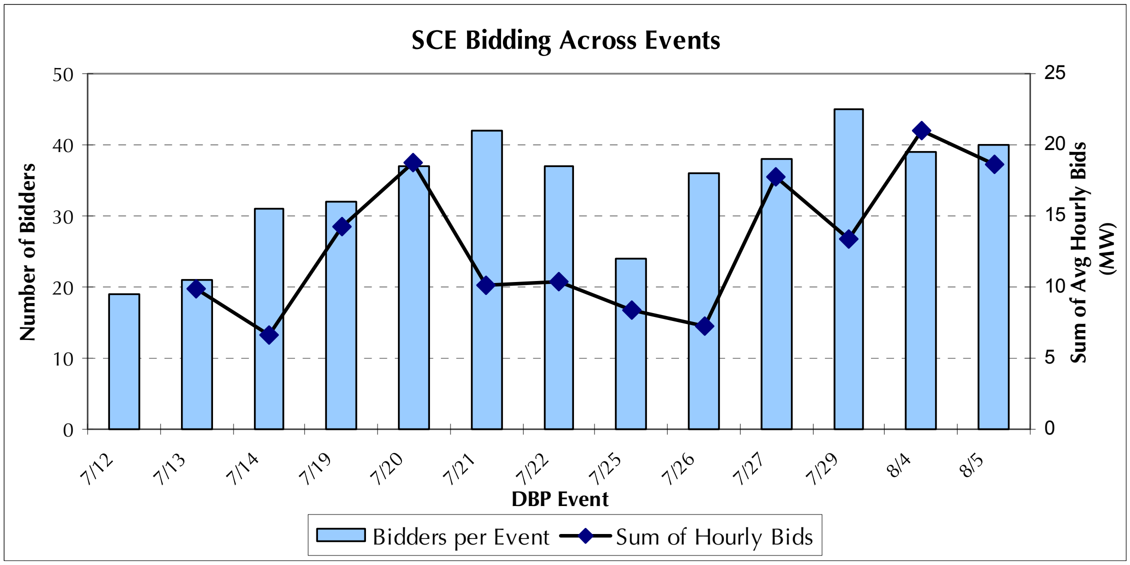
Exhibits 7-75 through 7-77 below show the variation in the number of bidders and the sum of the average hourly bids placed across the 2005 events at each of the utilities. One item apparent in the PG&E exhibit is how many fewer participants placed bids for the four Monday events (July 18th and 25th and August 1st and 8th) than for events falling on other days of the week.

Exhibit 7-75
Number of Bidders and Sum of Average Hourly Bids Placed per Event
for PG&E 2005 DBP Events (17 Events)



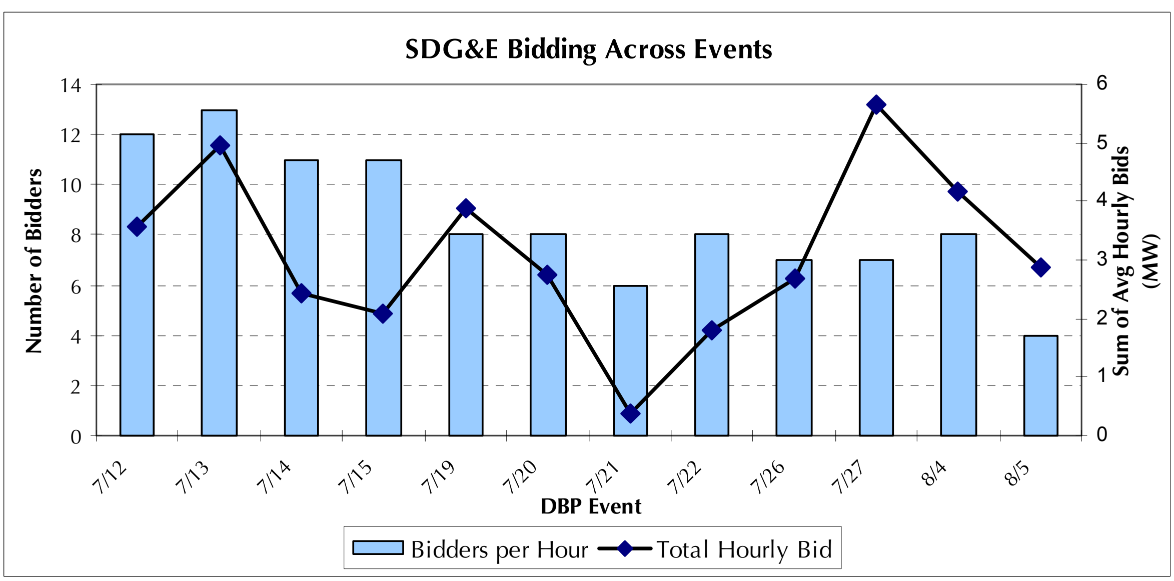
For SCE the number of bidders and the sum of the average bids seemed to have a slightly upward trend as the summer progressed. However, referring back to Exhibit 7-45, the impacts did not follow this same trend and showed much more impact fluctuation from event to event.

Exhibit 7-76
Number of Bidders and Sum of Average Hourly Bids Placed per Event for SCE 2005 DBP Events (13 Events)



The number of bidders in SDG&E territory had a downward trend over the course of the summer. Despite this, the total sum of the average bid amount across all participants fluctuated up and down throughout the summer. The July 27th DBP event received the highest average hourly bid (5.7 MW) from a total of 7 bidders and the July 21st event received the lowest average hourly bid (0.4 MW) from a total of 6 bidders.

Exhibit 7-77
Number of Bidders and Sum of Average Hourly Bids Placed per Event for SDG&E 2005 DBP Events (12 Events)



Analysis of Overlap Between DBP and Traditional Interruptible Participants

Customers who are enrolled in a Traditional Interruptible program (I-6 for SCE, Non-Firm for PG&E, or AL-TOU-CP for SDG&E customers) as their primary rate schedule may also participate in the DBP program so long as events are not called on the same day (in which case the Interruptible Program participation takes precedence). Exhibit 7-78 below illustrates that nearly 20 percent of SCE DBP participants are also enrolled in the I-6 program and that these customers delivered more than half of the DBP program impacts over the course of the 2005 summer events. In PG&E territory, 7 percent of the DBP participants are also enrolled a Non-Firm tariff and these customers delivered nearly 60 percent of the DBP program impacts. In SDG&E territory, the overlap is much smaller with only 3 percent of the DBP participants being signed up for AL-TOU-CP rate. This fraction of DBP participants only delivered 7 percent of the 2005 DBP program impacts overall. The bids placed by these participants were between 3.5 and 8.5 times larger across the three utilities than the bids coming from the non-interruptible participants. This exhibit also presents the percentage of DBP Bidders who are also Interruptible participants, as well as the percentage of estimated load and bids from the overlapping population.

Exhibit 7-78
Overlap Analysis of Customers who are Enrolled in Both DBP and the Traditional Interruptible Program (I-6, Non-Firm, AL-TOU-CP) at their Respective Utility

DBP and Traditional Interruptible Participant Overlap Analysis	Utility			Statewide Average
	PG&E	SDG&E	SCE	
% of **DBP Participants** who are also Trad Inter Parts	7%	3%	19%	14%
% of **DBP Bidders** who are also Trad Inter Parts	26%	7%	19%	21%
Average Bid Amt for Trad Inter Parts	2119	1651	1241	1419
Average Bid Amt for **Non** Trad Inter Parts	587	238	147	318
% of **Estimated Load** from DBP Bidders who are also Trad Inter Parts	39%	11%	32%	34%
% of **Bids** from DBP Bidders who are also Trad Inter Parts	56%	36%	67%	59%
% of **Impacts** from DBP Bidders who are also Trad Inter Parts	58%	7%	54%	56%

Impact Spillover Within and Beyond Program Event Hours for DBP

As described previously for CPP, spillover impacts consist of the impacts occurring in the hours before or after an event is called and can result in positive or negative impacts depending on the type of actions participants take during these pre- and post-event hours. One difference between the spillover that occurs within the CPP program versus the DBP program, is that for the DBP program the spillover can also occur within the hours for which their utility called the event. This is referred to as "In-Event" spillover and could arguably be more valuable than the pre- and post-event spillover since it occurs during the program hours. In-event spillover occurs as a result of the flexibility within the DBP program that allows customers to bid for a subset of the total event hours, as long as they bid for at least two consecutive hours.

Looking back to the daily load shape graphs presented in Exhibits 7-60 through 7-62, one can see a substantial amount of positive spillover occurring prior to the DBP event start; however the post-event spillover results are mixed depending on the utility. Exhibit 7-79 below provides the average hourly impact for each of the utilities and the percent of this average hourly impact that is achieved both during the actual event hours (in-event spillover) and in each of the two hours pre-event and post-event. The impacts presented in this exhibit are based on the 10-Day Adjusted baseline. The in-event spillover is calculated for each utility by summing the program impacts that occurred during the entire event period, regardless of the hours for which individual customers bid, and then subtracting off the program impacts occurring during the bid hours only. As the exhibit below shows, the in-event spillover ranges from adding an additional 11 percent to the reported program impacts (SDG&E) to reducing the reported program impacts by 9 percent (SCE). In the pre-event period there seemed to be a net positive impact that occurred at each of the utilities, however in the post-event period the spillover was minimally positive for PG&E, substantially negative for SCE, and substantially positive for SDG&E.

Exhibit 7-79
DBP Spillover Impacts as a Percent of Average Hourly Impact
Based on the 10-Day Adjusted Baseline

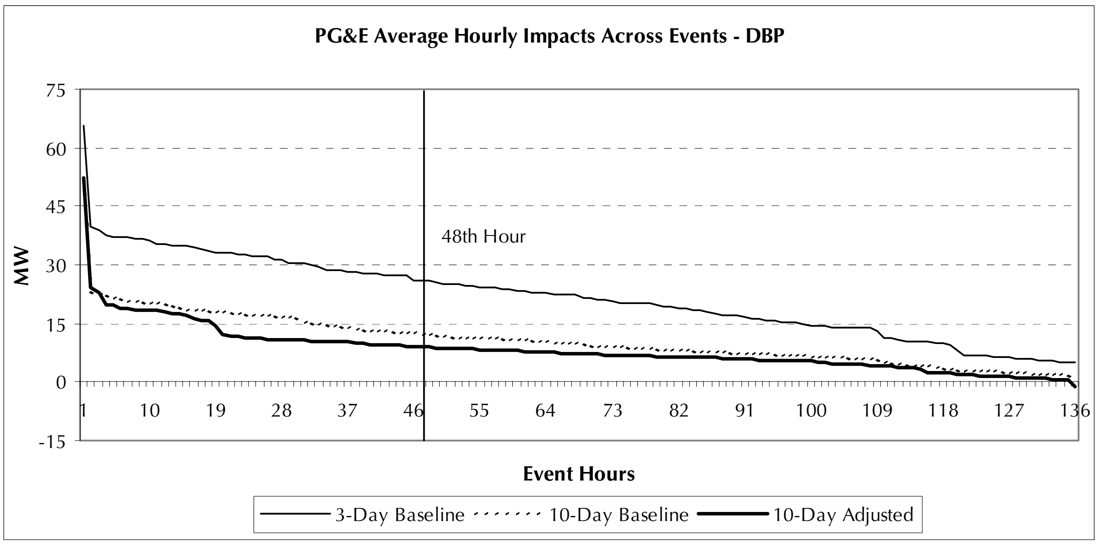
DBP Average Hourly Impact				
Average Hrly Impact (MW)		**PG&E**	**SCE**	**SDG&E**
		8.6	2.1	0.3
DBP Spillover as a Percent of Average Impact				
Period		**PG&E**	**SCE**	**SDG&E**
In-Event	-	3.8%	-9.5%	11.2%
Pre-Event	2-hr pre	33%	82%	70%
	1-hr pre	66%	74%	51%
Post-Event	1-hr post	21%	-77%	88%
	2-hr post	2%	-88%	68%

The average net daily change in consumption (MWh) was also evaluated for a DBP event day. This analysis showed that across all PG&E DBP participants the total daily consumption went down by an average of 71 MWh across the entire event day. Of this 71 MWh reduction, 69 MWh occurred during the 8 event hours, which indicates that DBP participants who placed bids operated on a normal level throughout the non-event hours. For SCE, the total daily consumption went down by 7 MWh on an event day. The impact during the event hours was 17 MWh, which indicates they made up about 10 MWh of the reduced consumption in the non-event hours. Within SDG&E service territory, the total daily consumption went down by an average of 5 MWh on an event day. The impact in the event hours alone was roughly half of that amount. The average hourly impact estimates across all event day hours for each of the utilities is provided in Appendix D4.

Impacts over 48 Hours

As mentioned previously in Section 7.1.1, draft resource adequacy requirements were proposed that would base the level of a resource, such as DBP program impacts, on the minimum amount this particular resource has been shown to deliver for at least 48 hours during the course of the summer[22]. Although this proposal was not adopted[23], Exhibits 7-80 through 7-82 present the qualifying amount of resource available from DBP if the proposed draft resource adequacy requirement had taken effect. These exhibits show the distribution of the DBP hourly impacts delivered for each of the utilities over all DBP event hours during the summer of 2005 based on the 10-Day Adjusted Baseline. These exhibits indicate the available resource for PG&E DBP would be around 10 MW, for SCE it would be approximately 2.5 MW, and again for SDG&E it would be undetermined since they only had 41 DBP program hours over the course of the 2005 summer events and thus the 48-hour minimum level could not be determined.

Exhibit 7-80
Distribution of Hourly Impacts for PG&E DBP Participants across All 2005 Events (17 Events, 8 Hours per Event, 136 Event Hours)



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22 In Decision 04-10-035 the CEC proposed "DR resources should be available at least 48 hours each summer season to count as a qualifying capacity".

23 Decision 05-10-042 stated "discussion should take place in future RAR proceedings before additional restrictions on DR are adopted." *Opinion on Resource Adequacy Requirements*, Decision of ALJ Cooke, Decision 05-10-042, October 27, 2005

Exhibit 7-81
Distribution of Hourly Impacts for SCE DBP Participants across All 2005 Events (13 Events, 8 Hours per Event, 104 Event Hours)

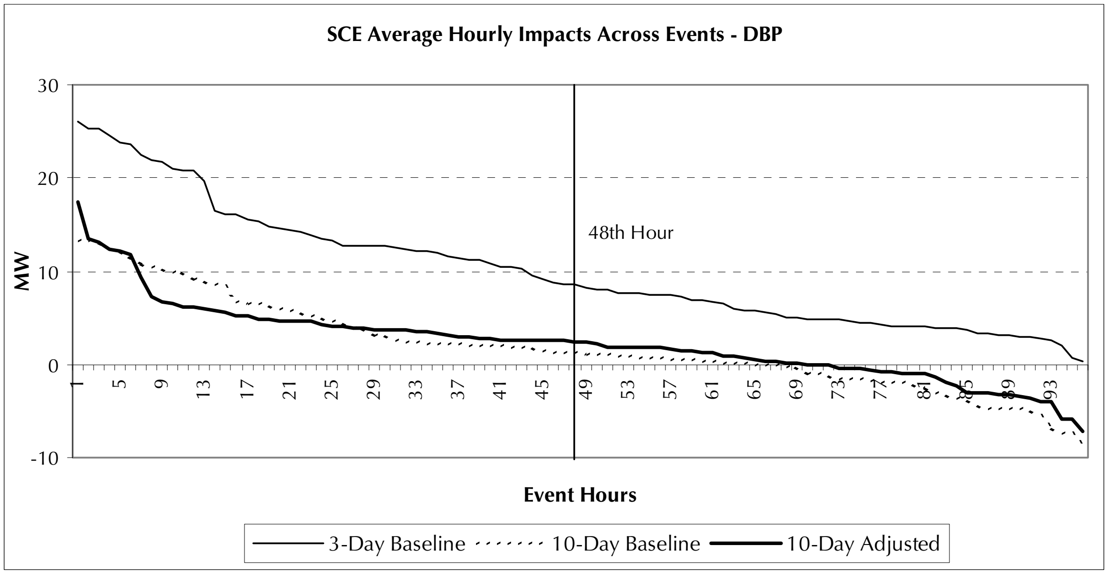
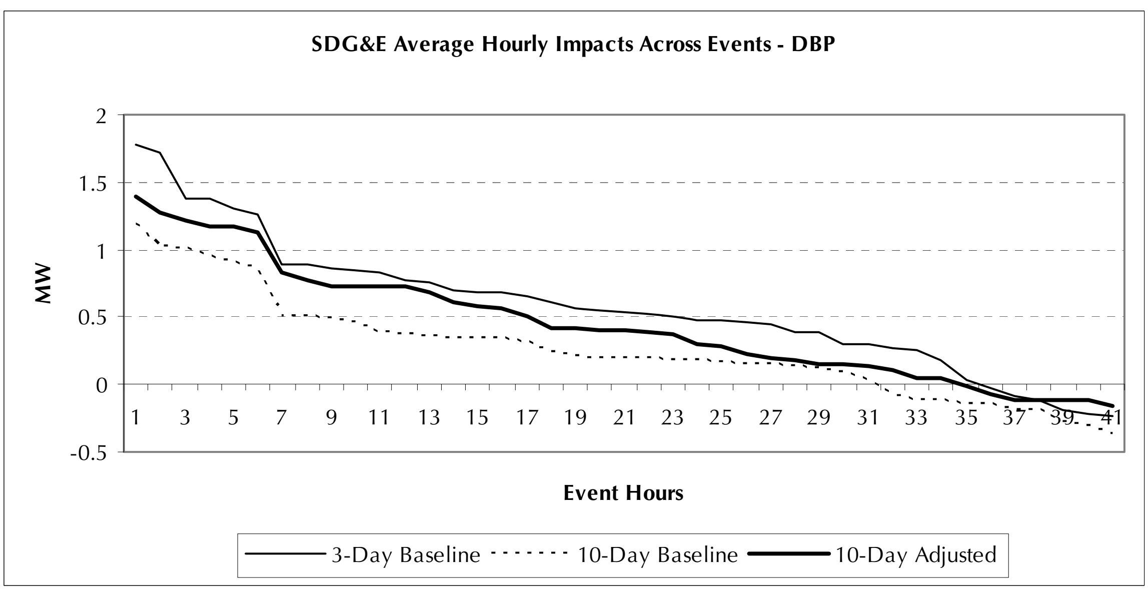


Exhibit 7-82
Distribution of Hourly Impacts for SDG&E DBP Participants across All 2005 Events (12 Events, Varied Event Length, 41 Event Hours)



7.1.3 Reliability Program Impact Results

During the summer of 2005, the reliability-triggered programs were only called in SCE and SDG&E service territories. As has been the case for the last several years, the reliability-triggered programs were called few times as compared to the allowed program maximums. For SCE, the I-6, BIP, and OBMC programs were called only on one occasion over the course the summer (as a result of the loss of the Pacific DC Intertie) and these events each lasted less than an hour and a half; the OBMC program event lasted only 30 minutes. The event hours for the three programs overlapped and therefore it was necessary to exclude any customers who participated in more than one program from multiple program impact estimates. Under current SCE program rules, customers enrolled in the I-6 program may also participate in BIP, however they will receive BIP credits only after their annual I-6 obligations have been fulfilled (which never occurred in 2005). Similarly, customers enrolled in the I-6 or BIP programs may also enroll in the OBMC program but will not be paid for the same reduced load. During the summer of 2005 there were no SCE customers signed up for both the I-6 and BIP programs or the I-6 and OBMC programs, however two customers were signed up for the BIP and OBMC programs. Based on SCE's hierarchical rules, QC excluded the load reductions from the two overlapping customers from the OBMC impact estimates presented in this section since they were included in the BIP program impact estimates. SDG&E called the AL-TOU-CP program four times over the course of the 2005 summer. BIP and OBMC were never called. The impact assessment results for the 2005 SCE and SDG&E events are presented below.

Utility Reported Impacts for the Reliability Programs

The impacts presented below in Exhibit 7-83 below for the reliability-triggered programs are based on the monthly reports submitted to the CPUC by each of the utilities. For SCE, the impacts included in these reports for the I-6, BIP, and OBMC programs are calculated as "the difference between the demand measured at the beginning of the event and the single highest hourly load reduction during the event." This exhibit also provides the impacts resulting from the SDG&E AL-TOU-CP program, which ranged from 1.0 to 1.7 MW per hour over the four summer events. SCE estimated that the single I-6 event called delivered a maximum of 606 MW, BIP delivered nearly 61 MW, and OBMC delivered approximately 39 MW.

Exhibit 7-83
Utility Estimated Impacts for 2005 Reliability Program Events

Utility	Program Event	Event Date	Event Start Time	Event End Time	Program Participants	Utility Estimated Impact (MW)
SDG&E	AL-TOU-CP #1	07/21/05	14:32 PM	16:12 PM	73	1.4
	AL-TOU-CP #2	07/22/05	13:28 PM	18:00 PM	73	1.7
	AL-TOU-CP #3	08/26/05	15:31 PM	16:55 PM	73	1.1
	AL-TOU-CP #4	08/29/05	15:19 PM	17:31 PM	73	1.0
SCE	I-6 #1	08/25/05	3:51 PM	5:08 PM	501	606.5
	BIP #1	08/25/05	3:51 PM	5:08 PM	78	60.7
	OBMC #1	08/25/05	4:14 PM	4:40 PM	12	38.8

Relationship Between the Baseline Method and Program Impacts for the Reliability Programs

As discussed in Section 6.4.1, the program impacts resulting from the Representative Day analysis approach are a function of the baseline method used within the analysis. If the baseline method is biased, so too will be the resulting impact estimates. Exhibits 7-84 through 7-88 provide the range in average load shapes for the reliability-triggered programs across the 3-Day, 10-Day, and 10-Day Adjusted baseline methods, and compare them to the actual event day consumption.

These exhibits illustrate the extent to which the 3-Day baseline over-estimates the average customer load shape more so than the other baseline methods evaluated. This is consistent with the results of the baseline analysis conducted as part of the 2004 WG2 DR evaluation[24], as well as the results presented earlier in this chapter for the CPP and the DBP programs. Both of these analyses found the 3-Day baseline had the most significant upward bias of all the baseline methodologies analyzed. Also similar to last year's findings and the 2005 CPP and DBP results is that the 10-Day unadjusted baseline under-estimated the average customer load shape. This is most likely attributable to the nature of when program events are called. Event days tend to be higher load/higher temperature than normal and thus an average of 10 recent "similar" days under-estimates the actual load on the event day. The 10-Day Adjusted baseline, which was found to be the most accurate, based on the 2004 baseline analysis typically estimates load shapes that fall in the middle of the range of baselines from the other methods analyzed. We continue to believe that the 10-Day Adjusted baseline is the most accurate of the Representative Day methods analyzed; the impacts presented for the reliability-triggered programs are based on the 10-Day Adjusted baseline.

Exhibits 7-84 and 7-85 below show the range in average load shapes for two of the SDG&E AL-TOU-CP program events (July 21st and July 22nd). As these exhibits show the 3-Day baseline load shapes are the highest across the majority of the event day hours, the 10-Day unadjusted load shapes are the lowest and the 10-Day Adjusted baseline load shapes fall somewhere between the two. In this exhibit the AL-TOU-CP event start and end hours are represented by the vertical bars. The impacts during the event period are quite evident for both of these AL-TOU-CP events.

24 *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

Exhibit 7-84
Comparison of Daily Load Shapes for the July 21st SDG&E AL-TOU-CP Event

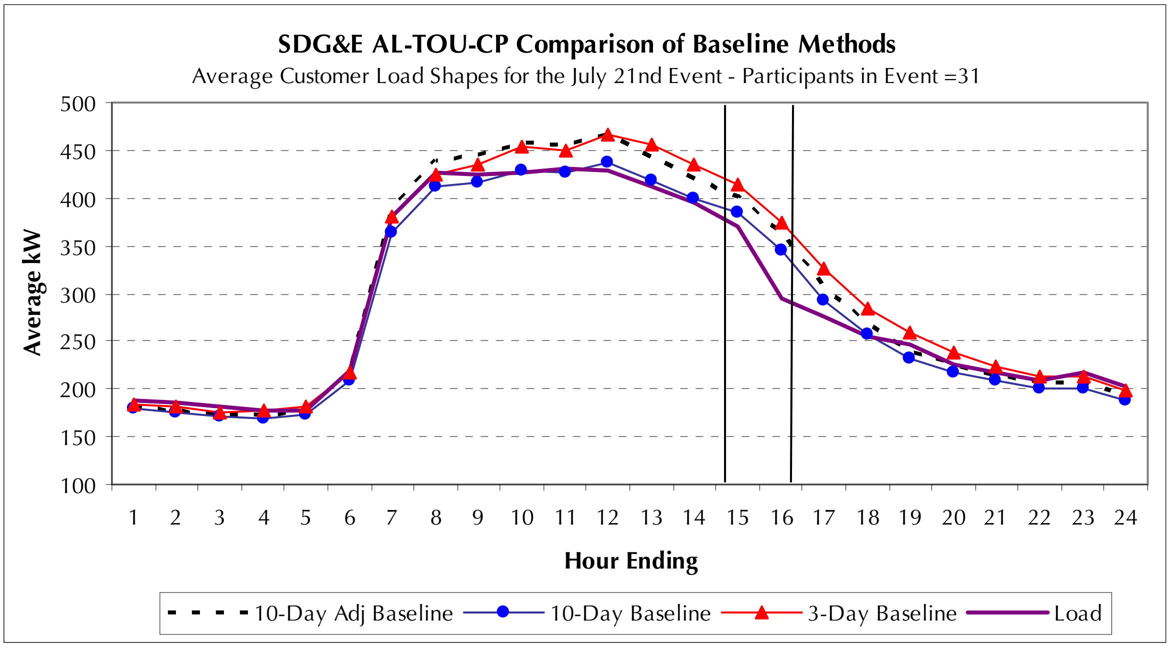


Exhibit 7-85
Comparison of Daily Load Shapes for the July 22nd SDG&E AL-TOU-CP Event

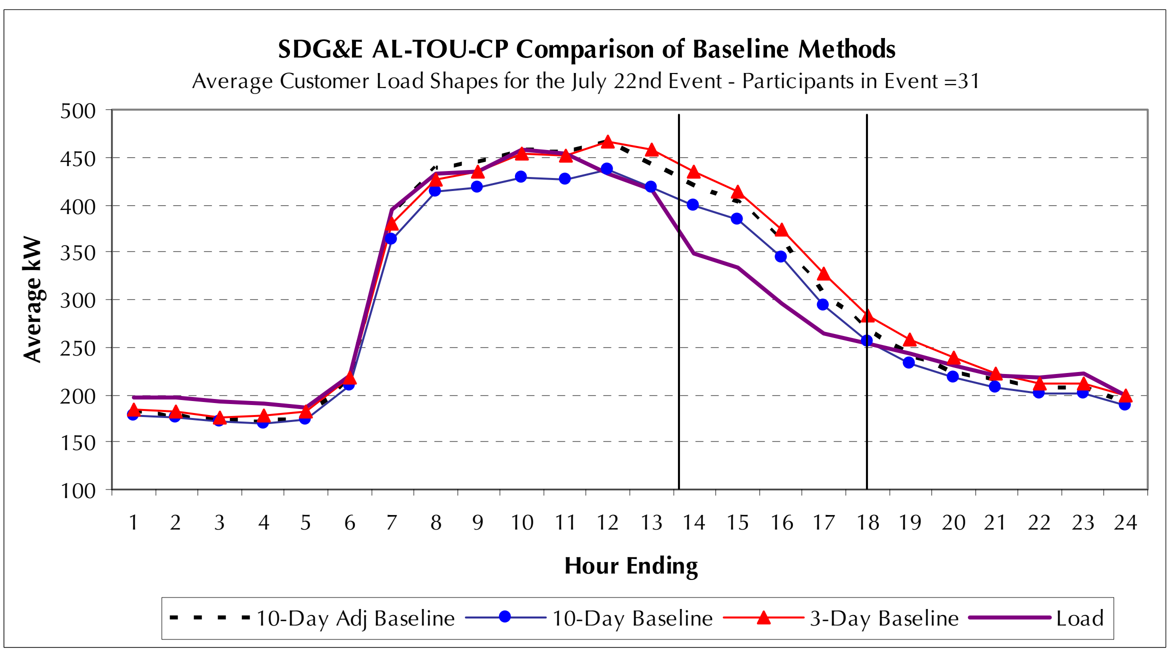


Exhibit 7-86 below presents the average predicted daily load shape (based on three of the baselines evaluated), as well as the actual event day load shape over all I-6 participants for the

August 26th event. This I-6 event was called due to a Transmission line issue, and thus the day most likely did not have any excessive heat or load characteristics. This exhibit shows that customers signed up for the I-6 program have, in general, flat, relatively stable load shapes. The 10-Day Adjusted baseline lies almost directly on top of the 10-Day baseline in this exhibit, which indicates the average calibration ratio[25] was very close to one for this event day. A calibration ratio close to one occurs when the day prior to the event has load levels that are very similar to the average load over the 10 similar days used in the 10-Day baseline. The 3-Day baseline appears to over-predict the actual load by slightly less than 10 percent throughout the course of the event day. The load reduction resulting from the I-6 program is quite evident in the exhibit below. The vertical bars in this exhibit indicate the event start and end times. As these bars illustrate it takes customers 30 to 45 minutes after being notified to reduce their load to their Firm Service Level (FSL) commitment and even longer for customers to ramp back up after the event. The magnitude of the event reduction is slightly minimized in the exhibit below since actual event day load is calculated as the average across the 15-minute interval load data. For reliability day-of programs, such as I-6, that are typically called 30 minutes in advance and last for short, non-hourly[26] intervals, the hourly averages smooth out some of the drastic reductions that actually occur. Exhibit 7-89, presented in the following section, provides a comparison of the actual daily load shape of the I-6 participant population on August 25th using the average hourly load versus the actual 15-minute interval data.

Exhibit 7-86
Comparison of Daily Load Shapes for the August 25th SCE I-6 Event

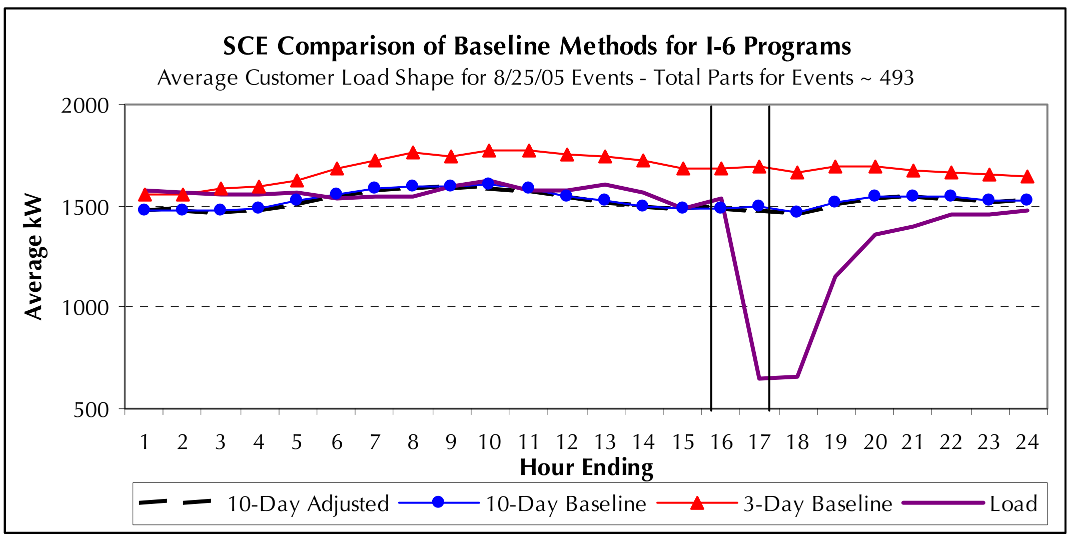


Exhibit 7-87 is similar to 7-86 above, except that it presents the average predicted and actual load shapes for the single SCE BIP event called this past summer. This BIP event was called

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[25] The calibration ratio is used to shift the 10-Day baseline up or down to improve it's approximation to recent consumption patterns.

[26] By non-hourly we mean that these events, unlike the CPP and DBP programs that run from 12PM to 6PM or 12PM to 8PM, are called for periods that do no align with hourly intervals.

along with I-6 on August 25th due to the Transmission line problem, and the BIP participants responded in a similar manner. The relationship between the actual event day load and the estimated baselines was also similar to the I-6 program, with the 3-Day over-predicting the actual load and the 10-Day under-predicting it. Again here the load reduction resulting from the BIP program is quite evident in the exhibit below, as is the time required to initially shed load and then to ramp back up to the pre-event levels. The vertical bars in this exhibit represent the event start time (3:50PM) and the event end time (5:08PM).

Exhibit 7-87
Comparison of Daily Load Shapes for the August 25th SCE BIP Event

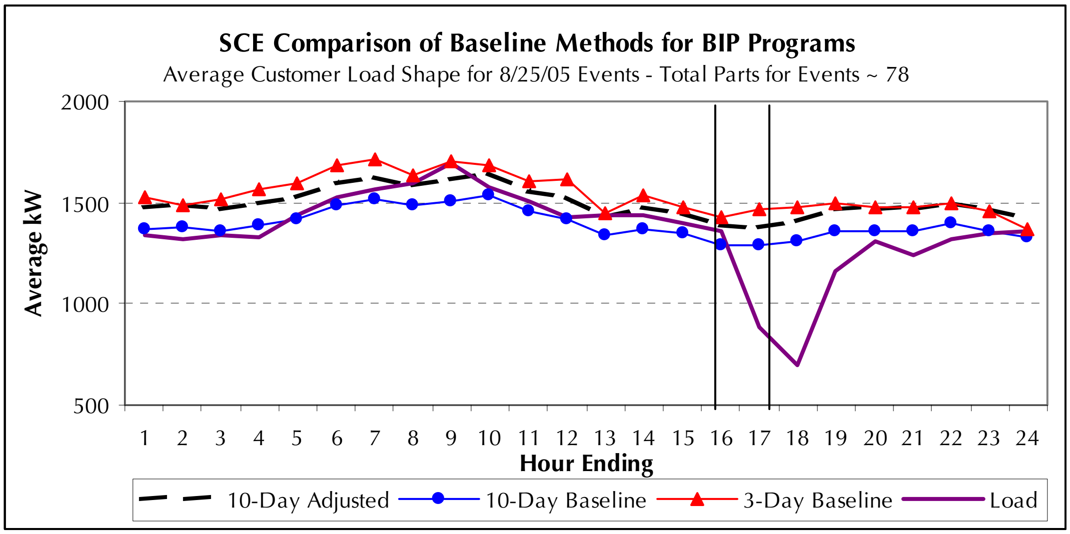
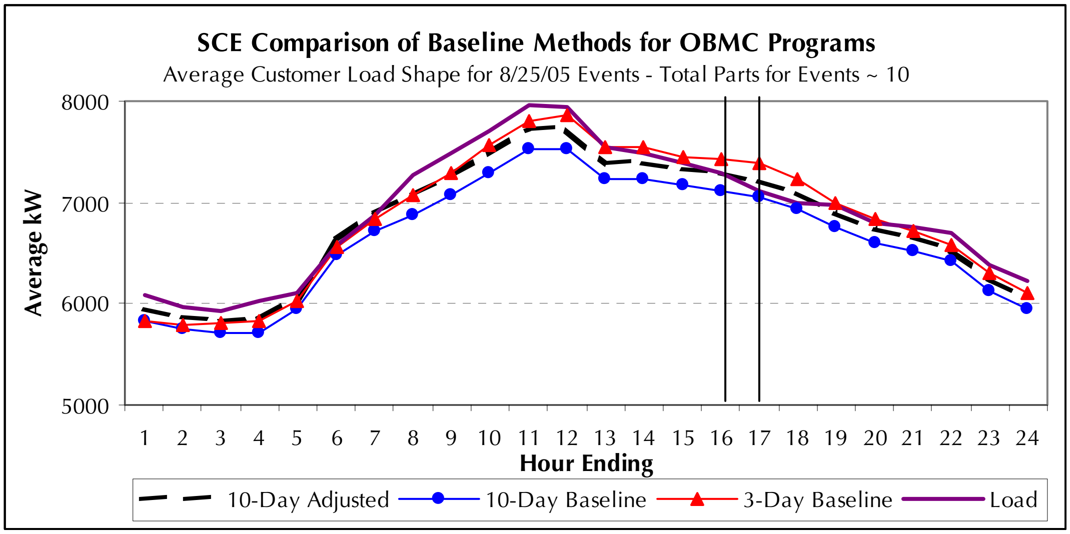


Exhibit 7-88 presents the average predicted and actual load shapes for the single SCE OBMC event called this past summer. The OMBC event was also called on August 25th due to the Transmission line problem. At the time of the event there were 12 accounts signed up for the OBMC program, two of which were also enrolled in the BIP program. These customers who were also enrolled in the BIP program are not included in the exhibit below, since according to SCE participation rules customers cannot participate in OBMC events until their BIP agreements have been fulfilled. One thing that is evident in this exhibit is how strongly peaked the load shapes of these customers are than those signed up for the I-6 and BIP programs. The average size of these customers is much larger as well (average load of 7 MW for OBMC participants versus 1.5 MW for the BIP and I-6 participants). The 3-Day baseline did not over-predict the event day load during the morning hours as it had for the I-6 and BIP participants. According to event data we received from SCE, this OBMC event was not billed as an OBMC event since it lasted less than 45 minutes, the minimum OBMC event length. However, participants were still notified and a slight load drop is observable from the 10 participating customers.

Exhibit 7-88
Comparison of Daily Load Shapes for the August 25th SCE OBMC Event



Average 15-Minute Program Impacts

The impact results presented in this section for the reliability-triggered programs are calculated as the sum of individual customer level hourly impacts across all participants who are signed up for the specific reliability-triggered program called on the day of the event (since the events are all day-of notification). Each individual customer's hourly impact is calculated as the difference between the customer's estimated load (based on the 10-Day Adjusted baseline) and the actual load consumed by that customer during the event hours (which is the average of the 15-minute interval load data).

CPP and DBP events are always called the day-ahead and on an hourly basis, thus the practice of calculating hourly baselines (based on the average load over the four 15-minute intervals that make up the hour) and estimating impacts on an hourly basis cause little concern. For the reliability-triggered programs, events are not called on an hourly basis and typically are activated only 30-minutes prior to the event start. Hence a customer's actual load reduction may vary significantly from one 15-minute interval to the next. This difference in the magnitude of the load reduction is illustrated in Exhibit 7-89 (based on the 15-minute interval data versus the sum based on the average hourly load data). This SCE I-6 event was called at 3:51PM and was in effect until 5:08PM (the entire event lasted a little over an hour). As this exhibit shows the magnitude of the maximum load drop during this I-6 event differs by about 150 MW depending on whether average hourly or 15-minute interval data is used. As a result of this difference, the program impact estimates presented in this section are based upon the 15-minute interval data which provides a more detailed program impact estimate for reliability-triggered events, such as I-6, that occur "real-time" and over a short event interval.

Exhibit 7-89
Difference between the Average Hourly and 15-Minute Interval Load for the SCE I-6 August 25th Event

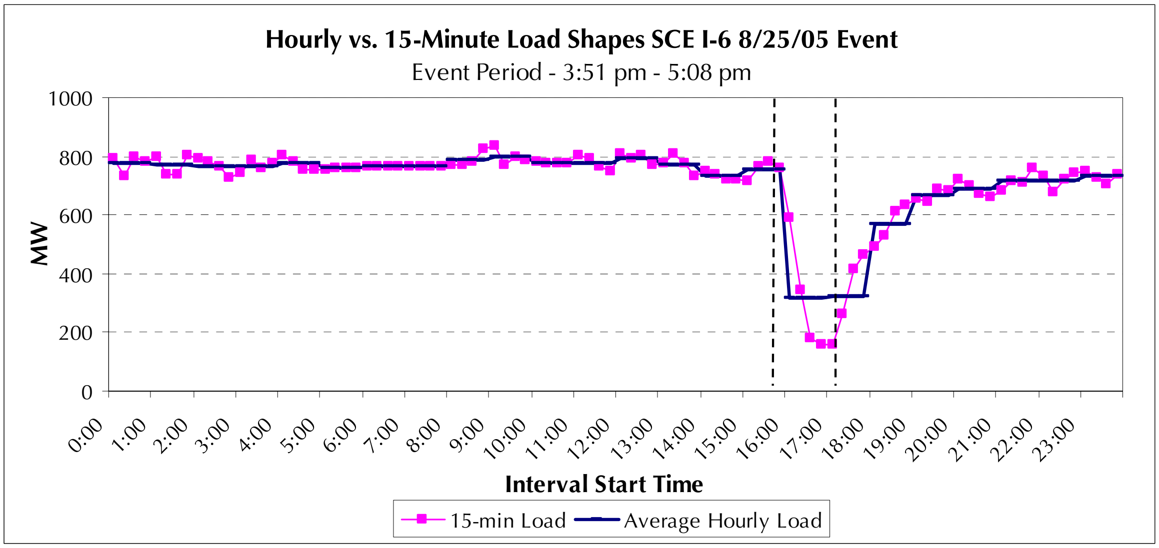


Exhibit 7-90 below presents the sum of the estimated base load and actual event day load across all I-6 participants (based on the 10-Day Adjusted baseline) for each of the 15-minute increments during the August 25th I-6 event. The event was called at 3:51PM and notification went out to all program participants between 3:52PM and 4:04PM. From the time a customer received notification, they had 30 minutes in which to reduce their load to their Firm Service Level (FSL) without facing any penalties. As the exhibit below shows, by 4:30PM the participants were within 40 MW of achieving their FSL and by 4:45 they had reduced approximately 571 MW, a 78 percent load reduction off their estimated base load, and were within 18 MW of achieving their FSL. In total penalties were assessed to 113 of the 500 program participants, and the average penalty was $256. The largest penalty assessed was $17,103 and the total amount of penalties assessed across all participants was $103,758.

Exhibit 7-90
Load Reductions by 15-Minute Interval for the SCE I-6 Program
August 25th 2005 Event, Based on Data from 493 of 500 Program Participants

SCE I-6 Event Results in MW (8/25/05 - 3:51-5:08 pm)					
Interval Start	FSL	Estimated Base Load*	Actual Load	Load Reduction	% Load Reduction
15:45	141	731	762	-31	-4%
16:00	141	730	588	142	19%
16:15	141	730	342	388	53%
16:30	141	730	181	549	75%
16:45	141	730	159	571	78%
17:00	141	720	156	564	78%

* Based on Hourly 10-Day Adjusted Baseline

Similar to the exhibit above, Exhibit 7-91 below presents the sum of the estimated base load and actual event day load across all BIP participants (based on the 10-Day Adjusted baseline) for each of the 15-minute increments during the August 25th BIP event. The event was called for the same time period as the I-6 event (beginning at 3:51PM and ending at 5:08). BIP participants also had 30 minutes from the time they received notification to reduce their load to their FSL before facing any penalties. The exhibit below shows that by 4:45PM the participants were within 26 MW of their FSL and by 5:00PM they had reduced approximately 61 MW, which was a 57 percent load reduction from their estimated base load, and were within 23 MW of their FSL. In total penalties were assessed to 38 of the 78 program participants, and the average penalty was $1,165. The largest penalty was $5,460 and the total amount of penalties assessed was $51,277.

Exhibit 7-91
Load Reductions by 15-Minute Interval for the SCE BIP Program
August 25th 2005 Event, Based on Data from All 78 Program Participants

SCE BIP Event Results In MW (8/25/05 - 3:51-5:08 pm)					
Interval Start	FSL	Estimated Base Load*	Actual Load	Load Reduction	% Load Reduction
15:45	24	108	108	0	0%
16:00	24	108	102	6	5%
16:15	24	108	75	33	30%
16:30	24	108	50	58	54%
16:45	24	108	47	61	57%
17:00	24	110	46	64	58%

* Based on Hourly 10-Day Adjusted Baseline

Exhibit 7-92 below presents the sum of the estimated base load and actual event day load across 10 of the 12 OBMC participants (based on the 10-Day Adjusted baseline) for two 15-minute intervals during the August 25th OBMC event. The event was initially called at 3:57PM, however the phone notifications did not begin until 4:14PM. The event was terminated at 4:40PM. Because the OBMC event lasted less than 45 minutes, the program minimum, the event was not considered valid and thus no penalties were assessed. As the exhibit below shows, the largest load reduction attained during the 30 minutes the customers believed the event was in effect was 3 MW, which represented a 4 percent reduction in load. This program is unlike I-6 and BIP in that customers do not have a pre-determined FSL. This program offers blackout avoidance, when the ISO declares rotating outages, in return for up to 15 percent reductions in load during events. Curtailments are called for when rotating outages (Stage 3) are required by the CAISO. The program requires that an OBMC curtailment plan be submitted that shows how the loads will be managed in 5 percent increments up to the 15 percent maximum curtailment level.

Exhibit 7-92
Load Reductions by 15-Minute Interval for the SCE OBMC Program
August 25th 2005 Event, Based on Data from 10 of the 12 Program Participants

SCE OBMC Event Results in MW (8/25/05 - 4:14-4:40 pm)				
Interval Start	**Estimated Base Load***	**Actual Load**	**Load Reduction**	**% Load Reduction**
16:15	72	70	2	3%
16:30	72	69	3	4%

* Based on Hourly 10-Day Adjusted Baseline

Maximum Event Impacts

Exhibit 7-93 below presents the maximum load reductions achieved by the SCE reliability-triggered programs over the course of the program event hours. This exhibit shows that the maximum reduction achieved for the I-6 program, based on the 15-minute load data and the hourly 10-Day Adjusted baseline, was 571 MW, which represents a 78 percent load reduction. The sum of the FSL for these participants was 141 MW, which would require an average load reduction of 81 percent from their estimated base load. Based on the minimum load achieved during this event of 159 MW, we calculated that this population of program participants came within 13 percent of achieving their FSL. The impact estimate calculated by QC for the I-6 program is very close to the program impact SCE reported to the CPUC (QC estimate was approximately 6 percent lower). Impacts for seven of the 500 I-6 program participants were excluded from the QC analysis due to missing load data for these participants.

For the BIP program the exhibit below shows that the maximum reduction achieved over the course of the event was 64 MW, which represents a 58 percent load reduction. The sum of the Firm Service Level (FSL) for these participants was 24 MW, which would require a 78 percent load reduction from the sum of the participant's estimated base load. Based on the minimum load achieved during this event, 46 MW, the population of program participants was still 91 percent over their FSL despite their load reductions. The impact estimate calculated by QC for the BIP event was approximately 3 MW higher than the impact SCE reported to the CPUC. No load data were missing for BIP program participants.

Results from the SCE OBMC program event are also displayed in the exhibit below. The impact estimates for the OBMC population included in this exhibit are based on the 10 OBMC participants that were not enrolled in the BIP or I-6 programs. Since events for these three programs were called for the same period, customers enrolled in either BIP or I-6, in addition to OBMC, were not eligible to participate in the OBMC event. For this OBMC event, the maximum load reduction achieved over the course of the event was 3 MW, which represents a 4 percent load reduction. The OBMC program is different from the BIP and I-6 programs in that there is no pre-determined FSL the participants are required to achieve. The estimated program impact calculated by QC for the OBMC program was significantly lower than the impact reported by SCE to the CPUC. This appears to be the result of SCE including the two participants who were also enrolled in the BIP program in their estimated program impact. These participants appeared to have large load reductions during the event period; however these reductions were attributed to the BIP program impact estimates. Customers were not billed for this event since it lasted less than 45 minutes, the minimum program length.

Exhibit 7-93
Maximum Load Reductions Across the SCE Reliability Triggered Programs
Based on 15-Minute Interval Data

SCE Program	Date	Event Start Time	Event End Time	n	Estimated Base Load* (MW)	Actual Event Day Load* (MW)	Estimated Program Impact* (MW)	Percent Reduction	FSL (MW)	% Actual Load Greater Than FSL
I-6	8/25/05	3:51 PM	5:08 PM	493	730	159	571	78%	141	13%
BIP	8/25/05	3:51 PM	5:08 PM	78	110	46	64	58%	24	91%
OBMC	8/25/05	4:14 PM	4:40 PM	10	72	69	3	4%	-	-

* Based on Hourly 10-Day Adj Baseline and the minimum 15-minute load during the event period

Unlike the SCE I-6 program and the PG&E Non-Firm program, the SDG&E AL-TOU-CP program does not require participants to pre-determine a Firm Service Level. The four SDG&E traditional interruptible events were called for different time periods and were slightly longer on average than SCE's I-6 events. As a result, the differences between the calculated impacts based on the hourly data and the 15-minute interval data are smaller than for the SCE I-6 event. Exhibit 7-94 below presents the estimated base load (based on the 10-Day Adjusted baseline), the actual event day load and the resulting MW and percent reductions impacts. The maximum estimated impact across all four events was 2.3 MW, which equated to a 17 percent load reduction from the AL-TOU-CP participant population.

Exhibit 7-94
Maximum Load Reductions Across for SCE Traditional Interruptible Program
Based on 15-Minute Interval Load

SDG&E Program Event	Date	Start Time	End Time	Analysis Period	N	Base Load* (MW)	Actual Load* (MW)	Program Impact* (MW)	Percent Reduction	Utility Reported Impact
AL-TOU-CP #1	07/21/05	14:51 PM	16:12 PM	HE15	31	12.5	11.5	1.0	8%	1.4
				HE16	31	11.2	9.1	2.1	18%	
				HE17	31	9.5	8.6	1.0	10%	
AL-TOU-CP #2	07/22/05	13:28 PM	18:00 PM	HE14	31	13.0	10.8	2.3	17%	1.7
				HE15	31	12.5	10.3	2.2	17%	
				HE16	31	11.2	9.2	2.0	18%	
				HE17	31	9.5	8.2	1.3	14%	
				HE18	31	8.3	7.9	0.4	5%	
AL-TOU-CP #3	08/26/05	15:31 PM	16:55 PM	HE16	31	11.9	10.8	1.1	9%	1.1
				HE17	31	10.7	9.0	1.6	15%	
AL-TOU-CP #4	08/29/05	15:19 PM	17:31 PM	HE16	31	11.9	10.4	1.5	12%	1
				HE17	31	10.7	9.2	1.4	13%	
				HE18	31	8.5	7.7	0.8	9%	

* Based on Hourly 10-Day Adj Baseline

Distribution of Impacts Across Customers

Exhibit 7-95 below shows the distribution of the percent of load reduction (based on the hour prior to the event start) that would be required of I-6 participants in order to achieve their Firm Service Level (FSL). This percent load reduction was calculated for I-6 participants as:

1 – (FSL/Load Prior to Event Start)

As this exhibit shows, 41 percent of the I-6 participant population would need to drop 100 percent of their load in order to achieve their FSL. Approximately 10 percent of I-6 participants would not need to take action to achieve their FSL since their load was already below their FSL.

Exhibit 7-95
Distribution of Percent Load Reduction Necessary to Achieve FSL Across SCE I-6 Participants

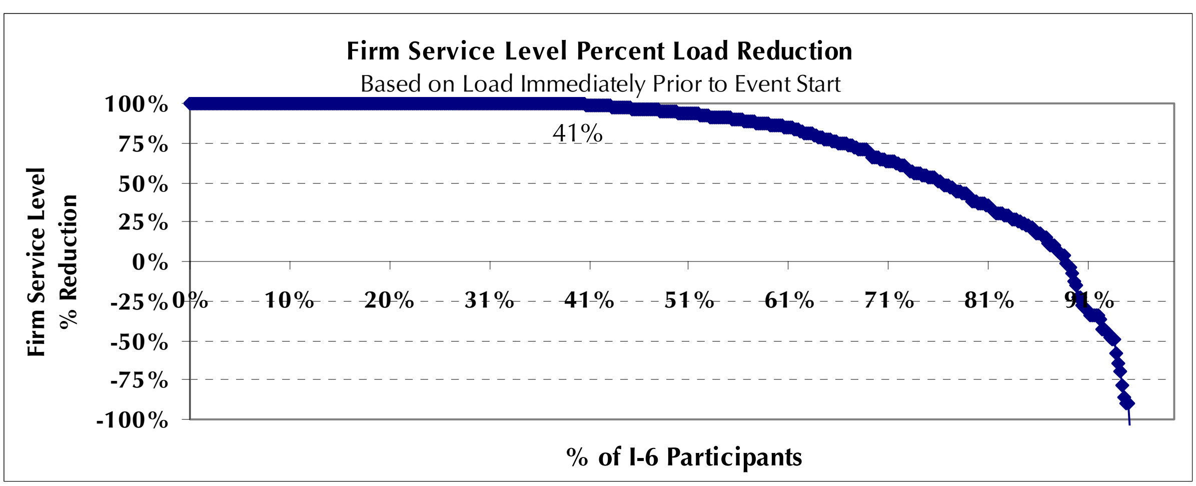


Exhibit 7-96 provides a summary of the SCE I-6 participant actions with respect to their pre-determined FSL for the August 26th event. This exhibit shows that 72 percent of I-6 participants achieved their FSL and 91 percent came within 100 kW or 10 percent of achieving it. Thirty-four percent of participants had set their FSL to be 0 kW, meaning they would have to completely shut down all operations or switch to another power source. Three percent of SCE I-6 participants did not achieve their FSL and based on the data appeared not to have attempted to reduce their load whatsoever.

Exhibit 7-96
Summary of SCE I-6 Participant Actions versus Firm Service Level Intentions for the August 26th 2005 Program Event

SCE I-6 Summary for 8/26/05 Event	N	%
Total I-6 Participants w/ Interval Data	493	-
Participants who **Achieved FSL** during Event	353	72%
Parts who **dropped to w/in 50kW** of FSL	415	84%
Parts who **dropped to w/in 100kW** of FSL	438	89%
Parts who **dropped to w/in 100kW or 10%** of FSL	447	91%
Parts with a **Firm Service Level of Zero**	170	34%
Parts whose **FSL required > 99.5% drop**	197	40%
Parts whose **FSL required >75% drop**	327	66%
Parts who **did not take action** during event	15	3%

Exhibit 7-97 is similar to 7-95 above in that it shows the distribution of the percent of load reduction that would be required of BIP participants in order to achieve their FSL. This percent load reduction was calculated in the same manner as above for BIP participants. This exhibit shows that nearly 50 percent of BIP participants would need to drop 100 percent of their load in order to achieve their FSL. Approximately 10 percent of the participants would not need to take action to achieve their FSL since their load was already below their FSL.

Exhibit 7-97
Distribution of Percent of Firm Service Level Achieved Across SCE BIP Participants

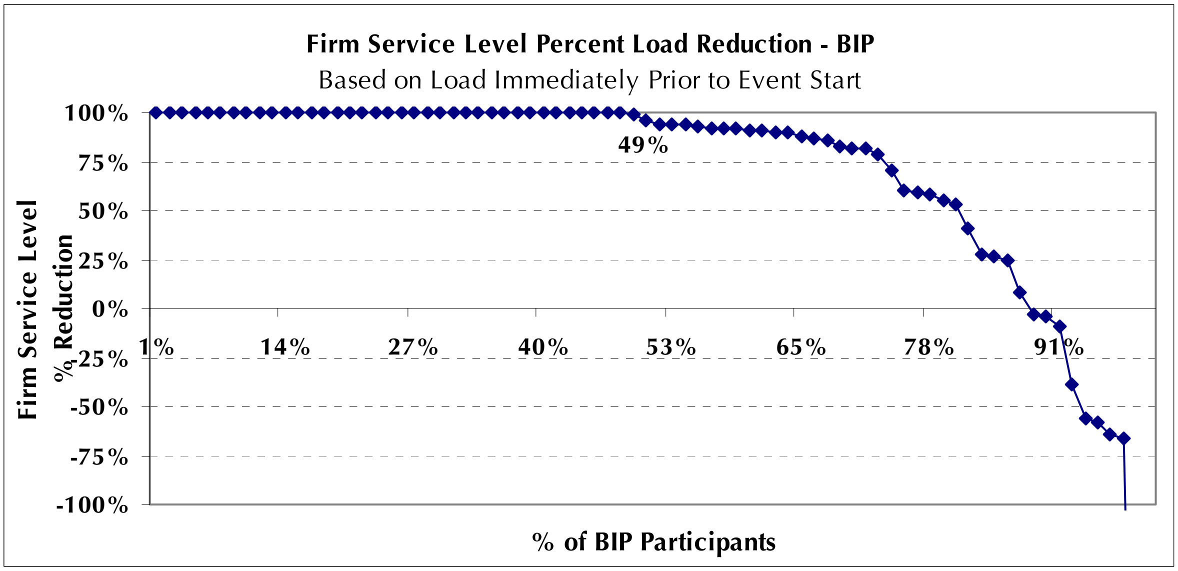


Exhibit 7-98 provides a summary of the SCE BIP participant actions with respect to their pre-determined FSL for the August 26th event. This exhibit shows that 45 percent of BIP participants achieved their FSL and 63 percent came within 100 kW or 10 percent of achieving it. Forty-two percent of participants had set their FSL to be 0 kW, meaning they would have to completely shut down all operations or switch to another power source if an event was called. Eighteen percent of SCE BIP participants did not achieve their FSL and based on the data appeared not to have attempted to reduce their load at all.

Exhibit 7-98
Summary of SCE BIP Participant Actions versus Firm Service Level Intentions for the August 26th 2005 Program Event

SCE BIP Summary for 8/26/05 Event	N	%
Total BIP Participants w/ Interval Data	78	-
Participants who **Achieved FSL** during Event	35	45%
Parts who **dropped to w/in 50kW** of FSL	42	54%
Parts who **dropped to w/in 100kW** of FSL	47	60%
Parts who **dropped to w/in 100kW or 10%** of FSL	49	63%
Parts with a **Firm Service Level of Zero**	33	42%
Parts whose **FSL required > 99.5% drop**	37	47%
Parts whose **FSL required >75% drop**	57	73%
Parts who **did not take action** during event	14	18%

Exhibit 7-99 shows the distribution of the average load reductions made by SDG&E AL-TOU-CP participants across all four of the 2005 events. This exhibit shows that 50 percent of the load reduction was achieved by approximately 20 percent of the AL-TOU-CP participants.

Exhibit 7-99
Distribution of Average Load Reduction Across Participants
Over All SDG&E 2005 AL-TOU-CP Events (4 total)

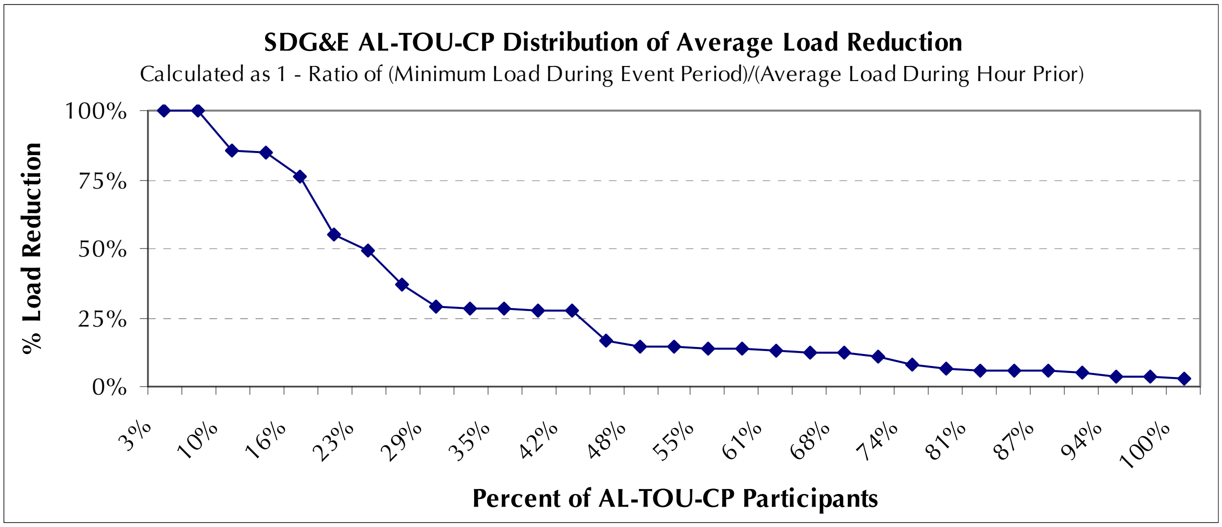


Exhibit 7-100 provides the distribution of SDG&E AL-TOU-CP participant load reductions across all four of the 2005 events. This exhibit shows that 90 percent of AL-TOU-CP participants dropped 5 percent of their load on average across all four of the events, while 42 percent dropped at least 25 percent of their load and 6 percent dropped 100 percent of their load.

Exhibit 7-100
Summary of SDG&E AL-TOU-CP Participant Average Load Reductions Average Across all 2005 Program Events

SDG&E AL-TOU-CP Summary for All 2005 Events	N	%
Total AL-TOU-CP Participants w/ Interval Data	31	-
Parts who **dropped 5% of Load** on Average	28	90%
Parts who **dropped 10% of Load** on Average	22	71%
Parts who **dropped 25% of Load** on Average	13	42%
Parts who **dropped 50% of Load** on Average	7	23%
Parts who **dropped 100% of Load** on Average	2	6%

7.1.4 DRP Impact Results

Portions of the DRP participants are Direct Access customers and thus the utilities do not necessarily have access to the interval meter data for these participants. Because of this all data included in this section has been collected from the DRP website, which is administered by APX on behalf of California Energy Resource Scheduling (CERS).

Statewide Participation in DRP

Exhibit 7-101 below provides the number of unique accounts and customers participating in the DRP program during the summer of 2005. This exhibit shows that the number of unique customers participating in DRP is approximately 15 percent of the number of unique accounts. This indicates that on average each participating customer has seven accounts enrolled in the DRP program. One DRP participant has accounts enrolled in each of the three utility demand zones. There are a total of six unique aggregators that are involved in the program on a statewide basis (all of which are active in PG&E demand zone 3) and 10 unique scheduling coordinators.

Exhibit 7-101
DRP Participation Statistics by Utility and Statewide Totals
Unique Accounts, Customers, Aggregators and Scheduling Coordinators

Cal-DRP Program Participation	Utility and Demand Zones					
	PGE3	PGE4	PG&E	SCE	SDG&E	Statewide
Number of Unique Accounts Participating	172	24	196	93	25	314
Number of Unique Customers Participating	22	7	27	18	2	45
Number of Aggregators	6	3	9	3	2	14
Number of Scheduling Coordinators	8	4	12	3	3	18

* One customer has accounts participating in Cal-DRP in all utility zones.

Exhibit 7-102 below shows the distribution of DRP participant customers enrolled in each of the DRP products (1-3 hour, 1-5 hour and 1-8 hour products) across each of the three utilities. This exhibit shows that the majority of customers signed up for DRP in PG&E and SCE service territories are enrolled in the 1-3 hour product. In SDG&E service territory, all customers are signed up for the 1-5 hour product. DRP events can be called for any number of consecutive hours, so long as the event length does not exceed the maximum event hours for a particular product type (i.e. the 1-3 hour product cannot be called for more than three consecutive hours in one day). The maximum number of monthly event hours for each product type within a utility zone is 24 hours. The exhibit below provides the number of events called this past summer and the average event length for each of the product types across the three utilities. This data illustrate that there were only minor differences in the average program length between the various product types. The longer product type events were typically called seven to eight times a month, for three to four hours at a time, causing dissatisfaction for some of the participants enrolled in this product type. These customers reported signing up for the 1-8 hour product thinking that the events would be called less frequently, but for longer event periods. They reported that curtailing for a few hours on multiple occasions was more difficult than curtailing for longer periods on fewer occasions.

Exhibit 7-102
DRP Participation Enrollment, Event Frequency and Average Event Length for Each of Product Type by Utility

Utility	PG&E			SCE			SDG&E		
Product Type	**1-3 hr**	**1-5 hr**	**1-8 hr**	**1-3 hr**	**1-5 hr**	**1-8 hr**	**1-3 hr**	**1-5 hr**	**1-8 hr**
Customers Enrolled	18	4	6	13	2	3	0	2	0
Total Events Called	24	23	23	19	19	18	0	7	0
Average Event Length	2.5 hrs	3 hrs	3.3 hrs	2.8 hrs	3.7 hrs	4.1 hrs	n/a	2.6 hrs	n/a
Total Summer Event Hrs	59	71	76	53	70	74	0	20	0
Event Hrs - June	1	1	4	8	11	11	0	1	0
Event Hrs - July	18	23	24	19	21	23	0	11	0
Event Hrs - August	23	24	24	11	14	16	0	8	0
Event Hrs - September	17	23	24	15	24	24	0	0	0

DRP Load Nomination

Exhibit 7-103 below shows the sum of the monthly, daily, and total nominations for DRP events across the summer. The nominations presented here are for the entire event day, regardless of the hours for which the event is called, and take into account the 60/100 rule[27]. This exhibit shows that across the entire summer customers on average nominated 78 percent of their available nomination capacity. Ninety-five percent of the load nominated was done so on a monthly basis, with an additional 5 percent being nominated on a daily basis. Daily nominations could be positive or negative, which effectively increased or decreased the amount of their monthly nomination for a particular event day. Over the course of the summer approximately 25 percent of the daily nominations were negative. In the exhibit below the "Daily Adj (+ or -)" nomination row is the net daily adjusted nomination (the sum of the positive and negative daily nominations). If the negative daily nominations had been deducted from the "Monthly" nomination row, the percent of the total nominations that the monthly nominations would represent would drop to 93 percent, and the daily nominations would increase to 7 percent.

Exhibit 7-103
Statewide Sum of Total DRP Hourly Nominations Across All Summer 2005 Events Monthly, Daily, Total and Facility Maximum Nomination

Nominations	Sum of Hourly Nominations Across the Summer (in MWh)								Hourly Average	Percent of Total	Percent of Max
	Part-Peak				"Super-Peak" Period			Part-Peak			
	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7			
Monthly	7,478	7,485	7,485	7,485	7,936	7,936	7,936	7,481	7,653	95%	75%
Daily Adj (+ or -)	424	424	424	424	335	319	315	403	383	5%	4%
Total	7,902	7,909	7,909	7,909	8,271	8,255	8,251	7,884	8,036	-	78%
Facility Max	10,244	10,256	10,256	10,265	10,258	10,242	10,237	10,237	10,249	-	-

27 The 60/100 rule effectively reduces the monthly nomination to 60 percent of the total MW nominated for the "Part Peak" event hours (11AM-3PM and 6-7PM). All other hours are considered "Super Peak" hours and the monthly nomination stands at 100 percent.

On average across all utilities and all events, approximately two-thirds of participating customers are actively nominating capacity for DRP events. Exhibit 7-104 provides the average nomination per event across all customers who nominated capacity for a particular event hour.

Exhibit 7-104
Statewide Average DRP Hourly Nominations for an Event
Monthly, Daily, Total and Facility Maximum Nominations

Nominations	Average Hourly Nominations (in MW)								Hourly Average	Percent of Total	Percent of Max
	Part-Peak				"Super-Peak" Period			Part-Peak			
	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7			
Monthly	5.5	5.4	5.4	5.4	5.7	5.7	5.8	5.5	5.6	93%	84%
Daily Adj (+ or -)	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	7%	7%
Total	5.9	5.9	5.9	5.9	6.2	6.2	6.3	6.0	6.0	-	91%
Facility Max	6.6	6.6	6.6	6.6	6.6	6.6	6.7	6.7	6.6	-	-

One customer in PG&E demand zone 3 primarily drives the impacts resulting from the DRP program. This customer is composed of 11 individual accounts, each of which is a large pumping facility. Although this customer makes up only 3.5 percent of the accounts participating in DRP program, its nominations make up 85 percent of the total load nominated across all summer 2005 events. Exhibit 7-105 provides the average nomination per event for these large pumping facilities across the summer events. As this exhibit shows, this customer nominates all of its capacity on a monthly basis. It was interesting to note that although this customer's base load decreased throughout the summer its nomination remained consistently at 200 MW. The relationship between this customer's nomination, its actual MW reduction and its percent load reduction is discussed in relation to Exhibit 7-114 which follows.

Exhibit 7-105
Statewide Average DRP Hourly Nominations Across All Summer 2005 Events
for the Large Pumping Customer Only
Monthly, Daily, Total and Facility Maximum Nominations

Nominations	Average Hourly Nominations (in MW)								Hourly Average	Percent of Total	Percent of Max
	Part-Peak				"Super-Peak" Period			Part-Peak			
	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7			
Monthly	200	200	200	200	200	200	200	200	200	100%	100%
Daily Adj (+ or -)	0	0	0	0	0	0	0	0	0	0%	0%
Total	200	200	200	200	200	200	200	200	200	-	100%
Facility Max	200	200	200	200	200	200	200	200	200	-	-

Exhibit 7-106 below provides the average nomination per event for the remaining customers once the large pumping facilities have been removed. This exhibit illustrates the difference in magnitude between the nominations from this large pumping customer and the remaining smaller customers. The nominations from the large pumping customer are 500 times larger than the sum of the nominations from the remaining customers. The next largest nomination from a single customer is 16 MW an hour. The following exhibit also shows that for the remaining customers, the division between daily and monthly nominations is nearly equal.

Exhibit 7-106
Statewide Average DRP Hourly Nominations Across All Summer 2005 Events for All Accounts Except the Large Pumping Customer Only
Monthly, Daily, Total and Facility Maximum Nominations

Nominations	Average Hourly Nominations (in MW)								Hourly Average	Percent of Total	Percent of Max
	Part-Peak				"Super-Peak" Period			Part-Peak			
	11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7			
Monthly	0.4	0.4	0.4	0.4	0.7	0.7	0.7	0.4	0.5	53%	32%
Daily Adj (+ or -)	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.4	47%	29%
Total	0.8	0.8	0.8	0.8	1.1	1.1	1.1	0.8	0.9	-	61%
Facility Max	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	-	-

Exhibit 7-107 below provides the distribution of hourly nominations across all event hours and all utilities for the July 14th event. This event had the second highest reported impact of any of the events. The only event with a higher reported impact was the July 15th event; however this event was not called for DRP participants within SDG&E service territory. For this particular event, 90 percent of the nominated load came from PG&E participants (of which 94 percent was from the large pumping customer), 9 percent came from SCE participants and 1 percent came from SDG&E participants.

Exhibit 7-107
Statewide Total DRP Hourly Nominations for the July 14th Event
Monthly, Daily, Total and Facility Maximum Nominations

Utility	Nominations	Average Hourly Nominations (in MW)								Hourly Average	Percent of Utility	Percent of Max	Percent of Total
		Part-Peak				"Super-Peak" Period			Part-Peak				
		11-12	12-1	1-2	2-3	3-4	4-5	5-6	6-7				
All	Monthly	228.0	228.6	228.6	228.6	247.1	247.1	247.1	228.2	235.4	94%	82%	-
	Daily Adj (+ or -)	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	16.1	6%	6%	-
	Total	244.1	244.7	244.7	244.7	263.1	263.1	263.1	244.3	251.5	-	88%	-
	Facility Max	277.9	278.8	278.8	278.8	278.3	278.3	278.3	278.3	278.4	-	-	-
PG&E	Monthly	209.4	209.4	209.4	209.4	215.8	215.8	215.8	209.4	211.8	96%	90%	90%
	Daily Adj (+ or -)	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	4%	4%	60%
	Total	219.1	219.1	219.1	219.1	225.4	225.4	225.4	219.1	221.5	-	94%	88%
	Facility Max	233.9	233.9	233.9	233.9	233.9	233.9	233.9	233.9	233.9	-	-	84%
PG&E w/o Large Customer	Monthly	9.4	9.4	9.4	9.4	15.8	15.8	15.8	9.4	11.8	55%	28%	5%
	Daily Adj (+ or -)	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	45%	29%	60%
	Total	19.1	19.1	19.1	19.1	25.4	25.4	25.4	19.1	21.5	-	56%	9%
	Facility Max	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	33.9	-	-	12%
SCE	Monthly	17.3	17.9	17.9	17.9	29.2	29.2	29.2	17.5	22.0	80%	44%	9%
	Daily Adj (+ or -)	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	20%	14%	35%
	Total	22.9	23.5	23.5	23.5	34.8	34.8	34.8	23.1	27.6	-	58%	11%
	Facility Max	39.7	40.6	40.6	40.6	40.1	40.1	40.1	40.1	40.2	-	-	14%
SDG&E	Monthly	1.3	1.3	1.3	1.3	2.1	2.1	2.1	1.3	1.6	68%	30%	1%
	Daily Adj (+ or -)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	32%	18%	5%
	Total	2.0	2.0	2.0	2.0	2.9	2.9	2.9	2.0	2.3	-	48%	1%
	Facility Max	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	-	-	2%

Relationship Between the Baseline Method and Program Impacts for the DRP Program

As was shown previously with regards to the CPP and DBP programs, the estimated load reduction impacts calculated using the Representative Day approach are a function of the baseline method selected for the analysis, such that if the baseline method is biased, so too will be the resulting impact estimates. The baselines used for the DRP analysis presented here are slightly different from those presented previously in this section for the CPP and DBP programs. The DRP program used an 8-Day Adjusted baseline for program settlement and impact estimation in 2005 versus the 3-Day baseline which is used for the CPP and DBP programs. Exhibits 7-108 through 7-122 show the range in average hourly impacts for the DRP program resulting from the DRP 8-Day Adjusted baseline, a QC 8-Day Adjusted, a QC 8-Day, a 10-Day, and a 10-Day Adjusted baseline. The difference between the DRP 8-Day Adjusted baseline and the QC 8-Day Adjusted baseline is that the QC 8-Day Adjusted is calculated so as to always be equal to the average of 8 "similar" days, whereas the DRP 8-Day Adjusted could be the average of fewer than 8-Days if recent DRP events had occurred. Each of the baselines is described in detail in Chapter 6. The exhibits present the average hourly impact across all 2005 DRP events.

In addition to the average hourly impact across the 2005 DRP events, Exhibits 7-108, 7-111 and 7-112 also include a line which represents the average utility reported impact across all 2005 events. This average is calculated from individual event impact estimates each utility files with the CPUC monthly. The method used to calculate the impact estimate for an event varies by utility. PG&E reports the average hourly nomination from the APX DRP website. As Exhibit 7-108 shows this method works fairly well when averaged over the whole summer, but doesn't perform as well for individual events where the nomination realization rate is significantly greater or less than 100 percent. Appendix D6 presents the hourly impact tables for the DRP program which include the hourly nomination realization rates for each of the baseline methods analyzed. SCE pulls the impact estimates submitted as part of their monthly CPUC report from the maximum hourly nomination on the APX DRP website. Exhibit 7-111 shows that this method over-estimates the actual load reduction by almost 100 percent. SDG&E down loads the actual hourly curtailment from the APX DRP website and takes an average over the event hours. Exhibit 7-112 shows that this method provides the most accurate impact estimated for the DRP program.

The hours for which a DRP event is called vary based on the event and the product type that is dispatched. In the series of exhibits that follow the number of events included in the hourly average is displayed along with the Hour Ending label on the X-axis. The product types called for a particular hour are included in Chapter 6, Exhibit 6-3.

Exhibit 7-108
PG&E Average Estimated Impact Across All Baseline Methods

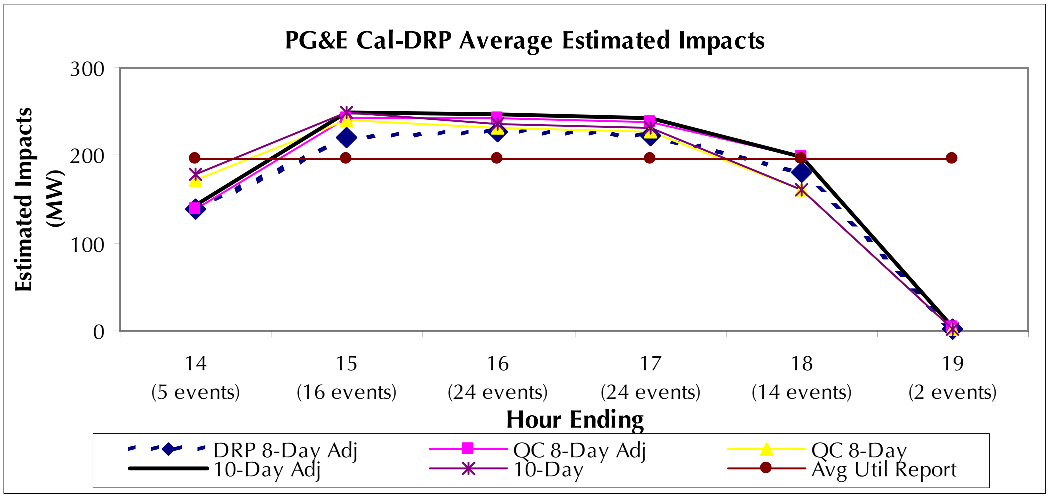


Exhibit 7-109
PG&E Average Estimated Impact Across All Baseline Methods
Based on Single Large Pumping Customer

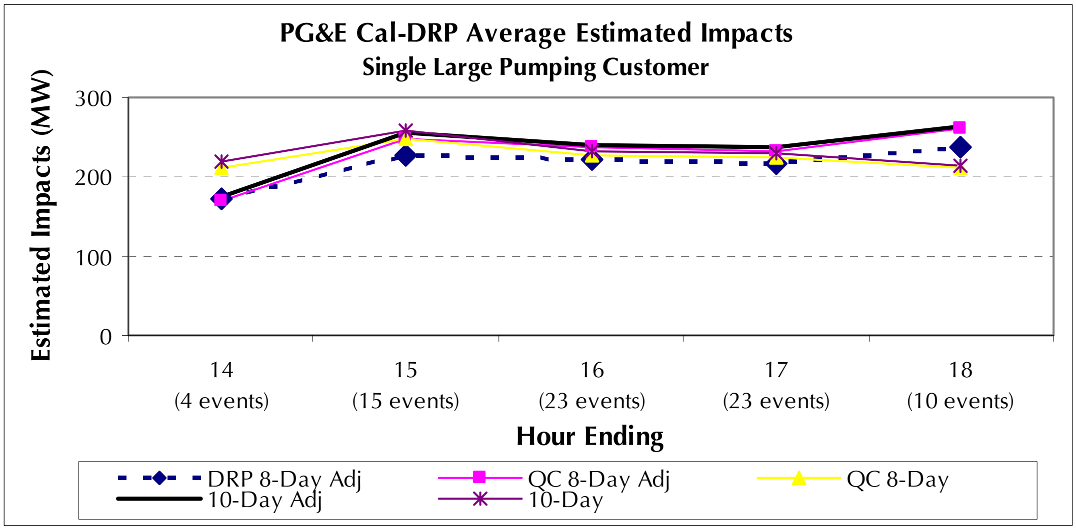


Exhibit 7-110
PG&E Average Estimated Impact Across All Baseline Methods
Excluding Single Large Pumping Customer

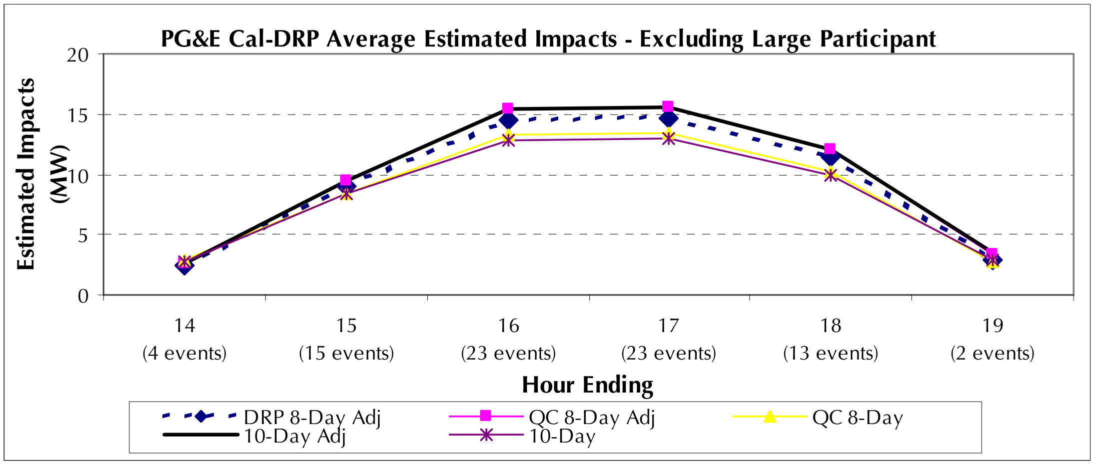


Exhibit 7-111
SCE Average Estimated Impact Across All Baseline Methods

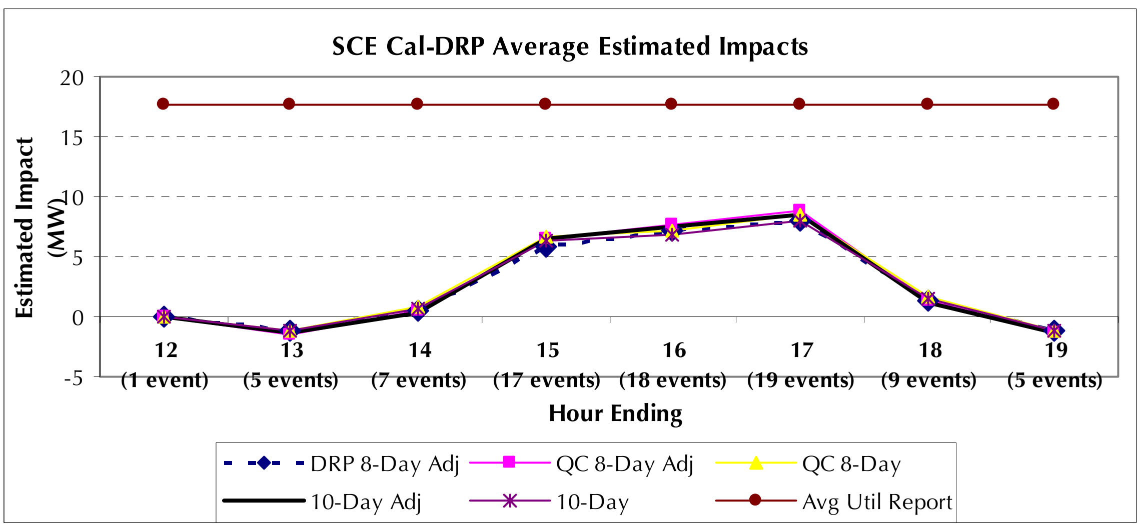
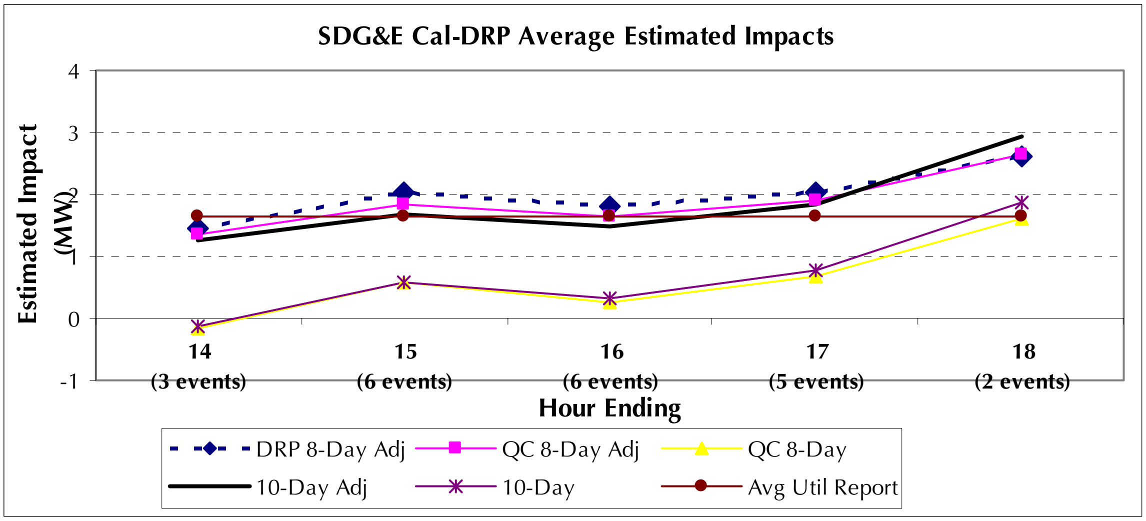


Exhibit 7-112
SDG&E Average Estimated Impact Across All Baseline Methods

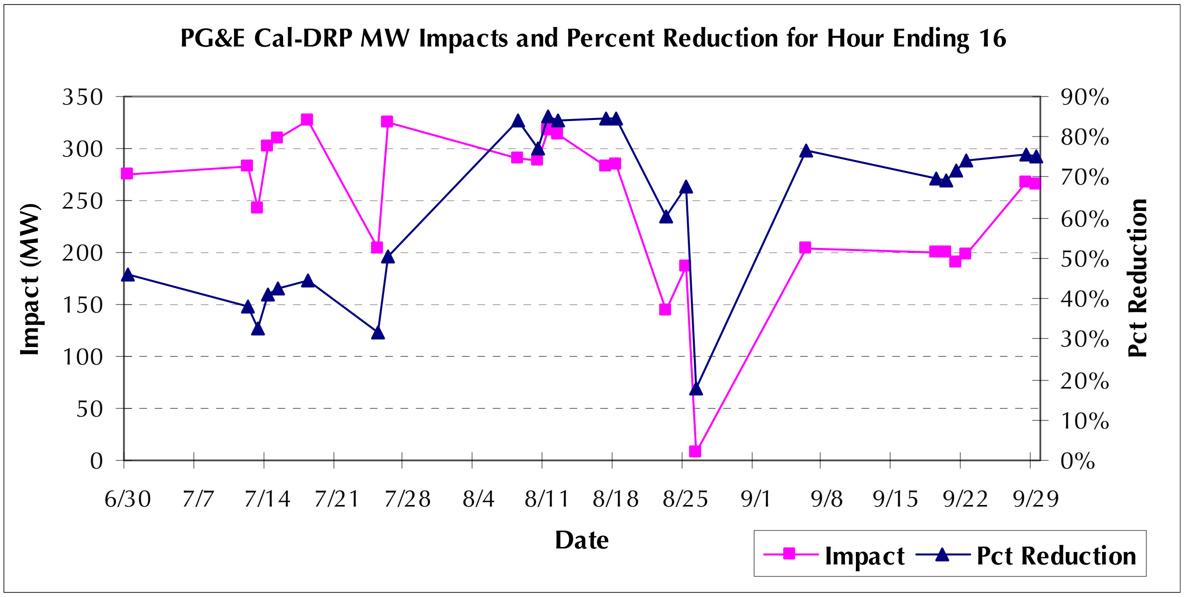


Hourly Program Impacts for DRP

To get an idea of how the DRP program performed in each of the service territories over the course of the entire summer, the hourly program impacts were calculated across all DRP participants who nominated load for an event. Exhibits 7-113 through 7-117 present the hourly DRP program impacts for a particular event hour based on the 10-Day Adjusted baseline. Within SDG&E service territory there was no one event for which all events were called and thus the exhibit reflects the maximum program impact out of a series of possible event hours. The impacts in these exhibits are expressed as both as a total MW reduction and as a percent load reduction. A complete listing of the average daily MWh impact estimates, as well as the average percent load reduction, for each of the summer 2005 DRP events is provided in Appendix D7.

As the following exhibits illustrate, the program impacts vary widely across events. This fluctuation is primarily driven by the hours, zones, and product types for which individual events are called. Exhibit 7-113 below presents the hourly program impact for hour ending 16 (3PM to 4PM) across all 24 of the DRP events that were called within the PG&E zone. This exhibit shows the DRP impacts range from a maximum of 326 MW for the July 18th event to a minimum of 7 MW for the August 26th event. The August 26th event is clearly out of range compared to the other PG&E DRP events which is a result of the event not being called on this date for the single large customer. The minimum hourly program impact for an event which included this large customer was 144 MW (August 23rd event).

Exhibit 7-113
PG&E DRP Hourly Program Impacts Across the 2005 Events (24 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced



The next exhibit, Exhibit 7-114, presents the hourly program impact for hour ending 16 (3PM to 4PM) across the 23 DRP events called for the single large pumping customer within one of the PG&E zones. This exhibit shows that for this customer the program impacts range from a maximum of 309 MW for the July 26th event to a minimum of 147 MW for the August 23rd event. It is interesting to observe how the hourly MW impact and percent load reduction seem to switch places half way through the summer in this exhibit. As mentioned previously, the estimated base load for this customer steadily declined between July and September. The customer's average base load in July was around 500 MW, decreased to 300 MW in August and was around 200 MW in September. Although this customer's nomination remained constant at 200 MW throughout the entire summer, and the exhibit shows they reduced their load by more than their nomination during the first half of the summer, their percent load reduction hovered around 50 percent since it was relative to this larger base load. As the summer progressed and the customer base load declined, their percent load reduction increased to close to a 100 percent despite the reduction in the impacts they delivered.

Exhibit 7-114
PG&E DRP Hourly Program Impacts Across the 2005 Events (23 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced
Single Large Pumping Customer

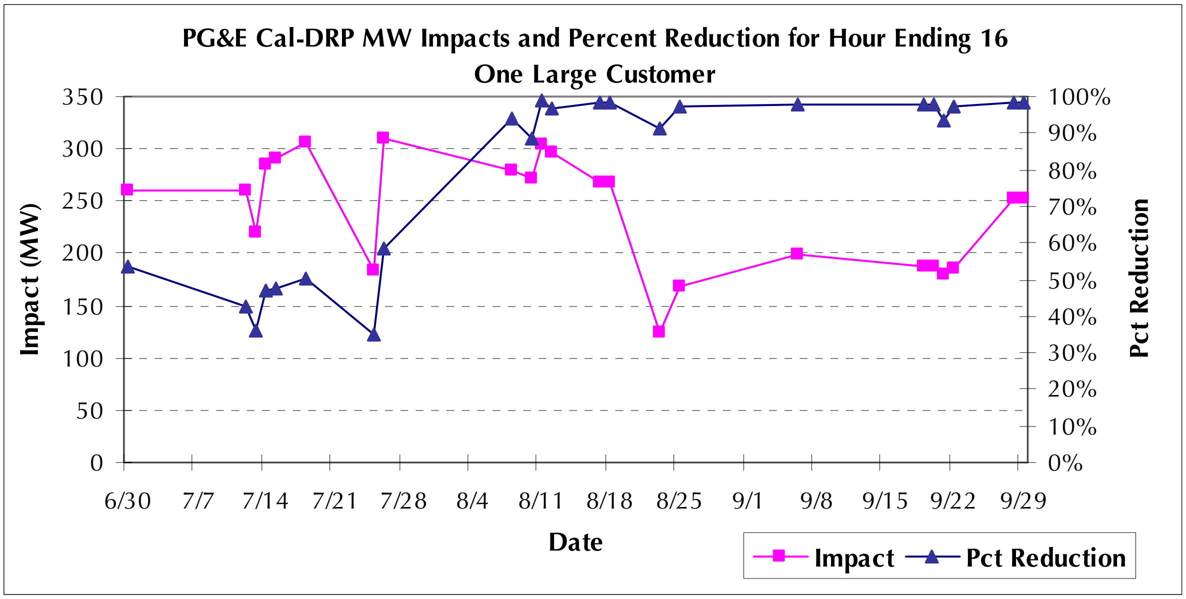


Exhibit 7-115 below presents the hourly program impact for hour ending 16 (3PM to 4PM) across the 24 DRP events called for all DRP participants within the PG&E zone except the single large pumping customer. This exhibit shows that with the single large pumping customer removed, the program impacts range from 21.7 MW for the July 12th event to a 5.7 MW for the August 6th event. Without the single large pumping customer the PG&E DRP impacts are approximately the same magnitude as the SCE impacts displayed in Exhibit 7-116.

Exhibit 7-115
PG&E DRP Average Hourly Program Impacts Across the 2005 Events (24 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced
Excluding Single Large Pumping Customer

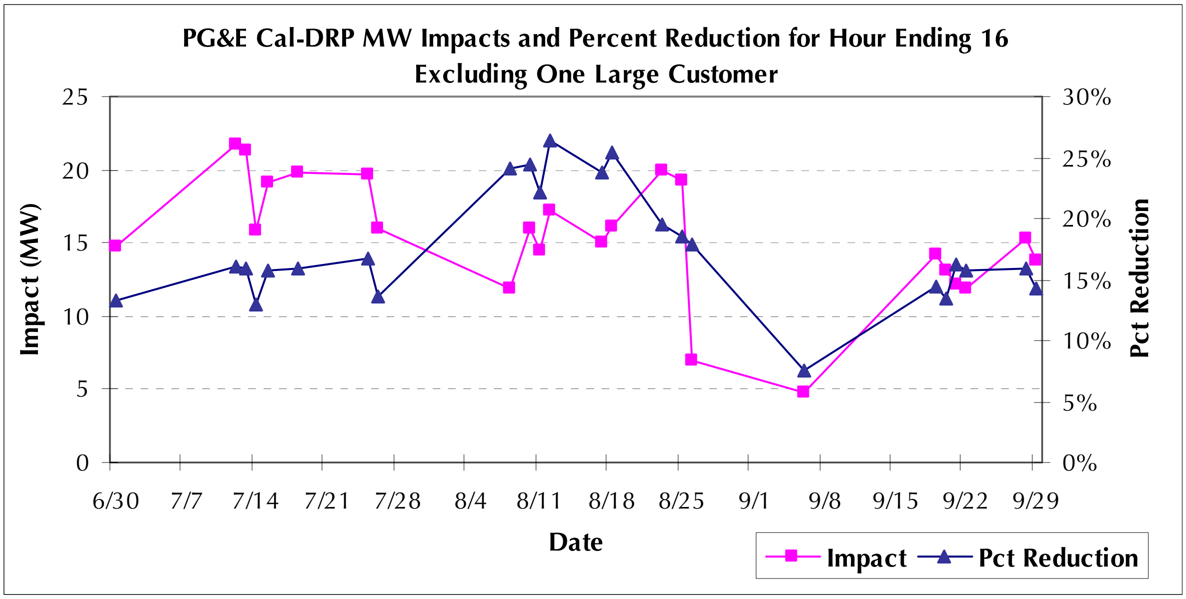


Exhibit 7-116 below presents the hourly program impact for hour ending 17 (4PM to 5PM) across the 19 DRP events called for participants within the SCE zone. The impacts across the SCE DRP events range from 25 MW for the August 25th event to a -1.2 MW for the September 6th event. There was also one fairly large customer enrolled in the DRP program within the SCE zone. This customer, who nominated load for five of the summer 2005 events, is responsible for the wide fluctuations in Exhibit 7-116. The five events for which this customer placed a nomination were the July 13th and 14th events and the August 17th, 25th and 26th events. The August 25th event was the only event for which this customer reduced its load to the nominated level, which is why the MW impact for this event is more than 10 MW larger than any of the other events. And for the events on July 14th and August 17th this customer actually increased its consumption, which is why the impacts associated with these two events are so low.

Exhibit 7-116
SCE DRP Hourly Program Impacts Across the 2005 Events (19 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced

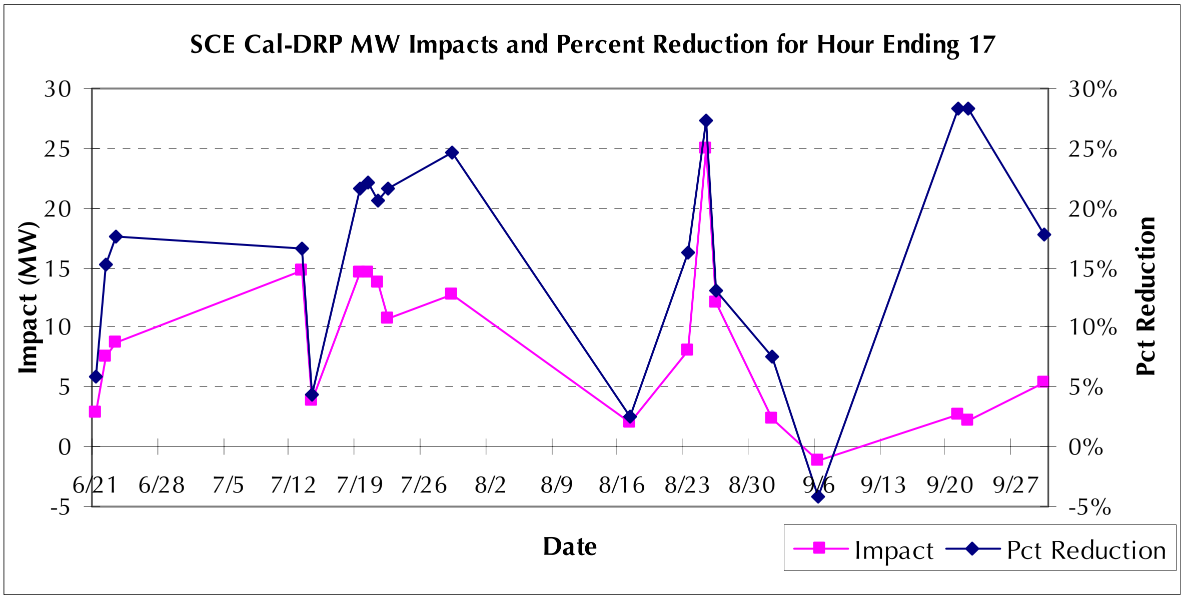
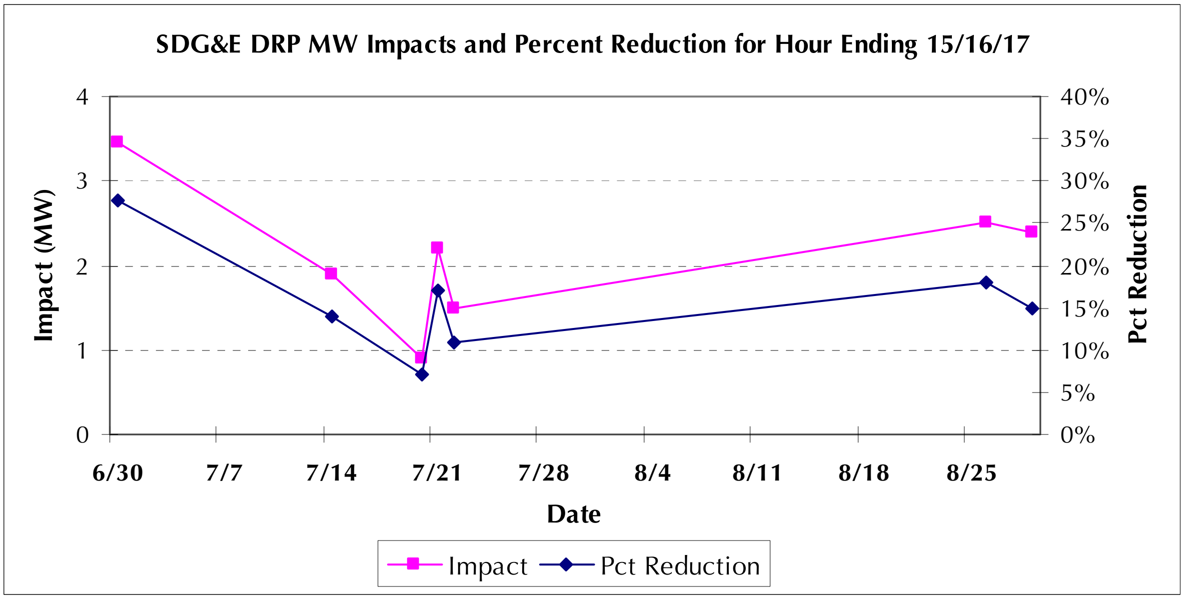


Exhibit 7-117 below presents the maximum hourly program impact for DRP participants within the SDG&E zone across hours ending 15, 16 and 17 for the 7 DRP events called within this zone. The impacts across the SDG&E DRP events range from a maximum of 3.4 MW for the June 30th test event to 0.5 MW for the July 22nd event.

Exhibit 7-117
SDG&E DRP Hourly Program Impacts Across the 2005 Events (7 Events)
Impacts Expressed as MW Reductions and Percent of Load Reduced



Complete Hourly Program Impacts for the DRP Program Events

The hourly variation in program impacts across all of the 2005 DRP events was also included in this year's impact analysis. Exhibits 7-118 though 7-121 present the hourly impacts for each of the DRP events occurring throughout the summer of 2005 based on the 10-Day Adjusted baseline, as well as the *average* hourly impact across all of the summer events. These exhibits illustrate that for all of the utilities there is a large degree of variation in the estimated impacts from event to event, as well as from hour to hour. For PG&E and SCE, the DRP impacts were at their highest levels during the mid-event hours. It is during these hours that the program tended to be called across the widest spectrum of DRP product types. For SDG&E the impacts seemed to increase over the course of the five program hours, the last hour being primarily driven by one of the seven events. A complete listing of the hour-by-hour MW impacts for each event across the three utilities can be found in Appendix D6.

Exhibit 7-118
PG&E DRP Hourly Program Impacts for Each of the 2005 Events (24 Events)

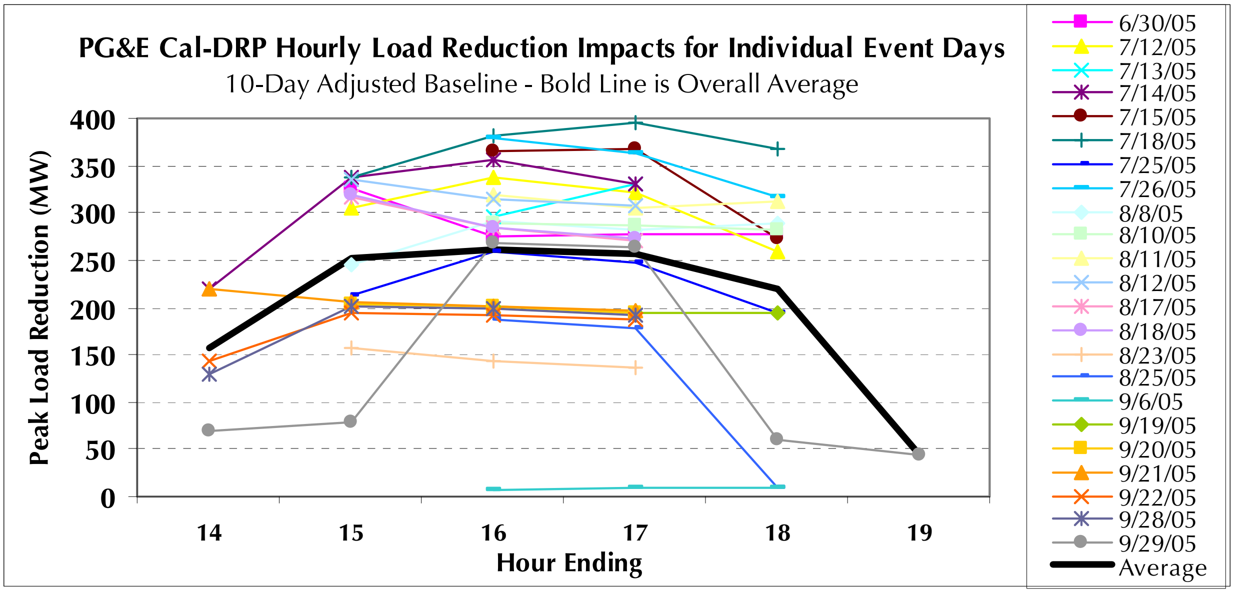


Exhibit 7-119
PG&E DRP Hourly Program Impacts for Each of the 2005 Events (24 Events)
Excluding Single Large Pumping Customer

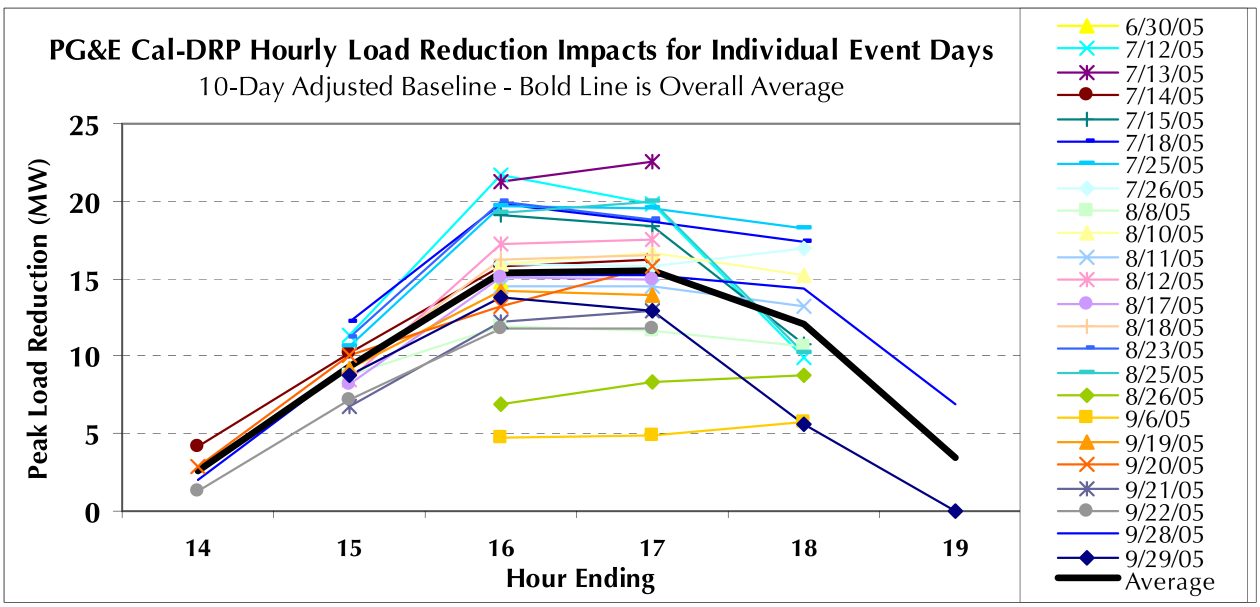


Exhibit 7-120
SCE DRP Hourly Program Impacts for Each of the 2005 Events (19 Events)

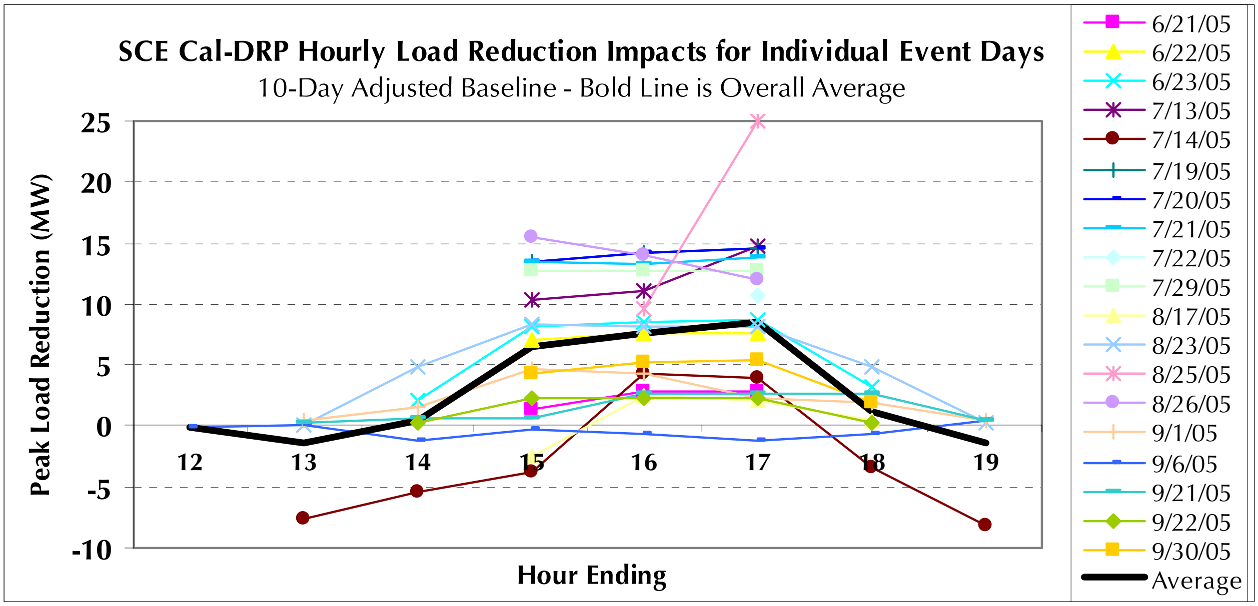


Exhibit 7-121
SDG&E DRP Hourly Program Impacts for Each of the 2005 Events (7 Events)

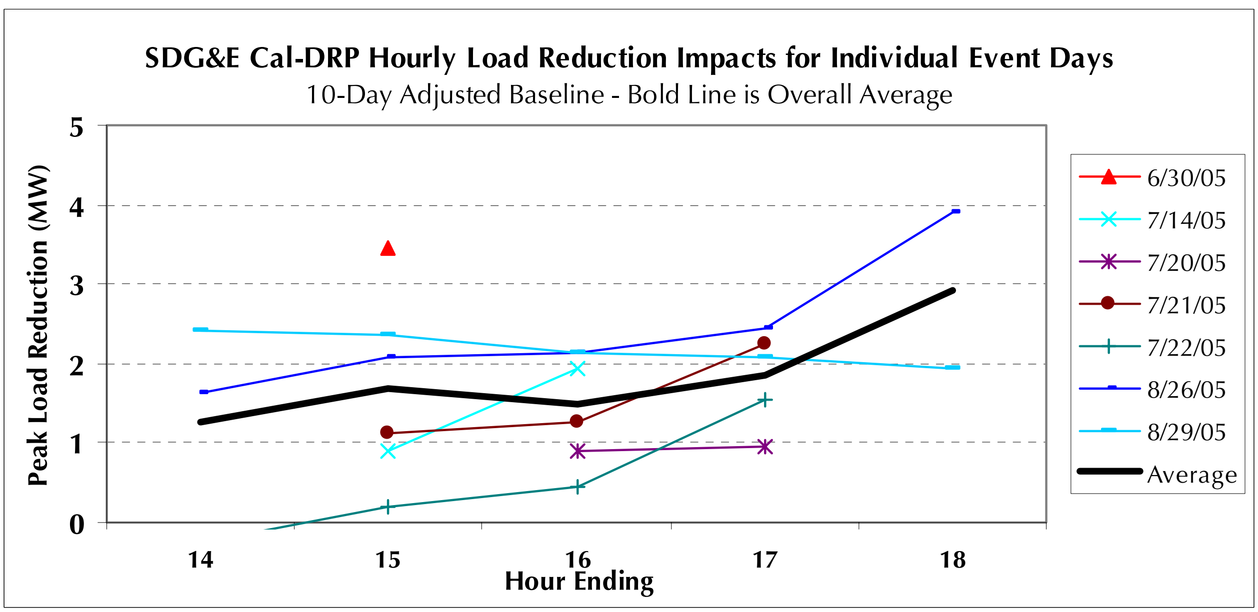


Exhibit 7-122 below presents the estimated average hourly base load and DRP impact for the single large PG&E participant, the remaining participants and the overall average. This exhibit shows that the single large participant is almost 100 times the magnitude of the other customers participating in the program. This large participant also reduces 66 percent of their load on average during an event hour, compared to 15 percent across the remaining customers. This participant also tends to reduce more than their nominated capacity, when they can feasibly do so, despite receiving no additional compensation for this excess load.

Exhibit 7-122
Average Hourly Estimated Load and Impacts over All Event Hours (MW)
Single Large Customer Vs. All Remaining Customers

Average Hourly Estimated Impacts and Percent Load Reduction Based on the 10-Day Adjusted Baseline			
Population	**Overall Average**	**Single Large Customer**	**All Remaining Customers**
Total Event Hours	**2,132**	**75**	**2,057**
Baseline Load (MW)	**17.4**	365.1	4.7
Estimated Impact (MW)	**9.2**	242.1	0.7
Percent Reduction	**53%**	**66%**	**15%**
Event Nomination (MW)	**8.1**	200	1.1
Nomination Realization Rate	**114%**	**121%**	**66%**

Exhibit 7-123 below shows that when we sum the MWh impacts for all event hours across the whole summer, the single large customer makes up 74 percent of the total base load, 87 percent of the total nominated load, and 92 percent of the total delivered impacts.

Exhibit 7-123
Sum of Hourly Estimated Load and Impacts over All Event Hours (MWh)
Single Large Customer vs All Remaining Customers

Total Estimated Impacts 10-Day Adjusted Baseline	**Overall Total**	**Single Large Pumping Customer**		**Remaining Customers**	
		Estimated (MWh)	**% of Total**	**Estimated (MWh)**	**% of Total**
Baseline Load (MWh)	**37,073**	27,385	74%	9,688	26%
Estimated Impact (MWh)	**19,643**	18,156	92%	1,487	8%
Event Nomination (MW)	**17,241**	15,000	87%	2,241	13%

Exhibit 7-124 below provides the average estimated hourly impact for the 3 to 4 o'clock hour (which was the hour with the maximum load reduction on a statewide basis) for each of the utilities. The range in average hourly impacts on a statewide basis was as low as negative 1 MW for the hour ending 13 (12-1PM) to as high as 25.9 for hour ending 17 (3-4PM). The average across all hours was approximately 11 MW. This exhibit excludes the large PG&E pumping customer. The customers nominating load for events were able to reduce their loads by similar levels across all three of the utilities (statewide average of 16 percent). DRP participants within the PG&E congestion zone realized a higher percentage of their nomination

(83 percent) than did participants in the SCE and SDG&E congestion zones (who realized 49 and 58 percent of their nominations respectively).

Exhibit 7-124
Average Estimated Hourly Impact for Maximum Impact Hour by Utility
Excludes Single Large Pumping Customer

Average Estimated Hourly Impacts for Higest Impact Hour (Hour Ending 17, 4 - 5 p.m.)				
10-Day Adjusted Baseline Estimates	**Total**	**PG&E**	**SCE**	**SDG&E**
Baseline Load (MW)	**158.6**	89.7	55.2	13.6
Impact (MW)	**25.9**	15.5	8.5	1.8
Percent Reduction	**16%**	17%	15%	14%
Event Nomination (MW)	**39.4**	18.7	17.5	3.2
Nomination Realization Rate	**66%**	83%	49%	58%

7.2 MULIVARITATE REGRESSION IMPACT RESULTS

In this section, impacts based on the multivariate regression methodology for the summer 2005 CPP and DBP are presented for each utility. In essence, this analysis was more of an investigation into the use of regression analysis for these types of programs in the large C&I sector rather than a definitive estimation of the impacts of these particular programs. As such, a small portion of the potential uses of these types of models is presented. Also, the multivariate regression analysis presented here is completed as an *ex post* analysis of the total impact of the programs, as opposed to a method to obtain real-time estimates for program settlement. This allows for the inclusion of all available data in the regression models (i.e., both pre- and post-event data). In addition, the regression specification used in this analysis produces the average impacts per event hour across the summer. Alternative specifications can produce estimates of hourly impacts for specific events, but this additional event-specific analysis was not performed as part of this assessment effort.

7.2.1 CPP Impact Results

As stated in Chapter 6, the multivariate regression of CPP involves estimating time-series regression models that were specific to each customer in each utility. In all cases, the dependent variable in these models was the average hourly metered kW for each customer for the summer of 2005 (over 3,000 observations for each firm). The independent variables were:

- A constant term
- The temperature for that hour
- The humidity for that hour
- The temperature for that hour squared (to capture non-linear responses)

- The temperature times humidity (to capture interactive weather response)

- Twenty-three hourly indicator variables for the hours of the day (e.g., hour1 equals 1 if the hour is 1:00AM, 0 otherwise). The 24th hour effect is subsumed into the constant term.

- Indicator variables for the months of June, July, and August (to capture seasonality)

- The hour's average kW 24, 48, and 72 hours prior (to capture daily carryover)

- The program response variable, which equals one if the hour is during a CPP event, zero otherwise.

The model used is linear, which implies that the coefficient on the CPP event zero is simply the change in average kW for the customer averaged over all CPP events. Later, a model that captures changes in kW after the CPP events is presented.

The issue of autocorrelation (i.e., error terms across hours are correlated) is significant in these models. In order to correct for this correlation, an AR(1) correction was employed using maximum likelihood methods. Under AR(1):

$$\varepsilon_{i,t} = \rho_i \varepsilon_{i,t-1} + \mu_{i,t}$$

Where $\varepsilon_{I,t}$ is the error term for customer i at time t, ρ is the AR term, and $\mu_{i,t}$ white noise error. Autocorrelation is commonly corrected by using the Cochrane-Orcutt approach, where the model first estimated without regard to the presence of autocorrelation. The error terms of this step are then used to develop an estimate of ρ:

$$\hat{\rho} = \frac{\hat{\varepsilon}_t \cdot \hat{\varepsilon}_{t-1}}{\hat{\varepsilon}_t^2}$$

One issue with this approach is that the first observation cannot be used. This analysis used maximum likelihood estimation, in which ρ is estimated at the same time as the regression coefficients (the βs).[28] This approach is preferred because it does not eliminate any observations from the analysis.

An example of an individual regression result is presented in Exhibit 7-125. This example shows that for this participant, the CPP program resulted in a savings of 52.9 kW for each CPP event hour. The key summary statistics for all the individual models are presented in Exhibit 7-126.

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[28] The log-likelihood function may be written

$$\ln L = -\frac{u'u}{2\sigma^2} + \frac{1}{2}\ln(1-\rho^2) - \frac{T}{2}\ln(\sigma^2)$$

Exhibit 7-125
Example Individual Regression Results CPP (dep. variable is hourly kW)

Variable	Coefficient	T-Value
Constant	49.6	0.72
Hour is a CPP event hour	-52.9	-3.07
Current hour's temperature	-0.8	-1.04
Current hour's humidity	0.1	0.46
kW used 24 hours ago	0.2	14.06
kW used 48 hours ago	-0.2	-8.65
kW used 72 hours ago	-0.1	-5.87
Hour is 1:00	-1.3	-0.28
Hour is 2:00	-2.2	-0.33
Hour is 3:00	5.7	0.74
Hour is 4:00	22.5	2.56
Hour is 5:00	172.0	16.32
Hour is 6:00	301.3	23.41
Hour is 7:00.	315.2	23.44
Hour is 8:00	316.4	23.21
Hour is 9:00	344.0	24.14
Hour is 10:00	366.7	24.46
Hour is 11:00	373.5	23.63
Hour is 12:00	351.4	21.14
Hour is 13:00	356.1	19.79
Hour is 14:00	348.2	18.25
Hour is 15:00	328.3	16.80
Hour is 16:00	298.3	15.59
Hour is 17:00	178.0	10.32
Hour is 18:00	38.6	2.53
Hour is 19:00	23.0	1.70
Hour is 20:00	12.0	1.08
Hour is 21:00	6.3	0.72
Hour is 22:00	3.8	0.57
Hour is 23:00	1.4	0.30
Day is a Monday	-8.3	-0.84
Day is a Tuesday	0.9	0.09
Day is a Thursday	8.5	0.86
Day is a Friday	10.2	1.04
Day is in June	-1.3	-0.05
Day is in July	-1.9	-0.07
Day is in August	1.4	0.05
Number of Observations (hours)	3240	
R-Squared	94.2	

Exhibit 7-126
Individual Regression Results Summary and Total Program Impacts for the CPP

Estimated Coefficient (savings are positive)	Utility		
	PG&E	SCE	SDG&E
Number of regression equations (customers)	262	8	105
Estimated Individual kW impacts			
Highest Savings and t-value	837 (3.9)	534 (12.9)	473 (5.9)
Lowest Savings and t-value	546 (2.2)	0.1 (0.1)	51.4 (0.9)
Number of Statistically Significant			
Savings	43	2	26
Increased consumption	24	1	10
Total Program Savings MW and t-value	**147 (5.8)**	**39.5 (10.6)**	**124.3 (15.4)**
Total Percentage Reduction	2.2%	33.9%	9.6%

These results show that according to the regression analysis, CPP does produce kW savings. The resulting impacts are consistent with the results obtained from the representative day baseline analysis for SCE and SDG&E, but differ for PG&E. A comparison of the impacts from the two methods is included below in Exhibit 7-133.

Since the individual regression models presented above use a single CPP indicator variable, the results are the average hourly impacts over the CPP event. One of the benefits of a regression approach is that there is the flexibility in how the program can be incorporated in the model. For example, one can replace the single CPP indicator variable with a series of variables that indicate each hour of the CPP event (i.e., first hour to the last hour), as well as hours after an event. As an illustration of how this approach can be used in future analyses of these programs, Exhibit 7-127 presents the summed results of using such a model for PG&E CPP.[29]

Exhibit 7-127
Example CPP Total Impacts Using Hour of Event Indicators, for PG&E
(Dependant variable is hourly kW)

Estimated Coefficient (savings are positive)	PG&E	
	Coeff.	t-value
First hour of CPP event	2,723	5.17
Second hour of CPP event	941	1.38
Third hour of CPP event	335	0.44
Fourth hour of CPP event	2,386	2.97
Fifth hour of CPP event	2,525	3.14
Sixth hour of CPP event	2,831	3.69
First hour ***after*** CPP event	901	1.32
Second hour ***after*** CPP event	313	0.60

29 PG&E's program was used for this and the next model because it has the largest group of participants. The individual models include all the other variables presented in Exhibit 7-125.

These results indicate that the savings during a CPP event is relatively constant except, in this case, for a dip during the second and third hours. Much of this change in the second and third hours is due to changes by customers who actually increase their consumption during the CPP event, so this variability is probably due to other non-observed effects. The results also show that there appears to be no "takeback" after an event. The total average kW continues to drop slightly, but the results are not statistically significantly different from no effect at all. This approach can be used to specify impacts for any given hour in any given CPP event.

Another example of this approach involves determining the variation in impact depending upon the day of the week, or the month for which an event is called. The regression model that produced the results presented in Exhibit 7-128 below included dummy variables for all possible event days, except Mondays, and for all CPP event months, excluding September. The model coefficients listed below for Tuesday through Friday events, or July and August events, represent deviations to the savings estimates calculated for Monday events in September. These results show that CPP program impacts within PG&E territory are highest for events occurring on Mondays and lowest for events on Thursdays. Similarly, events occurring in July realized more load reductions than August or September events.

Exhibit 7-128
Example CPP Total Impacts Using Month and Day of Week Indicators, for PG&E
(Dependant Variable is Hourly kW)

Estimated Coefficient (savings are positive)	**PG&E**	
	Coeff.	**t-value**
CPP Event in July	3,096	6.17
CPP Event in August	414	0.61
CPP Event on Tuesday (incremental)	-269	-0.37
CPP Event on Wednesday (incremental)	-448	-0.48
CPP Event on Thursday (incremental)	-1,442	-1.53
CPP Event on Friday (incremental)	-571	-0.73

These results show that there is variation in the impacts, with the largest savings occurring for Thursday events, where savings are 1,442 kW greater than the rest of the week. However, these results are not statistically significant, so definitive statements cannot be made regarding these results.

The impacts presented so far only present the average response across customers. As discussed in Chapter 6, a key input for understanding the current and future program response is estimating how the program response differs across customers. In other words, are there customers that are inherently more responsive to the program than other groups? In order to address this issue, it is possible to develop a pooled model that relates the estimated program response produced by individual time-series models to customer characteristics. Given the limited participant population of the current programs, the robustness of the model shown here is limited. However, to aid in potential future research, we developed this model for the PG&E CPP population.

In this model, the dependent variable is the estimated individual program response coefficients from the individual time-series models. The independent variables in this example were restricted to those variables that are both readily observable and available for all CPP participants. In this case, that amounted to business type and size[30].

Since this is a cross-sectional model, heteroskedasticity can be an issue. The dependent variable is the estimated program response and the natural measure of this variable's variance is the variance found from the regression equation. Therefore, by using weighted least squares, where the weight is the estimated variance of each individual's price response, it can be expected that the effect of heteroskedasticity is minimal.[31] The results are presented in Exhibit 7-129.

Exhibit 7-129
Example CPP Impacts Using Customer Size and Business Type Indicators, for PG&E
Dependent Variable is Estimated CPP Response

Estimated Coefficient (savings are positive)	PG&E	
	Coeff.	t-value
Constant	3.5	1.40
Extra large firm	-1.4	-0.16
Large firm	1.2	0.55
Medium firm	0.1	0.05
Very small firm	-4.9	-1.00
Institutional	-1.9	-0.71
Commercial	-3.5	-1.27

This application did not identify any statistically significant variables, and it is difficult to draw many conclusions from this model. However, the model can be used to show how impacts from a given customer segment can be estimated. For example, the model indicates that a Large Institutional customer is likely to save 2.8 kW during a CPP event (i.e., 3.5 kW + 1.2 kW + -1.9 kW).

7.2.2 DBP Impact Results

The multivariate regression impact evaluation of the DBP is similar to the approach used for the evaluation of CPP. The only difference in the individual time-series models is that the CPP event indicator variable is replaced with the customer's bid during a DBP event. Thus, the dependent variable in these models was the average hourly metered kW for each customer for the summer of 2005 (over 3,000 observations for each firm). The independent variables were:

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[30] Business type was defined based on the NAICS code associated with the participating account. For this analysis the NAICS codes were rolled up into 3 business types: Industrial, Commercial, and Institutional (which included Transportation, Communication, and Utilities). The size classification variable was assigned based on the customer's maximum demand in 2004. The size categories included Extra-Large (>2MW), Large (1-2MW), Medium (500kW – 1MW), Small (200-500kW), Very Small (100-200kW) and for SDG&E only Extra Small (20-100kW).

[31] The model includes program responses that are both savings and increases in consumption (to be consistent with the baseline work). Since there is nothing inherent in the program that would make customers consume more during an event, an alternative is to recode all positive savings (increased consumption) to zero, In this case, a weighted Tobit (i.e., censored) model is appropriate.

- A constant term
- The temperature for that hour
- The humidity for that hour
- The temperature for that hour squared (to capture non-linear responses)
- The temperature times humidity (to capture interactive weather response)
- Twenty-three hourly indicator variables for the hours of the day (e.g., hour1 equals 1 if the hour is 1:00AM, 0 otherwise). The 24th hour effect is subsumed into the constant term.
- Indicators variables for the months of June, July, and August (to capture seasonality)
- The hour's average kW 24, 48, and 72 hours prior (to capture daily carryover)
- The program effect is captured by a variable equal to the customer's bid for that hour

If the customer did not bid, or the hour is not a DBP event, then the value for this variable is zero. As such, this coefficient represents the customer's bid realization rate (i.e., the proportion of their bid that the customer actually achieved). To control for autocorrelation, an AR(1) specification was used, and all estimated autocorrelation terms where near one and highly statistically significant. The key summary statistics of these models are presented in Exhibit 7-130.

Exhibit 7-130
Individual Regression Results Summary and Total Program Impacts for the DBP

Estimated Coefficient (savings are positive)	**Utility**		
	PG&E	**SCE**	**SDG&E**
Number of regression equations (customers)	68	93	23
Estimated Individual kW impacts (all bids)			
Highest Savings and t-value	30,029 (5.3)	4,557 (19.5)	633 (4.7)
Lowest Savings and t-value	-23,194 (2.0)	-109 (0.6)	-9.9 (0.7)
Number of Statistically Significant			
Savings	29	26	11
Increased consumption	3	3	0
Total Program Savings MW and t-value	**226.4 (10.4)**	**172.4 (13.8)**	**9.2 (7.0)**
Total Bid Realization Rate	11.9%	13.8%	7.4%
Total Percentage Reduction	7.8%	2.5%	5.5%

These results show that there are load impacts associated with DBP, and these impacts are statistically significant.

The other models that were presented in the CPP discussion, i.e., impacts by hour of the event, or impacts of a function of customer characteristics, can be estimated for DBP as well.

However, given the relatively small population, these models may not be appropriate at this time.

There is one significant difference between CPP and DBP. In CPP, the program effect is exogenous in that firm's do not have the ability to set electricity prices during a CPP event. For DBP however, the program effect term is endogenous since firms determine the level of their bid. This endogenaity can lead to biased coefficients.[32] One common approach to correct for this is a two-stage model. The first stage involves estimating a bid amount model that attempts to characterize the bid decision as a function of firm characteristics. In the second stage, the load impact model is used and the actual bid is replaced with the estimated bid for all customers from the first stage. This approach can become complicated with repeated events. In addition, determination of the program effect becomes less clear. Therefore, this approach is not recommended for this current analysis. However, we do present an example of the first stage model to help illustrate the concept.

In this bid amount model, the dependent variable is the bid amount (including zeros) the SCE customers made for all DBP events (SCE was used because they had the largest number of DBP participants). Since there are many zeros, a Tobit model is used. The independent variables include:

- Temperature and humidity variables for the DBP hours the day before the event (since the bid must be placed the day before)
- Firm size
- Business type
- The firm's baseline, again on the hours on the day the bid is due. This variable was used to try to capture the flexibility the firm may have in altering their consumption.

The results are presented in Exhibit 7-131.

[32] This is the same endogenaity found in self-selection bias.

Exhibit 7-131
Example of DBP Bid Amount Model, for SCE.
Dependent Variable is Hourly Bid

Estimated Coefficient (bids are positive)	SCE	
	Coeff.	t-value
Constant	1,628.5	3.25
Temperature	-7.7	-1.66
Humidity	-14.0	-5.55
Baseline	0.1	14.37
Large firm	-29.3	-0.56
Medium firm	-119.1	-2.21
Small firm	-194.3	-3.45
Institutional	-451.0	-13.40
Commercial	-338.1	-6.92

This model shows that as the temperature and humidity increase, the bid amount decreases. Also, Institutional firms are likely to bid the least. Again, to predict the likely bid for any customer type, one just combines the coefficients for that customer. For example, the estimated bid for an Large Commercial customer with a 1,000 kW load when the temperature is 90° and the humidity is 50 percent is likely to bid -131.9 kW (1628.5+90*-7.7+50*-14+1000*.1-29.3-338.1). Thus, we would observe no bids from this customer (since the bid amount is less than 0).

7.3 COMPARISON OF IMPACT CALCULATION METHODS

This section compares the impacts based on the three primary impact calculation methods: the current utility settlement method (the 3-Day baseline), the evaluation method (10-Day Adjusted baseline), and the regression method. Exhibit 7-132 below provides average hourly impacts based on these three methods, along with percent load reductions these impacts represent. This exhibit also presents the relative size of the impact estimates based on one method versus another. For instance, within the PG&E CPP program the 3-Day baseline estimated an average load reduction of 11.2 MW compared to the 10-Day Adjusted baseline which resulted in an hourly impact estimation of 7.0 MW. The relative size of these two impact estimates was calculated as the ratio of the 10-Day Adjusted impact estimate divided by the 3-Day impact estimate. This comparison showed that the 10-Day Adjusted baseline method resulted in an hourly impact estimate that was 63 percent of the estimate from the 3-Day baseline method.

Exhibit 7-132
Impact Calculation Method Comparison – 3-Day Baseline vs. 10-Day Baseline vs. Regression

Program	Impact Calculation Method	Utility					
		PG&E		SCE		SDG&E	
		Avg Hrly Impact (MW)	Pct Reduction	Avg Hrly Impact (MW)	Pct Reduction	Avg Hrly Impact (MW)	Pct Reduction
CPP	3-Day	11.2	8.7%	0.9	50.9%	5.2	13.5%
	10-Day Adjusted	7.0	5.6%	0.7	44.3%	3.5	9.4%
	Regression	2.7	2%	0.5	34%	3.6	10%
DBP*	3-Day	29.7	47.2%	11.3	12.7%	0.6	13.8%
	10-Day Adjusted	9.9	23%	2.7	3%	0.4	11%
	Regression	3.4	8%	2.1	3%	0.2	6%
Relative Size of Estimated Hourly Impacts Among Methods							
CPP	10-Day vs 3-Day	63%		80%		66%	
	Reg vs 3-Day	24%		61%		68%	
	Reg vs 10-Day	39%		76%		103%	
DBP*	10-Day vs 3-Day	33%		24%		74%	
	Reg vs 3-Day	11%		19%		37%	
	Reg vs 10-Day	34%		77%		50%	

* This exhibit does not include spillover impacts that might occur outside of bid hours.

Comparison between Baseline and Multivariate Regression Results

A natural question that arises from this analysis concerns the relationship between the load reduction impact estimates resulting from the regression analysis and those resulting from the representative day baseline analysis. Exhibit 7-133 and 7-134 present a comparison of the total (i.e., over all customers and all events during the summer of 2005) impacts of the CPP and DBP programs, respectively. They also provide a breakdown for each of the utilities between the impacts contributed by the population of participants identified as High-Load High-Variance based on the algorithms described previously in this chapter.

Exhibit 7-133
Total CPP Impacts: Representative Day versus Regression Results

CPP Impact Analysis Comparison: Representative Day (10-Day Adjusted) versus Regression Results															
CPP Event Information							Representative Day Results				Regression Results				Comparison
Utility	Participants		2005 Events		Total Load		Total Impact		Percent Reduction	Average Hourly Impact	Total Impact		Percent Reduction	Average Hourly Impact	Regression vs Rep Day
	N	%	#	Hrs	MWh	%	MWh	%			MWh	%			
PG&E	**276**	**71%**	**9**	**6**	**6,706**	**83%**	**378**	**69%**	**5.6%**	**7.0**	**147**	**47.3%**	**2.2%**	**2.7**	**39%**
HLHV	9	3%	9	6	2,058	31%	31	8%	1%	0.6	-53	-36%	-3%	-1.0	-173%
non-HLHV	267	97%	9	6	4,648	69%	348	92%	7%	6.4	200	136%	4%	3.7	58%
SCE*	**8**	**2%**	**12**	**6**	**117**	**1%**	**52**	**9%**	**44.3%**	**0.7**	**40**	**12.7%**	**33.9%**	**0.5**	**76%**
SDG&E	**107**	**27%**	**5**	**7**	**1,290**	**16%**	**121**	**22%**	**9.4%**	**3.5**	**124**	**40.0%**	**9.6%**	**3.6**	**103%**
HLHV	7	7%	5	7	88	7%	47	39%	53%	1.3	42	34%	48%	1.2	90%
non-HLHV	100	93%	5	7	1,203	93%	74	61%	6%	2.1	84	68%	7%	2.4	113%
STATEWIDE	**391**	**-**	**26**	**19**	**8113**	**-**	**551**	**-**	**6.8%**	**11.2**	**311**	**-**	**3.8%**	**6.8**	**56%**

* Based on 8 CPP Participants for SCE

Exhibit 7-134
Total DBP Impacts: Representative Day versus Regression Results

DBP Impact Analysis Comparison: Representative Day (10-Day Adjusted) versus Regression Results																			
DBP Event Information									Representative Day Results					Regression Results					Comparison
Utility	Participants		2005 Events		Total Load		Total Bids		Total Impact		Percent Reduction	Bid RR	Average Hourly Impact	Total Impact		Percent Reduction	Bid RR	Average Hourly Impact	Regression vs Rep Day
	N	%	#	Hrs	MWh	%	MWh	%	MWh	%				MWh	%				
PG&E	**73**	**39%**	**10***	**8**	**2,884**	**29%**	**1,901**	**58%**	**664**	**73%**	**23.0%**	**35%**	**8.3**	**226**	**55%**	**7.8%**	**12%**	**2.8**	**34%**
HLHV	**16**	22%	10	8	1,746	61%	1,635	86%	489	74%	28%	30%	6.1	150	66%	9%	9%	1.9	31%
non-HLHV	**57**	78%	10	8	1,138	39%	266	14%	175	26%	15%	66%	2.2	77	34%	7%	29%	1.0	44%
SCE	**93**	**49%**	**12****	**8**	**6,892**	**69%**	**1,253**	**38%**	**225**	**25%**	**3.3%**	**18%**	**2.3**	**172**	**42%**	**2.5%**	**14%**	**1.8**	**77%**
HLHV	**9**	10%	12	8	3,082	45%	751	60%	83	37%	3%	11%	0.9	36	21%	1%	5%	0.4	43%
non-HLHV	**84**	90%	12	8	3,810	55%	502	40%	142	63%	4%	28%	1.5	137	79%	4%	27%	1.4	96%
SDG&E	**22**	**12%**	**12**	**varied**	**167**	**2%**	**124**	**4%**	**18**	**2%**	**11.0%**	**15%**	**0.4**	**9**	**2%**	**5.5%**	**7%**	**0.2**	**50%**
STATEWIDE	**188**	**-**	**34**	**-**	**9,943**	**-**	**3,278**	**-**	**907**	**-**	**9.1%**	**28%**	**11.1**	**408**	**-**	**4.1%**	**12%**	**4.9**	**45%**

* The first 7 PG&E events were excluded from this table due to missing bids
** One of the SCE DBP events was excluded from this table due to missing bids

Based on the results presented in these tables, the estimated impacts resulting from the two techniques for CPP are close for SCE and SDG&E. For PG&E however, the regression approach total estimated impacts are only 40 percent of the estimated impacts based on the representative day approach. This pattern is repeated for the impacts found in DBP, where the regression analysis produces estimates that are below the representative day analysis for all utilities.

One explanation for this difference can be found in the baseline work conducted during the 2004 WG2 DR evaluation.[33] In that analysis, it was found that the all representative day approaches tended to be biased high. Thus, it can be expected that a representative day approach may also produce higher impact estimates. However, this alone does not account for the differences found between the two approaches.

One major difference between the two approaches is that the regression analysis directly incorporates weather conditions, as well as seasonality, month, and day effects. In essence, the representative day approach attempts to manually control for these effects by selecting representative days. This approach may minimize the effects of weather, but is likely to have little effect on seasonal and calendar effects. Additionally, during a summer where events are called repeatedly, which was the case for DBP during the summer of 2005, the choice of similar days requires the analyst to go further back in time, in some cases as many as 30 days, reducing the similarity in the days included in the calculated baselines.

One other significant difference between the two approaches is that the regression model uses data from the entire summer to produce estimates of the load reduction impacts, while the representative day uses a small number (10 at most in this analysis) of days to produce impact estimates. As the discussion of the representative day analysis revealed, there is a large variation in impacts depending upon how many days are used to compute the baseline. This is particularly true of those customers whose day-to-day load varies tremendously (the high variance customers discussed above). The regression analysis, in contrast, essentially eliminates much of this day-to-day variation by looking at data that covers the entire summer. Thus,

[33] *Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

many of the issues associated with the high-variance customers are not found in the regression approach.[34]

A related aspect of this difference is that the representative day approaches examined here only used pre-event data in the baseline, whereas the regression uses data spanning the entire summer, both pre- and post-event. This summer, for example, we found evidence of a few companies that decreased their consumption as of a certain date for numerous consecutive days (both event and non-event days) that did not seem correlated with any of the DR programs. This load reduction, although likely not a result of the program, may be counted as a program impact under the representative day approach. The regression analysis, however, was able to capture the post-event behavior, and thus would not attribute the load reduction to the program. In our analysis of the difference between the two approaches, we determined that this behavior did indeed occur in a fair number of cases (some with significant changes in load).

Exhibits 7-135 and 7-136 below provide an example of a DBP participant whose average hourly load was consistently close to 6 MW during the end of June. Their average hourly load dropped to around 3 MW during the first few weeks in July and finally dropped to 30 kW for the end of July and the entire month of August. Exhibit 7-135 provides the daily load shapes of this participant during the 10 previous "similar" days that are used to calculate the representative day baselines for this participant for the August 4th DBP event. Due to the number of DBP events that occurred in July, within PG&E service territory (13 in total), it was necessary to go back to June to select 10 "similar" days for the representative day baseline calculations for this August 4th event. The 3-Day baseline calculated for this event day had an average hourly load between 3 and 4 MW since June 30th, the 6 MW load day, was included as one of the days in the 3-day average. The 10-Day Adjusted baseline had an average load around 1 MW, which is quite a bit lower than the 3-Day method, because it included a few of the 30 kW load days that occurred in the end of July and early August in the 10-day average.

Looking at the series of load shapes presented in Exhibit 7-135 it is clear to see that the 3-Day baseline overestimates the predicted load and thus the participant's program impact; however the 10-Day baseline in this exhibit appears to be a reasonably good estimate in relation to the 10 previous days. The overestimation that exists for both of these representative day methods does not become obvious until the August 4th event is put into context with other August days (both before and after the event). Exhibit 7-136 displays the daily load shapes for all weekdays in August, including the August 4th event day, as well as the 3-Day and 10-Day Adjusted baseline estimates. From this exhibit, you can see the program impacts estimated using both of these representative day methods, attribute load reductions to the DBP program that most likely should not be counted since this participant shuts down their operations during the month of August. This August shutdown was captured by the regression analysis, and therefore no load reduction impact was counted for this participant for this August 4th event.

[34] We investigated the relative results between the representative day and the regression approaches for the high-variance customers. For these customers, the relative difference between the two approaches was larger than there difference found for non-high-variance customers, with the regression results even further below the representative day results. In addition, the statistical significance of the regression results was lower for the high-variance customers compared to the non-high-variance customers.

Exhibit 7-135
Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the August 4th DBP Event, the Actual Event Day and the 3-Day and 10-Day Adjusted Baseline Estimates

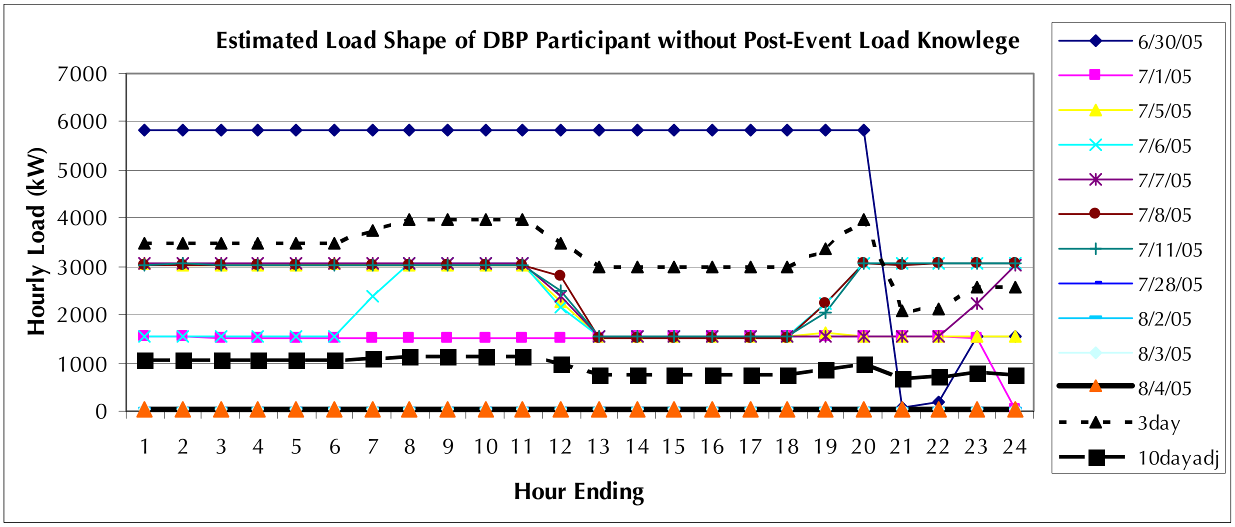
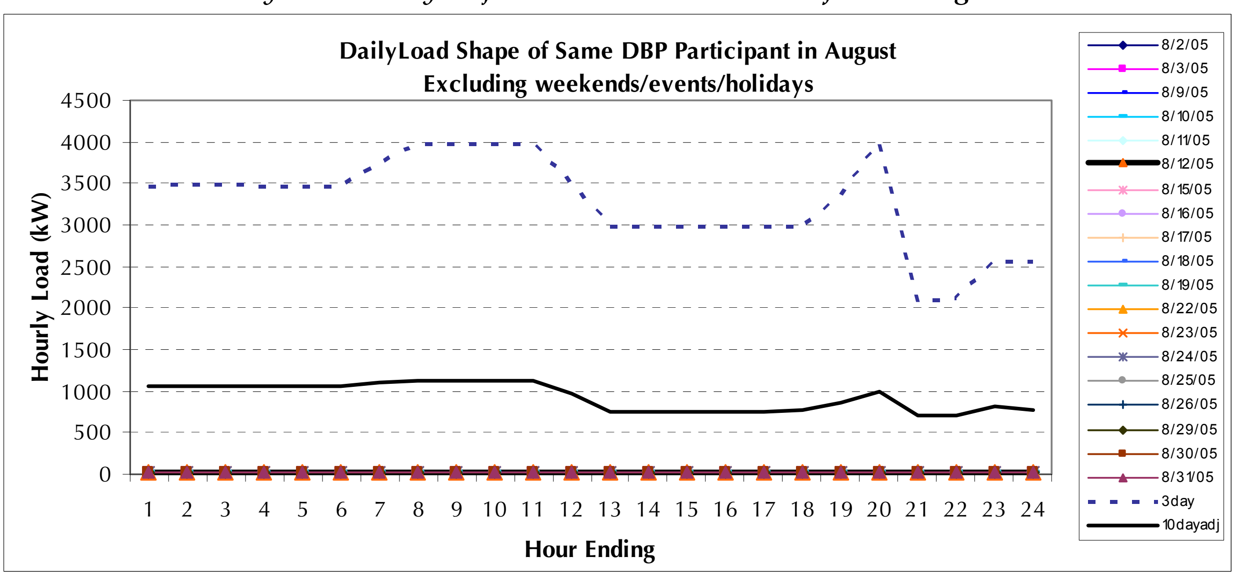


Exhibit 7-136
Daily Load Shapes Associated with a Single Customer for the Month of August in Relation to the 3-Day and 10-Day Adjusted Baseline Estimates for the August 4th Event



A related aspect of this difference is that the representative day approach is only backwards looking for a given event, whereas the regression uses data spanning the entire summer, both pre- and post-event. If, for example, a company decreased its consumption for a long period of time during the summer for a reason unrelated to the program, the load reduction may be counted as a program impact under the representative day approach. The regression analysis, however is able to capture the post-event behavior, and would not attribute the load reduction to the program. In our analysis of the difference between the two impact methodologies, we were able to identify a fair number of customers illustrating this behavior, and for whom the estimated program impacts stemming from the two impact estimation methods were vastly different.

The obvious question is therefore, which approach produced the "truest" estimate of the impact of the program? The answer is that they both do. In terms of an *ex post* analysis, a regression-based approach can be expected to produce more accurate estimates of the impact of the program because it can control for non-program effects and incorporates information for the entire event season. However, for a real-time analysis for settlement purposes, the representative day approach may be preferred for its ease of understanding and implementation. It is likely that in a real-time environment using only pre-event data, the differences between the two approaches are likely to be relatively small. In essence, both approaches are doing the same thing – predicting unobservable behavior from observable data. The main difference is that the effect of non-program variables, such as weather, is directly controlled for in the regression model, whereas it is implicitly controlled for in the representative day model in the process of defining these "representative" days.

7.4 SUMMARY AND KEY FINDINGS

The key findings presented below are based on actual hourly load data of all participants using representative-day and regression-based calculation methodologies. They are broken down by program type, Day-Ahead Programs versus Reliability Programs. The methods used for these findings are presented and discussed in detail in Chapter 6.

7.4.1 Day-Ahead Impact Findings

CPP and DBP Impact Findings

Day-Ahead Programs Were Called Numerous Times in 2005

In the 2004 evaluation we noted that the DBP and CPP programs were called infrequently in summer 2004, with a few exceptions. We also noted that the limited number and types of events called constrained the 2004 impact evaluation and associated confidence with which program impacts were estimated. For example, a key limitation in 2004 was that the DBP program was never called on a day-ahead basis and the day-of events that were called were few and often were test events.[35] For CPP, the vast majority of the participants were in the PG&E and SDG&E programs (as they continue to be) and those programs were called only six and five times, respectively, but often on sequential days. Because of these 2004 event limitations, it was unclear whether the customer behavior observed was representative of behavior under normal program operation or was biased downward. Factors that were considered to have possibly limited observed program impacts for 2004 included the fact that it was the first year of the

[35] In 2004, PG&E called one event, SCE two events, and SDG&E three events, all of the PG&E and SCE events were "test" events, while one of the SDG&E events was a test event.

statewide programs, the fact that only day-of DBP events were called,[36] and the fact that DBP customers may not have taken the test events seriously.

In contrast to 2004, the 2005 CPP, DBP, and DRP programs were called many times in summer 2005 as shown in Exhibit 7-137. In the case of DRP, all of these events were triggered at the request of the utilities because of price. California Energy Resource Scheduling (CERS), which has the ability to dispatch the program when requested by the ISO in cases of supply or transmission constraints, said they had not initiated any of the 2005 events. In the case of the temperature-triggered CPP, periodic adjustments were made to the trigger temperatures (specific to utilities and climate zones within utilities) to ensure that the program would be called the maximum 12 times prescribed by the tariff. For the DBP, events were triggered by a predicted statewide system load of 43,000 MW, which was reached multiple times – even though this was typically not accompanied by supply shortages.

The numbers of events across programs provided a significant increase in the amount of information available for the 2005 impact and process evaluations, the results of which are discussed in the findings throughout this chapter. Given this increase in events, a key question for the 2005 day-ahead programs is the extent to which participants believed the number of events, and justification for calling them, were appropriate. Those issues are addressed in the process evaluation results presented in Chapter 8.

Exhibit 7-137
Number of Day-Ahead Program Events in 2004 versus 2005

Program	Utility	Day-Ahead Program Events	
		2004	2005
CPP	PG&E	5	9*
	SCE	12	12
	SDG&E	6	5
DBP	PG&E	1	17
	SCE	2	13
	SDG&E	3	12
Cal-DRP	PG&E	5	24
	SCE	2	19
	SDG&E	2	7

* First PG&E CPP not billed due to late notification

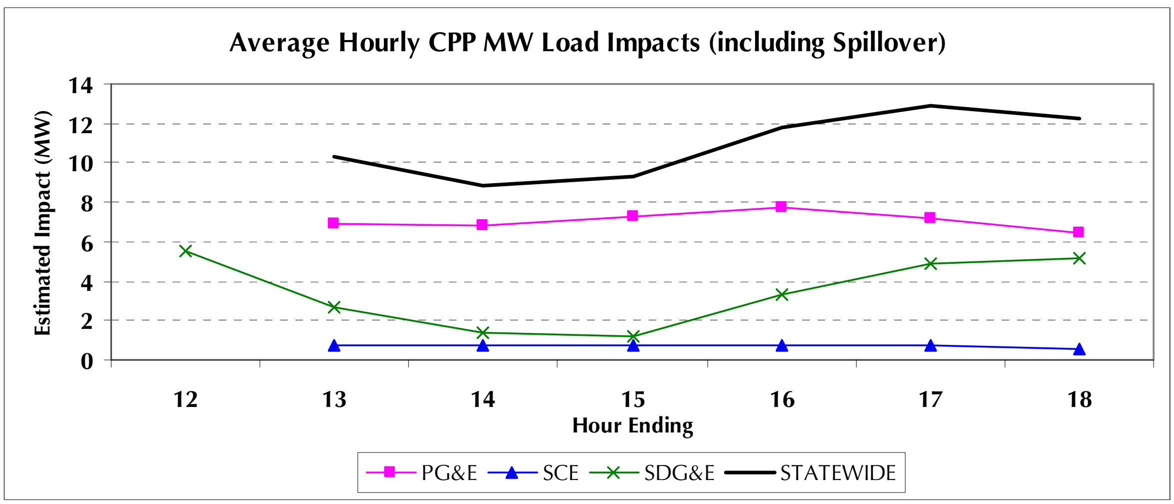
Overall CPP Impacts Averaged 11 MW or 7 Percent of Baseline Load for All Participants

Based on the 10-Day Adjusted baseline method, total estimated impacts for the 2005 voluntary CPP impacts are similar to in size to those from the DBP program at roughly 11 MW. On a

[36] Note that this factor actually cut two ways in 2004 (toward and against lower impacts) in that day-of events are theoretically more difficult to respond to, but were expected to pay more than day-of events.

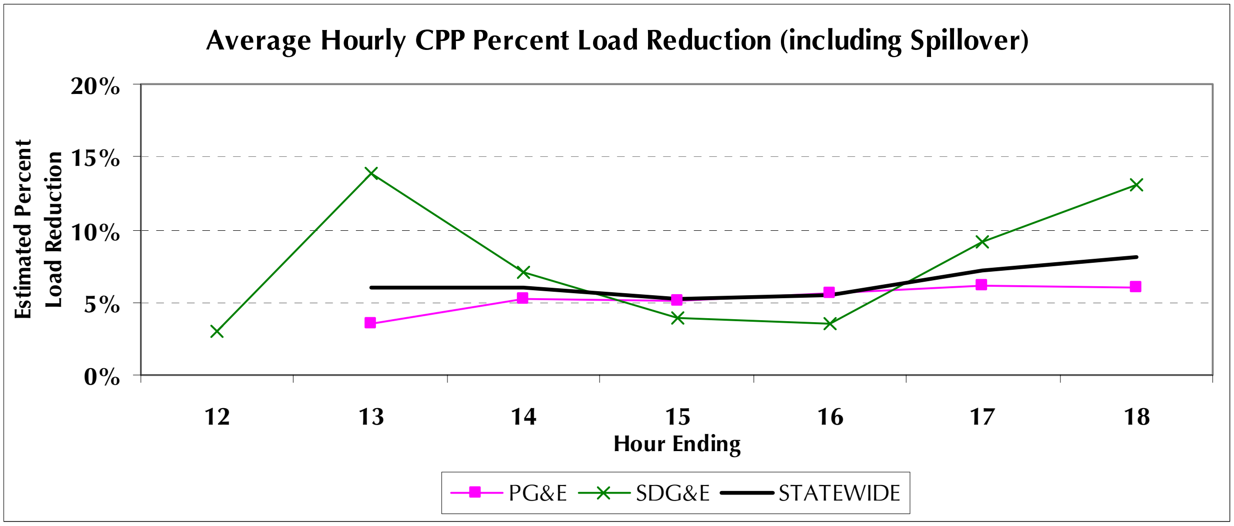
percentage basis, voluntary CPP impacts averaged 7 percent across all CPP participants.[37] As discussed below, a small portion of participants delivered most of the impacts. As was the case with DBP, estimated impacts vary widely across utilities and across events. Exhibits 7-14 and 7-15 presented the average hourly program impacts in MW and as a percentage of load reduced for each of the utilities over all 2005 event hours. To illustrate the variation in estimated impacts across events and event hours, the exhibits also provided the estimated impacts falling at the 25th and 75th percentiles, as well as the mean, for each utility. Although there is considerable variation across event hours, the estimated CPP impacts remain positive across all hours and vary far less than DBP impacts. Impacts for all event hours are provided in Appendices D1 and D4. Exhibit 7-138 below presents the average CPP hourly load reduction across all summer 2005 events for each of the utilities and statewide. Exhibit 7-139 below presents the average CPP hourly load reduction as a percentage of estimated base load for all summer 2005 events for each of the utilities and statewide.

Exhibit 7-138
Average Hourly Load Reduction Impact for Summer 2005 CPP Events
(Note that Hour Ending 12 was a Program Hour for SDG&E Only)



37 Note that CPP impacts estimated using customer-specific regression models are somewhat lower than those summarized here from the 10-Day Adjusted representative day method. Regression-based results are summarized in a separate finding below.

Exhibit 7-139
Average Percent Load Reduction for Summer 2005 CPP Events[38]



Approximately 9 out of 10 CPP participants interviewed as part of this evaluation indicated that they took some load reduction actions for at least one event. This self-reported information can be compared to our estimates of percent reductions associated with CPP impacts across individual customers, which was shown in Exhibits 7-16 and 7-17. These exhibits showed, for example, that for PG&E, roughly three fourths of CPP participants achieved a 5 percent load reduction for *at least one event*; however, only 38 percent of participants averaged a 5 percent load reduction *across all events*.

These results indicate that, regardless of whether a large portion of the voluntary CPP participants are structural benefitters,[39] there are consistent, observable load reductions attributable to the program.

2005 DBP Bidding Rates Averaged Approximately 6 Percent Across Utilities and Events

Despite relatively high enrollment levels, the fraction of program enrollees that placed bids in 2005 was very limited. This finding is consistent with results from the 2004 DBP evaluation. The 2004 results were qualified because there were very few DBP events in 2004 and, in some cases, the only events called were test events. In 2005, due to the number of events called, DBP participants had numerous opportunities to place bids.

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[38] SCE was excluded from this CPP Percent Load Reduction exhibit because there were only eight customers enrolled in the program. The average load reduction SCE was 45 percent, however, almost all of this was attributable to one of the eight customers..

[39] We did not have the information available for the 2005 CPP participants to calculate the share of participants that benefit on the tariff without making load reductions on CPP event days (so-called "structural benefitters"), however, in 2004 the portion was roughly 80 percent.

When *averaged over all events*, relatively few DBP participants, 6 percent, placed bids in 2005. About three times as many participants, 18 percent, placed a bid for *at least one event*.[40] Thus, 82 percent of enrolled DBP participants did not place a bid for any of the summer 2005 events. Averaged across all events in 2005, bidding rates varied from 5 percent of participants for SCE to 14 percent for SDG&E, and 7 percent for PG&E.

Overall DBP Impacts Averaged 11 MW or Roughly 1 Percent of Baseline Load for All DBP Participants and 9 Percent of Load for Bidders

Using the 10-Day Adjusted baseline method, we estimate that 2005 DBP impacts averaged roughly 11 MW[41]; however, our estimated impacts varied widely across utilities, event days, and customer sub-groups. We also found that significant differences existed between estimated impacts among methods, and these are discussed further in subsequent findings. This variation is presented in detail earlier in Chapter 7 and in Appendices D1 and D2. One way of summarizing the amount of variation across events is to look at the quartile ranges of impacts for all of the 2005 DBP event hours, which were shown by utility in Exhibit 7-52. Estimated impacts range from 5 to 15 MW between the 25th and 75th percentiles. As shown previously in Chapter 7, much of the variation is associated with differences in estimated impacts across event days, though in the case of SCE, there is also significant variation across hours within an event. Exhibit 7-140 below presents the average DBP hourly load reduction across all summer 2005 events (where bids were available) for each of the utilities and statewide. The exhibit below includes spillover impacts resulting from participants who bid for only a portion of the actual event hours.

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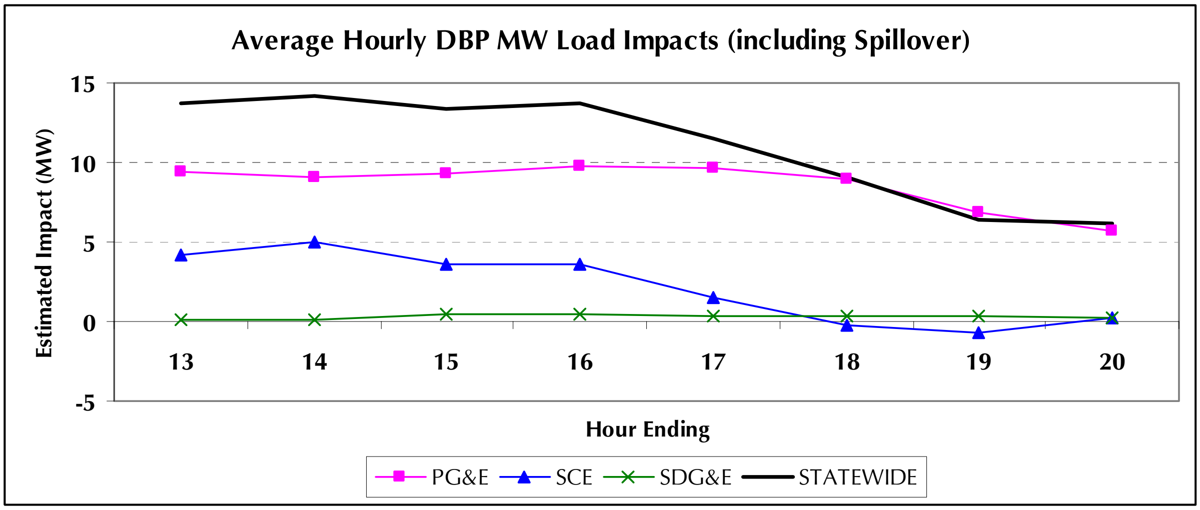
40 Bidding rates for at least one event by utility were14 percent for SCE; 22 percent for PG&E; and 37 percent SDG&E.

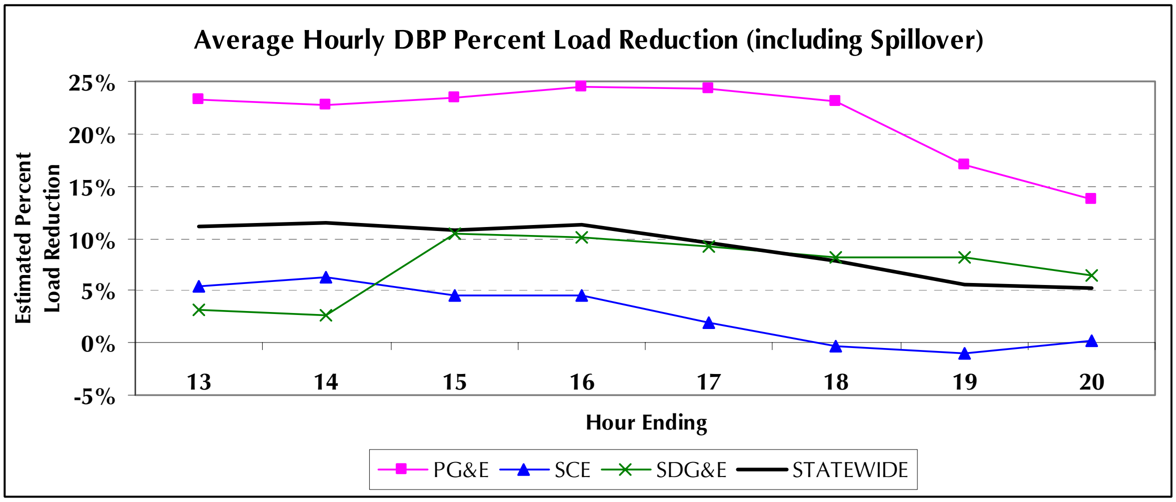
41 These results are based on estimation of baseline load using the 10-Day Adjusted method. However, although the evidence from this evaluation, the 2004 evaluation, and the CEC's DR Protocol study (*Protocol Development For Demand Response Calculations – Findings and Recommendations.* Prepared by KEMA-XENERGY, February 2003) all indicate that a 10-Day Adjusted method is good estimator and is superior to the 3-Day program settlement method (which is more systematically biased [upward]), there is also error and some potential for bias associated with the 10-day adjusted method, as documented in *Chapter 6 – Baseline Assessment* of the 2004 WG2 DR Evaluation (*Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report.* Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December 2004)

Exhibit 7-140
Average Hourly Load Reduction Impact for Summer 2005 Events where Bids were Captured



DBP impacts vary significantly by utility. Average estimated impacts as a percent of bidders' baseline loads are 22 percent for PG&E, 10 percent for SDG&E, and 3 percent for SCE. As shown in Chapter 7, Exhibits 7-59 through 7-61, the impacts for PG&E and SDG&E can be easily seen from the graphic analysis of estimated and actual load shapes on event days, whereas the DBP impacts for SCE are not nearly as apparent. As discussed further below, small numbers of very large customers with highly variable loads contribute significantly to uncertainty in the impact estimates, particularly for SCE. Exhibit 7-141 below presents the average DBP hourly load reduction as a percentage of estimated base load for all summer 2005 events (where bids were available) for each of the utilities and statewide.

Exhibit 7-141
Average Percent Load Reduction for Summer 2005 Events where Bids were Captured[42]



Estimated CPP and DBP Day-Ahead Program Impacts Ranged Widely Across Events

As noted above and shown in the event-specific results in Chapter 7, estimated impacts for the 2005 CPP and DBP programs vary widely across events throughout the summer. This lack of predictability may make it difficult to accurately incorporate program impacts into resource planning and procurement. The event by event variation is largely due to three factors. First, some customers take action in one event but not another. Second, a small number of very large customers with highly variable loads have a correspondingly large effect on the estimated impact. It is very difficult to predict the baseline load for these high-load, high variance customers from one day to another because their loads are not well correlated with weather, season, day of the week, or other readily available parameters. Third, the number of customers that take action in any particular event remains small and very heterogeneous. Thus, without a much larger pool of active participants, average impacts are likely to remain highly variable.

Estimated CPP and DBP Impacts Also Ranged Widely Across Estimation Methods

Among the representative day baseline estimation methods, estimated 2005 program impacts using the 3-Day baseline method are about three times as high as impacts estimated using the preferred 10-Day Adjusted baseline method. Estimated impacts resulting from the other representative day methods, including the 3-Day Utility Coincident, the 8-Day Baseline and the 10-Day unadjusted baseline, fell somewhere between the 3-Day and the 10-Day Adjusted Methods. Based on the research conducted over past three years, there is conclusive evidence

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[42] Although DBP events in SDG&E service territory could be called between noon and 8pm, all 2005 summer events were called for shorter two to five hour blocks of time. No events were called to start prior to 1PM (hour ending 14) or end after 6PM (hour ending 18) and thus all SDG&E impacts in hours ending 13, 19 and 20 are pre- or post-event spillover impacts. All utilities also include in-event spillover impacts for customers who bid for only a portion of the total event hours.

that the 3-Day baseline method is biased upward and significantly overestimates customer baselines and program impacts.

For this 2005 evaluation, we also included multivariate regression analysis as a method to estimate customer-specific baselines. The multivariate regression analysis resulted in lower impact estimates than all of the representative day methods. Even as compared to the 10-Day Adjusted baseline method, the regression-based results were roughly half (or nearly a quarter of the estimated impacts under the 3-Day method).

There are a few major differences between the two representative day and regression approaches. The first is that the regression analysis directly incorporates weather conditions, as well as seasonality, month, and day-of-week effects. A second difference between the two approaches is that the regression model uses data from the entire summer to produce estimates of the load reduction impacts, while the representative day uses a very small number (10 at most in this analysis) of days to produce impact estimates. The regression analysis, in contrast, essentially eliminates much of this day-to-day variation by looking at data that covers the entire summer. A related aspect of this difference is that the representative day approach is only backwards looking for a given event, whereas the regression uses both pre- and post-event data. By incorporating post-event data, we found that in some cases the regression results netted out changes in load that may have been seasonal rather than program induced.

In general, for most of the utility programs analyzed with the regression approach, the regression-based impacts were lower than the 10-Day Adjusted method. As discussed above, this may be because the regression approach more accurately captures load impacts that are program induced by controlling for seasonal, day-of-week, and other effects that are not explicitly addressed in the representative methods. If correct, this indicates that net impacts for the 2005 programs may be even lower than those presented under the 10-Day Adjusted method.

The features of the regression analysis that allow it to make use of this expanded information are also what make it less than ideal for determining impacts for program settlement. Although the final regression results provided important insight into our 2005 impact estimates, additional analysis is needed to further explore the results from this method.

Applicability of Regression Models for Estimating Impacts of DR Programs

The use of multivariate regression models for estimating load impacts from the CPP and DBP programs was tested in Section 7.2 and compared to the results of the representative day approach. While this is viewed as an initial investigation of this method, the models developed seemed to be well designed to address the estimation of load impacts. A regression-based approach has the potential to offer several advantages compared to the traditional representative day approaches. Specifically, the regression models can use hourly load data for the entire season and can incorporate factors such as weather, day of week, size of customer, customer type variables, and other variables can influence both hourly loads in non-event hours, as well as load for hours within event periods. A key difference is the representative day approach uses pre-event data while the regression analysis used both pre- and post-event data. Load data for days right after an event may be as important in determining a baseline as are days preceding the event. In some cases, getting 10 similar pre-event days (excluding weekends, holidays and other event days) required going back almost a month in time. Program participants that have seasonal schedules or that may shut down their plant for a period of time may be better represented by a baseline that includes both pre-event and post-event data. While a regression approach shows promise for estimating program impacts, it is not a replacement for the use of the representative day method in determining settlements where the baseline needs to be known essentially at the time it occurs for timely accounting. A disadvantage is that the method is more complex than the representative day approach, but it is no more complex than many methods currently applied in evaluation. Also, by using all the available data, there is no need to choose between 8-day, 10-day, etc. baselines. The choice in the regression framework is more straight forward, i.e., use all the available data to get the best baseline.

Bid Realization Rates Were Significantly Lower under the 10-Day Adjusted Method as Compared to the 3-Day Method; The 3-Day Method Likely Results in Significant Overpayment

Across all three utilities, roughly 90 percent of bids were estimated to be impacts under the 3-Day baseline method.[43,44] This is somewhat as expected since participants place their bids relative to the 3-Day method. However, bid realization rates under the more accurate 10-Day Adjusted baseline were far lower and averaged 30 percent.[45] Moreover, based on the regression results, only about 12 percent of the bid amounts are estimated to have occurred. In short, based on the 10-Day method and regression approach, the program significantly over paid (by roughly two- to four-fold) for actual impacts delivered. Thus, the bias in the 3-Day method may have lead to significant free ridership.

Exhibit 7-142 below provides the percentage of account bid hours during which the load reduction equaled at least 50 percent of the hourly kW bid, the minimum necessary to receive payment, and the percentage that achieved 100 percent of the hourly bid load reduction based on the 3-Day and 10-Day Adjusted baselines. This exhibit shows, for example, that 79 percent of the PG&E bid hours achieved a 50 percent load reduction, based on the 3-Day baseline, and thus received compensation for the reduction. Under the 10-Day Adjusted baseline only 43 percent of the bid hours would have achieved this minimum reduction and received compensation.

Exhibit 7-142
Differences between Bid Achievements Across Baseline Methods

Bid Hour Achievement Analysis	Baseline	Utility		
		PG&E	SCE	SDG&E
Bid Hours Achieving at least 50% of Bid (Criteria for Payment)	3-Day	79%	44%	34%
	10-Day Adj	43%	31%	17%
Bid Hours Achieving 100% of Bid	3-Day	54%	25%	9%
	10-Day Adj	28%	15%	3%

43 Bid realization rate equals bid amount divided by estimated reduction.

44 The bid realization rate based on the 3-Day baseline method varied significantly across the three utilities with PG&E participants realizing 106 percent of their bids, SCE participants realizing 77 percent, and SDG&E participants realizing 20 percent.

45 The bid realization rate for the 3-Day Utility Coincident baseline was approximately 50 percent.

Small Numbers of DBP and CPP Participants Contribute a Large Portion of Total Impacts

Similar to our findings for 2004, our 2005 analysis indicates that a small percentage of DBP bidders and CPP participants account for a very large percentage of total program impacts. As was shown in Exhibits 7-18 through 7-20 for CPP and 7-80 through 7-82 for DBP, roughly 20 percent of DBP bidders and CPP participants contributed 80 percent of the estimated program impacts under the 10-Day Adjusted method. The results from the regression analysis showed even fewer participants contributing the majority of the program savings; for the CPP program 4 percent of the participants made up 80 percent of the program savings, and for the DBP program 10 percent of the bidders made up 80 percent of the program savings. The average percent load reductions for these two sub-groups are presented are presented in Exhibit 7-143 below. As this exhibit shows there are significant differences between the percent load reductions achieved by the 20 percent of program participants who are the most active and the 80 percent who are the least active.

Exhibit 7-143
Distribution of Percent Load Reductions Between Most Active and Least Active Participants

Active Level	Average Percent Load Reduction (10-Day Adjusted Baseline)					
	PG&E		SCE		SDG&E	
	CPP	DBP	CPP	DBP	CPP	DBP
Overall	5.6%	23.0%	44.1%	3.3%	9.4%	11.0%
20% Most Active	9.3%	41.7%	83.2%	17.0%	42.6%	18.9%
80% Least Active	0.0%	5.9%	1.3%	-3.7%	-2.3%	2.5%

Small Numbers of DBP and CPP Participants Also Contribute a Large Portion of Measurement Uncertainty

Also similar to our findings for 2004, our 2005 analysis indicates that a small percentage of DBP bidders and CPP participants account for a very large percentage of measurement uncertainty. Many of these participants are large customers with loads that vary significantly from day to day for reasons that are not readily observable (e.g., they are not highly weather dependent).

At an individual customer level, we found that baseline loads for many of these large customers varied considerably from day to day, sometimes by up to tens of mega-watts. Consequently, we developed an algorithm to identify those customers with both large and highly variable loads to assess the extent to which the 10-Day Adjusted impact estimates varied for this sub-group as compared to the remaining bidders. Roughly 1 in 3 PG&E and 1 in 5 SCE DBP bidders were identified as "High Load-High Variance" (HLHV) customers (none of SDG&E's bidders were so identified). The effects of these HLHV customers were shown in Exhibit 7-66. The HLHV customers represent more than half of the baseline load for all PG&E and SCE bidders and about three-fourths of the load bid. As it turns out, the effect of these customers is very different for PG&E and SCE. In PG&E's case, average impacts were higher for these customers (roughly 28 percent load reduction) and they represented nearly 75 percent of total PG&E DBP impacts. For SCE, average load reductions for the HLHV customers were slightly lower than the non-HLHV customers and they contributed less than 40 percent of total SCE DBP impacts.

For the CPP program, only about 5 percent of participants were identified as HLHV, as was shown in Exhibit 7-27. Their influence on overall program impacts was modest for PG&E (they made up 3 percent of the program participants and contributed about 10 percent of the total program impact) but very significant for SDG&E (where they were 6 percent of program participants, but contributed 39 percent of the total impacts).

The regression analysis results provided a statistical basis for comparing the HLHV and non-HLHV participants. Those results showed much larger standard errors and wider confidence intervals for the HLHV group and provided a statistical indication of the greater uncertainty in estimated impacts for those customers.

Roughly 50 Percent of 2005 DBP Impacts Were Delivered by Interruptible Customers

As illustrated in Exhibit 7-78, nearly 20 percent of SCE DBP participants are also enrolled in the I-6 program and these customers delivered more than half of the DBP program impacts over the course of the 2005 summer events. In the PG&E service territory, 7 percent of the DBP participants are also enrolled in a non-firm tariff and these customers delivered nearly 60 percent of the DBP program impacts. In the SDG&E service territory, the overlap is much less with only 3 percent of the DBP participants being signed up for AL-TOU-CP rate and they only delivered 7 percent of the 2005 DBP program impacts overall. The bids placed by these participants were between 3.5 and 8.5 times larger across the three utilities than the bids coming from the non-interruptible participants.

The Majority of CPP and DBP Load Reductions Are Associated with Institutional and Industrial Customers

Exhibits 7-144 and 7-145 below provide the distribution of participation hours (event hours for CPP and bid hours for DBP) and program impacts across the three primary business types for the CPP and DBP programs by utility. Exhibit 7-144 shows that the majority of participation hours and program impacts, based on the 10-Day Adjusted baseline, for PG&E and SCE come from the Industrial segment, while the majority of SDG&E 's impacts come from the Institutional segment (which are primarily water pumping facilities).

Exhibit 7-144
Distribution of CPP Participation Hours and Program Impacts Across Business Types Based on 10-Day Adjusted Baseline

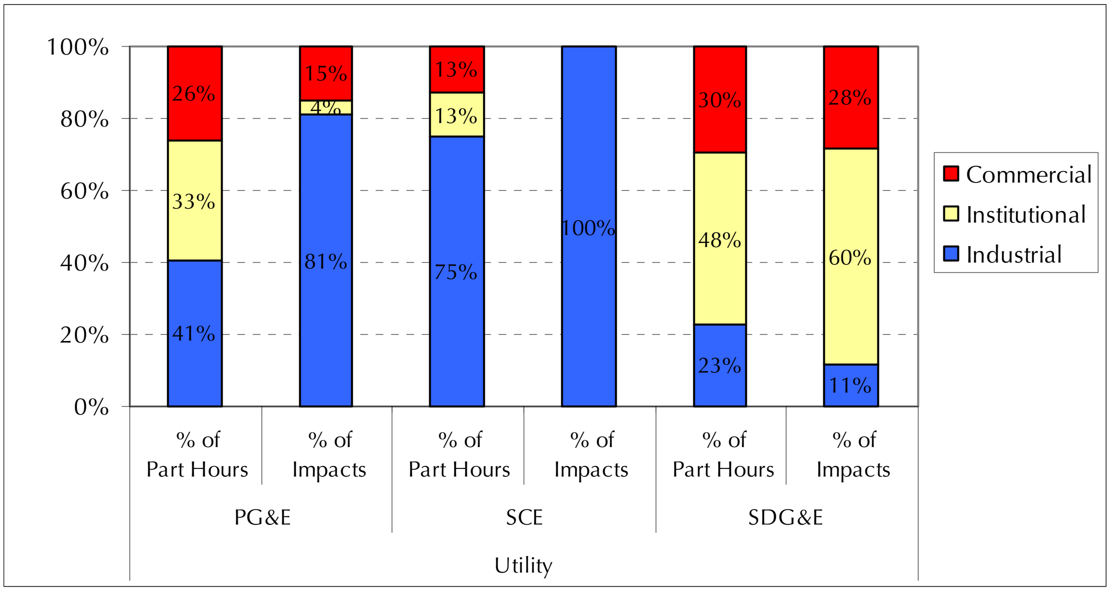
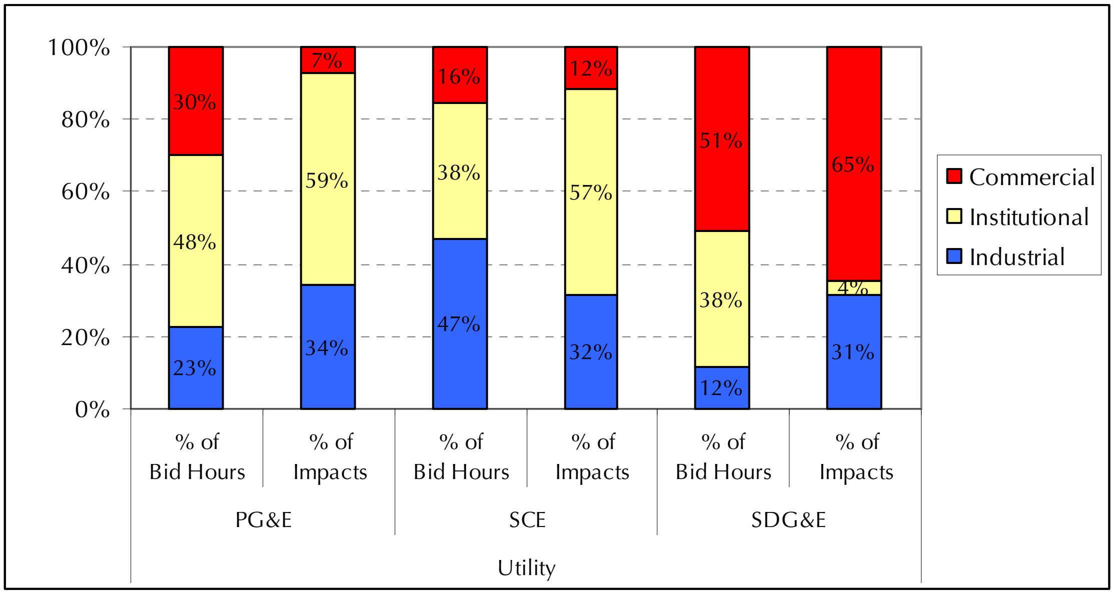


Exhibit 7-145 below provides the distribution of bid hours and program impacts across the three primary business types for DBP. Bid hours are used for DBP rather than program participants since the bid rates across the three business types are not consistent. Exhibit 4-12 presented in Chapter 4 provided the distribution of day-ahead program participation by business type for each utility. A comparison of these two exhibits shows that, although the Commercial segment makes up the majority of the DBP program participants, across all three utilities the Institutional segment places bids at a much higher rate. SCE also experiences high bidding rates in their Industrial segment. The exhibit below shows that for the DBP program, based on the 10-Day Adjusted baseline, the majority of bid hours and program impacts for PG&E and SCE come from the Institutional segment, while the majority of SDG&E impacts come from the Commercial segment. Upon reviewing similar tables for DBP based on the 3-Day baselines that were used for settlement, we found the percentage of impacts associated with the Industrial segment for SCE went from 32 to 76 percent, while the impacts from the SCE Institutional segment dropped from 57 to 18 percent. This indicates that reductions in estimated impacts associated with the 10-Day Adjusted as compared with the 3-Day method came primarily from the Industrial sector.

Exhibit 7-145
Distribution of DBP Participation Hours and Program Impacts Across Business Types Based on 10-Day Adjusted Baseline



Pre-, Post- and In-Event Spillover Contributed Additional Program Savings for CPP and DBP Programs

Spillover impacts, as defined here, consist of the impacts occurring in the hours before or after event participation. For DBP, spillover is calculated for the pre- and post-bid hours on a customer-specific basis. For CPP, spillover is calculated for pre- and post-event hours which are the same for all participants. One difference between the spillover that occurs within the CPP versus the DBP program is that, for the DBP program, the spillover can also occur within the hours for which their utility called the event. We refer to this as “In-Event” spillover, which could be arguably more valuable than the pre- and post-event spillover since it occurs during the program hours. In-event spillover occurs as a result of the flexibility within the DBP program that allows customers to bid for a subset of the total event hours, as long as they bid for at least two consecutive hours. The in-event spillover is calculated for each utility by summing the program impacts that occurred during the entire event period, regardless of the hours for which individual customers bid, and then subtracting off the program impacts occurring during the bid hours only.

Spillover can result in positive or negative impacts depending on the type of actions participants take during these pre and post hours. Positive spillover for both the CPP and DBP programs was readily apparent in the daily load shape graphs (Exhibits 7-21 through 7-23 for CPP and Exhibits 7-60 through 7-62 for DBP), which indicated that the participants tend to ramp down operations prior to events and take a short while to come back online after the event is over. The exception to this was for SCE DBP where both the post-event and in-event spillover was found to be negative, which indicates these customers may have increased their load during the non-event hours, perhaps to make up for their curtailed load. We showed in Exhibits 7-32 and 7-79 that positive spillover in the one hour prior to the event ranged from 36 to 69 percent of the average hourly impact for the CPP program and from 51 to 74 percent of the average hourly impact for the DBP program. All of these spillover rates were based on impacts from the 10-Day Adjusted baseline. In Exhibit 7-79, we also showed that for DBP the in-event spillover ranged from a positive 11 percent for SDG&E to a negative 9 percent for SCE.

CPP and DBP Programs had Small Effects on Overall Daily Consumption

The load reductions that occurred during the CPP and DBP events had mixed effects on the total daily consumption of the participant population. The analysis performed for 2005 participants showed that the net daily change in consumption (MWh) was negative for the PG&E and SDG&E CPP participants. PG&E CPP participants had an average reduction of 3.5 MW an hour in the pre- and post-event periods, indicating that some of the participants who shed load for the CPP events continued to operate at lower levels throughout the entire event day. SDG&E CPP participants also had a net negative average daily consumption across event days; however this negative impact was equal to the total event impact. This indicates that these participants operated at normal levels during non-event hours, neither making up for their previous reduction, nor keeping their load at reduced levels for the remainder of the day.

For DBP we found that the total daily consumption went down across all three of the utilities. PG&E DBP bidders seemed to operate at normal levels throughout the remaining event day non-event hours, SCE bidders made up about half of their event reduction during these hours, and SDG&E bidders continued to decrease their load throughout the rest of the day.

Changes to 2005 DBP Participation Eligibility and Bid Minimums had Mixed Effect on Program Impacts

One of the changes made to the DBP program eligibility for 2005 allowed Direct Access (DA) customers to participate in the DBP program. This change appears to have increased enrollment but had mixed effects on program impacts. Since this change went into effect, DA customers now make up 31 percent of all new PG&E accounts enrolled in the DBP program, such that they currently make up approximately 24 percent of all PG&E DBP participants. Similarly for SCE, DA customers accounted for 24 percent of all accounts that enrolled in DBP during the 2005 program, and now comprise approximately 4 percent of the overall DBP program signups. Based on the last SDG&E participant data made available to us, no DA customers had enrolled in the DBP program. Exhibit 7-74 showed that although DA customers in PG&E and SCE service territories have average loads that are five times larger than non-DA customers, their average percent load reductions are much lower (zero in the case of SCE) than what the non-DA customers' nominate and deliver. Even so, in the case of PG&E, the DA participants contributed about a quarter of the program impact, whereas the additional DA participants for SCE do not appear to have contributed any load reductions.

Another program change implemented for 2005 lowered the DBP bid minimum from 100 kW to 50 kW for PG&E and SCE, and to 10 percent of maximum demand for SDG&E. Changing the minimum bid amount for the 2005 DBP had a mixed effect on program impact estimates. Exhibit 7-72 showed that 26 percent of PG&E bids, 13 percent of SCE bids, and 51 percent of SDG&E bids were for amounts less than 100 kW. Despite the relatively large number of participants placing these smaller bids, the portion of overall impacts contributed by these participants was 8 percent for PG&E, 3 percent for SCE, and a negative 4 percent for SDG&E.

DRP Impact Findings

Average DRP Event Length Similar Across Product Types; Dissatisfaction Expressed by 1-8 Hour Product Participants

DRP events can be called for any number of consecutive hours, so long as the event length does not exceed the maximum event hours for a particular product type (i.e., the 1-3 hour product cannot be called for more than three consecutive hours in one day) and the maximum number of monthly event hours for each product within a utility congestion zone is 24 hours. Exhibit 7-102 provided the average DRP event length across all utility zones for this past summer. This exhibit illustrated how there were only minor differences in the average program length between the 1-3, 1-5 and 1-8 hour products. In the PG&E congestion zone, for example, the average event length was 2.5 hours for the 1-3 hour product, 3 hours for the 1-5 hour product, and 3.3 hours for the 1-8 hour product. The 1-8 hour product events were typically called seven to eight times a month, for three to four hours at a time. This caused dissatisfaction for some of the program participants enrolled in this product type since they reported signing up for this product believing that longer events would be called and that they would be called less frequently than the shorter period products. These participants were unhappy because curtailing for a few hours on multiple occasions was more difficult for their operation than curtailing for longer periods a few days a month.

Variations in Methods Used Among Utilities to Estimate DRP Program Impacts; SCE Significantly Over Reporting

DRP differs from the other programs included in this evaluation in that the utilities do not necessarily have access to the load data for all of the DRP participants within their congestion zone. As a result, they are not able to calculate the estimated program impacts for individual DRP events as they do for the other day-ahead programs. Instead, they rely on various reports from the DRP website (developed and administered by APX) to determine the estimated program impact. Currently each of the utilities uses a different methodology to determine the individual event impacts they report to the CPUC each month. Both PG&E and SCE base their estimated event impacts on the nominations submitted for the event. PG&E calculates the average hourly nomination across all event hours and uses this for their estimate, and SCE reports the maximum hourly nomination across all event hours. SDG&E references a different section of the DRP website and bases their estimate on the average hourly load reduction across all event hours. As Exhibits 7-108, 7-111 and 7-112 illustrated, the methodologies employed by PG&E and SDG&E resulted in the most accurate overall impact estimates. The SCE method overstated that true program impacts by nearly 100 percent.

DRP Impacts Average Well Over 200 MW But Are Dominated by a Single Large Pumping Customer that Accounts for Roughly 90 Percent

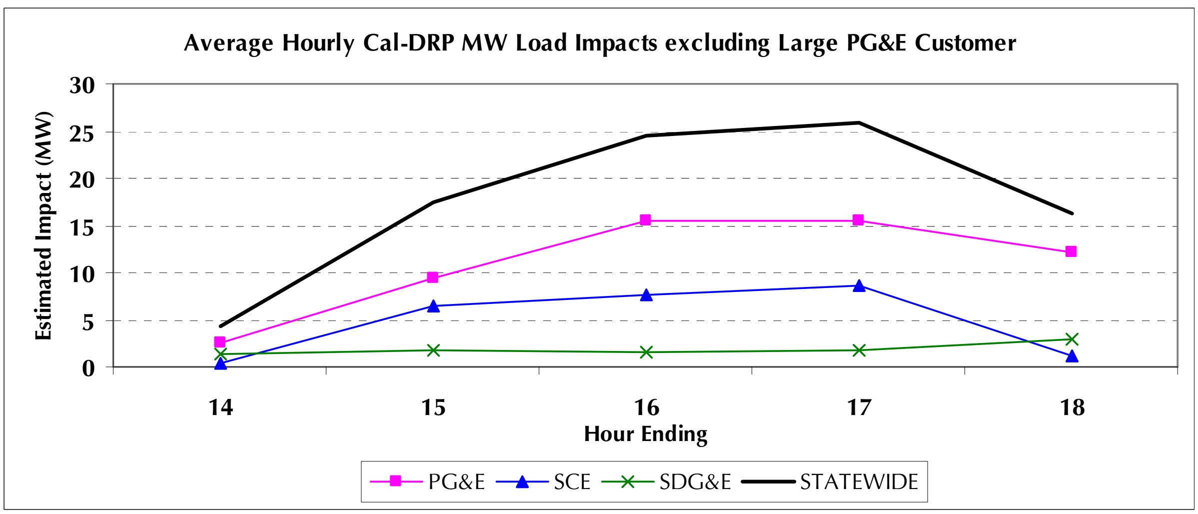
The DRP program in 2005 was once again dominated by a single large pumping customer. This customer made up three-quarters of the total estimated baseline load during the summer events, slightly less than 90 percent of the event nominations, and just over 90 percent of the overall impacts. The overall average load reduction across the DRP participants was roughly 50 percent; however, this was driven entirely by this one large customer who averaged a 66 percent load reduction, compared to an average 15 percent reduction from the other participants. The average impact from the large customer was 242 MW based on the 10-Day

Adjusted baseline, compared to an average reduction from the remaining customers of less than 1 MW (0.7 MW). This one large customer also tended to reduce its load by more than its original nomination by about 20 percent. As shown below, without this large customer the impacts resulting from the DRP program were of a magnitude similar to what was calculated for the CPP and DBP programs.

DRP Impacts Vary Widely Across Events and Event Hours for Participants Other than Its Single Large Pumping Customer

Using the 10-Day Adjusted baseline method, we estimate that 2005 DRP impacts from all program participants, excluding the single large pumping customer, averaged roughly 18 to 24 MW across the late afternoon hours; however, our estimated impacts varied widely across utilities, event days, and customer sub-groups and product types. Exhibit 7-146 below presents the average 2005 DRP hourly load reduction across all participants who nominated load for each of the utilities and statewide. Hourly impacts for the PG&E large pumping customer are not included in this exhibit. Hourly impacts for this customer ranged from a high of 344.4 MW for the 5 o'clock hour on July 18th to a low of 117 MW for the 4 o'clock hour on August 23rd based on the 10-Day Adjusted baseline.

Exhibit 7-146
Average Hourly Load Reduction Impact for Summer 2005 DRP Events (Non-Coincident) Excluding Large PG&E Pumping Customer – Based on the 10-Day Adjusted Baseline



Comparing the results above to those for the CPP and DBP programs shows, without the large pumping customer, the size of the average hourly impacts across all three programs is similar.

7.4.2 Reliability Program Findings

Reliability Programs Had Very Few Calls in 2005

In contrast to the day-ahead programs, the reliability-triggered programs had very few calls in 2005, as shown in Exhibit 3-9. As has been the case for the last several years, only SCE and SDG&E programs were called. As discussed elsewhere in this chapter and report, the reliability programs have been called very little as compared to allowed maximums since the end of the energy crisis. The extent to which current reliability program participants are willing to accept more program calls is explored as part of the research conducted for this evaluation. Complete results are discussed in Chapter 9.

Exhibit 7-147
Number of Reliability Program Events for 2005

Reliablity Program Events Summer 2005			
Utility	Traditional Interruptible	Base Interruptible Program (BIP)	Other Programs
PG&E	0	0	0
SCE	1	1	1
SDG&E	4	0	0

Significant Interruptible Impacts Consistent with Required Reductions for SCE I-6 and BIP programs

In 2005 SCE interruptible events were called on only one occasion, August 25th, due to transmission difficulties associated with the Pacific Intertie. The I-6 and BIP events called on August 25th lasted only a little over an hour, however, during this time significant load reductions occurred. Participants enrolled in the I-6 program reduced their load by 571 MW based on the difference between the hourly 10-Day Adjusted baseline and the 15-minute interval load data. This was a 78 percent load reduction and was within 18 MW of their Firm Service Level (FSL). The participants enrolled in the BIP program also contributed a significant load reduction, 64 MW, which corresponded to an average load reduction of 58 percent. However, we estimate that a much larger share of I-6 participants met their FSL (72 percent) as compared with BIP participants (45 percent). In addition, we estimate that only 3 percent of I-6 participants did not take any action as compared to 18 percent of BIP.

The OBMC event that was also called on this day was cancelled after a little less than 30 minutes. Because this event lasted less than 45 minutes, the program minimum, this event was not considered a valid event, and penalties were not assessed. A slight load reduction of 3 MW appeared to occur during short time period the event was in effect. This estimated load reduction was significantly less than what was reported by SCE since two participants who were also enrolled in the BIP program, and had considerable reductions, were removed from our impact estimate.

SDG&E AL-TOU-CP Program Averaged 15 Percent Load Reduction Across Events

The AL-TOU-CP program is unlike the traditional interruptible programs in the other service territories in that it does not require participants to pre-determine a Firm Service Level that they will attempt to achieve during events. As shown in Exhibit 7-94, the average estimated base load of the AL-TOU-CP participants during the four summer 2005 events was around 10 MW and the average load reduction was approximately 1.5 MW, or 15 percent of base load.

7.4.3 Overall Impact Related Program Findings

Vast Majority of Load Reduction Capability is Associated with Reliability Programs and a Single Large DRP Participant

As noted above, roughly 18 percent of eligible load is enrolled in one of the day-ahead or reliability programs addressed in this evaluation and this enrolled load is split relatively evenly between day-ahead and reliability programs. In terms of expected load reduction, however, the reliability programs plus the single large DRP participant account for about 30 times more load reduction capability than the day-ahead program participants exclusive of this large participant (i.e., roughly 1,000 – 1,200 MW versus roughly 30 - 50 MW).

We do not mean to imply by this that the program types should be compared with each other based on size of impact. As discussed in D. 05-01-056, the rationales and objectives for these program types are clearly different. Rather, since D. 05-01-056 makes clear that the system-wide demand response goals for 2005-2007 are exclusive of reliability programs, it is important to isolate and benchmark the impacts of the day-ahead programs and to distinguish the size of this resource with and without the one large participant. The size of the reliability program resource, along with our estimates of DR potential developed from our market survey (see findings on potential below and Chapter 5 of this report), provide useful information to help assess the size of the day-ahead programs to date. Although the day-ahead program impacts, excluding the large DRP participant, to date are a small fraction of the reliability program resource, these impacts are already a significant portion (roughly one-quarter) of the estimated size of the remaining economic potential for DR (exclusive of reliability programs).[46]

[46] For more information on estimation of economic potential, see Chapter 5.

8. CPP AND DBP PROCESS EVALUATION

This chapter addresses process issues relating to the implementation of the CPP and DBP Programs. This process analysis is designed to complement the impact evaluation results presented in Chapter 7. In this chapter we begin with a brief summary of the CPP and DBP process evaluation findings. Second, the goals and scope of the process evaluation are discussed, followed by a discussion of issues that are covered and the methods that were used to address those issues. Results of interviews with program managers are presented next, since these provide an overview of the effects of program changes and also helped guide the development of the customer survey instruments. Detailed results of the participant customer data collection efforts are then discussed, both in aggregate and for specific segments (e.g., by size, program, or utility).

8.1 EVALUATION GOALS AND SCOPE

The process evaluation of the 2005 CPP and DBP programs focuses on changes in the programs since their first full year. As such, it builds upon the process evaluation conducted of the 2004 program, which started at the beginning of 2004 and ran concurrent with the programs throughout the year.

Both the scope and the results of the process evaluation should be viewed in the context of the evolution of the DR programs being evaluated. CPP and DBP are still relatively new programs that continue to be revised and fine-tuned to make them more acceptable to customers while still meeting each utility's mandate to develop DR capability and deliver load reduction. While the extent to which these programs are works in progress is certainly much less pronounced than last year, the process evaluation results should still be interpreted in light of the ongoing effort to build DR capability. Issues addressed by the data collection efforts and analyzed in this chapter include the following:

- Effectiveness of event notification, bidding tools, tracking, response, and follow-up
- Perceptions regarding the frequency, duration and perceived urgency of events
- Perceptions regarding the notification process and the amount of time customers have to respond
- Specific curtailment actions taken by customers and their effect on operations
- Continued barriers to actual curtailment, particularly among the large group of DBP participants who have not bid for any DBP events and among CPP participants who have not curtailed during CPP events.
- Program satisfaction and likelihood of continued DR program participation

The process evaluation of the CPP and DBP programs used data from a variety of sources. The following data sources were used:

- Interviews with program managers and other utility staff, including account managers

- Review of utility filings and program documents

- Post-event surveys with participating customers to address issues of notification, planned and actual customer response, and other concerns

- A final evaluation survey with participating customers to assess their overall perception of program operations for the season.

- Bidding data and program impact analyses (see Chapter 7)

In the analyses below, both program-manager and customer responses are used to present as complete a picture as possible of program implementation.

8.2 PROGRAM MANAGER INTERVIEWS

Program manager interviews were conducted with the individuals responsible for the DBP, CPP, and TA/TI programs at all three utilities, as well as several individuals with implementation responsibility across programs. All program managers interviewed said they recognize the importance of offering a diverse DR portfolio, and that the CPP and DBP programs are key aspects of building DR capability.

8.2.1 Overall Day-Ahead DR Program Design/Marketing

A central issue that program managers agreed on was the difficulty of designing and delivering day-ahead DR programs in the face of what they perceive to be conflicting, ill-timed, or inconsistent directives from regulatory agencies.

- Several program managers said that the utilities receive mixed messages from the CPUC regarding the importance of reliability vs. day-ahead DR programs. On the one hand, they say, it seems that CPUC favors day-ahead DR over reliability rates; on the other hand, utilities are told to do whatever they can to get peak demand impacts.

- Program managers also believe that regulatory agencies tend to misunderstand day-ahead DR and the time it takes to gain customer acceptance; one program manager stated that "you don't just throw a switch; it's a long-term market development and education process" that may need five or more years.

- What is perceived to be a boom/bust mentality toward long-term support for both day-ahead and reliability programs has hurt the portfolio effort, according to program managers, who are frustrated in that they believe that regulators do not understand why utilities are so far behind on day-ahead DR goals.

The timing of the regulatory process is also seen as a problem that hampers the ability of utilities to deliver their programs.

- Program managers need decisions to align with their annual budget cycle and marketing and sales logistics requirements to get participation before summer. To be effective, the sales effort by field staff should start earlier, but being able to do so would mean realigning the regulatory process accordingly.

- Regulatory lag also impacts collateral development/ marketing. An iterative collateral development process takes time, particularly if customers are involved (as they should be). Program managers recognize the importance of statewide consistency of programs and marketing materials, but note that this also adds time. In practice, program managers plan their marketing materials using their own regulatory filing as a straw man, then change per final rate approval.

In addition to the time crunch created by the timing of regulatory actions, program managers say there is also a shortage of resources to market day-ahead programs, since Account Executives (AEs) are struggling with a growing workload:

- AEs are being asked to take on more rates, more customers with the same staff, and to address smaller size eligibility; all this on top of resuming expanded energy efficiency (EE) program duties following the CPUC decision to remand EE to the utilities.

- The variety of reliability and day-ahead DR rates with different purposes are believed to further complicate the AE's job. Still, AEs generally want a variety of rates to tailor to various customer situations, but they believe the portfolio needs to be better rationalized. As an example, an SCE program manager cited the CPP-GCCD program as one the PUC had said they wanted for over 500 kW customers, yet there had been little interest from those customers.

Program managers also note that AEs say they have little time for training on program changes due to more pressing customer service responsibilities and generally being understaffed.

- One example of the AE workload consequences cited by a program manager is that reps are not keeping up with courtesy notice contact updates.

- Another program manager said they had not done much with collateral development in the last two years, in part because AEs say they do not have time for focus groups and other feedback efforts.

- Yet another program manager summarizes the AE attitude as: "don't tell me to stop cutting trees to sharpen my saw."

The TA/TI program, discussed below, is seen as potentially helping to alleviate this situation by offering additional resources to assist AEs, but it also creates an additional need for training, working with contractors, and working with customers.

8.2.2 Program Manager Perceptions of Marketing Activities

In discussing their perceptions of marketing approaches and activities, program managers are quick to point out that the CPP and DBP programs have been in the field only two years, so it is still early in the overall life of these programs. They compare the relatively rapid ramp-up of the day-ahead DR programs with the many years it took to get customers to accept energy efficiency, which is now an integral part of how many of them do business.

Nevertheless, program managers report continued push-back (both directly and through the AEs) from customers.

- Customers tell their account reps that they are not in the energy business so they do not take well to being asked to do things like load curtailment, watching the energy markets, and placing bids. They say they have neither the time nor the expertise to dedicate to hourly energy management required by day-ahead programs.

- In addition, some customers say they have done all the load shifting and energy efficiency improvements they can, either through energy efficiency programs or in response to TOU rates, although this could not be independently verified.

- An SDG&E account rep supervisor reported a strong sense among large C&I customers that they are being targeted to take on excessive burdens relative to residential and small C&I customers. Thus, day-ahead DR is seen as being more punitive than it might be if California were not already being perceived as unfriendly to business. Discussions of a default CPP tariff earlier in 2005 reinforced this perception, and prompted some customers to say that, given a choice between default CPP and rolling blackouts, they would likely choose the blackouts.

For day-ahead DR program managers, this presents a marketing challenge. As they noted last year, program managers say they can make hard-to-sell programs sound great in marketing efforts, but then risk losing credibility when complexity is seen first-hand. An SCE marketing manager said, “DBP has lots of hoops and a relatively small credit. We can try to really sell it but if it doesn’t deliver then you lose credibility.” Similarly, marketers see themselves as caught in a dilemma: they need more financial incentive to entice customers to sign up, but believe that, with more incentive, day-ahead DR programs are not cost-effective, at least according to standard economic tests.

- One program manager said that narrowly defined standard economic tests may not be capturing all of the economic benefits of program participation, particularly the development of day-ahead DR capability and infrastructure that can be relied on when a need arises.

- Another manager notes that incentives are not large enough to pay for many customers’ internal costs to prepare for and execute controls during events. Incentives are therefore more for recognition and good corporate citizenship than economic payback.

The fundamental problem, according to an SCE program manager, is that most customers do not care about electricity prices in relation to their other business costs. Unless customers are large enough and energy-intensive enough to have an energy management function, the cost of monitoring and responding to price signals outweighs the potential savings.

Moreover, there appears to be considerable willingness to just accept penalties on the bet that events will be few enough that incentives/discounts are a net positive. This view was reinforced by an SDG&E customer interviewed for the BIP survey, who flatly stated that his company never curtailed – and could not curtail -- when called, and that they still come out ahead on the AL-TOU-CP tariff.

An SDG&E program manager mentioned their 20/20 program for commercial customers as one that takes the right approach (in that it is relatively simple and has no penalties) and as a result has been very well received. She noted that customers representing several MW of load had moved from DBP to 20/20.

8.2.3 Program Manager Perceptions of Program Changes

Program managers discussed their reaction to a number of changes made to the DBB and CPP programs made between 2004 and 2005.

Eligibility – Direct Access Customers

Of the changes to eligibility requirement, several program managers said making direct access (DA) customers eligible has probably had the greatest impact to date on program enrollment, primarily because these customers individually bring a significant amount of load. This is confirmed by the participation tracking results presented in Chapter 4 and an analysis of DBP customers who placed bids in 2005. In SCE's territory, DA participants in DBP who bid had average loads of 6.8 MW vs. 1.3 MW for bundled customers who bid, while in PG&E's territory the difference was 6.6 MW for DA vs. 1.0 MW for bundled customers. One manager cited a property manager who "signed up 20-30 properties" (apparently not as an aggregated single customer.) Program managers also mentioned difficulties enrolling DA customers, however, noting that there are the extra steps involved in dealing with the customer's Metering Data Management Agent (MDMA) and Energy Service Provider (ESP).

Eligibility – Lower Minimum

Program managers say the lower minimum has primarily affected existing customers that also have larger accounts; very few customers with only small accounts have signed on. First, smaller customers are less likely to have energy management expertise or the equipment or software to monitor their load. Second it requires too much time and effort for program managers to manage their enrollment, since there typically is no AE contact to facilitate the process for these unassigned accounts. Program managers are hopeful that this may change next year with more automation and as new ways are found to work with these customers. PG&E, for example, is using unassigned account reps to reach out to smaller customers.

Eligibility – Aggregation

Program managers say customers have responded to opportunities for aggregation under the new program rules, but they note that the enrollment process for these accounts is relatively complex and time consuming. Before a set of aggregated accounts can participate there is a need to synchronize the billing cycles for all the accounts and to designate lead account (the process is even more complex if a customer has some bundled service and some direct access accounts). Moreover, this may involve working with chains whose headquarters are out of state or even in a different time zone. As a result, the process is typically taking several months, and relatively few aggregated accounts were up and running for the summer of 2005, although it is anticipated that more aggregated accounts will be in place by the summer of 2006. Because of the complex enrollment process, one SCE program manager said, "Aggregation has been a real challenge. So far it's been more trouble than benefit."

Enrollment

The length and complexity of the DBP contract remain a concern to program managers and customers. Because of "the sheer size of the contract," notes one manager, the agreement must almost always go through the corporate legal department. A concern that often comes up during these reviews is the third party authorization for the CEC to have access to customer usage data – both as a confidentiality issue and because more than three requests for data could lead to a charge to the customer (although this rarely happens). To allay these concerns, program marketers try to refer to "agreements" rather than contracts, and PG&E is considering a web-based application to replace the paper document.

Year-to-year changes in programs also pose a challenge. Because of the changes to the DBP program for 2005, utility legal departments felt that new contracts might be required. However, one program manager said they received "lots of pushback" from AEs, so the program change was handled through a letter, notifying customers of the change.

Another manager said that changes in the DR programs mean that "every year I have to go out and sign new contracts, which means the reps have to go back and resell, resign, re-educate. That in itself is confusing."

Notification/Event Timing

Both CPP and DBP are now day-ahead programs. For DBP, this has meant lower incentives, which reduces the already limited financial benefit to participants and has not been popular either with customers or with the account representatives who must sell the program. One program manager recalled "I was booed when I told them (the AEs) about the 10 cents." Another manager, however, noted that "even the day-of prices were not a motivation, so the loss was not an issue." In addition, the day-ahead DBP still poses the participation barrier of a limited bidding window, as discussed in the survey results.

Event Triggers

With DBP now called based upon predicted overall system load and CPP on temperature, neither of these programs is now price based. This puts the programs in a somewhat vague status as being linked neither to price nor reliability, since there has not been a close correlation between actual power shortages and the triggers for the two programs. Moreover, program managers question whether the triggers may be too sensitive, since there are many days when the overall load or temperature trigger is reached, but price is low and supplies are ample. As a result, program managers and AEs say they lose credibility when they urge program participation (not only signup, but bidding) and customers see there is no real need. As one SDG&E Program Manager said, "I would like to see us revisit the 43,000 MW trigger because the daily calling takes away that sense of urgency. "

This is particularly important because program staff believe that customers generally are not doing these programs – particularly DBP – for the money. Certainly, customers would like to see some financial benefit, say the program managers, but the majority of customers do this to be good corporate citizens and help avoid rolling blackouts. When customers see neither a pressing need nor a substantive financial benefit, they question their participation in day-ahead DR programs.

On the other hand, says a PG&E program manager, the more sensitive triggers have provided them with a better indication of customer response to CPP events, especially in one part of PG&E's territory where events were called for three consecutive days. She notes, "This is really the first year we've actually implemented, so we will have to do a post-mortem and tell the reps what we see so they can educate their customers."

DBP Issues

DBP generally remains more popular than CPP because it is voluntary, but the percentage actually bidding and curtailing remains low across utilities (although the percentage is lowest at SCE), as shown both by the results of DBP events and by the surveys. Program managers say that some customers bid repeatedly, but that most never do, perhaps because of the lack of perceived crisis discussed above. As one program manager noted, "DBP is easy to sign up, but hard to get them to do it. It's like trying to get people to give blood. They can do it and they know they should, but it takes a sense of urgency."

Since the program costs of DBP are associated only with performance rather than with potential (i.e., the utilities are not paying for capacity that is made available but may not be called), the load reductions provided by the program can be cost effective in spite of the low absolute level of bidding. The low level of bidding/curtailment activity simply highlights how much lower actual results to date for this program have been compared to what is suggested by enrollment numbers.

While DBP customer responses to events during the summer of 2005 are analyzed below, discussions with program managers revealed several implementation issues with DBP. Specifically noted was that a number of customers across utilities had problems logging in and using the bidding software. In some cases this was because they had lost their password or confused their "regular" logon ID with the one they have for DBP. In other instances there were problems with the DBP software for events early in the summer where, for example, customers were unable to see their baseline and/or place bids. These were generally resolved as bugs were worked out and as customers and utilities became more familiar with executing and tracking events, and there is no indication that these problems will persist in future years.

CPP Issues

There were more CPP events called in 2005 than 2004, in part because program managers now have greater flexibility in adjusting the temperature trigger used to call the program. This led to some negative feedback from customers, especially when events were called several days in a row.

There are also ongoing concerns among program managers that many CPP participants are still "structural benefitters" who gain financially from the CPP tariff without having to change their operations. An SDG&E program manager noted that bill analysis showed that all their CPP customers benefited last year (they had only 6 events in 2004, but their customers would have benefited even with 12).

SCE continues to have relatively few CPP participants relative to its large number of DBP enrollees. A program manager noted that SCE now offers CPP–GCCD (Generation Capacity Charge Discount), which was developed in response to an Office of Ratepayer Advocates (now

Division of Ratepayer Advocates) request for programs targeted to customers larger than 500kW (who were already eligible for CPP). However there were no participants in this rate by late summer.

Finally, a number of program managers said that default CPP is viewed with suspicion by most customers who have heard about it, as noted earlier. One program manager said that the default CPP had a negative impact on the voluntary programs, saying "just as we start to get momentum in 2004, this comes in December and pulls all the attention away from the voluntary." Other program managers did say they had used the talk about default CPP to encourage customers to enroll in voluntary programs to gain experience with day-ahead DR.

8.2.4 Program Manager Perceptions of TA/TI

This section presents program manager perspectives on the TA/TI programs of each of the three utilities. Key aspects of TA/TI for 2005 are that:

- TA/TI was relatively slow getting out to customers in 2005 because the initial ruling authorizing the revised program was just a two page description, which had to be clarified through discussions with CPUC staff as the utilities developed detailed program implementation procedures. The utilities all agreed to a common program framework, but differed in their approach to working within that framework.

- The basic program is the same for all utilities: first a preliminary audit is conducted at no cost to the customer. If the preliminary audit indicates DR potential, the customer is provided an incentive of up to $50/kW of identified load reduction potential to have a detailed audit conducted. Finally, customers are eligible for an incentive of $100/kW of DR reduction for installed DR measures, up to the actual cost of the measure. Payment is contingent on performance verification.

While all of the utilities are moving forward with TA/TI, each has its own approach and focus. Progress – as measured by the number of preliminary or detailed audits completed or funds disbursed – has varied according to the approach the utility has chosen to follow and the extent to which each utility waited for formal approval before moving forward, as described below.

SDG&E

SDG&E was in the field with its program somewhat earlier than the other utilities and has taken a number of customers from the preliminary audit through the installation of measures. As of mid-December, more than 40 preliminary audits had been conducted and 11 applications for technology incentives had been received and were either approved or pending.

- SDG&E has emphasized the selection of specific projects in which the customer will have "ownership," and it tailors both the audits and the recommendations to that. The SDG&E program manager has an overall strategy of focusing its initial marketing of TA/TI on the largest (>300 kW) customers, since they are the most likely to have a detailed control infrastructure in place. For this group, the preliminary assessment might be done by SDG&E itself, but the emphasis would be on bringing in the customer's EMS contractor, who would do the detailed audit in light of their knowledge of the customer and the customer's control systems. For a second tier of customers (100-

200 kW), the goal would be to work with well established vendors (e.g., Trane, Carrier) who could successfully identify and implement somewhat more standardized approaches focused on HVAC or lighting. Finally SDG&E anticipates that smaller customers will be more fully able to participate in the TA/TI program (and in day-ahead DR) in several years as automation technology becomes more widely available and allows the broad implementation of relatively simple automated responses to day-ahead events.

- SDG&E also plans to front-load participation in the program to create a sense of urgency by sharply increasing the incentive level for 2006. To help develop understanding and interest sooner rather than later, SDG&E, under the terms of the 2006-2008 DR Program Settlement Agreement, will pay $250/kW in technology incentives in 2006, declining to $200 in 2007 and back to $100 beyond that. While the current $100/kW incentive is paid 50 percent upon completion of a well supported application and 50 percent upon demonstrated reduction in demand, SDG&E has proposed to pay the $250/kW in three installments: 25 percent with the application, 25 percent with the demonstrated demand reduction, and 50 percent upon enrollment in a DR program.

- The SDG&E program manager says that some customers who have signed up for DR and did not get very good response have requested the preliminary audit. This group will continue to be a target of the program.

- SDG&E's program manager would like to see DR follow the same evolutionary path that the energy efficiency Standard Performance Contract (SPC) program has taken. Initially SPC had numerous milestones and extensive monitoring; now it is standardized and uses stipulated or deemed savings. SDG&E hopes to do that for DR as well: put together default calculations for various DR technologies, given weather, technology, and other factors. Such estimates might be conservative, but would make the whole process easier, as it has for energy efficiency.

SCE

SCE has focused on setting up the infrastructure to handle a larger volume of audits as the TA/TI effort gets up to speed, including a detailed 120-step flowchart, a cadre of on-call engineering firms, and a set of forms to ensure consistency in the format and structure of audit findings.

- SCE has trained and set up blanket purchase orders with 7 engineers to perform preliminary assessments (and one program verification engineer to review preliminary assessments and technical audits and field technical questions of engineering firms and account reps), and had signed more than 160 customers up for preliminary audits by early December. Some of the earliest audits initiated outside the current detailed process have gone to the detailed audits. Of those audits that have been requested, about 23 had the completed preliminary audit returned to SCE by early December, and probably 80-90 percent of those have justified going on with the full audit. The few that did not were usually customers who cannot or will not shut down during the summer. For example, a movie studio was interested, but they operate under the orders of their production company in the summer and could not consistently shut down.

- SCE has a series of forms covering all phases of participation, from the preliminary audit to the detailed study to the request for incentive, and is currently working on forms for inspection and payment. They have retained a systems specialist to make this a streamlined process. Because they anticipate having hundreds of customers, they do not want to look at different varieties of assessments; they want them to be consistent. What engineers have to do is spelled out, so a program manager can go to the same place on 20 audits and find the same information in the same format. This is also seen as critical to the design and management of the program database.

- In addition to retaining and training consulting engineers, SCE has developed tools to support its account managers in marketing TA/TI. Account executives were trained; provided with a Fact Sheet, Q&A, Quick Reference guide, and presentation material; and given the opportunity to earn ACE points for recruiting customers for TA/TI (ACE points can be used to purchase a variety of gifts from a catalog.)

- While SCE plans to integrate the DR audits with energy efficiency audits in the future, this will require integrating the two sets of document flow, so it will probably be 2007 before this occurs.

PG&E

PG&E initially moved more slowly than the other utilities, setting up a system that fully integrates TA/TI as part of its IDSM approach. All the audits are designed to serve multiple purposes and the forms allow the audit to generate projects either for energy efficiency (through SPC) or for DR. PG&E also emphasizes the importance of training AEs to "sell" to customers in the sense of recognizing the competition for customer time and resources when energy efficiency and DR are being offered.

- PG&E interpreted the Commission's direction to mean, "You need to send us and have us approve all your implementation stuff. So we played by the rules." As a result, fully integrating the TA/TI and SPC applications took time, but PG&E believes this was the right way to go.

- While the preliminary audits specifically for TA were just getting under way in the late fall, PG&E had already been incorporating DR into "about 90 percent of its audits," according to the program manager responsible for audits. As of early November, about 65 audits had been completed for 2005, meaning that nearly 60 facilities had been audited with an eye to DR, although not specifically with the TA/TI process in mind.

- PG&E's approach is driven by very ambitious goals – goals that have gotten more ambitious even as evaluation results cause "real" impacts from both energy efficiency and DR to be trimmed back. PG&E managers believe TA/TI is an integral part of helping achieve those goals in the context of the overall IDSM strategy. "Everyone realizes the enormity of the goals, and we have to change how we do this."

- PG&E is implementing activities to train AEs to understand customer needs and present programs to customers in a way that shows how these offerings work for them.

- Other factors affecting PG&E's approach, according to the program manager, include "changes at the global level from the CEO on down, where there is an absolute commitment to a transformation of business practices and processes in order to 'delight the customer.' Employees attend forums with our officers, all of whom are absolutely committed to this. The goal is to make processes more customer-focused, so more of this time that we spend dealing with problems will go to satisfying customers."

- The approach to TA/TI is an example of this approach; rather than creating a new form that customers have to deal with, TA/TI is integrated with the overall approach to the customer – to competing for their time and resources in a way that meets their organization's needs.

- TA/TI from PG&E's perspective appears to be a key to the IDSM approach in that it embodies the overall integrated focus on the needs of the customer. However, IDSM itself is still in the developmental stages. While there have been updates of marketing materials to reflect IDSM, PG&E is still in the process of developing a marketing "identity" for the IDSM concept – which could even lead to a change in the term "IDSM" to describe the concept. In addition, account reps are continuing to be trained in sales and marketing techniques that will enable them to present DR as part of a customer-oriented solution rather than as a standalone product.

8.3 CPP AND DBP PARTICIPANT SURVEYS

To complement the information collected from the program manager interviews, Quantum Consulting also conducted two telephone surveys of customers participating in the CPP and DBP programs during the summer of 2005. The first survey, referred to as the Post-Event Survey, was designed to explore issues of notification, planned and actual customer response, and other customer participation concerns. The second survey, referred to as the End of Summer Survey, was also designed to assess their overall perception of program operations for the season, in addition to exploring notification and response issues.

This section begins with an overview of the survey methodology, including a description of the survey topics and sample frame. This is followed by a review of the results from both surveys and a discussion of the key findings.

8.3.1 Survey Methodology

Below we describe the methods used to conduct the Post-Event Survey and the End of Summer Survey for the 2005 WG2 Demand Response Evaluation. We begin with a brief overview of the surveys and the design of the survey instruments. This is followed by a discussion of the sampling plan and data collection, including details on data sources and construction of the population frame.

Overview of Participant Surveys

The main objectives of the CPP and DBP participant surveys were to obtain statistically reliable data on specific curtailment actions taken by customers and their effect on operations; perceived barriers to actual curtailment; program satisfaction and likelihood of continued DR program participation; and customer perceptions regarding the frequency, duration and perceived urgency of events.

To this end, Quantum Consulting developed two telephone survey instruments with guidance from the WG2 oversight committee. The survey questions explored the following topics:

- Receipt of event notification
- Decision to bid
- Types of DR actions planned
- Types of DR actions actually taken
- Impact of event participation
- Utility assistance utilized to respond to an event
- Changes to overall usage patterns since signing up for program
- New knowledge/other changes since summer of 2004
- What was most helpful in designing curtailment actions
- Satisfaction with program process elements
- Satisfaction with program/tariff features

The final survey instruments developed for the Post-Event Survey and the End of Summer Survey are presented in Appendix B.

Data Sources

Data for the WG2 Demand Response Evaluation was provided to Quantum Consulting from each of the three investor-owned utilities (PG&E, SCE, and SDG&E). The utilities provided the following types of data:

- Demand Response Participant Tracking Data. The participant tracking data was used to identify accounts that had signed up to participate in the CPP or DBP programs.

- Commercial Population Data. Customer Information System (CIS) data was used to determine whether an account was eligible for the CPP or DBP programs. Premise and Customer identifiers from the CIS were used to identify unique premises (across multiple accounts at a site) and customers (across multiple accounts and premises), and classification variables associated with these aggregated units.

- Customer Contact Information. Contact information (names and phone numbers) for both participants and non-participants were provided to Quantum from Customer Representative tracking databases, as opposed to the CIS. Where applicable, this helped ensure the customer we contacted was the same individual the utility account representative spoke with while marketing the DR programs. These contacts were provided on an as needed basis after samples had been selected.

Participant Population Frame

Quantum Consulting created a population frame containing all PG&E, SCE and SDG&E accounts that were signed up to participate in either the CPP or DBP program. The participant population frame used to create the Post-Event Survey sample included participant updates through the middle of August. Due to the large number of new PG&E participants over the course of the summer the PG&E participant population frame was updated for in October prior to the sample selection for the End of Summer survey. Exhibit 8-1 below shows the distribution of the available sample.

Exhibit 8-1
Distribution of Available Sample
for the Post-Event and End of Summer Surveys

3 IOUs	CPP and DBP Participants	CPP Participants	DBP Participants
Utility Breakdown			
PG&E	332	140	238
SCE	334	8	327
SDG&E	75	49	33
Unique Customers	741	197	598

Sample Selection

The survey sample dataset began with the creation of a statewide database of participating premises. The sample design for both the Post-Event Survey and the End of Summer Survey targeted the decision-makers for all accounts signed for the CPP and DBP programs across the three utilities (PG&E, SCE and SDG&E). A limited number of participants were excluded from the sample due to the lack of contact information for the primary decision-maker. The sample was stratified based on the IOU service territory of the account or accounts the decision-maker was responsible for, the DR program the account(s) were enrolled in (CPP, DBP or both), and whether or not the DBP account(s) had placed bids for the 2005 DBP events. Quotas for the 15 distinct strata were set to include all available decision-makers for all except the SCE DBP non-bidder stratum. At the time quotas were set there was a total of 598 unique DBP decision-makers in the sample, of which only 127 (or 21 percent) had placed bids for previous DBP events. Exhibit 8-2 below shows the distribution of the available sample and assigned quotas across the 15 strata. These numbers reflect the available sample for the End of Summer Survey, which was slightly higher than the available sample for the Post-Event Survey due to additional contact information for decision-makers provided to Quantum from each of the utilities.

Exhibit 8-2
Distribution of Available Sample and Quota for
the Post-Event and End of Summer Surveys across all Strata

Utility	Program	Action	Sample	Quota
PG&E	CPP		94	42
PG&E	DBP	Bidder	45	30
PG&E	DBP	Non-bidder	147	45
PG&E	CPP & DBP	Bidder	17	14
PG&E	CPP & DBP	Non-bidder	29	11
SCE	CPP		7	4
SCE	DBP	Bidder	53	31
SCE	DBP	Non-bidder	273	85
SCE	CPP & DBP	Bidder	1	1
SCE	CPP & DBP	Non-bidder	0	0
SDG&E	CPP		42	22
SDG&E	DBP	Bidder	8	2
SDG&E	DBP	Non-bidder	18	6
SDG&E	CPP & DBP	Bidder	3	2
SDG&E	CPP & DBP	Non-bidder	4	3
Total			741	298

Data Collection

Telephone interviews for both the Post-Event Survey and the End of Summer Survey were conducted with a representative group of decision-makers that were responsible for accounts participating in the 2005 CPP and/or DBP programs from sample described above. The surveys were conducted by Quantum Consulting's Computer Aided Telephone Interview (CATI) center. As mentioned above, customers were assigned to one of 15 strata based on their utility, whether they were enrolled in CPP or DBP, and whether they had taken any DR action in previous events.

The Post-Event Survey was completed in late August and early September and asked DR participants questions concerning the CPP or DBP events they had experienced prior to the survey. Specifically, they were asked detailed questions about their participation in specific events (whether or not they had placed bids or had taken demand reduction actions and the types of actions taken), their likelihood of participating in future events, and their thoughts on the current notification process. In total, 171 participants completed the Post-Event Survey. The final distribution of completes for the Post-Event Survey is shown in Exhibit 8-3 below.

Exhibit 8-3
Number of Survey Completes for the Post Event Survey

3 IOUs	CPP and DBP Participants	CPP Participants	DBP Participants
Utility Breakdown			
PG&E	81	33	61
SCE	64	3	62
SDG&E	26	19	11
Unique Customers	171	55	134

The End of Summer Survey was dialed in late November and early December. A total of 211 participants completed the End of Summer Survey. Eighty-four of these respondents had also previously completed the Post-Event survey. In the second survey, these 84 participants were asked about any CPP or DBP events that had occurred since the initial Post-Event survey had been administered. Once the questions from the Post-Event survey had been asked, all survey respondents were asked a series of questions concerning reasons for participation, barriers to participation, program satisfaction, likelihood of further participation, and general market perception.

The final distribution of completes for the End of Summer Survey is shown in Exhibit 8-4 below.

Exhibit 8-4
Number of Survey Completes for the End of Summer Survey

3 IOUs	CPP and DBP Participants	CPP Participants	DBP Participants
Utility Breakdown			
PG&E	115	56	79
SCE	78	3	75
SDG&E	18	15	4
Unique Customers	211	74	158

In total, 382 surveys were completed with 298 unique customer decision-makers. Exhibit 8-5 shows the breakdown of survey completes for the two participant surveys by Utility and Program.

Exhibit 8-5
Number of Survey Completes for Both Surveys

3 IOUs	CPP and DBP Participants	CPP Participants	DBP Participants
Utility Breakdown			
PG&E	142	67	100
SCE	121	5	117
SDG&E	35	27	13
Unique Customers	298	99	230

Representation

The responses to the survey questions in this section are shown un-weighted and thus represent the distribution of the customers surveyed, not necessarily the entire participant population. To account for the fact that the SCE DBP bidding population was over-sampled, and for the possible response bias that could exist since customers who are active in these DR programs are probably more likely to take the time to participate in these surveying activities, certain questions have been broken out by whether customers took bidding or demand reduction actions.

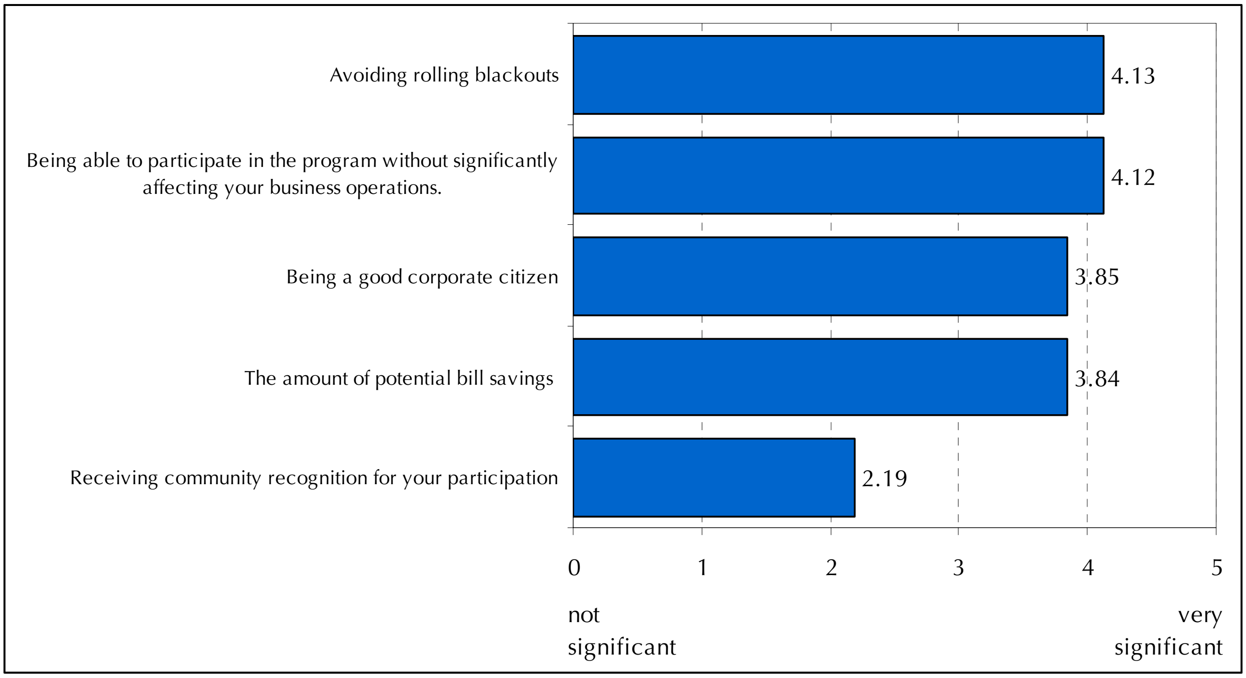
8.3.2 Participant Survey Results

This section presents the final results of the two participant surveys – the Post-Event Survey and the End of Summer Survey – conducted for the 2005 WG2 Demand Response Evaluation. The alphanumeric series in parentheses in each subsection heading correspond to the question numbers from the survey instruments (see Appendix B). Key results are presented below. Complete results are shown in Appendix C.

Reasons for Participation (ES12)

Respondents were asked to rate the significance of a variety of reasons for program participation on a scale of 1 to 5, where 1 is "not significant" and 5 is "very significant". Exhibit 8-6 below shows the average significance for each reason given.

Exhibit 8-6
One a 1 to 5 Scale, How Significant a Reason for Participation is:

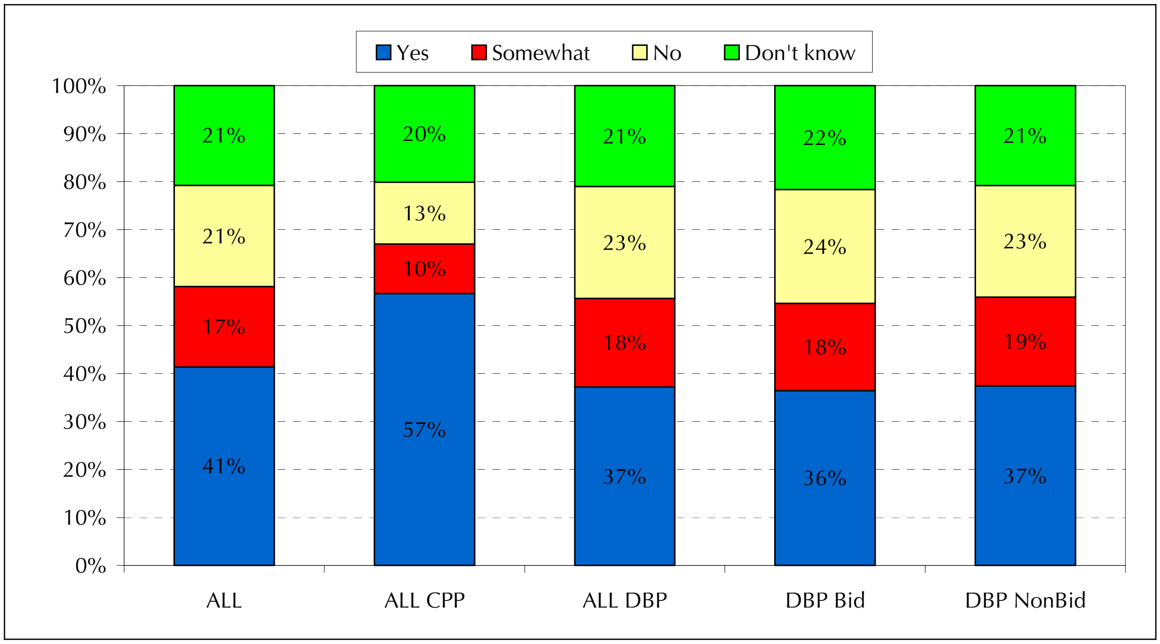


Overall, avoiding rolling blackouts and being able to participate without significantly affecting business operation were rated the most significant reasons for participation, receiving essentially identical mean importance ratings. Avoiding rolling blackouts was the only reason rated 5 (very significant) by more than half of all respondents. CPP participants in particular rated this reason very significant, with more than two-thirds (68%) assigning it a rating of 5.

Being a good corporate citizen and the amount of bills savings both received mean significance ratings of approximately 3.8. Despite the similar mean ratings, however, potential bill savings were rated extremely significant by 45 percent of respondents, compared to 34 percent of respondents for corporate citizenship. CPP participants were the most likely to have been motivated by bill savings, with 64 percent of this group giving this factor a "5" rating. This may reflect the marketing approaches used for the CPP and DBP, with the former primarily marketed using a rate analysis tool and the latter often using an appeal to help build DR capability and avoid blackouts. (As a voluntary program, DBP would be more likely to appeal to customers based on their civic duty, while CPP, with its more rigid performance criteria, would be judged based on bottom line impacts before customers make a commitment.)

In contrast, receiving community recognition received a mean rating of only 2.2, and received extremely significant ratings of 5 from fewer than 10 percent of respondents in all segments. Thus, while it is clear that many participants are motivated in part by the desire to be good corporate citizens, only a few are strongly interested in public recognition for their participation.

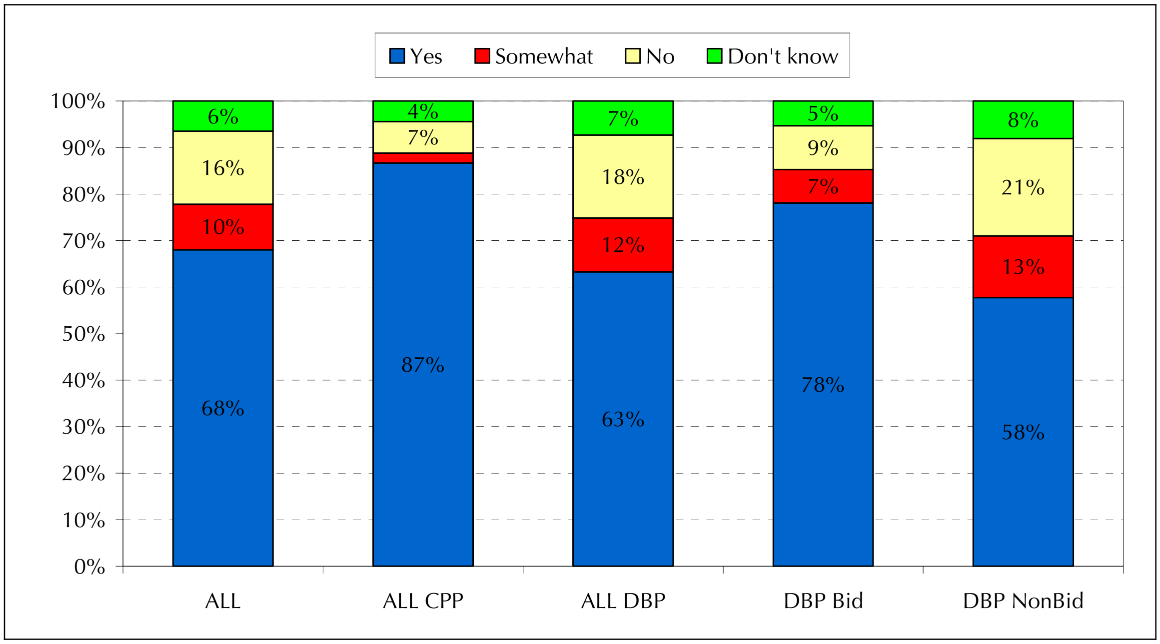
Exhibit 8-7
Have the financial incentives associated with the program met your expectations?



While almost two-third of respondents gave bill savings a 4 or 5 rating in motivating their participation, only 41 percent of customers surveyed said that the financial incentives associated with the DR program had met their expectations, while 17 percent said they had "somewhat" met their expectations, as shown in Exhibit 8-7 above. CPP participants were significantly more likely than DBP participants to say the financial incentives had met their expectations, regardless of whether DBP participants had placed bids or not (57% for CPP vs. 36% for DBP bidders and 37% for DBP non-bidders).

Among those who said the incentives had not met their expectations, some DBP participants said that was because they had not participated (37%), while CPP participants more often said they were paying more for energy now (20%). Most other responses were variations on the reply that incentives were too low, including "incentive not high enough to participate," "not much savings," "costs us more than we save," and "incentive too low."

Exhibit 8-8
Do you feel that your participation is having a positive effect on system reliability?



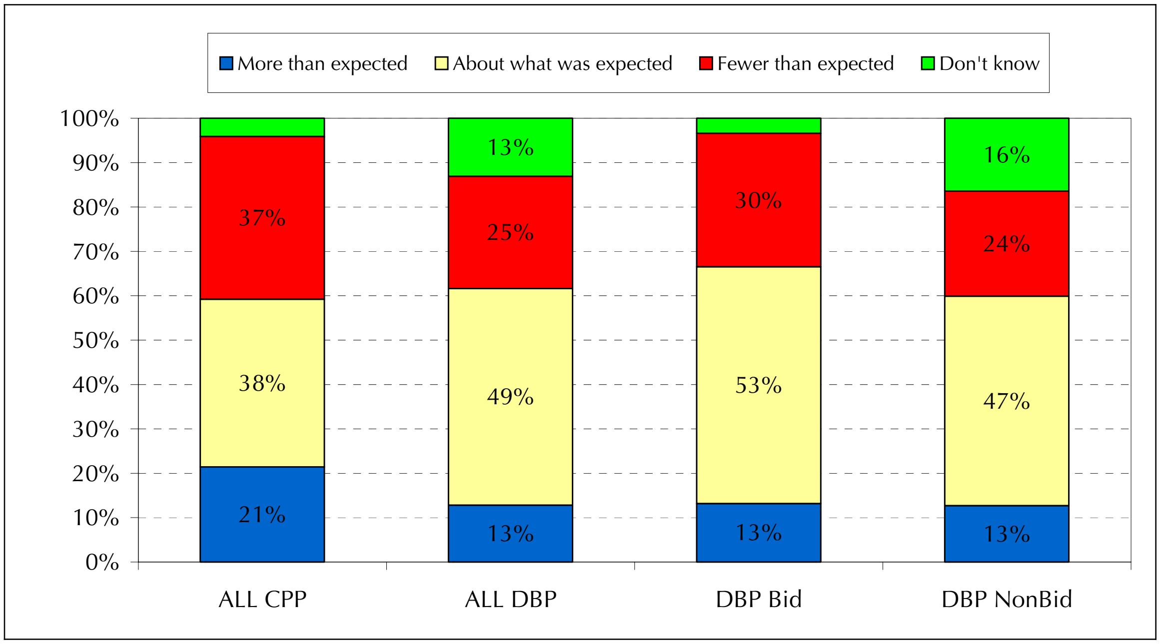
As Exhibit 8-8 shows, more than two-thirds of respondents felt that their participation was having a positive effect on their utility's ability to maintain system reliability, and another 10 percent said it was having a somewhat positive effect. Eighty-six percent of CPP participants said they were having a positive effect, compared to just 56 percent of DBP non-bidders. Among those who did not feel their participation had a positive effect, two-thirds (68%) attributed this to their inability to curtail usage.

When asked what other concerns their organization had about trying to reduce peak loads through DR program participation, about one-third (32%) said they had none, while 16 percent had concerns about their ability to participate, 15 percent worried about negative impacts on their business or production, and 12 percent said they were concerned with saving money. All other concerns were mentioned by fewer than 6 percent of participants.

Overall Perceptions of and Response to Events (ES1-ES7B)

Both CPP and DBP participants were asked a series of questions about the number of DR events they experienced during the summer of 2005, including their perception of the number of events relative to their expectations.

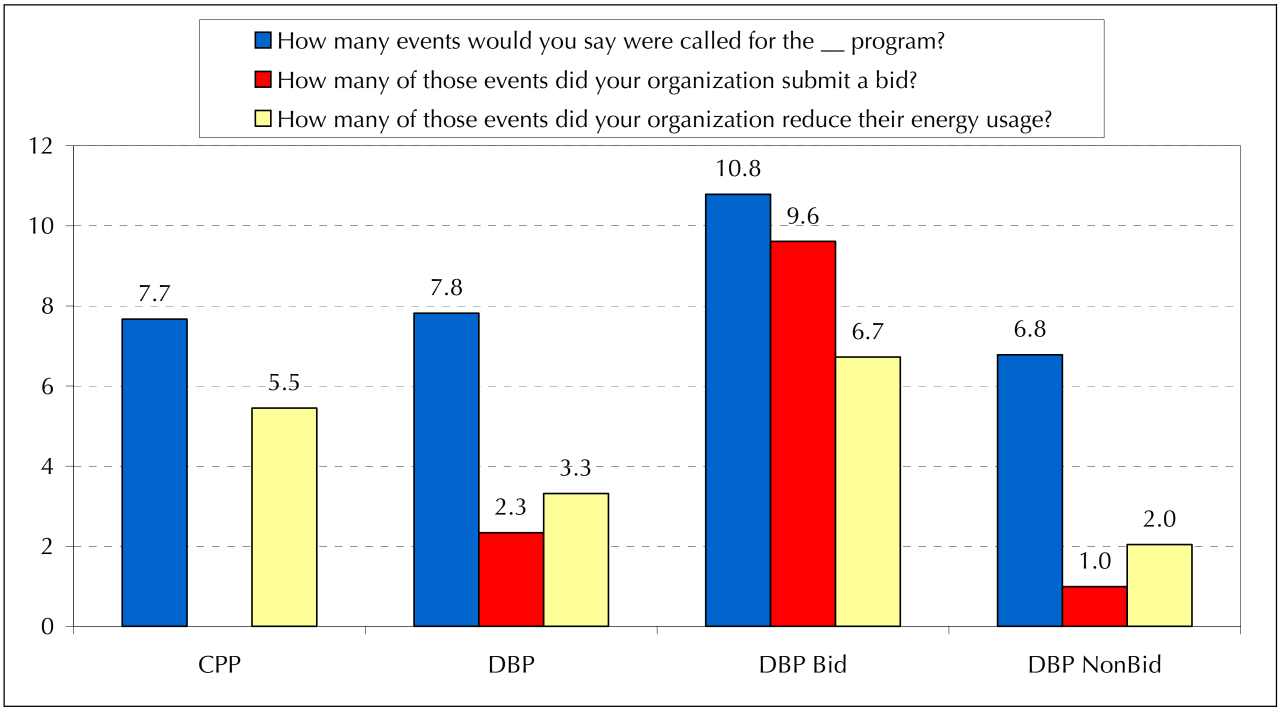
Exhibit 8-9
Were there more events than you expected, fewer events, or about what you expected?



As Exhibit 8-9 shows above, overall only 21 percent of CPP participants said there were more events than they expected. This percentage was more than twice as high, however, among extra large participants (43%). For both DBP bidders and non-bidders, only 13 percent of participants said there were more events than they expected.

Respondents were also asked how many events they recalled and how many they responded to, including submitting bids (for DBP only) and taking demand reduction actions (both programs.)

Exhibit 8-10
Number of Events Called and Response



Despite the significant percentage of customers who said the number of events exceeded their expectations, Exhibit 8-10 shows that the vast majority of customers reported taking action in at least one event. Of the CPP participants surveyed, only 11 percent said they did not reduce for any events. On average CPP participants said they recalled 7.7 events, and participated in 5.5 of those. To verify these self-reports, survey responses (i.e., self-reported data) were compared to actual load reductions during 2005 events. The results indicate that the CPP participants that said they took action two or fewer times indeed showed little or no load reduction on average during the events, while those that said they took action three or more times demonstrated average load reductions of 13 percent.

DBP continues to have a problem with many participants being unable or unwilling to curtail. Even though a smaller percentage of participants said the number of events was higher than expected (13%, vs. 21% for CPP), almost 60 percent of all DBP participants said they did not place bids for any events. DBP participants recalled an average of 7.8 events, placed bids for 2.3 events and curtailed usage for 3.3 events, with a clear distinction between bidders and non-bidders. Note that:

- DBP bidders said they placed bids for almost 90 percent of the events they recalled.
- DBP non-bidders said they reduced usage for an average of 2 of the 6.8 events they recalled.
- In comparison, impact results (see Chapter 7) show that 82 percent of enrolled DBP participants did not place a bid for any of the summer 2005 events. Averaged across all

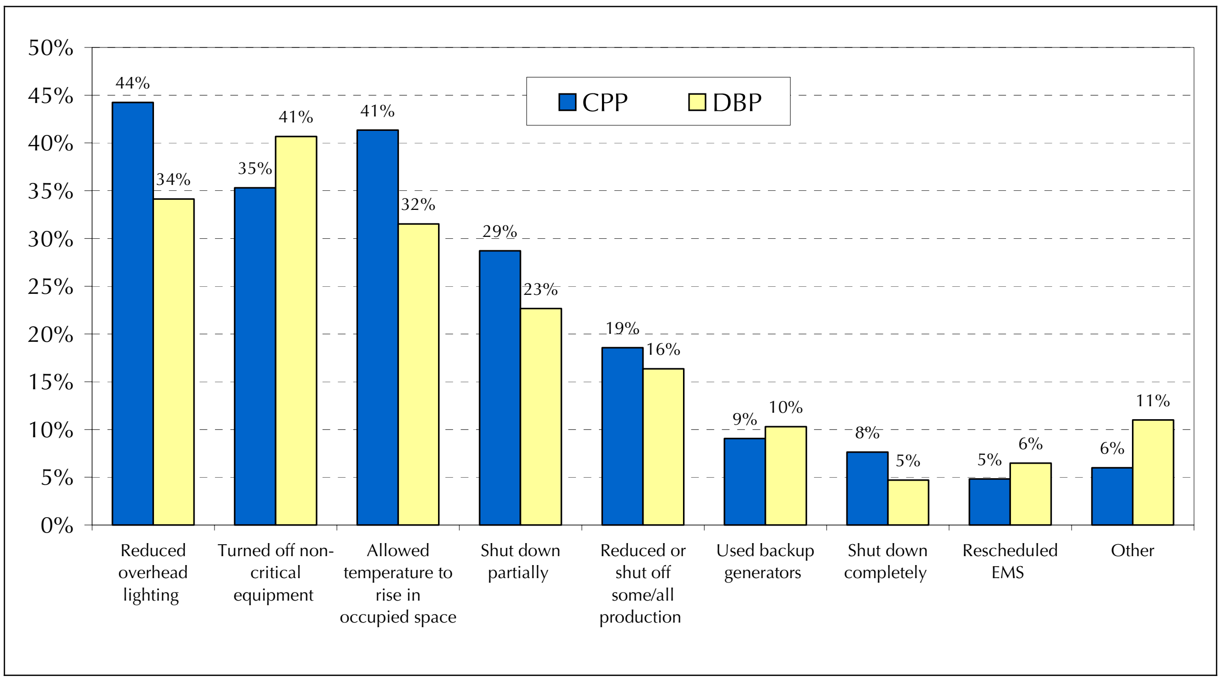
events in 2005, bidding rates varied from 5 percent of participants for SCE to 14 percent for SDG&E, and 7 percent for PG&E.

Among the DBP participants who placed bids for at least one event, only 11 percent said there were events for which they placed bids but did not take load reduction action, with more than two thirds of those saying either that they could not reduce load (45%), could not respond (22%), or were not available to bid (18%).

Actions Taken and Effects on Operations (DR5, DR9, IMPACT)

As noted above, most participants – including more than one-third of DBP non-bidders – said they took action to reduce their energy usage for at least some events. The self-reported actions taken by each group of participants are presented below in Exhibit 8-11a. Note that many respondents reported taking multiple demand reduction actions.

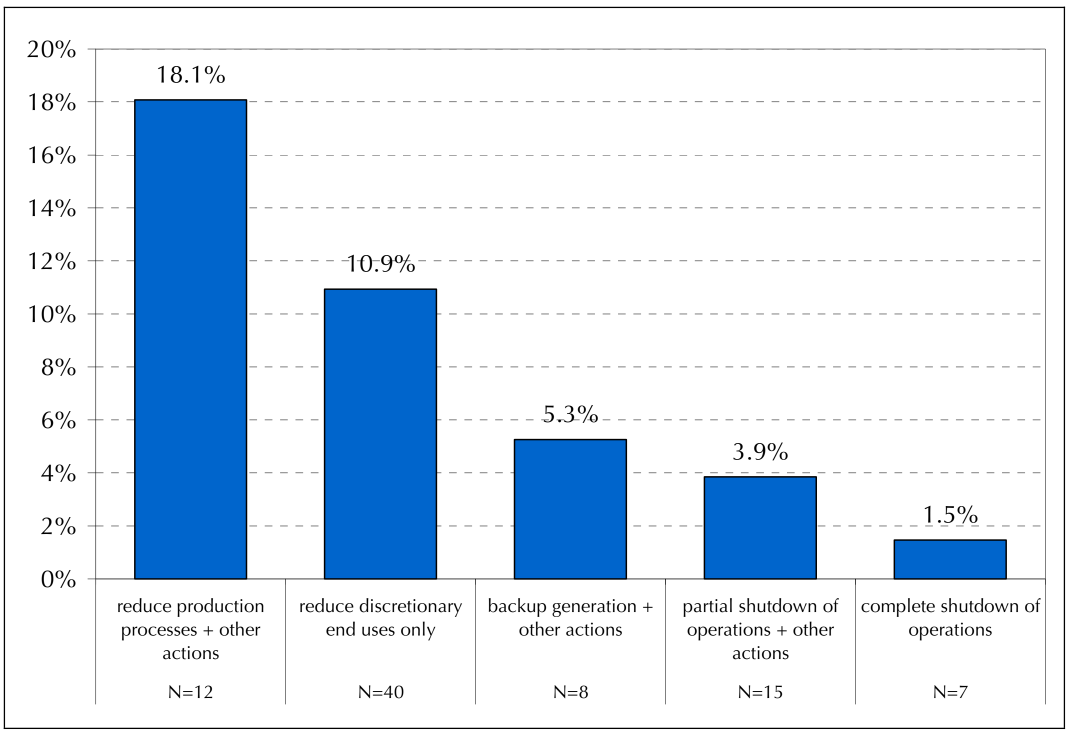
Exhibit 8-11a
Self-Reported Actions Taken to Reduce Demand



As the exhibit above shows, the most frequent self-reported curtailment actions were reductions in discretionary end uses, i.e. reducing overhead lighting, turning off non-critical equipment, and allowing temperatures to rise in occupied spaces. Partial operations shut down and reducing some or all production processes were also cited frequently by CPP and DBP participants. In comparison, using backup generation, shutting down operations completely, and rescheduling energy management systems were cited by relatively few CPP and DBP participants. The relative frequency of self-reported curtailment actions differs significantly with the curtailment actions most frequently reported by reliability program participants (see Chapter 9), who most frequently cite using backup generation and shutting down operations completely.

To gauge the relative impact of various curtailment actions on the total impacts realized from the CPP and DBP programs, the customer-level hourly load reductions were summed across customers who reported similar sets of curtailment actions.[1] These results are shown in Exhibits 8-11b and 8-11c for CPP and DBP, respectively. Due to the small sample size associated with these results, the total load reductions from customers that reported similar curtailment actions are shown not normalized across customers or number of events. Rather, they are shown as overall contributions to the total statewide CPP or DBP program impacts for all summer 2005 events. It should be noted that the participant population shown in Exhibit 8-11b represents 23 percent of accounts enrolled in CPP and 40 percent of total estimated CPP program impacts for summer 2005. Due to data limitations, we did not attempt to scale the impact contributions to represent all actions from the entire population of CPP and DBP participants. Nonetheless, Exhibits 8-11b and 8-11c serve as useful first order decompositions of total program impacts into specific groups of curtailment actions.

Exhibit 8-11b
Contributions to Total Statewide CPP Program Impacts by Self-Reported Curtailment Action



[1] Due to the frequency of customers who cited using multiple curtailment actions, responses were grouped preferentially into the following 'sets' of curtailment actions: backup generation plus other actions, complete operations shutdown plus other actions, partial shutdown of operations plus other actions, reduce production processes plus other actions, reschedule energy management systems plus other actions, and reduce discretionary end uses only. These sets were chosen based on the assumption that certain actions produce large, predictable load reductions (e.g. backup generation and complete shutdown) and tend to swamp other types of load reductions. In this scheme, customers who stated using backup generation along with any other action were preferentially grouped in the 'backup generation plus' category. The remaining customers who stated shutting down operations completely were then grouped in the 'complete shutdown plus' category. This grouping was repeated until only customers that stated reducing discretionary end uses (e.g. overhead lighting, indoor temperatures, etc.) remained.

Exhibit 8-11b above shows that, within the sample population of CPP participants shown, the set of curtailment actions that made the largest contributions to total CPP program impacts were reducing production processes grouped with other actions (18% of total CPP impacts), followed by reducing discretionary end uses (11% of total CPP impacts). The results for reducing production processes are consistent with the finding from impact analyses that Industrial customers account for the majority of total CPP program impacts (see Chapter 7). Also note that the results for reducing discretionary end uses suggest that these types of actions likely result in smaller load reductions on a per-customer basis, but because of the high relative frequency of CPP participants reporting to use these types of actions, these types of actions appear to contribute significantly to total CPP program impacts.

Exhibit 8-11c
Contributions to Total Statewide DBP Program Impacts by Self-Reported Curtailment Action

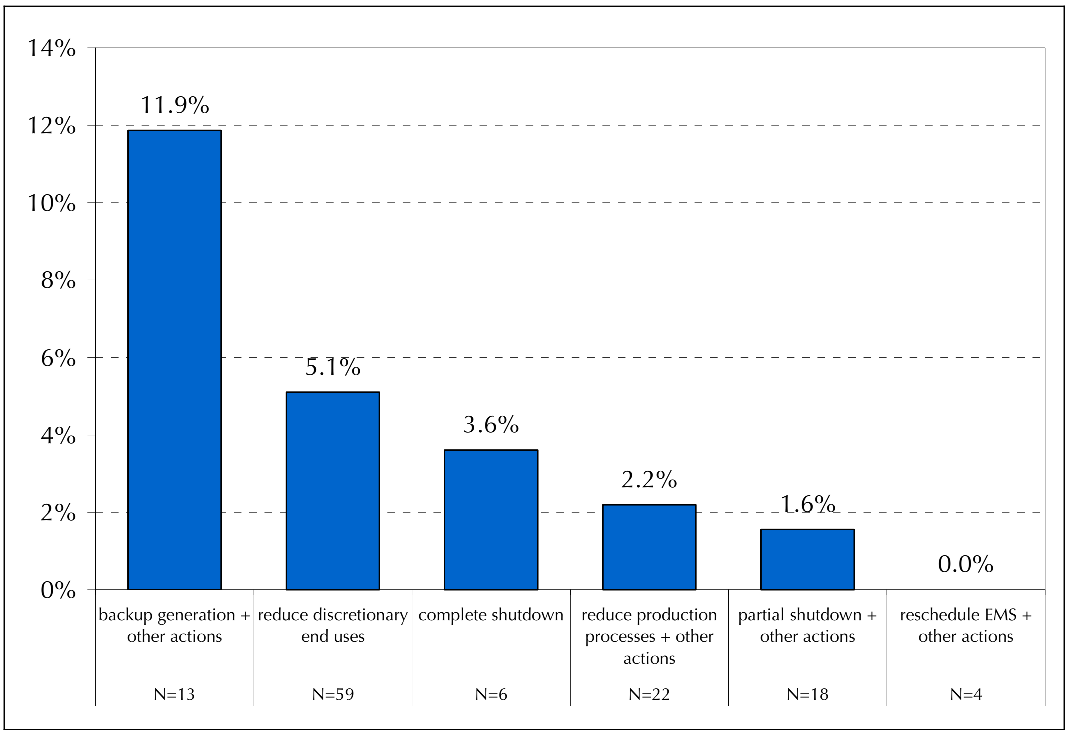
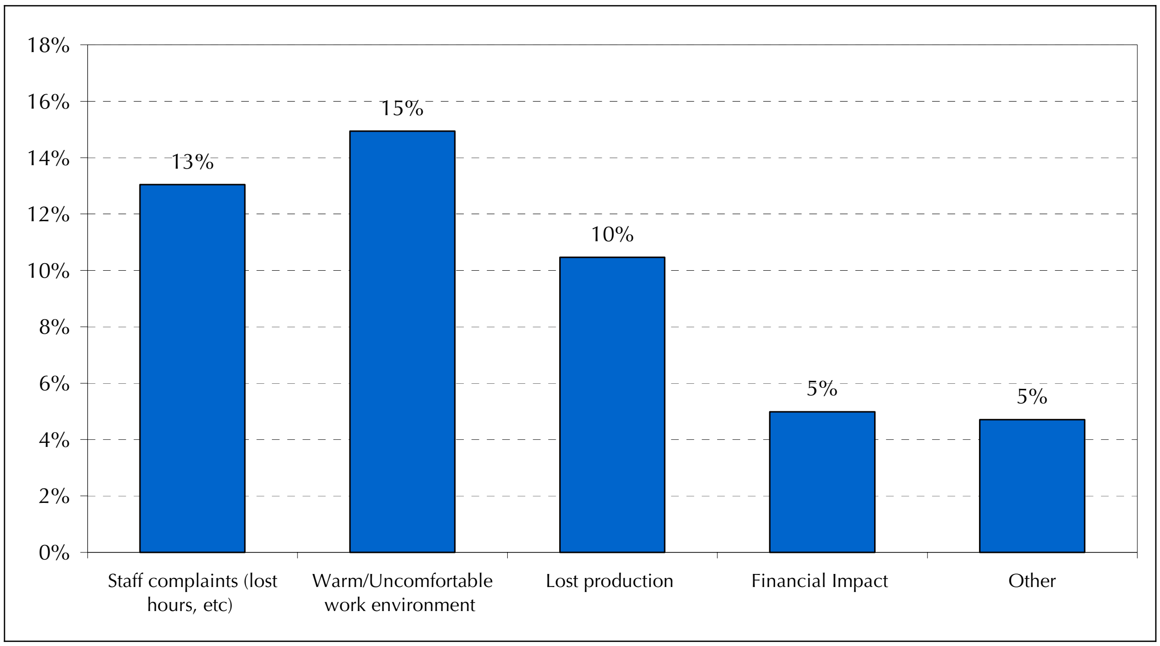


Exhibit 8-11c above shows that, within the sample population of DBP participants shown, the set of curtailment actions that made the largest contributions to total DBP program impacts were the use of backup generation grouped with other actions (12% of total DBP impacts), followed by reducing discretionary end uses (5% of total DBP impacts). The results for backup generators are consistent with the fact that over half of total DBP program impacts come from interruptible customers that participate concurrently in DBP (see Chapter 4) and that interruptible customers frequently cite the use of backup generation as a curtailment action (see Chapter 9).

Overall, fewer than one-third (31%) of respondents said they had experienced negative effects on personnel comfort or productivity as a result of their demand reduction actions, with Institutional customers (19%) significantly less likely than either Commercial (34%) or Industrial

(35%) customers to experience these effects. Small customers were the most likely to have experienced negative effects from demand reductions (50%). As shown in Exhibit 8-12, those who experienced effects from demand reductions typically cited a warm or uncomfortable work environment (48%), staff complaints (42%), lost production (33%), or financial impact (16%). The fact that the percentages shown are relatively low indicates that most participants have been able to implement demand reduction actions without significantly impacting their operations.

Exhibit 8-12
Effects of Demand Reduction Actions



About one-third of respondents report no delay in ramping up to their full electricity use after an interruption, either because it takes "no time at all" (21%) or because the facility is already shut down or closed (15%). Overall, just 20 percent of respondents said it takes more than an hour to ramp up, while 3 percent said they do not ramp up until the next day.

Reasons for Not Bidding/Curtailing (DR4, BID4-BID5, ES7C, ES99)

Participants who do not curtail for DR events have been a source of concern for both the CPP and DBP program: the former because of concerns about customers who benefit from the rate without taking any actions at all and the latter because of the large proportion of participants who appear to be unable to provide demand reductions subject to the terms of the program. Reasons for not bidding or curtailing are presented below.

Exhibit 8-13
Reasons for Not Bidding/Curtailing

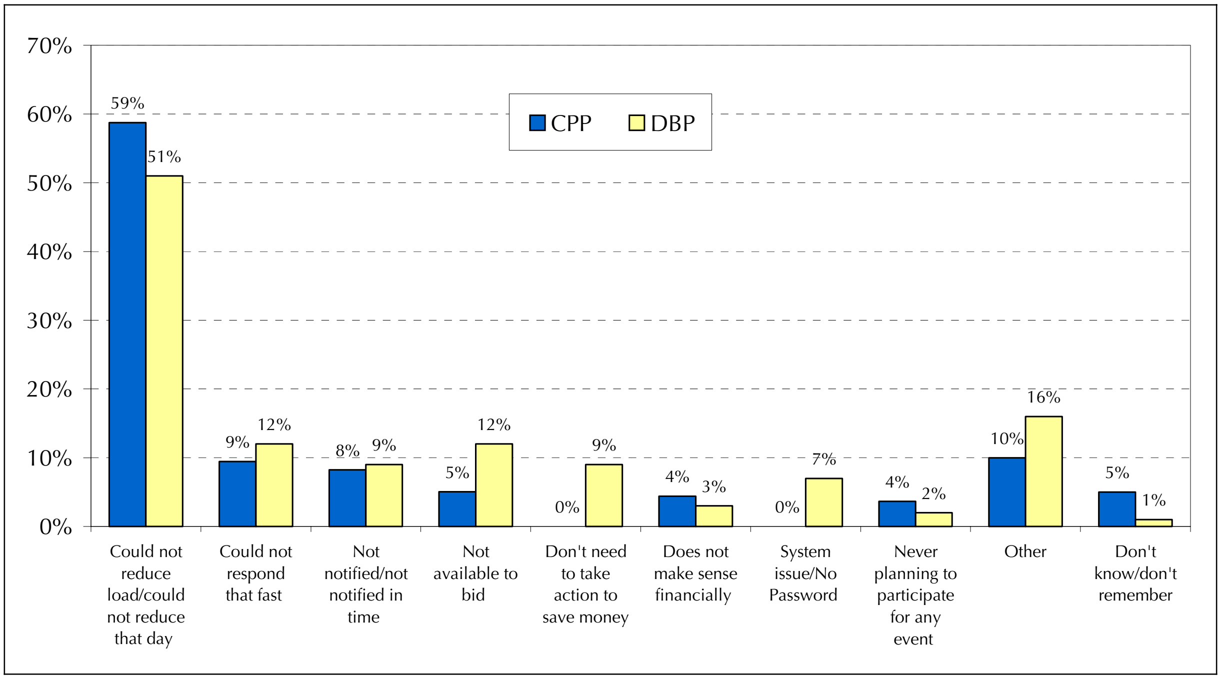
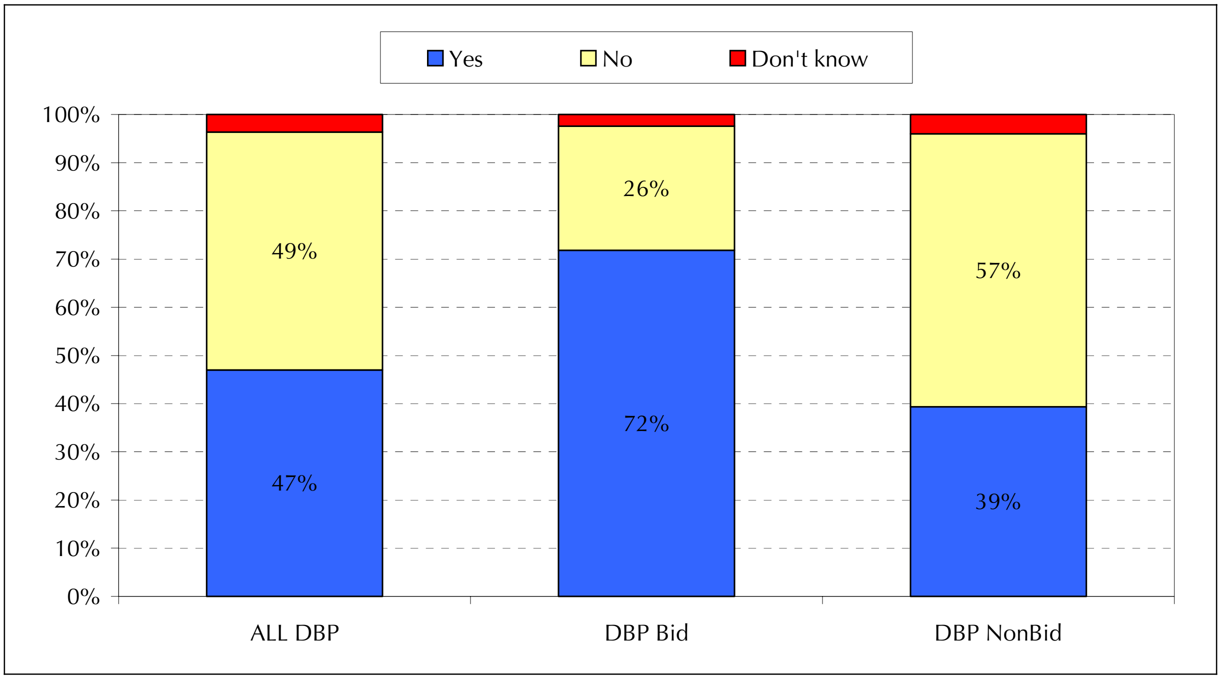


Exhibit 8-13 shows that, of the CPP participants who said that they did not make all of the events, 59 percent said that they could not shut down for some events, while only 4 percent said they were never planning to curtail, and none of the CPP participants offered the reply that they did not need to take action to save money. Like the previous finding, this suggests that there are few pure structural benefitters who take no action in response to program events but still benefit, although the impact results seem to indicate otherwise.

For DBP participants, Exhibit 8-13 shows that about half indicated that they did not bid because they could not reduce load, either in general (15%) or for a specific day (36%), while about 40 percent offered reasons related to the bidding process, such as the limited amount of time, the fact that they were unavailable to bid, or system/password issues. As noted elsewhere, this indicates that these customers need more help in learning the use of the bidding tool.

This finding is reinforced by responses regarding the effect of a wider bidding window, shown in Exhibit 8-14 below.

Exhibit 8-14
Would extending bidding window to 2 hours increase your bidding activity?

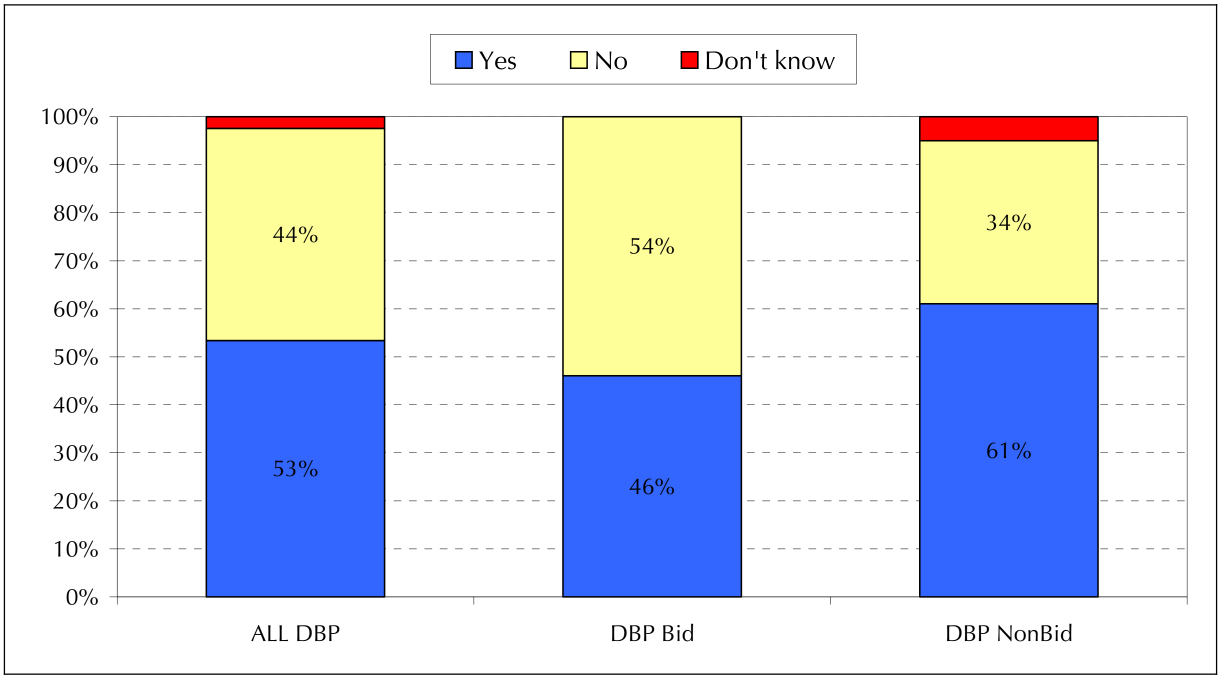


While almost half of DBP participants overall said that increasing the bidding window to 2 hours would increase their bidding activity, nearly three fourths of DBP bidders said it would do so. In other words, DBP participants who only bid for some events would likely have bid for more of them if they had more time. Of those who wanted to see the broader window, 46 percent preferred to see 1 hour earlier notification, 36 percent preferred a one-hour later bid deadline, and 18 percent didn't care as long as they got the extra hour.

Both the difficulty of bidding and the willingness of at least some DBP participants to take action to help maintain system reliability without financial gain are illustrated by the results shown Exhibit 8-15 below. As the exhibit shows, more than half (53%) of the DBP participants who did not place bids said there were events for which they had taken action even though they had not bid. To verify this self-reported activity, the average per-event impacts for DBP participants who said they took action even though they did not submit bids were compared to impacts for those who said they never took action. Indeed, those who said they reduced showed a 5 percent load reduction, while those who said they never acted showed a 1 percent increase.

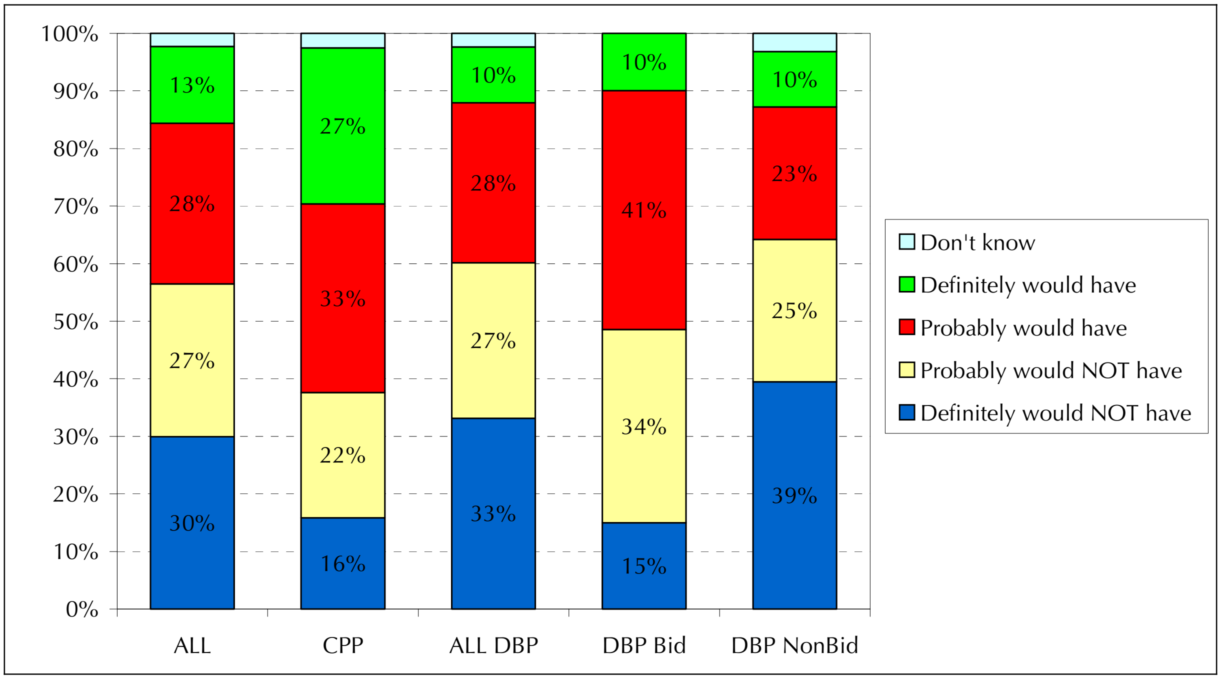
The main reasons stated for not bidding but still taking action were either because they missed the bidding window (27%), were unprepared or still learning the system (22%), or could not meet the minimum bid requirement (21%). Fully two-thirds (66%) of medium customers said they had taken action "in at least one event" despite not bidding, with 42 percent of those saying it was because they could not meet the minimum.

Exhibit 8-15
Were there any DBP events for which you took demand reduction actions despite not bidding?



The results shown in Exhibit 8-16 further illustrate the complex relationship between financial incentives for participation and actions taken in the public interest, which shows survey responses regarding the actions participants would have taken without the financial incentives in place. Overall, more than half (57%) of respondents said they definitely (30%) or probably (27%) would not have taken action if no financial incentives were offered, including 59 percent of extra large and 63 percent of large participants. Note that CPP participants – and to a lesser extent DBP bidders – were more likely to say that they probably would have taken action without incentives.

Exhibit 8-16
Would you have taken load reduction actions if no financial incentives were offered?



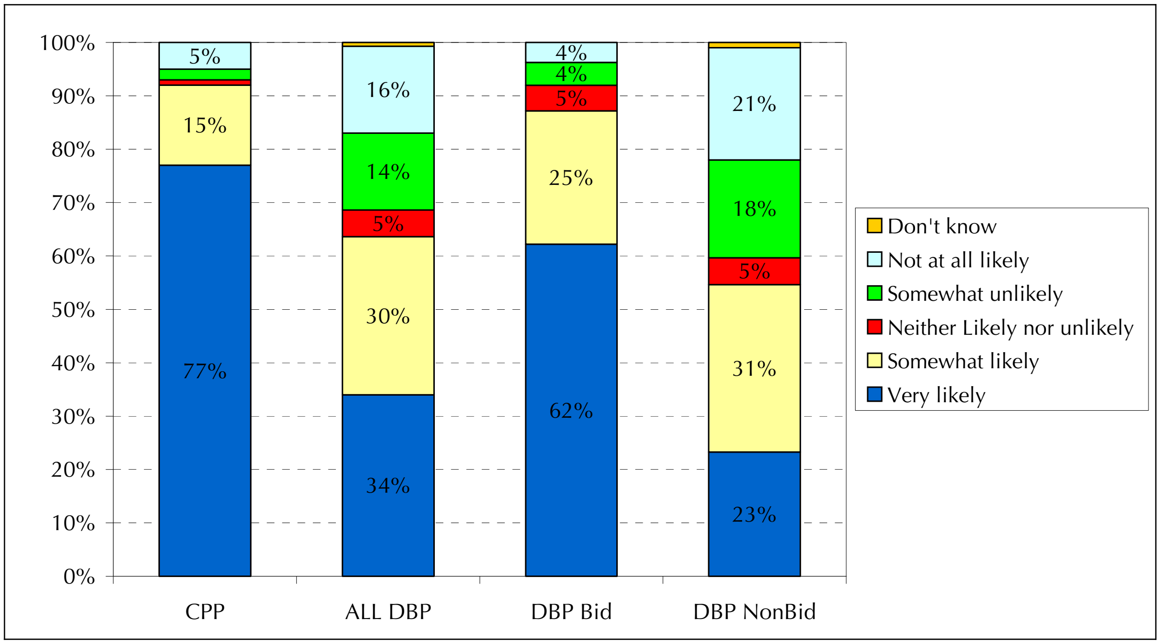
In addition to financial incentives, participant actions were motivated by their perception of the need for demand reduction to maintain system reliability – which relates to the discussion of program triggers earlier. Among survey respondents, only one-third (34%) said the events were very critical to helping their utility manage their supply or avoid rolling blackouts, while about half (52%) said it was somewhat critical. Only 7 percent thought it was not at all critical.

Among those who did not think the events were very critical, 56 percent said their response would have been different if they felt that the need was more critical, with more than two-thirds (69%) saying that they would reduce more load or would try harder to reduce load.

Intent to Respond to Future Events (DR23)

To further investigate the extent to which current participants do, in fact, represent a potential future resource, respondents were asked about their future intention to take DR action.

Exhibit 8-17
What is the likelihood that you will take demand reduction actions for future events?



The results shown in Exhibit 8-17 indicate that most participants are very likely or somewhat likely to participate in future events, but that percentage varies substantially across group.

- Only 7 percent of CPP participants said they were somewhat or unlikely to take action, again suggesting that only a limited number of these participants are acting as structural benefitters, although this is in conflict with impact evaluation results, which show about two thirds of CPP participants reducing their load an average of less than 5 percent for 2005 events (see Chapter 7, Exhibit 7-15).

- DBP bidders also had a high likelihood of continuing to participate. This is encouraging in that it suggests that once they have mastered the bidding/reduction process, most DBP participants will continue to place bids and take action.

- Conversely, just over half of DBP non-bidders said they were very or somewhat likely to participate in future events, which further highlights the need to target these customers for additional training and technical assistance. About 30 percent of DBP participants said they were somewhat or very unlikely to take demand reductions for future DBP events, including 34 percent of extra large respondents.

Among the DBP participants who said they were very unlikely to take action for future events, 35 percent said there were no circumstances under which they would take demand reduction actions. When asked why they had signed up for the program in light of their intentions, the 10 respondents who offered answers explained that they had thought they could participate (4), had signed up by mistake (2), or had been told to sign up by their rep (3). Other reasons mentioned once included incentives and access to real-time monitoring software.

DR Preparedness/Use of Utility Assistance (ES8, DR15, DR17, DR20-22, ASSIST, TA1-TA2)

As shown in Exhibit 8-18 below, just over one-third (35%) of respondents said they felt their organization had been very well prepared to manage demand reductions during the summer of 2005, while 45 percent said they had been somewhat prepared. While 19 percent of respondents overall said their organization had been not at all prepared, this percentage was lower for PG&E customers (8%) and CPP participants (4%), and higher for non-bidding DBP participants (27%), Commercial customers (23%), SCE customers (26%), and SDG&E customers (28%).

Exhibit 8-18
How well prepared was your organization to manage this summer's DR events?

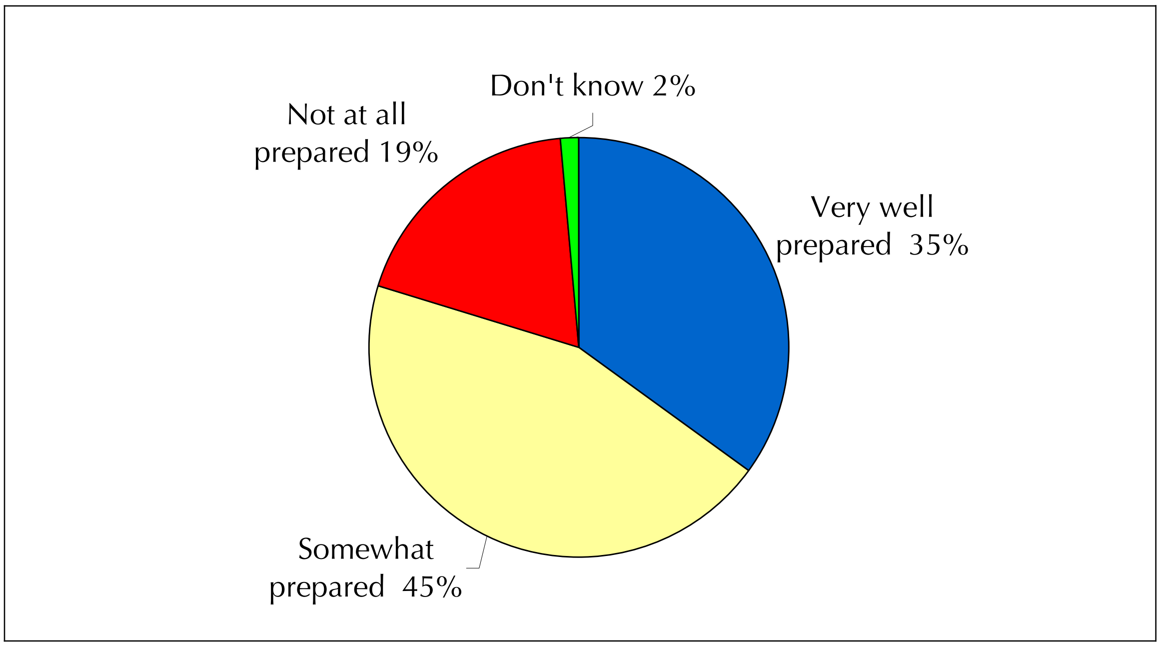


Exhibit 8-19
Percent with plan detailing DR actions

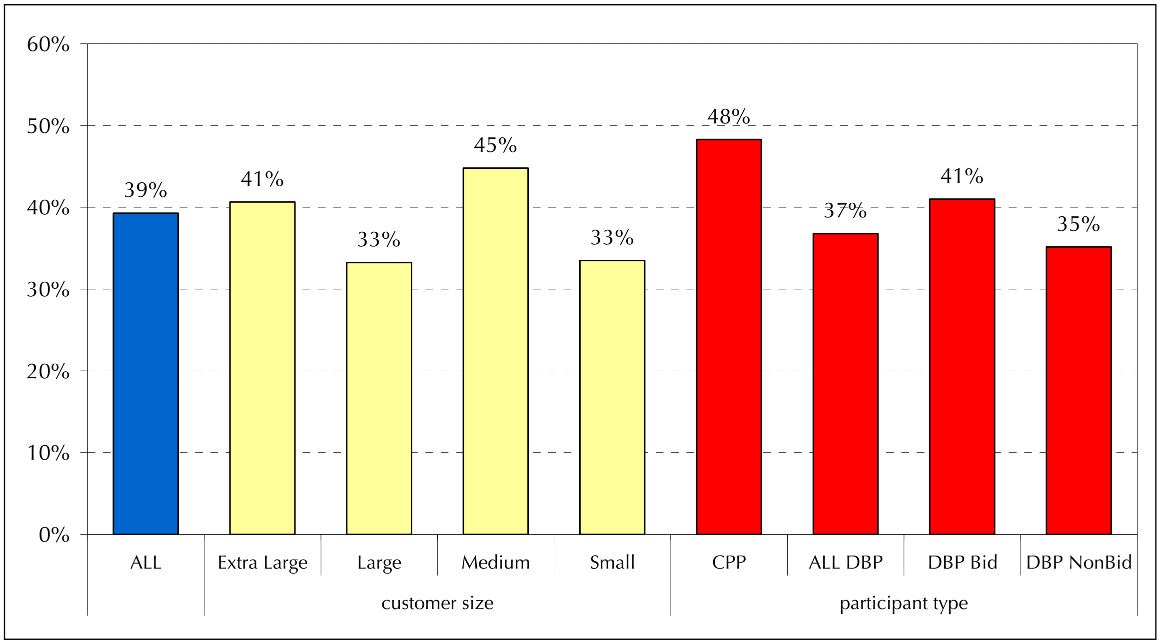


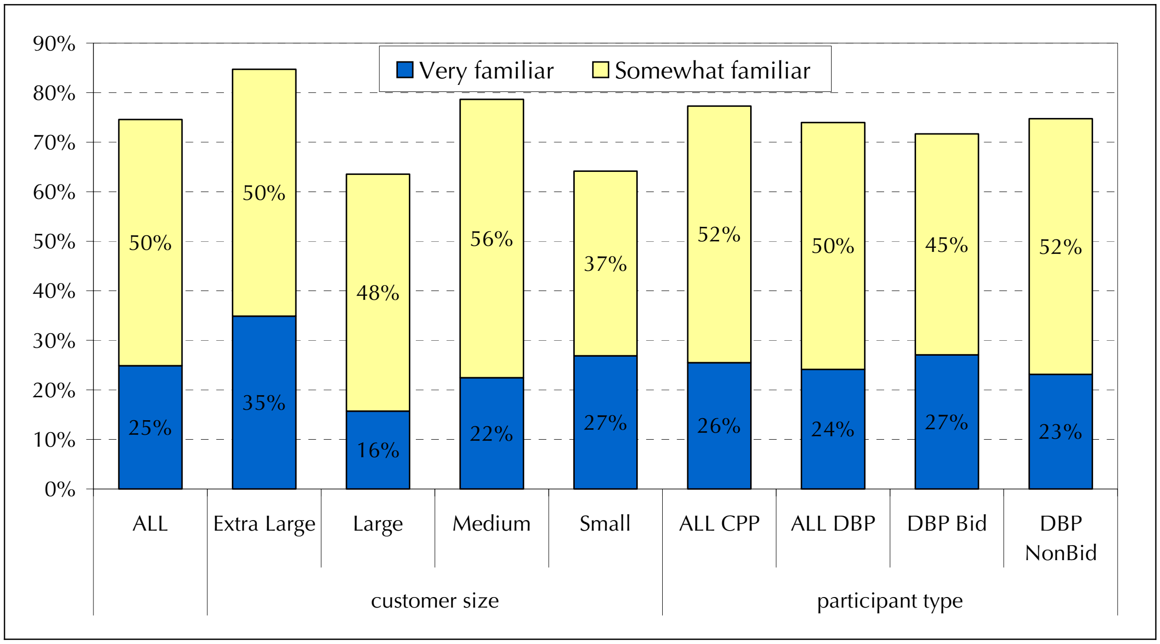
Exhibit 8-19 above shows that about two-fifths (39%) of respondents said they have a plan detailing the steps their organization will take in response to a DR event, ranging from 33 percent for small and medium customers to almost 50 percent for CPP participants. Moreover, 83 percent of those who had a plan said their actions this past summer did not differ from that plan. The percentage of participants who did not respond according to their plan was highest for very large customers (30%) and lowest for medium customers (3%).

Less than one-fourth (24%) of DR program participants said they had taken advantage of utility assistance services to help them prepare for DR events, although the percentage topped one-third (35%) for SDG&E participants. The type of assistance utilized included meetings and seminars (35%), technical assistance (30%), or access to the web (16%). The vast majority (83%) of those who used utility assistance said they found it helpful in enabling them to respond to 2005 DR events.

When asked what utility assistance they would find most useful in helping them take DR actions, just over one-fourth (27%) said no additional assistance was needed or the utilities should continue what they are doing. Types of assistance identified as helpful by more than 10 percent of respondents included more training (19%), increased incentives (19%), and the provision of energy audits/surveys (12%).

Since the TA/TI program is designed to help customers achieve demand reductions, survey participants were asked about their familiarity with the program and the likelihood that they would use it.

Exhibit 8-19
Percent familiar with TA/TI Program



As shown in Exhibit 8-19, about three-fourths of respondents said they were either very familiar (25%) or somewhat familiar (50%) with the TA/TI program offered by their utility. Extra large customers, CPP participants, and DBP non-bidders reported the highest degree of familiarity. The high level of awareness among DBP non-bidders is encouraging in that this group should be a natural target for TA/TI efforts.

To determine whether these groups would be receptive to the use of the TA/TI program, those who were familiar with the program were asked about their likelihood of using it.

Exhibit 8-20
Percent likely to use TA/TI Program

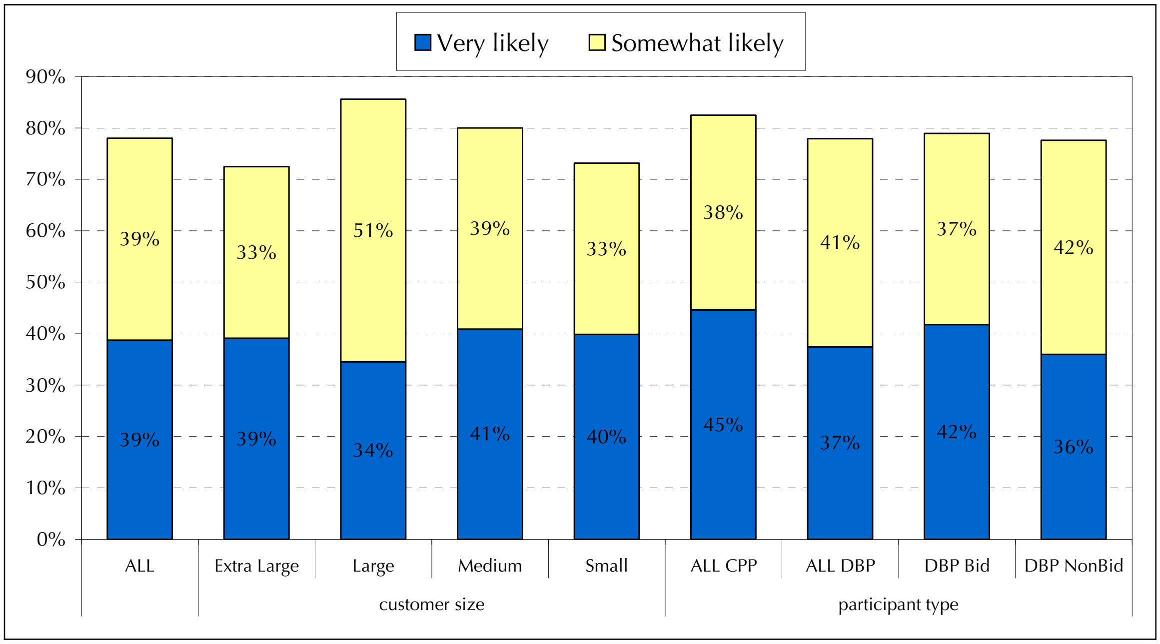


Exhibit 8-20 shows that, among those who were somewhat or very familiar with TA/TI, nearly 80 percent said they were either very likely (39%) or somewhat likely (39%) to utilize the TA/TI program, with at least 80 percent of large, medium, and CPP customers somewhat or very likely to use the program. This percentage is likely to rise as utility marketing activities for TA/TI continue in 2006. SDG&E, which launched its TA/TI marketing efforts before the other two utilities, had 100 percent of its customers who were aware of the program somewhat or very likely to participate.

DR Capability in Managing Events (CA3, FEED1-FEED5)

Program participants were also asked about their capability to manage DR events, both using in-house tools and the software provided by their utility.

Exhibit 8-21
Do you have the ability to view hourly demand…

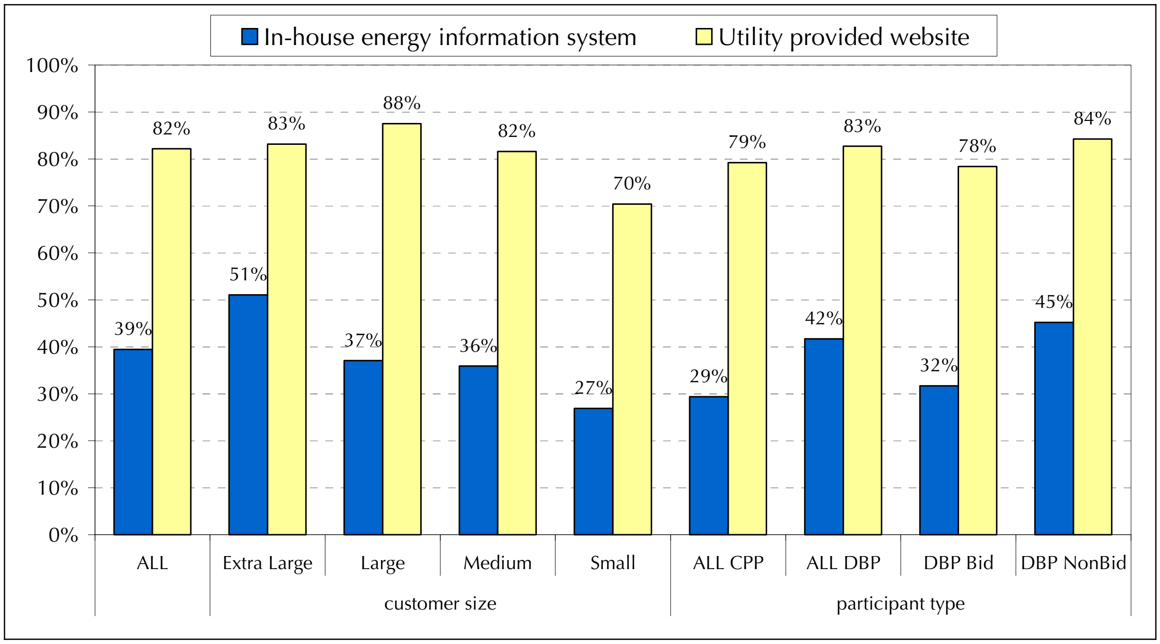


Exhibit 8-21 shows that, overall, 39 percent said they had the ability to view their hourly demand on an in-house energy information system, with the percentage ranging from a high of 51 percent for extra large customers to a low of 27 percent for small customers. There was no significant variation among utilities in customers' in-house ability to monitor load. Surprisingly, CPP participants and DBP participants who placed bids were less likely to say they have this ability (29% and 32%, respectively) than DBP customers who did not place bids (45%).

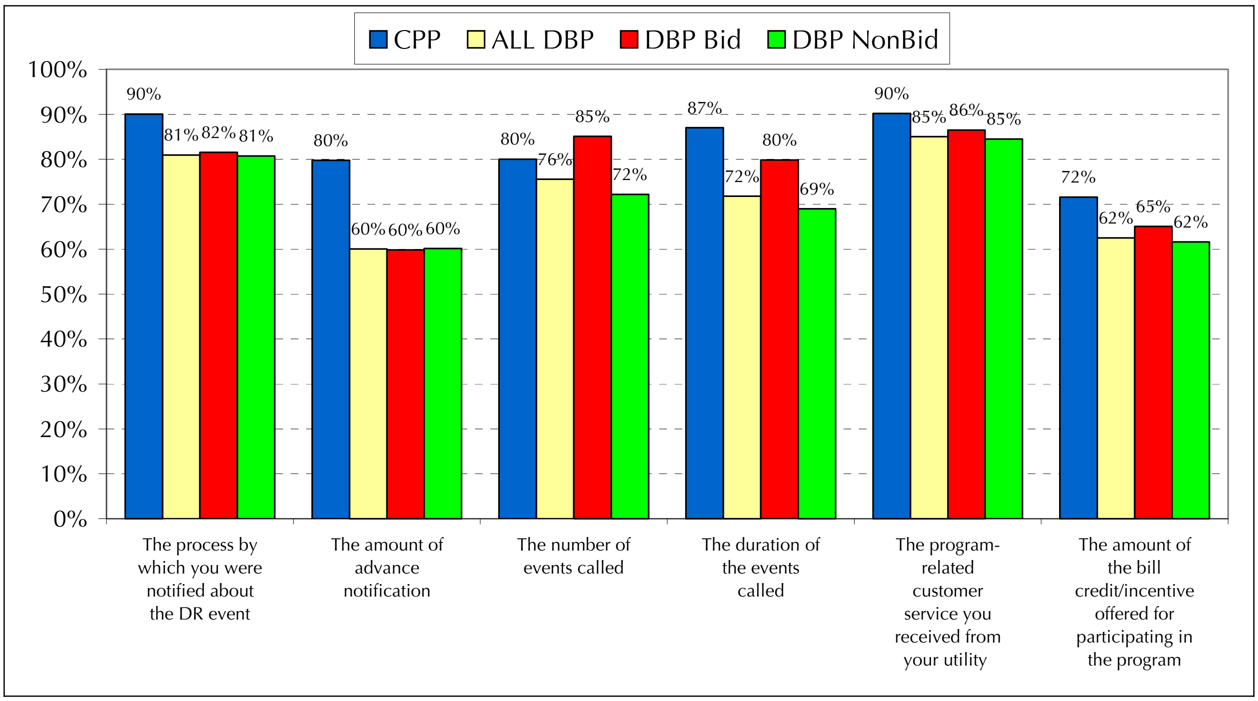
Exhibit 8-21 also shows that a much higher percentage (82%) of respondents reported having the ability to view their hourly demand on their utility's website, and more than half (56%) said they had used the online tool to monitor their electricity usage before or during a 2005 DR event. Not surprisingly, DBP non-bidders were less likely (44%) to have used the online tool for this purpose than CPP participants (61%) or DBP participants who placed bids (71%). Among those who used the tool, more than 80 percent – across all utilities – said the tool gave them the information needed to effectively manage their response to events, and 70 percent said it was easy to use, with only 2 percent overall saying it was very difficult. However, that more than one-fourth of all respondents across all size groups and business types found the tool "somewhat difficult" to use indicates that additional outreach efforts to train customers in the use of these tools would be appropriate.

Among those respondents who reported using the online tool, 25 percent said that others in their organization also regularly use their utility's website to view the facility's hourly demand, with the percentage declining as facility size declines – from 35 percent for extra large to just 4 percent for small customers. Reasons for use of the online tool by others primarily related to general energy management, with 60 percent citing "to manage energy usage" and 28 percent mentioning "evaluate/monitor energy usage." While only 10 percent of respondents overall said others used the website to place bids, 25 percent of DBP bidders said it was used for that purpose.

Satisfaction with Program Elements/Suggestions for Improvement (ES14-ES22)

Program participants were asked to rate their satisfaction with a number of program features as either "very satisfied", "somewhat satisfied," "somewhat dissatisfied" or "very dissatisfied." Since there was no "neutral" response, a good indication of satisfaction is provided by the percentage responding that they were either very satisfied or somewhat satisfied with that aspect of the program, as shown below in Exhibit 8-22.

Exhibit 8-22
Percent Somewhat or Very Satisfied with…



Using that indication, 83 percent of all participants were satisfied with the notification process and 85 percent were satisfied with the service they received from their utility (note that only 5% were dissatisfied with the service they received, since 9% said they didn't know.) In contrast, only 65 percent of respondents overall were satisfied with the amount of advance notification.

CPP participants were generally more satisfied than DBP participants. CPP participants were more satisfied than DBP participants with the number of events called (80% vs. 75%), the duration of events (87% vs. 72%), and the amount of bill credits or incentives, (72% vs. 52%). Not surprisingly, CPP participants were not particularly satisfied (36%) with the higher rates they paid for not reducing load during CPP events – something that DBP participants do not have to contend with.

CPP participants also had higher overall program satisfaction, as shown in Exhibit 8-23 below.

Exhibit 8-23
Overall Program Satisfaction

	PGE	SCE	SDGE	Extra Large	Large	Medium	Small	ALL CPP	ALL DBP	DBP Bid	DBP NonBid
CPP program	90%	81%	94%	88%	89%	92%	90%	90%	-	-	-
DBP program	78%	63%	65%	66%	67%	71%	81%	-	69%	87%	62%

Overall, when asked to rate their satisfaction on a 1 to 5 scale, where 1 is extremely satisfied and 5 is not at all satisfied, 90 percent of CPP participants gave a 1 or 2 rating, compared to just 69 percent of DBP participants. Similarly, the mean overall satisfaction rating for CPP participants was 1.7, compared to 2.2 for DBB participants. Note, however, that 87 percent of DBP participants who placed bids gave 1 or 2 ratings, compared to 62 percent of those who did not place bids, highlighting the problem noted earlier that many customers who signed up for DBP were unable to actively participate in the program, and were dissatisfied with it as a result.

For both the DBP and CPP, about 45 percent of participants said they had no suggestions for improving the program. Among those who had suggestions, the most commonly offered was earlier notification (20% overall for DBP, 9% for CPP). Segments most likely to offer this response included DBP bidders (29%) and CPP extra large (23%) participants. The fact that DBP non-bidders (18%) did not offer this suggestion more frequently suggests that earlier notification alone will not encourage more of these customers to bid, although it should increase bidding activity among DBP participants who have already placed bids. Other suggestions included:

- More information/training (8% for DBP, 8% for CPP)
- Increase incentives (8% for DBP, 3% for CPP)
- More feedback (2% for DBP, 7% for CPP)

Other suggestions – including make it more flexible, provide more education, improve the website, and encourage renewables – were made by fewer than 5 percent of respondents for either CPP or DBP.

Regarding lessons learned from their participation in the 2005 program, 15 percent of respondents said they were much more knowledgeable and 26 percent said they were no more knowledgeable, with the remainder saying they were somewhat more knowledgeable. Customers more likely to say they were no more knowledgeable included DBP participants (29%), large customers (34%), small customers (36%), and SCE customers (31%), the latter comprising DBP non-bidders almost exclusively. These results further highlight the need to work closely with DBP non-bidders to educate them about program participation or, barring that, to remove them from the program.

8.4 SUMMARY AND KEY FINDINGS

Motivation to Participate and Take Action is Strongly Affected by Non-Financial Factors; Bill Savings are also Important for CPP Participation

Consistent with the 2004 findings, most participants in the CPP and DBP programs report that non-financial factors play a very strong role in their participation. Overall, avoiding rolling blackouts and being able to participate without significantly affecting business operation were rated the most significant reasons for participation. Being a good corporate citizen and the amount of bill savings were also both rated highly as significant reasons for participating. CPP participants were more likely than DBP participants to have been motivated by bill savings. As a voluntary program, DBP would be more likely to appeal to customers based on their civic duty, while CPP, with its imbedded price signals, would be judged based on bottom line impacts before customers make a commitment.

Program managers say that customers generally are not doing these programs – particularly DBP – for the money. Certainly, customers would like to see some financial benefit, say the program managers, but the majority of customers participate to be good corporate citizens and help avoid rolling blackouts. As a result, when customers see neither a pressing need nor a substantive financial benefit, they question their participation in the DR Programs.

Bidding and Load Reduction Also Appear to be Linked to Civic Responsibility

Most respondents said they felt the 2005 DR events were important (i.e., somewhat or very critical) to helping maintaining system reliability. In addition, roughly half of CPP participants and DBP bidders reported that they "definitely" or "probably" would have taken the load reductions actions they did even without any direct financial incentives. The survey results for DBP non-bidders lend some support to that claim; when average per-event impacts for DBP participants who said they took action even though they did not submit bids are compared to impacts for those who said they never took action, the results shows a 5 percent load reduction for those who said they acted and a 1 percent increase for those who did not.

In addition, 56 percent of customers who did not see the 2005 events as important to maintaining system reliability said their response to the events would have been different if the need had been more urgent, with more than two-thirds (69%) saying that they would have reduced more load or would have tried harder to reduce load.

Most Participants were Satisfied with Their Overall Program Experience; Satisfaction was Somewhat Lower for DBP Non-Bidders

CPP participants generally have higher levels of satisfaction than DBP participants with their program overall and with specific aspects of the program (number of events, event duration, notification time and process, amount of credit or incentive). The difference diminishes when only DBP participants who placed bids or took action are considered, reflecting the influence of customers who appear to be poorly suited to program participation and probably should not have been enrolled.

Overall, 90 percent of CPP and 87 percent of DBP bidders reported they were "very" or "somewhat" satisfied with their overall program experience in 2005. With regard to specific program features, over eighty percent of all participants were satisfied with the notification process and the service they received from their utility. In contrast, only 65 percent of respondents overall were satisfied with the amount of advance notification.

Despite Concerns Among Program Managers and Some Customers, CPP and DBP Customers are Generally Satisfied with 2005 Day-Ahead Event Triggering

With DBP now called based upon predicted overall system load and CPP on temperature, neither of these programs is currently directly price based. Program managers question whether the triggers may be too sensitive, since there are many days when the overall load or temperature trigger is reached, but price is low and supplies are ample. As a result, program managers and account executives say they lose credibility when they urge program participation (not only signup, but bidding) and some customers see there is no real need.

However, despite these trigger conditions and the numerous resulting program events in 2005, the customer survey results for 2005 do not indicate that CPP and DBP participants had concerns about the number of events or the rationale for calling them. A strong majority of participants (roughly three-fourths) stated that the number of events was about what they expected or less than what they expected. Among CPP and DBP survey respondents, one-third said they believed the events were very critical to helping their utility manage their supply or avoid rolling blackouts, while about half said it was somewhat critical. Less than 10 percent thought it was not at all critical. In addition, those participants that said they did not take action in the summer of 2005 did not cite lack of system need for resources as a reason. In addition, over 80 percent of CPP participants and DBP bidders indicated that they were “very” or “somewhat” satisfied with the number of events called in 2005.

Load Reductions in CPP Appear to be Achieved Primarily Through Industrial Process Reductions and Curtailing Discretionary End Uses; Load Reductions in DBP Appear to Achieved Primarily Through the Use of Backup Generation

The most frequent self-reported curtailment actions reported by CPP and DBP participants were reductions in discretionary end uses, i.e. reducing overhead lighting, turning off non-critical equipment, and allowing temperatures to rise in occupied spaces. Partial operations shut down and reducing some or all production processes were also cited frequently by CPP and DBP participants. In comparison, using backup generation, shutting down operations completely, and rescheduling energy management systems were cited by relatively few CPP and DBP participants.

Based on a first order decomposition of total program impacts into specific groups of curtailment actions, the curtailment actions that appear to make the largest contributions to total CPP program impacts are reducing production processes, which is consistent with the finding from impact analyses that Industrial customers account for the majority of total CPP program impacts (see Chapter 7). Reducing discretionary end uses, which likely result in smaller load reductions on a per-customer basis, also appear to contribute significantly to total CPP program impacts due to the high relative frequency of CPP participants reporting to use these types of actions, these types of actions. For DBP, the curtailment actions that appear to make the largest contributions to total DBP program impacts are using backup generation together with other actions. This result is consistent with the fact that over half of total DBP program impacts come from interruptible customers that participate concurrently in DBP (see

Chapter 4) and that interruptible customers frequently cite the use of backup generation as a curtailment action (see Chapter 9).

Participants Reported only Moderate Effects on Productivity and Comfort

Overall, slightly less than one-third of DBP participants said they had experienced impacts on personnel comfort or productivity as a result of their demand reduction actions. Small customers were the most likely to have experienced impacts, while Institutional customers were the least likely. Those who experienced impacts typically cited a warm or uncomfortable work environment (48%), staff complaints (42%), lost production (33%), or financial impact (16%). The fact that the percentage of customers reporting impacts is relatively low indicates that most participants have been able to implement demand reduction actions without major impacts to their operations.

Some Evidence of Increased DR-Related Knowledge Among Active CPP and DBP Participants

As a result of their 2005 DR program participation, about three-fourths of surveyed CPP and DBP participants said they were somewhat or much more knowledgeable about managing their energy usage at times of peak demand. In addition, while the overall bidding percentage for DBP participants was low, a high percentage of those who placed bids in 2005 said they planned to do so in the future.

Active Participants Indicate a High Likelihood of Continuing to Participate in the Future, but Half of DBP Non-Bidders Indicate They will not Take DR Actions in the Future

Over 90 percent of CPP participants said they were somewhat or very likely to take demand response actions in the future. DBP bidders also expressed a high likelihood of continuing to participate and take demand response actions in the future. However, slightly less than half of DBP non-bidders indicated that they were not likely to participate in future events. Among the DBP participants who said they were very unlikely to take action for future events, 35 percent said there were no circumstances under which they would take demand reduction actions in the future. When asked why they had signed up for the program in light of their intentions, most of these respondents either said they had originally thought they could participate (38%), had signed up by mistake (25%), or had been told to sign up by their rep (17%). Others said they signed up for the incentives or to gain access to real-time monitoring software.

Many DBP Participants Indicated that an Extra Hour of Bidding Time Would Increase Their Ability to Place Bids

While almost half of DBP participants overall said that increasing the bidding window to 2 hours would increase their bidding activity, nearly three fourths of DBP bidders said it would do so. In other words, DBP participants who only bid for some events would likely have bid for more of them if they had more time. Of those who wanted to see the broader window, almost half preferred to see 1 hour earlier notification, about a third preferred a one-hour later bid deadline, and a remaining fifth did not care as long as they got an extra hour.

Some Remaining Need for Training on Use of Website Bidding Tools

While 82 percent of customers said they had access to their utility's online bidding tool and 56 percent of those said they used it to respond to DR events, 30 percent of those who used the online tools said they found them somewhat or very difficult to use, indicating a need for additional training.

Specifically noted was that a number of customers across utilities had problems logging in and using the bidding software. In some cases this was because they had lost their password or confused their "regular" logon ID with the one they have for DBP. In other instances there were problems with the DBP software for events early in the summer where, for example, customers were unable to see their baseline and/or place bids. These were generally resolved as bugs were worked out and as customers and utilities became more familiar with executing and tracking events, and there is no indication that these should pose a problem in future years.

Preliminary Indications of Need for and Strong Interest in 2005 TA/TI Incentives

Less than one-fourth of all DR program participants said they had taken advantage of utility assistance services to help them prepare for DR events, and only one third of day-ahead participants said they felt their organization had been very well prepared to manage demand reductions during the summer of 2005. These findings, together with the high degree of reported awareness and interest in TA/TI among DR program participants, suggest that the TA/TI programs could prove very valuable in increasing participation and active response to DR events in 2006 and beyond. Program managers across utilities also noted the enthusiastic response to the TA/TI program despite the relatively late rollout of the 2005 program.

9. RELIABILITY PROGRAMS: MARKET AND PROCESS ANALYSES

This chapter addresses process issues related to the implementation of reliability programs and assesses the potential market for reliability programs going forward. The chapter begins with an overview of the research goals of both the process and market analyses. Summaries of in-depth interviews with reliability program managers are presented next, followed by findings from a telephone survey of current interruptible service customers. We then summarize the results of in-depth interviews with customers eligible for, but not currently participating in, the Base Interruptible Program (BIP). Finally, we summarize the key findings derived from the body of data collected. Note that the samples for these customer interviews purposefully excluded the roughly 30 percent of interruptible service customers that currently participate in the Demand Bidding Program (DBP) or the Demand Reserves Partnership (DRP).

9.1 EVALUATION GOALS AND SCOPE

The Base Interruptible Program (BIP) was designed to provide customers financial incentives similar to traditional interruptible rates but in a single, consistent framework across all three utilities. However, customers have thus far been reluctant to switch from traditional interruptible tariffs to BIP.[1] One of the overarching goals of the 2005 WG2 Demand Response Evaluation is to assess the remaining potential for both firm and non-firm customers to migrate to BIP and/or day-ahead DR programs. Another goal is to assess and analyze the program experiences and preferences of traditional interruptible customers.

To accomplish these objectives, Quantum Consulting conducted the following data collection activities: 1) interviews with reliability program managers at each utility, 2) a telephone survey of current participants in traditional interruptible tariffs, and 3) a set of in-depth interviews with customers eligible to participate in BIP but currently not participating, including customers on traditional interruptible service tariffs as well as customers on firm service tariffs. Together, the data collected from these interviews form the basis of the process and market analysis presented below. Readers should note that both sets of customer interviews targeted customers not currently participating either in BIP or day-ahead DR programs. These analytic boundaries exclude the roughly 30 percent of the traditional interruptible customer population that also currently participates in the DBP program.[2]

The remainder of this chapter is organized as follows. The findings from the reliability program manager interviews are presented first. The following section presents the methodology and results of the telephone survey of traditional interruptible service customers. The last section presents the findings from the in-depth interviews conducted with both firm service and non-firm service customers eligible to participate in BIP.

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[1] Descriptions of BIP as well as each utility's traditional interruptible tariffs are provided in Chapter 2.

[2] See Chapter 4 for a specific discussion of this customer population.

9.2 PROGRAM MANAGER INTERVIEWS

Program managers at all three utilities were interviewed about BIP and about the role of "traditional" interruptible or non-firm tariffs: SCE's Schedule I-6, PG&E's Schedule E-19/E-20 Non-firm, and SDG&E's Schedule AL-TOU-CP.

The context for the current investigation into customer interest in BIP is the fact that the CPUC is trying to rationalize the reliability programs and make them more standardized across utilities. In practice that means the goal is to phase out the traditional interruptible tariffs and migrate IR customers to BIP. In addition, BIP is seen as a program that will enroll customers who might in the past have enrolled in the IRs (which have been closed to all but new load for several years.)

"One of the ways BIP came to be," explained one program manager, "was that the CPUC wanted to have comparable terms and conditions across the utilities for the interruptible rates and, ultimately, to have a single interruptible program statewide, just like the statewide CPP and DBP programs for DR."

In theory, said another program manager, "the legacy non-firm tariffs and BIP are meant to be six of one, a half dozen of the other. If you look at price per kW, it's $84 per kW per year for both non-firm and BIP; it's just paid differently." (i.e. as a rate reduction for IR versus a bill credit for BIP).

While rate designers have tried to make the two as nearly comparable as possible and believed that customers would see them as such, this has not been the case. Reaction to BIP has been less than enthusiastic, particularly among existing IR customers. Several reasons were offered for this:

- **The rates are not truly comparable**. The BIP incentive is paid on an average monthly on-peak demand reduction, not the reduction in the customer's peak demand. Thus, it is not equivalent to the demand charge discount in the interruptible rate. Moreover, the interruptible rates offer a discount on both the demand and the energy component of the charge, where the BIP discount does not. The difference between the two rate options can be as much as 20% with the equivalent amount of load drop.

- **Customers know and are comfortable with traditional IRs**. Most non-firm customers have been on their tariff for a long time and are used to it.

- **Timing**. As one manager put it, BIP was announced when the largest customers were "getting slammed with rate increases," and the focus on BIP raised the fear that "they're going to take away the non-firm rates."

- **Penalties.** The penalties for BIP are seen as high, even though they are theoretically consistent with those for the IR, in part because the IR penalties are lower for customers who only miss on a single event.

- **Actual vs. potential events**. The program conditions (number and length of interruptions) tend to be compared on their contractual maximums for BIP against the actual (very limited) number of interruptions customers have experienced on the IRs in the past few years.

In addition to the reluctance among IR customers to leave their non-firm tariffs for BIP, interest has also been limited among other eligible customers. Program managers suggested the following reasons:

- The penalties are high, particularly as a downside risk for customers who may not have much experience with curtailments.

- A PM with SCE noted that account reps may be reluctant to push this program and customers may be reluctant to try it because they have bad memories of the difficulty of shutting down during the energy crisis.

- Relatively few customers (other than those already on IR) can respond quickly and consistently with just 30 minutes notice.

- DR programs such as DBP, although less rewarding, carry less risk and allow much more time to prepare for curtailments.

As an alternative that would address concerns regarding notification time and penalties, the utilities have offered BIP Option B, which provides 3 hours notification and a lower penalty, but also offers a much lower bill credit. So far there have been very few takers. A PG&E manager noted "A few customers said they would be interested in Option B during focus groups, like the agricultural users, but we offered it and no-one has taken it."

On balance, there are two opposing forces with regard to the traditional interruptible tariffs. One the one hand, there appears to be an inexorable push to eventually sunset the existing non-firm tariffs and move customers to BIP or other programs. To the extent that BIP features are adjusted so that the incentive structure is truly comparable to the non-firm tariffs, customers may gradually make that transition.

In addition, there has been a tendency for the number of IR customers (and the amount of non-firm load) to gradually decline independently from any efforts to shift them to BIP. Even after the obvious sharp decline (particularly at SCE) after the energy crisis, a number of customers leave the non-firm tariffs each year, with some of these becoming candidates for the BIP program. Reasons for the decline in IR enrollment include the following:

- Increasingly stringent air quality requirements limit the extent to which onsite generation can be used to shed load, forcing some participants off the IR tariffs

- Either temporary economic downturns or the general downsizing of California manufacturing have caused some customers to fall below the 500 kW minimum required for participation.

- Some manufacturing facilities have closed and moved operations offshore or to another state.

On the other hand, most IR customers are committed to their non-firm tariffs, and the CPUC has not shown a strong inclination to force the issue to date. One program manager noted "It's very rare that they (the CPUC) take away anything from large industrial customers," but he also pointed out "there's not any other way to get another 300 MW at 30 minutes notice."

Finally, as the above comments suggest, non-firm tariffs appear to represent a more robust resource than the newer price-based DR programs. One program manager summed up the IRs with the following: "it's basically a 10-15% discount and those on it have been on for a long time, they know what to do. There's no problem with compliance, which is around 95%. The customers would like it to continue. They're used to what they have."

9.3 TRADITIONAL INTERRUPTIBLE CUSTOMER SURVEY

This section presents the methodology and results of a telephone survey of 99 customers currently taking service on traditional interruptible service tariffs. A brief overview of the survey objectives is presented first, followed by a review of the data sources and survey methodology. It is followed by a discussion of the key results and findings from the survey.

9.3.1 Survey Overview

The objective of the Traditional Interruptible Customer Survey was to obtain representative data on program satisfaction, awareness and attitudes towards DR programs, and preferences going forward for customers currently on traditional non-firm tariffs and not participating in other reliability or DR programs. Additionally, the survey sought to examine customer curtailment strategies, ownership of DR enabling technologies, and sensitivity to the potential frequency of curtailment events. To this end, Quantum Consulting developed a telephone survey instrument with guidance from the WG2 oversight committee and additional input from the PIER Demand Response Research Center. The survey questions explored the following topics:

- Ownership of key enabling and automation technologies
- Recent trends in automation and control investments
- Experience with interruption events in 2005
- Satisfaction with current interruptible service
- Demand response program familiarity and awareness
- Outlook and rate preferences going forward

The final survey instrument developed for the Traditional Interruptible Customer Survey is presented in Appendix B. Readers will note that a portion of the survey questions found in the Traditional Interruptible Customer Survey are also found in the Non-Participant Market Survey. This overlap was designed to allow results pertaining to DR program awareness, ownership of enabling technology, and recent automation and control investments to be compared between these two customer populations.

9.3.2 *Data Sources*

Data for the WG2 Demand Response Evaluation was provided to Quantum Consulting from each of the three utilities (PG&E, SCE, and SDG&E). The utilities provided the following types of data:

- Demand Response Participant Tracking Data. The participant tracking data was used to identify accounts that currently take service on traditional non-firm service tariffs (Schedule E-19/20 Non-Firm Service in PG&E, Schedule I-6 in SCE, and Schedule AL-TOU-CP in SDG&E).

- Commercial Population Data. Customer Information System (CIS) data was used to create the size and business type classifications for each account. Premise and Customer identifiers from the CIS were used to identify unique premises (across multiple accounts at a site) and customers (across multiple accounts and premises), and classification variables associated with these aggregated units.

- Customer Contact Information. Contact information (names and phone numbers) for both traditional interruptible service participants and non-participants were provided to Quantum from Customer Representative tracking databases, as opposed to the CIS. Where applicable, this helped ensure the customer we contacted was the same individual the utility account representative spoke with while marketing reliability programs. These contacts were provided on an as needed basis after samples had been selected.

9.3.3 *Population Frame*

Quantum Consulting created a population frame containing all PG&E, SCE and SDG&E accounts that currently take service on a traditional non-firm service tariff and not participating in day-ahead DR programs. Accounts in the population frame were assigned flags indicating their Size and Business type. These flags were created on an account level, a premise level and a customer level. The premise level flags were selected based on the largest account at that premise. In a similar manner the customer level flags were selected based on the largest account for that customer. The size flags were defined based on an account's monthly maximum demand:

- Extra Small customers are defined as those having a maximum demand between 20 kW and 100 kW (SDG&E only)

- Very Small customers are defined as those having a maximum demand between 100 kW and 200 kW (SDG&E only)

- Small customers are those with maximum demand between 200 kW and 500 kW (SDG&E only)

- Medium customers are those with maximum demand between 500 kW and 1000 kW

- Large customers are those with maximum demand between 1000 kW and 2000 kW

- Extra Large customers are those with maximum demand greater than 2000 kW

The business type flags were defined based on SIC code for SCE and SDG&E and a mapping of NAICS to SIC codes for PG&E. The three business types used for the population frame of the Traditional Interruptible Customers Survey were:

- Institutional
- Commercial
- Industrial

The size and business type distributions of the accounts in the population frame, along with the sum of their non-coincident demand (in MW) are presented in Exhibit 9-1. Note that the customer demand coincident with utility system peaks will be significantly less than the non-coincident figures shown in Exhibit 9-1 below.

Exhibit 9-1
Population of Traditional Interruptible Tariff Customers not Participating in DR Programs

3 IOUs	Total Participating Accounts	Total Participant MW Sum*	INTER Accounts PG&E	INTER Accounts SCE	INTER Accounts SDG&E
Size					
Extra Small (20-100 kW)	8	0	-	7	1
Very Small (100-200 kW)	15	2	-	5	10
Small (200-500 kW)	29	10	-	23	6
Medium (500-1000 kW)	121	91	5	108	8
Large (1000-2000 kW)	140	201	17	119	4
Extra Large (2000+ kW)	136	940	39	97	0
Unknown	6	0	0	6	0
Business Type					
Commercial and TCU					
Office	4	8	0	4	0
Retail/Grocery	18	10	0	6	12
Institutional	20	41	6	14	0
Other Commercial	18	39	3	13	2
Transportation/Communication/Utility	42	93	10	31	1
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	82	191	3	79	0
Mining, Metals, Stone, Glass, Concrete	96	454	11	85	0
Electronic, Machinery, Fabricated Metals	56	182	0	50	6
Other Industrial and Agriculture	119	226	28	83	8
Unclassified					
Unknown	0	0	0	0	0
Totals	455	1,245	61	365	29

9.3.4 Sample Selection & Data Collection

The sample design targeted 100 decision-makers of such premises across the three utilities (PG&E, SCE and SDG&E). Primary quotas were assigned based upon four customer sizes and three business types with roughly equal points allocated to each category to ensure comprehensive representation. The sample was then reduced to ensure multiple premises with the same decision maker would not be contacted more than once. The final sample frame included decision-makers who may be responsible for one or more accounts and/or premises.

Telephone interviews were conducted with a representative group of customers taking service on traditional interruptible tariffs as of December 2005. The survey was implemented by Quantum Consulting's Computer Aided Telephone Interview (CATI) center. A disposition of the results from the interviews is provide in Appendix C. As mentioned in Section 9.2.4, customers were assigned to one of 54 strata based on their utility, business type and size. Quotas were then set for each of the 54 strata. Exhibit 9-2 presents the final distribution of the completed non-participant surveys by size, business type and utility.

Exhibit 9-2
Final Distribution of Completes by Customer Size, Business Type, and Utility

	Total			Commercial			Institutional			Industrial		
Size:	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E	PG&E	SCE	SDG&E
Small (20/200-500 kW)	6	6	1	0	0	0	0	0	0	6	6	1
Medium (500-1000 kW)	2	18	0	0	1	0	0	2	0	2	15	0
Large (1000-2000 kW)	5	36	0	1	4	0	2	6	0	2	26	0
Extra Large (2000+ kW)	10	21	0	2	3	0	4	3	0	4	15	0
Total	**23**	**81**	**1**	**3**	**8**	**0**	**6**	**11**	**0**	**14**	**62**	**1**

9.3.5 Traditional Interruptible Customer Survey Results

This section presents the results of the Traditional Interruptible Customer Survey conducted for the 2005 WG2 Demand Response Evaluation. The alphanumeric series in parentheses in each section heading correspond to the question numbers from the survey instrument (see Appendix B). Key results are presented below. Complete results are shown in Appendix C. Where appropriate, results are also compared with those from the Non-Participant Market Survey (presented earlier in Chapter 5 of this report).

Business Demographics and Ownership of DR Enabling Technologies (EC1-EC10, AT1-AT2)

Each of the customers surveyed were asked to describe some basic characteristics of their organization's operations relevant to electricity use, management, and curtailment. These characteristics included the largest end uses of electricity, the extent to which energy management is a formal staff responsibility, estimates of the energy cost share of annual operating costs, and ownership of DR enabling technologies. The key findings relevant to assessing the additional DR resource potentially available from the non-participant traditional interruptible customer population are presented below.

In terms of energy management, eighty-four percent of customers reported having assigned responsibility for controlling energy use and costs to an individual, a group of staff, or an outside contractor. In terms of energy costs, one third of customers reported that their energy costs represent more than 10 percent of total operating costs, with an average reported energy cost share of 15 percent. As one might expect, these results are significantly higher than the results for the non-participant population, indicating that interruptible customers have both higher energy cost shares and higher levels of energy management, on average, than customers not currently participating in reliability or DR programs.

Across all interruptible customers surveyed, production processes were most frequently cited as their largest single end use of electricity (68%). Compared to the results from the non-participant population, this value represents nearly a two-fold increase, indicating that production processes play a significantly more important role in the load profiles of interruptible customers, on average, compared to those of non-participants. This reflects the fact that the interruptible customer population is dominated by Industrial customers, accounting for 76% of the total interruptible customer population and 71% of the customer sample frame used for the Traditional Interruptible Customer Survey.

Fifty-six percent of interruptible customers surveyed reported having on-site generation. In the aggregate, this reported ownership is only slightly higher than the reported on-site generation ownership among non-participants (49%). However, interruptible customers in the Commercial and Institutional sectors reported significantly higher ownership of on-site generators (82% and 76%, respectively) compared to interruptible customers in the Industrial sector (39%).

Only 38 percent of customers reported having an energy management and control system (EMCS) to centrally control all or some of their HVAC or other energy-using equipment. This value is much lower compared to EMCS ownership among non-participants (52%) but is consistent with the fact that Industrial customers make up the vast majority the interruptible customer population and tend to have significantly lower EMCS ownership rates compared to Commercial and Institutional customers (see Exhibit 5-12). Of those interruptible customers reporting to have EMCS, the systems most frequently controlled were rooftop or distributed HVAC (68%) and major ventilation fans (55%).

Automation Investments (EA8-EA11)

Interruptible customers were asked a series of questions about recent investment activity related to automation and control measures in order to gauge how the installed base of control technologies has been changing within the interruptible customer population.

Forty-four percent of the interruptible customers surveyed reported having considered automation investments to improve energy management in the past two years. Saving on energy costs was far and away the most important driver for those who considered automation investments (86%). Only 9 percent of those who considered automation investments did so primarily to increase the flexibility of their controls or respond to dynamic pricing.

Twenty-five percent of the interruptible customers surveyed actually installed upgrades to their automation and control systems in the past two years. Approximately half of these investments were in EMCS systems, a third in variable frequency drives, and a quarter in thermostats or sensors/motion detectors.

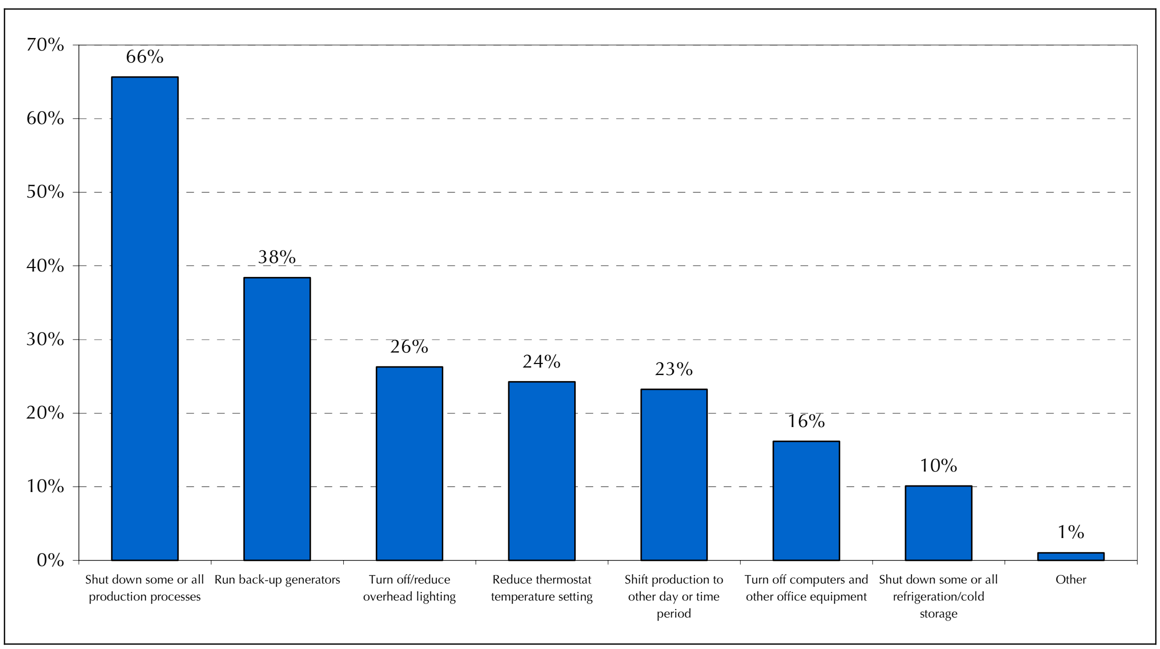
For the most part, the values reported above are not significantly different from the values reported by non-participants. Interruptible customers reported a slightly lower overall rate of actually installing automation and control upgrades in the past two years compared to non-participants (25% compared to 35%), but the reported drivers behind these investments and the types of upgrades actually installed are quite similar between interruptible customers and non-participants.

Curtailment Strategies and Recent Event Experience (EX1-EX6)

One of the key objectives of the Traditional Interruptible Customer Survey was to examine the curtailment strategies used by interruptible customers and their experiences with curtailment events. To this end, customers were asked a battery of questions that explored the nature of existing curtailment strategies, the costs associated with curtailment actions, and the role of enabling technologies. The results from these questions provide important perspectives on how much of the existing reliability resource from interruptible customers could potentially be available to DR programs.

Eighty-five percent of the interruptible customers surveyed reported having a pre-established curtailment strategy in place for interruption events. As Exhibit 9-3 shows, the most frequent curtailment actions cited by interruptible customers were shutting down some or all production processes (66%), and running backup generators (38%). Turning off or reducing discretionary loads like overhead lighting, office equipment, and indoor temperature settings were cited by less than 26 percent of interruptible customers. Notably, shifting production to other days or periods was cited as a curtailment action by only 23% of the interruptible customers surveyed.

Exhibit 9-3
Curtailment Actions Taken by Interruptible Customers



It is also important to note that across business types, running backup generators was the most frequent curtailment action reported among Institutional and Commercial customers (76% and 55%, respectively), while shutting down some or all production processes was the most frequent curtailment action reported among Industrial customers (80%).

Interruptible customers were also asked to provide estimates of the cost to their organization of each type of curtailment action they employ during interruption events, either on a per-hour or per-event basis. Exhibit 9-4 shows the average cost estimates reported for each type of curtailment action rounded to two significant digits. Note that typically 40 to 50 percent of the customers interviewed were not able to reliably estimate the costs incurred due to their curtailment actions. As a result, the sample size behind the cost estimates shown in Exhibit 9-4 are very small, and thus the estimates should be treated as indicative rather than statistically representative of the interruptible customer population. Despite this caveat, however, the results indicate that the most common curtailment action cited by interruptible customers, shutting down some or all production processes, also incurs the highest average costs by approximately an order of magnitude.

Exhibit 9-4
Self-Reported Estimates of Costs Incurred from Curtailment Actions

	Estimated Curtailment Costs			
Curtailment Action:	Per-hour	*(N)*	Per-event	*(N)*
Turn off/reduce overhead lighting	$1,000	*5*	$1,800	*4*
Turn off computers and other office equipment	-	-	$1,700	*3*
Reduce thermostat temperature setting	-	-	$330	*3*
Shut down some or all production processes	$18,000	*21*	$21,000	*12*
Shift production to other day or time period	$4,300	*8*	$5,000	*1*
Shut down some or all refrigeration/cold storage	$200	*1*	$2,400	*4*
Run back-up generators	$1,100	*12*	$3,900	*6*

To complement the information about the types of curtailment actions taken, interruptible customers were asked to describe the characterize the extent to which their curtailment actions are centrally controlled, as opposed to being a diffuse set of manual actions. Overall, 39 percent of the interruptible customers surveyed reported that their curtailments are entirely centrally controlled, 23 percent reported only partial levels of central control, and 37 percent reported that their curtailments are not at all centrally controlled. Interestingly, these results do not vary significantly across business types or customer sizes. Furthermore, the extent of central control is not significantly correlated with the types of curtailment actions currently taken.

Interruptible customers were also asked about their use of utility-provided software in their curtailment planning and management.[3] Only 22 percent of customers reported using utility-provided software to help plan or manage load reductions. Of those customers, however, the vast majority found the software to be very or somewhat helpful.

Overall, 25 percent of the interruptible customers surveyed find it generally easy for their organization to reduce required loads within the required timeframe, and 41 percent of customers find it somewhat easy. The most common reasons given by these customers to explain the general ease of short-notice curtailments were having an established curtailment

[3] These software packages are: InterAct II (PG&E), EnergyManager (SCE), and kWickview (SDG&E).

plan (28%), having the ability to switch to backup generation (16%), and using automated controls (12%).

In contrast, 27 percent of the interruptible customers surveyed find it somewhat difficult for their organization to reduce required loads within the required timeframe, and 6 percent of customers find it very difficult. The most common reasons given by these customers to explain the general difficulty of short-notice curtailment were cost and production losses (24%), not having enough time to curtail after receiving interruption notices (24%), and difficulties in shutting down production processes (21%).

Program Satisfaction (PS1-PS5)

Interruptible customers were asked a battery of questions related to their satisfaction with their current non-firm service programs. The questions examined general satisfaction, motivations for taking non-firm service, and satisfaction with specific elements of their non-firm service. Because other reliability and DR programs share many of the program elements found in traditional interruptible programs, information on customer satisfaction with these elements can help shed light on DR program design features that might appeal strongly to current interruptible customers.

Most of those enrolled in the utilities' traditional interruptible programs have been participating for a long time, demonstrating a high level of continuity and loyalty to the programs. Fifty-nine percent of the interruptible customers surveyed have been in the program for 10 years or more, and 82 percent have been in the program for 5 years or more.

The primary motivation for participating in traditional interruptible programs is saving money on energy bills. Fully 95 percent of traditional interruptible customers participate in order to reduce their energy costs. A small number of customers also mentioned being grandfathered into existing programs.

In general, interruptible customers reported to be very satisfied with their current non-firm service. Two-thirds of the interruptible customers surveyed reported being very satisfied with their current non-firm service, while the remainder was somewhat satisfied. Traditional programs also received high satisfaction ratings with respect to specific program elements detailed below.

Enrollment and determination of Firm Service Level. Although it has been a long time since most participants first enrolled in traditional interruptible programs, their recall of the enrollment process and determination of Firm Service Level (FSL) was overwhelmingly positive. Eighty-five percent of the customers surveyed reported high or medium satisfaction levels with the initial processes administered by each program prior to participation in the program. The remaining customers did not recall these processes, probably due to the amount of time elapsed since they joined the programs.

Significant shares of participants in the SCE and PG&E traditional interruptible programs (around 40%) have adjusted their FSLs since they joined the program, although the majority has not. Most adjusted their FSLs in 2002 and 2003, following the adoption of limits on the frequency and duration of interruption events in the traditional interruptible tariffs. The vast majority of the reported FSL adjustments were increases, which signals a decrease in kW load reduction commitments. Most customers gave one of two primary explanations for increasing their FSLs: either they decided that their previous curtailment commitments were unrealistically high or they decided that they wanted to be able to maintain a minimum level of energy services at their facility at all times. In the latter case, customers cited worker safety issues, reliability issues related to IT systems, and minimum energy services that enable faster and less costly ramp-up following interruption events.

Notification process. The notification procedure is critical for traditional interruptible program participants, since failure to receive notice of an interruption event means failure to interrupt load as required by the program, resulting in stiff monetary penalties to the customer. Over 90 percent of participants indicated medium or high satisfaction with the notification processes used by the utilities, indicating a high level of confidence in the utilities' established procedures for letting them know when an interruption event is called. This result likely reflects both past experiences with event notification as well as the fact that so few events have been called in recent years.

Frequency of interruption events. In general, the frequency of interruption events is a critical aspect of interruptible program satisfaction since more frequent interruptions reduces the value of the capacity payments that traditional non-firm customers receive. Ninety percent of the interruptible customers surveyed reported high or medium satisfaction levels with respect to the frequency of interruption events. However, given the low number of events called for recently, these high satisfaction scores would be expected. This clouds the picture of long-term satisfaction with this aspect of the program since it is essentially untested given so few recent interruptions.

Duration of interruption events. Another aspect of interruptible programs that impact the value of capacity payments to participants is the duration of individual interruption events. Satisfaction scores for the duration of interruptions were likewise high, with over 81 percent of interruptible customers reporting either medium or very high satisfaction levels. The picture regarding long-term participant satisfaction with interruptible event duration is likewise unclear due to the fact that interruptions have rarely been called in the past five years.

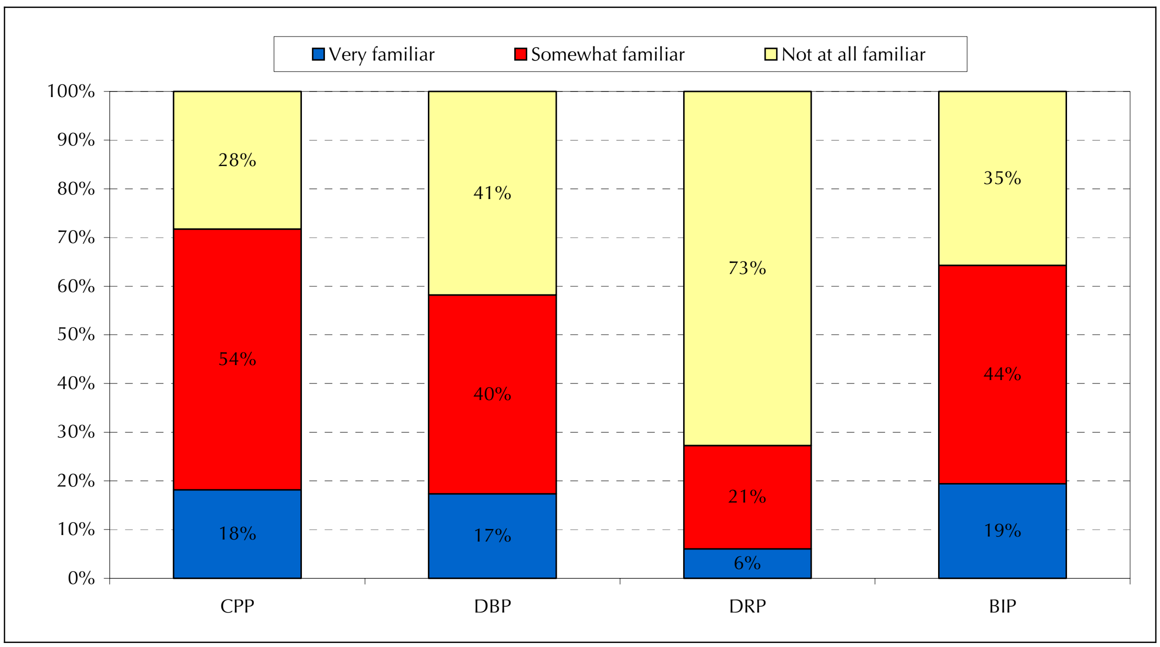
Interruptible Rate Reductions. As discussed earlier, rate reductions (leading to bill savings) are the primary reason for participation in interruptible programs and therefore are a very important element of overall satisfaction with the program. Participants' levels of satisfaction with reduced energy and demand charges for participation were likewise high. Almost 90 percent of interruptible customers surveyed reported either medium or high satisfaction with demand and energy discounts provided by traditional interruptible programs. It is clear from these findings that the programs are meeting participants' needs and expectations with respect to rate reductions and resulting bill savings.

Penalties for Failure to Interrupt. Participants were also asked about their satisfaction with traditional interruptible rate penalties for failure to curtail load during interruption events. Not surprisingly, interruptible customers are less satisfied with interruptible rate penalties than with any other aspect of the interruptible program. Possibly, this is because they are subject to the inherent risk of non-compliance penalties at all times. Overall, only 60 percent of interruptible customers reported being very or somewhat satisfied with program penalties.

DR Program Awareness (F2)

As in the Non-Participant Market Survey, interruptible customers were asked to describe their level of familiarity with demand response programs as well as BIP.[4] Overall, a large share of the interruptible customers surveyed reported to be either very or somewhat familiar with the CPP, DBP, and BIP programs (72%, 58%, and 64%, respectively). These program familiarity levels are consistent with those reported by non-participants. However, the shares of interruptible customers reporting to be very familiar with these DR programs were rather low in absolute terms (18%, 17%, and 19%, respectively) and significantly lower than the shares of non-participants reporting to be very familiar with the same programs (24%, 32%, and 37%, respectively). In contrast to familiarity with CPP, DBP, and BIP, familiarity with the DRP program was reported to be quite low among interruptible customers, with only 6% reporting to be very familiar with the program and 27% reporting to be somewhat familiar.

Exhibit 9-5
Familiarity with WG2 Demand Response Programs
Among Traditional Interruptible Customers



Interruptible customers were also asked about their familiarity with the Technical Assistance Incentive Program. Sixty-seven percent of the interruptible customers surveyed reported to be aware of the Technical Assistance Incentive Program, but only 21 percent of those customers stated that they planned to enroll in the program.

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[4] Note that the DR program awareness questions posed to interruptible customers were unaided, while those posed to eligible non-participants were aided (see section 5.3.6).

Preferences Going Forward (GF1-GF5)

The final section of the Traditional Interruptible Customer Survey sought to explore the risk tolerance of interruptible customers and their rate preferences going forward. The section began by asking customers whether they had considered switching to other rates or programs over the past two years and, if so, which program features they found particularly attractive or unattractive.

Twenty-six percent of the interruptible customers surveyed reported that in the past two years they had considered switching to another rate or participating in demand response programs. Of these customers, the rate or program considered most often was DBP (8 customers) followed by CPP tariffs (3 customers) and time-of-use tariffs (3 customers). Among customers that considered these alternatives, the vast majority cited pricing and incentives as the most attractive program feature, with a small number citing day-ahead notification or low risk of noncompliance penalties. Interestingly, the small number of customers who cited the risk-free nature of DBP or time-of-use tariffs as the most attractive program feature viewed the corresponding price incentives as the most unattractive feature of these programs.

Customers were then asked a short series of questions about their tolerance threshold for interruption events. Customers were first read a brief summary of the maximum number and duration of interruption events (or critical price periods for SDG&E customers) allowed under current respective tariff rules.[5] Customers were then asked how likely it would be that they would remain on their current tariff if the maximum allowable number of events actually occurred. Fifty-one percent of the interruptible customers interviewed reported they would be very likely to remain on their current tariff, and 17 percent reported that they would be somewhat likely to remain on their current tariff. Twenty-eight percent reported that it would be very or somewhat unlikely that they would remain on their current tariff if the maximum number of interruptions occurred.

Customers who reported to be unlikely to remain on their current tariff were asked to estimate the upper limit on the number of interruption events that they could withstand in a worst-case scenario before they would consider leaving their current interruptible program. The reported tolerance thresholds ranged from zero interruptions to 20 interruptions. Nearly half of the reported thresholds fell between 5 and 10 interruptions, however, and the mean value reported was 9.5.

Customers who reported to be unlikely to remain on their current tariff were also asked what tariffs and/or programs they would be most likely to consider if their stated tolerance thresholds were exceeded. One third of these customers stated that they would likely seek a firm service tariff and not participate in DR programs. Another third stated that they would likely seek a firm service tariff and also participate in DR programs. Twelve percent indicated that they would likely discontinue service and move operations outside of California. Only one customer indicated that they would likely seek a different non-firm service rate.

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[5] For PG&E's Schedule E19/20 Nonfirm tariff, the interruption limits are 30 events per year, 6 hours per event, and no more than 100 total hours per year. For SCE's I-6 tariff, the interruption limits are 25 events per year, 6 hours per event, and no more than 150 total hours per year. For SDG&E's AL TOU CP tariff, the critical peak period limits are 6 hours per period and 120 total hours per year.

Finally, all of the interruptible customers surveyed were asked what their rate preferences would be if their current interruptible tariffs were discontinued. Seventeen percent stated that they would likely seek a firm service tariff. Another 20 percent stated that they would likely seek a firm service tariff and also participate in DR programs. Only five percent stated that they would seek another non-firm service rate, but 20 percent indicated that they would seek a non-firm service rate and also participate in DR programs. Nine percent of the interruptible customers surveyed indicated that they would likely discontinue service and move operations outside of California if their current interruptible tariffs were discontinued.

The results presented above indicate that under current system conditions (i.e. very few, if any, interruption events per year) the interruptible customer base can be expected to be stable going forward, with little to no natural migration to DR programs or alternative non-firm rates. Because incentives under these traditional programs are currently very attractive, there is little financial motivation for participants to consider shifting to DR programs or non-firm service rates. Moreover, curtailment strategies used by interruptible customers are currently dominated by actions with large incremental impacts that also have large costs associated with them, indicating that it may not be a straightforward process to adapt these curtailment actions to the higher event frequencies and lower financial incentives typical of DR programs.

Should future system conditions warrant more regular and frequent reliability events, the survey results indicate that only a small portion of the interruptible customer market would either switch to other non-firm service rates or take firm service and participate in DR programs. This result is consistent with the fact that the vast majority of traditional interruptible customers are survivors of the 2000-2001 Energy Crisis. However, it should be noted that this result could also reflect a certain degree of tactical response on the part of current interruptible customers who want to ensure continuation of their current rate discounts.

9.4 IN-DEPTH INTERVIEWS WITH BIP-ELIGIBLE CUSTOMERS

This section presents the methodology and results of a set of in-depth interviews with 34 customers eligible for BIP. A brief overview of the interview objectives is presented first, followed by a review of the data sources and interview methodology. It is followed by a discussion of the key results and findings from the interviews.

9.4.1 Interview Overview

To complement the data collected in the Traditional Interruptible Customer Survey, a set of in-depth interviews were conducted with a total of 34 commercial and industrial customers across all three IOU service territories that are eligible for BIP but not currently participating, including but not limited to customers currently on traditional non-firm tariffs. These interviews sought to provide a deeper and more textured understanding of customer perceptions regarding the relative risks and merits of BIP compared to both traditional non-firm tariffs and DR programs.

Quantum Consulting developed an interview guide to help structure discussions with BIP-eligible customers and ensure collection of a minimum set of information. Unlike the telephone survey instrument, however, the majority of the interview questions were open-ended to allow customers and interviewers to explore relevant topics in more depth. The in-depth interviewed centered on the following topics:

- Experience with traditional interruptible service tariffs
- Experience with demand response programs
- Familiarity with BIP
- Reaction to BIP program features
- Outlook and rate preferences going forward

9.4.2 Data Sources & Population Frame

The data necessary to construct the population and sample frames for the BIP in-depth interviews was identical to that used to construct the analogous frames for the Traditional Interruptible Customer Survey discussed previously in Section 9.3.2.

Using these data, a population frame was then created containing all PG&E, SCE, and SDG&E accounts that were either eligible for the 2005 BIP program but not participating or currently taking service on a traditional interruptible tariff and not participating in any day-ahead DR programs. Eligibility was based primarily on the account having a minimum monthly demand greater than 200 kW for SCE, and 100 kW for PG&E and SDG&E. Accounts in the population frame were assigned flags indicating their Size and Business type. These flags were created on an account level, a premise level and a customer level. The premise level flags were selected based on the largest account at that premise. In a similar manner the customer level flags were selected based on the largest account for that customer. The following size flags were defined based on an account's monthly maximum demand:

- Extra Small customers are defined as those having a max demand between 20 kW and 100 kW (SDG&E only)
- Very Small customers are defined as those having a max demand between 100 kW and 200 kW (PG&E and SDG&E only)
- Small customers are those with max demand between 200 kW and 500 kW
- Medium customers are those with max demand between 500 kW and 1000 kW
- Large customers are those with max demand between 1000 kW and 2000 kW
- Extra Large customers are those with max demand greater than 2000 kW

Business type flags were defined based on SIC code for SCE and SDG&E and a mapping of NAICS to SIC codes for PG&E. The three business types used for the eligible population frame of the BIP in-depth interviews were:

- Institutional
- Commercial
- Industrial

Because the BIP in-depth interviews also sought perspectives from both customers on traditional non-firm tariffs as well as customers on firm service tariffs, a third key flag was also defined based on customers' participation status in traditional non-firm tariffs. The following three participation status flags used for the eligible population frame:

- Participants are customers that currently take service on traditional non-firm service rates
- Dropouts are customers that previously took service on traditional non-firm service rates but opted out of the program and are eligible for BIP
- Non-participants are customers that have never taken service on traditional non-firm service rates and are eligible for BIP

The size and business type distributions of the accounts in the eligible population frame, along with the sum of their non-coincident peak demands (in MW) and annual energy consumption (in GWh) are presented in Exhibit 9-6. Note that the amount of eligible customer peak demand coincident with utility system peaks will be significantly less than the non-coincident values shown in Exhibit 9-6 below.

Exhibit 9-6
Population Frame of BIP-Eligible Customers and Interruptible Participants

3 IOUs	Accounts Eligible for BIP	MW Eligible for BIP*	Accounts Participating in INTER	MW Participating in INTER*
Size				
Extra Small (20-100 kW)	-	-	8	0
Very Small (100-200 kW)**	3,053	407	15	2
Small (200-500 kW)	17,111	5,306	29	10
Medium (500-1000 kW)	5,216	3,577	121	91
Large (1000-2000 kW)	1,944	2,655	140	201
Extra Large (2000+ kW)	1,262	7,776	136	940
Unknown	24	2	6	0
Business Type				
Commercial	13,761	6,896	40	57
Institutional	8,020	5,995	62	134
Industrial	6,405	6,583	353	1,054
Unclassified				
Unknown	459	251	-	-
Totals	28,610	19,725	455	1,245
Utility Breakdown				
PG&E	10,910	8,587	61	219
SCE	11,788	8,312	365	1,011
SDG&E	5,912	2,826	29	14

* Non-coincident peak load
** BIP-eligible data reflect SDG&E and PG&E only

9.4.3 Sample Selection & Data Collection

The sample design targeted 35 decision-makers of such premises across the three utilities (PG&E, SCE and SDG&E). Because the number of potential strata (54) was larger than the target number of interviews, the number of customer size categories was reduced from six to two by collapsing Extra Small, Very Small, Small, and Medium customers into "Small and Medium customers" and Large and Extra Large customers into "Large" customers. Primary quotas were then assigned based upon these two customer sizes and the three business types listed earlier. Between BIP-eligible and traditional interruptible customers, higher quotas were set for traditional interruptible customers. Within BIP-eligible customers, quotas were set with roughly equal points allocated to each category to ensure comprehensive representation. Within interruptible customers, however, quotas were adjusted across size and business types to accommodate the limited sample set available for the BIP in-depth interviews.[6] The final sample frame included decision-makers who may be responsible for one or more accounts and/or premises.

In-depth telephone interviews were then conducted with a total of 34 customers drawn from the sample frame. Exhibit 9-7 presents the final distribution of the completed in-depth interviews surveys by participation status and utility.

Exhibit 9-7
Final Distribution of Interviews by Utility

3 IOUs	**Total**	PG&E	SCE	SDG&E
Size				
Small and Medium (100-1000 kW)	**16**	5	5	6
Large (1000+ kW)	**18**	4	12	2
Business Type				
Commercial	**6**	0	3	3
Institutional	**3**	1	2	0
Industrial	**25**	8	12	5
Participation Status				
Participants	**20**	4	13	3
Dropouts	**4**	1	1	2
Non-participants	**10**	4	3	3
Total	**34**	**9**	**17**	**8**

9.4.4 In-Depth Interview Results

The results of the BIP in-depth interviews conducted for the 2005 Demand Response Evaluation are summarized below. The alphanumeric series in parentheses in each section heading correspond to the question numbers from the in-depth interview guide (see Appendix B).

Experience with Traditional Interruptible Service Tariffs (1a-1c)

Of the 34 BIP-eligible customers interviewed, 21 were currently on their utility's interruptible tariff, although one SCE customer noted that they had opted out of the I-6 rate effective January

[6] The majority of traditional interruptible customers were previously surveyed for other tasks in this evaluation, namely the End of Summer Survey and the Traditional Interruptible Customer Survey.

1, 2006 and was therefore counted as a dropout. Since these tariffs are closed to new participants, most participants said they had been on the tariff for a long time, with the length of time reported most often limited by the respondent's tenure at the company. A few respondents said they had been on their interruptible tariff "since its inception" and several pointed out that they had been on it since before the Energy Crisis.

Without exception, participants cited cost savings as the primary benefit from enrollment in the IR tariff; only one participant mentioned that the interruptible tariffs help maintain the integrity of the grid, while another noted that there were few interruptions during their peak production season of October through January. Comments offered to elaborate on the importance of cost savings answer ranged from a respondent who enthusiastically endorsed the I-6 rate as "ideal" because it is "well defined, realistic, and provides clear benefits" to a participant who said that "electricity costs are upward of 80% of operating costs" and it would be simply impossible to operate in California without the financial benefit provided by the IR. One participant on SDG&E's AL-TOU-CP rate frankly stated that the benefits from the reduced rate were significant enough to offset the much higher costs they paid during curtailment events, even though they are unable to reduce their usage when called.

Since most of the participants interviewed were industrial customers, it is not surprising that the downside to the programs centered on disruption of operations and lost income (rather than, for example, customer or employee discomfort). Several mentioned that they go to a backup generator to meet at least part of their load, but that they were limited by law on how often the generator could be used.

Among customers who were not currently on an interruptible tariff (including the one who had just opted out of I-6), 6 said they had been on a tariff at one time.

- Two of the six were forced off because of changes in regulations regarding operation of generators, with one noting that new regulations called for "a 10-fold reduction in emissions."

- Three said they had left the interruptible rate for business reasons, with one specifically citing their experience during the energy crisis and one noting that their business had changed so that interruptions were no longer feasible.

- One respondent had not been at the company when, according to utility records, they were on the interruptible rate.

The other non-participants said they had never been on an interruptible rate, and that they had fundamental problems with being able to curtail their usage when called.

Most interruptible rate participants said they had no problems with curtailment events this past summer. A few noted the contrast with the energy crisis, when frequent events made it difficult or expensive to comply with program requirements. One participant explained the economics of participation for his firm in terms of the number of interruptions as follows:

> *"We had one this year. One a year is on the side of the fence that's favorable. If interruptible is basically $84/kW, it's worth about $1.7 million to us each year, but one normal interruption costs us, say, roughly $270,000. Divide $1.7 million by $270,000 and you get a breakeven of about six*

interruptions, based on lost sales and production. There could be other costs, since interruption also risks equipment damage, refractory damage, and additional downtime. So a best case breakeven is about six. It takes only a handful of interruptions before it makes no sense."

Experience with Demand Response Programs (1d)

None of the IR participants or dropouts said they were currently enrolled in a DR program (although one said his firm participates in DR programs in Oklahoma), and among non-participants one said they participate in SDG&E's 20/20 program. Several customers said they had investigated the DBP and other DR programs.

- One non-participant noted that his company found they could do better by staying on the TOU rate and shifting production permanently off-peak for the summer, while a former IR participant said that his firm would be at a disadvantage under the 10-day baseline used by DR programs, since they periodically reduce their demand to near zero as part of their normal business operation.

- A current interruptible participant said they had investigated all the DR options and were "constantly called by the account rep about participating", but found that DR programs not only had "baseline measurement and verification issues," but also lacked the capacity payment offered by interruptible tariffs.

Familiarity with BIP (5-6)

Overall, 13 respondents said they were very or somewhat familiar with BIP. While only 2 non-participants and one dropout were familiar with BIP, 50 percent of IR participants were aware, with 4 saying they were familiar and 6 somewhat familiar with BIP. One of the IR participants recently signed another account at his facility on to BIP.

Both non-participants said they had considered BIP, but only 2 of the participants (including the one who already signed up) said they had done so. Another 2 participants said they had investigated it in greater detail, but had never considered signing up.

- "We've looked at it but haven't considered signing up. There just does not seem to be as much benefit."

- "From what I saw I didn't see any advantage."

Among those who had considered BIP, one, as noted, already signed up. All but one of those who looked into BIP said they did so through their utility or through utility workshops and seminars. One respondent relied primarily on his company's corporate headquarters for information.

Only 3 respondents said they had not received enough information to make up their mind about BIP, specifying that they would need more details: "I'd have to see all the details and run the numbers, including how often we would be interrupted."

Reaction to BIP Program Features (7-8f)

For non-participants and dropouts, the concerns about BIP features echo those reported for all DR programs, and center on the inability of these organizations to interrupt their operations by curtailing load. Most of the non-participants said it would be difficult or impossible to shed load in response to event notifications without severely disrupting operations. Specific business concerns mentioned included:

- "We're an asphalt producer, we have things we do that have to go on 24 hours a day, can't let things get cold. I wouldn't know how to do that and stay in business. Would have to shut everything down."
- "Demand for product is greater than supply capability. Company would not shut down for any reason for the foreseeable future."
- "We have quick turnaround deadlines for processing millions of feet of film. We have to keep running or we lose millions of dollars."
- "We run mostly big furnace loads, in 6-hour cycles that cannot be stopped or started easily in the middle of a cycle."
- "Most of our load is production and we are on 24-hour production cycles; we cannot start and stop on short notice."

In addition, two former participants noted the loss of flexibility in their ability to use on-site generation to reduce their demand during events. If they are unable to switch to self-generated power, these respondents say, their firms would be unable to reduce load quickly enough or long enough to participate in BIP.

Two non-participants said that they might be able to shed some load, but were uncertain that they could do it subject to the requirements of the BIP program.

- One non-participant said his facility would be somewhat likely to participate in BIP Option B, but expressed the following concerns: "Not sure if we can reduce load enough to qualify or not; 30 minutes not enough time, but 3 hours would be; 4 hours at a time is the biggest concern; incentives seem OK, but data center computers are a big concern. Also concerned about temperature provisions of leases with tenants in the building."
- Another non-participant who concluded that they were not very likely to participate also noted that the credit and penalty seemed reasonable, but added that: "We would have a hard time reducing load by 15 percent; 3 hours is better than 30 minutes; and the main problem with participating in BIP or any DR rate is difficulty in reducing production load much at all during peak periods."

Since they are already on interruptible tariffs, most participants did not note any problems in complying with the technical requirements of BIP (e.g., notification, duration of interruptions.) Several noted, however, that actual curtailments under the IR tariffs had been well below the maximum numbers possible under BIP, so that comparing the maximum events under BIP to the actual events under IR naturally made BIP seem less desirable. Comments regarding the number and duration of events included:

- "If I'm comparing as many outages as you're telling me to what I've seen with my rate, no way I'm going there."

- "If they actually reached those levels, it would definitely be a problem in terms of lost production."

- "4 hours a day is O.K.; 10 events a month is NOT O.K."

- "If I'm in a situation where I need to finish my production but I have penalties, I have to compare that to hurting the customer relationship. So if it happens a couple of times a summer, not a big deal, but if it's like those 10 events per month that's too much."

- "10 events per month is a lot."

- "10 events per month is too many."

- "Maximum number of events would cause us to violate the air quality permit for our generator."

- "Length of time isn't the big issue; it's the number of events. When we shut down and go to backup, we don't produce, and generators are enough to reopen our shipping department so we can take care of our customers. A key part of the value to industrials with the IR is how many times you're called upon. In 2001 we were called the limit: 25 a year, and that was a loss year, in terms of the value of the interruptible. If BIP has the same relative value but can be called more often, it's not good for us."

Given their experience with non-firm tariffs, most interruptible rate participants said the 30 minutes of notification was not a problem for them. Even when they would be more comfortable with the 3 hour notification provided by BIP Option B, most respondents felt it would not be worth their while and they would manage to curtail within 30 minutes. On the other hand, a number of interruptible rate participants offered comments on the incentive and penalty features of BIP.

- "Given the constraints described above, this is simply not worth the risk."

- "(The penalty) seems like it's higher than what we're paying. And Option B sounds like it would be less worthwhile."

- "A larger credit would make it easier to justify signing up."

- "A $7/kW credit is reasonable. The $10/kW penalty is a bit much, but we wouldn't expect to get hit by it."

- "Seems similar to what we get now; but we have a high load factor and would likely get higher payment under I-6; as long as our curtailments are automated we would be comfortable with the BIP penalty."

- "Sounds like about the same as currently available with I-6."

- “Incentives would be pretty good, but the penalties are too high. If we run for one hour during one of those events we lose our credit for the month.”

- “Incentives relative to penalties are not enough for us to consider switching.”

- “Those incentives are, I think close to what we get. But we couldn't live with those penalties. That's why they (management) picked this program (AL-TOU-CP) and we just pay what we have to pay.”

Outlook and Rate Preferences Going Forward (2-4, 8g-8h, 9-10)

If there were no changes in their current rate and the BIP program, one non-participant would be somewhat likely and one dropout would be fairly likely to enroll in BIP. Among IR participants, one has already enrolled in BIP and one other respondent said they would “possibly” do so. All other respondents said they would be unlikely to sign up for BIP.

Interruptible tariff participants were a little more receptive when asked what they would do if their non-firm rate were eliminated, with about half saying they would be likely or very likely to sign up for BIP under those circumstances, although several added comments to the effect that they preferred their current rate. Of the 20 currently on IR:

- 12 would go to another interruptible tariff or DR program (including BIP)

- 7 would go to firm service and then evaluate

- 1 would most likely go to firm service and stay there

Comments from current IR participants included:

- “I think we would look to see if we could gain value from one of the other DR programs, we would have to analyze whether it makes sense or not. If you ask SCE how many times, we could make a decision, but it's hard if you base it on the program maximum.”

- “I would like to think about it, but it would be questionable at this point based on the penalty. If we do anything we would do the whole thing (about 2 MW).”

- “Very likely. Need to keep energy costs as low as possible (would reduce by 75% or 1,500 kW).”

- “Might go to BIP if they do away with I-6. But I'm a strong adherent of I-6.”

- If IR discontinued, “Greater than 50% probability of switching.”

The bottom line appears to be that, although IR participants are happy to be on their current tariff and would hate to see it discontinued; they make their decisions based on their best available options. Their responses above indicate that most would look for some alternative to the higher priced firm service only option if the current IR tariffs were discontinued. In that scenario, BIP may well become the preferred option for many or even most current IR participants.

9.5 SUMMARY AND KEY FINDINGS

Interruptible Customers are Very Satisfied with Current Tariffs and Are Not Actively Seeking Alternative Tariffs

Participants are generally very satisfied with all aspects of current interruptible service, which have involved very few or no interruption events over the recent past, in contrast to the frequent interruptions called in 2000-01. Two-thirds of the interruptible customers surveyed reported being "very" satisfied with their current non-firm service, while the remainder was "somewhat" satisfied. Traditional programs also received high satisfaction ratings with respect to specific program elements. Without exception, participants cited cost savings as the primary benefit of taking service on IR tariffs, with several noting that the reduced rates were essential to their ability to operate in California.

Consistent with this reported level of satisfaction, the survey responses indicated that most interruptible customers are not actively seeking out or investigating alternatives to their current interruptible service, with only a fifth of those surveyed reporting to be "very familiar" with the BIP program, and less than 2 percent reporting any current plans to enroll in BIP.

Curtailment Actions Currently Used by Interruptible Customers Have Large Incremental Impacts and Costs

An investigation of current curtailment strategies among IR customers revealed that shutting down production processes and running backup generators are the two most common curtailment actions used (or planned). Load shifting and curtailing discretionary end uses are comparatively less common among curtailment actions reported by interruptible customers. The self-reported costs of curtailing production processes are also an order of magnitude higher on average than the self-reported costs associated with other curtailment actions. Together, these findings indicate that load reduction among interruptible customers currently tends to be dominated by actions with large incremental impacts and significant participant costs.[7] Indeed, customers who had recently opted out of traditional interruptible tariffs indicated they did so because of the detrimental impact of multiple curtailments on their business or because of more stringent air quality regulations that limit their ability to use on-site generators during interruption events.

Overall, one-fourth of the interruptible customers surveyed find it generally easy for their organization to reduce required loads within the required timeframes, and about 40 percent of customers find it somewhat easy. The most common reasons given by these customers to explain the general ease of short-notice curtailments were having an established curtailment plan, having the ability to switch to backup generation, and using automated controls. In contrast, another quarter of the interruptible customers reported it was somewhat difficult for their organization to reduce required loads within the required timeframe, while less than 10 percent of interruptible customers find it very difficult. The most common reasons given by these customers to explain the general difficulty of short-notice curtailment were cost and

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[7] Note, however, that only half of the interruptible customers interviews were able to provide an estimate of the costs of their load curtailment actions.

production losses, not having enough time to curtail after receiving interruption notices, and difficulties in shutting down production processes.

Interruptible Customers Indicate a Willingness to Accept Significant Interruptions in "Worst Case" Years

Despite participants' reports of significant costs of curtailing, more than two-thirds of the interruptible customers surveyed reported a high tolerance for interruption events, stating that they would be likely to remain on their current interruptible tariff even if the maximum number of interruption events were to occur. Conversely, about a third of participants indicated they would likely leave their program/tariff if the maximum number of events did occur. These customers reported a mean interruption tolerance of 9.5 events per year. Note, however, that results from in-depth interviews with interruptible participants indicate that some customers assess the overall benefits and costs of participation on a long-term (i.e., multi-year) basis. As a result, it is not clear that those customers indicating they would tolerate a high number of events in a worst-case year would tolerate this for consecutive years. Some customers made clear that they are willing to tolerate some years in which they consider participation a financial loss as long as those years are made up for by years in which participation provides a compensating financial gain.

There is Significant Reluctance Among Eligible Customers to Migrate to BIP

BIP was designed to attract both current interruptible customers as well as customers who might have enrolled in interruptible tariffs had they not been closed to new customers. To date, however, BIP has attracted very few customers from either target group. From the perspective of current interruptible customers, program managers noted two aspects of BIP incentives that interruptible customers perceive as significantly less attractive compared to traditional interruptible tariffs. First, BIP's capacity payments are based on the difference between a customer's *average* monthly peak and firm service level (FSL), as opposed to a customer's *maximum* monthly peak and FSL, which is the basis of the demand charge discounts in traditional interruptible tariffs. Second, BIP offers participants only capacity payments, while traditional interruptible tariffs also offer discounts on the energy charges associated with nominated loads. Lower total payments, coupled with penalty levels that are identical to those of traditional interruptible tariffs, thus provide little financial incentive for current interruptible customers to switch to BIP.[8] Program managers also noted that even though most other BIP program features are nearly identical to those in traditional interruptible tariffs (particularly the maximum number events that can be called), current interruptible customers tend to compare BIP's terms of service to the actual very low number of interruption events that they have experienced in the past few years.

Based on customer self-reports, which should be viewed cautiously, if current traditional interruptible tariffs were discontinued, about half of the current interruptible customers can be expected to migrate to BIP or day-ahead DR programs. Twenty-five percent indicated that they

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[8] For PG&E Schedule 19/20 Non-firm customers, non-compliance penalties are reduced by 50 percent for customers that successfully curtailed to their FSL for all events in the previous 12 calendar months. These lower penalty levels compared to BIP contribute significantly to the perceived inequities between BIP payments and Schedule 19/20 Non-firm payments.

would seek another non-firm service tariff such as BIP, including 20 percent that said they would seek non-firm service and also participate in day-ahead DR programs. Another 20 percent indicated that they would seek a firm service rate but would also participate in day-ahead DR programs, while seventeen percent indicated that they would likely seek a firm service tariff and not participate in day-ahead DR programs.

From the perspective of other customers eligible for BIP, program managers offered that BIP's penalty levels are often perceived as being prohibitively high, particularly as a downside risk for customers who may not have much experience with curtailing peak demand. Perhaps more importantly, however, program mangers offered that relatively few eligible firm service customers have the capability to respond quickly and consistently with just 30-minutes advance notice. This sentiment was echoed by the vast majority of the eligible customers interviewed, that it would be difficult or impossible to shed the required load in response to day-of event notifications without severely disrupting operations. These results strongly suggest that those eligible customers that do possess the capability to significantly curtail load on short notice are already on interruptible tariffs or enrolled in BIP.

Outlook Going Forward

The findings presented above indicate that under current system conditions (i.e., few, if any, interruption events per year) the interruptible customer base can be expected to be stable going forward, with little to no natural migration to day-ahead DR programs or alternative non-firm rates (e.g., BIP). Because incentives under traditional interruptible programs are currently very attractive, there is little financial motivation for participants to consider shifting to day-ahead DR programs or BIP. Moreover, curtailment strategies used by interruptible customers are currently dominated by actions with large incremental impacts that also have large costs associated with them, indicating that it may not be a straightforward process to adapt these curtailment actions to the higher event frequencies and lower financial incentives typical of day-ahead DR programs.

Should future system conditions warrant more regular and frequent reliability events, the survey results indicate that only a small portion of the interruptible customer market would either switch to other non-firm service rates or take firm service and participate in day-ahead DR programs. This result is consistent with the fact that the vast majority of traditional interruptible customers are survivors of the 2000-2001 Energy Crisis.

It should be noted that all of these self-report based results could reflect a certain degree of tactical response on the part of current interruptible customers who want to ensure continuation of their current rate discounts. At the same time, however, it should also be noted that current interruptible tariffs represent a more robust resource than the newer price-based DR programs. Indeed, the impact analysis presented in Chapter 7 confirms that current interruptible customers (for SCE and SDG&E) delivered over 95 percent of nominated load reductions in 2005, albeit for only a few short events. This aspect of interruptible tariffs is emphasized by program managers. As one program manager opined, "there's not any other way to get another 300 MW at 30 minutes notice."

10. DRP PROCESS ANALYSIS AND PARTICIPANT SURVEY

This chapter addresses process issues relating to the implementation of the California Power Authority's Demand Reserves Partnership (DRP) program. This process analysis is designed to complement the impact evaluation results presented in Chapter 7. In this chapter we begin by reviewing the goals and scope of the process evaluation, followed by a discussion of issues that are covered and the methods that were used to address those issues. Results of interviews with program managers and aggregators are presented next, since these provide an overview of the program implementation issues and also helped guide the development of the customer survey instrument. Results of the participant customer data collection effort are then discussed, and key findings presented.

10.1 EVALUATION GOALS AND SCOPE

To put this current chapter in context, it should be noted that the DRP program is unique among the demand response (DR) programs offered in California in that: 1) it is the only truly price-based program, since it can be called whenever the price of power is projected to exceed $80/MW, 2) it is the only program that is delivered not through the utilities, but through a number of independent resellers (aggregators), with coordination provided by the California Power Authority (CPA), a state agency that no longer has any direct state funding, and 3) it offers a capacity payment as well as an energy payment.

The process evaluation of the 2005 DRP program builds upon the more limited process evaluation conducted of the 2004 program, where a detailed description of DRP program operations is presented. Because of the unique characteristics of the program, the current evaluation addressed a number of issues specific to the DRP. These include:

- Effectiveness of communication and coordination between the operating agency (CPA), the scheduling subsidiary of the Department of Water Resources (DWR) known as California Energy Resource Scheduling (CERS), the aggregators, the data contractor (APX), the utilities, and customers.
- Perceptions regarding the DRP program capacity and energy payments
- Perceptions regarding baseline calculations and penalties for failure to curtail

In addition, many of the same issues addressed by the data collection efforts and analyzed for the utility programs presented in Chapter 8 and 9 are relevant to this evaluation, including the following:

- Reasons for program participation
- Effectiveness of event notification, bidding tools, tracking, response, and follow-up
- Perceptions regarding the frequency, duration and perceived urgency of events

- Perceptions regarding the notification process and the amount of time customers have to respond

- Specific curtailment actions taken by customers and their effect on operations

- Program satisfaction and likelihood of continued DRP program participation

Finally, it should be noted that this evaluation takes place in the context of the overall life cycle of the DRP program. Specifically, the program is set to expire in May of 2007, and decisions must be made regarding the role of a DRP or DRP-like program in the future portfolio of DR program options.

10.2 PROCESS EVALUATION METHODS

The process evaluation of the DRP program used data from a variety of sources, including the following:

- Review of program materials and the DRP program website

- Interviews with program managers at the utilities, CPA, data management contractor APX, and CERS

- Interviews with aggregators

- A survey of participating customers to assess their overall perception of program operations for the season.
- Nomination data and initial program impact analyses (see Chapter 7)

In the analysis below, both program manager and customer responses are used to present as complete a picture as possible of DRP program implementation

10.3 RESULTS

10.3.1 Program Manager Interviews

Program manager interviews were conducted with the individuals responsible for the DRP program at all three utilities, as well as several individuals with overall responsibility across programs. We also spoke with program managers at CPA, APX, and CERS.

All of the utility program managers see the DRP program as a potentially valuable adjunct that they can offer as an alternative to other day-ahead DR programs, but all of them also note: 1) the sometimes confusing relationship between the DRP program and the utility product offerings 2) the level of uncertainty that has been (and continues to be) associated with DRP.

Both program managers and their supervisors recognize the value of DRP in achieving their aggressive price-responsive DR program goals. One senior manager noted that, "Anything that creates dispatchability toward goals counts, so DRP is another arrow in our quiver. It's the first time someone else's program have counted. We keep reinforcing that to our account execs. If the commission counts it, it counts for you. We have to pull everything out of the program we can."

On the other hand, the fact that DRP is not a utility program creates problems in the overall marketing approach, as reflected in the following program manager comments:

- "DRP is included in our marketing material, but not heavily marketed."
- "At this point, we're not really looking at it, but leaving it to CPA and the aggregators. There is a portfolio of programs that we offer with a sheet on every program. There's a fact sheet that looks like every other sheet and that simply says here's another one in our portfolio. Our reps have incentives to sign up customers on all programs, but the reps are hampered by lack of control with DRP, since they don't know what aggregators are going to do."
- "The AEs push all programs and because this is more cumbersome, even for internal folks, it's really hard for them to just say, sign up for DRP. Instead they may encourage them to go to demand bidding. Reps have general DR goals, so it doesn't matter, but there's no incentive to push this program over another."
- "We kind of approach it from a portfolio perspective and go out with a couple of alternatives. We have utility sponsored programs where we can really handhold, compared to DRP where it's really difficult to provide that kind of help, so DRP appeals to a different kind of customer."

Program managers also emphasized that the uncertainty surrounding DRP for the past several years has hampered marketing. At the end of 2004, it was not clear if CPA would be able to manage the program in 2005, since direct funding to the agency had been cut off. The original plan was for PG&E to take over the administration of the program, with agency agreements to be signed enabling the individual utilities to dispatch the program. That did not happen because the agency agreements could not be worked out, and CPA again managed the program in 2005, funded by the difference between the amount paid to CPA by DWR for program capacity and the amount CPA pays to the aggregators. Utility program managers generally say that CPA has done a good job but that the uncertainty surrounding the program overall – and its May 2007 expiration date – make it more difficult for some customers to commit to the program.

With regard to the level of uncertainty, program managers noted:

- "This program has suffered from the uncertainties year to year about CPA, the level of incentive, the length of interruptions etc. It still suffers from uncertainty by the commission, which makes customers ask, should I as a company make a change in my operations for this program that may not be around?"

- "When the agency agreement is signed, if ever, then we will have specific responsibility for tracking this. Until then we don't want to make the investment. We heard PG&E was going to take this over, but that's gone away. And it's still not clear, what's going on with the agency agreements."

Lacking agency agreements, program managers note, the utilities tend to play an informal role in dispatching the program, which can create confusion among reps, aggregators, and customers. Program managers commented:

- "For price-based events, we call, and DWR calls reliability events."

- "The only events that SCE advises DWR to dispatch are economic, only if it goes over $80/MWh dispatch price. As far as reliability, those are all through the ISO directly."

- "After we'd called a bunch of events in June we were getting calls from our reps and from aggregators asking why we were dispatching it. We told aggregators that we recommended the dispatch but CERS made the dispatch. Our reps were getting calls, the whole relationship chain had to be verified. Some aggregators suggested we use it for reliability only, but it's supposed to be a price response program; aggregators should not offer it as just a reliability program."

A dispatcher from one of the utilities commented, "In the scheme of things, this is pretty small to the procurement group, 10-20 MW is in the noise. But we look at the incremental cost just like for other contracts we have with CERS, so it's dispatched accordingly. "

Overall, program managers appear to feel that the current DRP puts them in a difficult situation, with one stating "It's a different situation than in other programs. We're kind of in a strange role; to some extent it doesn't concern us that much. We do think the program should be marketed correctly and not misrepresented, so that it's clear that it should be called based on price. With respect to DA customers, we don't care, but we don't want our bundled customers to be unhappy. "

Finally, despite the uncertainty and ambiguity surrounding the current DRP program, all the program managers said their utility plans to keep a DRP-like program in place after the current program expires in early 2007, although the exact structure of the program will be determined through the regulatory process.

All the utilities filed proposals with the Commission on June 1, 2005 to develop a successor program to DRP. The plans were described in the utilities' filings and were reflected in the utilities subsequent settlement on DR programs for 2006-2008, in which this program is an important element. The utilities have filed with the Commission their intention to file a detailed proposal for a successor program by June 1, 2006, and this has been adopted both by the settling parties and by the Commission in the March 2006 settlement.

Like the program proposed by the aggregators (described below), the utility-proposed successor program retains many of the DRP program features, including a role for aggregators, monthly nominations, capacity and energy payments, and penalties for non-performance. Differences from the current program include:

- Customers could participate directly with the utility as well as with an aggregator
- The program would have a heat rate trigger rather than a price trigger to take gas price volatility out of the equation, so that the program would be called under conditions of hot weather and/or when there were other resource limitations (generation, transmission) or a CAISO Stage 2 alert or emergency.
- Dispatch would truly be day-ahead
- Three curtailment options or products would be offered: 1-3, 2-6, and 4-8 hours
- The program would run June through October only

Overall, the utilities envision the DRP program as occupying a niche in the range of DR program offerings, requiring more commitment (along with greater compensation and penalties) than DBP, but greater flexibility (along with lower compensation and penalties) relative to BIP.

10.3.2 Aggregator Interviews

While the firms who market the DRP program to end users are still known as aggregators, this is now a misnomer, since these firms no longer play that role; that is, they do not combine or aggregate the nominations of individual companies. Since late in the summer of 2004, customer performance has been determined at an individual level rather than for all the customers signed up by an aggregator (in the past, aggregators had the ability to combine all the monthly and daily nominations of their customer and "shape" their overall load, so that there was room for individual customers to have some leeway in responding to specific events if other customers of that same aggregator did in fact respond.)

Aggregators are generally not pleased at having this function taken away, as illustrated by the following comments.

- "[It's] true [that] aggregation would allow us to aggregate customers; we can aggregate different facilities for one customer, but not in total. That's a change from how it was originally started back in 2001 – a change for the worse. Under the current program there is retail name and zone aggregation done by the customer, but not within zone by the aggregator."

- “Originally we were supposed to be able to aggregate. That changed when they changed the penalty structure in summer 04. If you have more than one customer meter, you can aggregate for a customer; we have some that do that.”

- “Actually aggregating would be better for us. The reason for the shift away from aggregation was not a technological problem; it came down to what CERS wanted. Everybody got what they wanted except us.”

The services offered by aggregators through the DRP program range from primarily acting as marketers/facilitators of program participation to providing automation or controlling customer facilities to ensure compliance with curtailments. All of the aggregators contacted said they were extremely surprised by the number of events that occurred during the summer of 2005. While there were relatively few actual capacity constraints observed during the summer, the program was called “early and often” in the words of one aggregator. As noted in Chapter 7, there were a total of 35 events across the three zones, and back-to-back events started as early as June. All of these events were triggered at the request of the utilities because of price. CERS, which has the ability to dispatch the program when requested by the ISO in cases of supply or transmission constraints, said they had not initiated any of the 2005 events.

As mentioned in the program manager results, aggregators noted that the frequency of events in 2005 caused concern for a number of reasons.

- First, these events were not associated with the kind of capacity constraints (e.g., Stage 2 alerts) that many customers and aggregators associate with interruptions.

- Second, and related, the fact that events occurred on days that were not particularly hot, and/or had not been preceded by a number of hot days that established hot weather baseline usage, meant that customers whose nominations were based on shedding weather dependent load found it virtually impossible to do so because their baseline had been determined by a series of mild days.

- Third, back-to-back interruptions of relatively short duration over a number of days severely impacted industrial or other customers who planned to deal with curtailments by shifting production to other days.

Like their customers, aggregators questioned the need to call the program as often as it was called, stating that many of the calls were made on a prediction (subsequently not realized) that the price would go over $80 on a particular day. Aggregator comments included:

- “The $80 strike price was always calling it, even if it wasn't going to reach $80. They look prospectively, make a decision in the morning, and there’s no downside for them to make that call. They missed more than they hit - probably 70 percent of those hours didn't reach the $80. We made contact with SCE, who said they have to make their best estimate. But ultimately it was our sense that it wasn't really their program, it was a resource, and there was no reason not to do it. Even if it's off, they have no downside.”

- “Before it was used primarily as a reliability program; in 2005 it became more a price or economic program. And there are no clearly defined triggers as to when the utilities will call. We were told more or less that they have experts, and when they feel it's going to go above the $80/kW, they'll call. But there's no definitive index that customers could look at."

- "It's unfortunate, but no one saw that the $80 strike price giving the utilities the right to call would lead to the program being called so often. Everybody recognizes that it's too low but it looks like we're stuck with a strike price set at $80… For customers, even though there's money involved a lot of them participate as corporate citizens, and they're getting called when it's overcast. They want to know why they are being called."

- "We were under the impression that the DRP program would be called like on the East Coast, where these programs are reliability focused, so the trigger is tied to a Stage 2 alert from ISO, so they have really no limitations on how many hours can be called; they have a broad call opportunity but a very specific trigger. Here we have a vague trigger; the IOUs are directed to call it economically, called as price response rather than reliability. That is in keeping with how the program was envisioned, both price response and reliability. But there is a customer preference issue, and some customers don't want to be called in price response; they'll help the grid, but it's not about the money, not the primary motivator. So having a program that is bundling those two makes it hard to target customers according to what they desire."

The effect of the multiple events was also an issue for aggregators.

- "This year was considerably different than years past, mainly because of the number of calls, with the maximum for 3 months. That made it tough; it wore our customers out when they were called 9 days in a row."

- "You need to translate the customer burden into percentage of days in the summer during which there are events. If you have 24 hours per month, and variable duration, the program can have many short events, and the level of intrusion goes up. Intrusion is tied to the event, not the length of the event."

- "We were split; most of our customers were 1-5 hours, a smaller number 1-8 hours. All were called 2-4 hours no matter what product it was. The months of July and August were both curtailed the maximum 24 hours. Our customers were called the full 24 hours during July and August. Customers were concerned; but they were involved in a contract, and they honored that."

Because of the more frequent, short curtailment events, there were also concerns about the level of payments and the severity of the penalty, as reflected in the following comments.

- "DWR did renegotiate a bunch of contracts with providers after the energy crisis, they were able to do that then when it was to their benefit, but when the shoe was on other foot, they wouldn't. The contract was renegotiated (starting in 2003 and finalized in 2004) to reduce compensation from $15K- $9K per MW, because CERS was upset because we had 2, 4, and 8 hour products (pre-2004) and there was a majority on the 2 hour, and they wanted to renegotiate because the 2-hour didn't cover the peak period, so they cut compensation by 40 percent and got a day-of program at day-ahead prices."

- "Customers have to make 95 percent of their nominated load to get anything. They do it (the penalty calculation) by hours as a formula, total hours vs. total hours called, but with multiple meters you could have a 5 percent shortfall just on the multiple meters, since meters can be off."

- "Saying you have to have 99 percent or 95 percent is false precision, especially when you're calculating that with a baseline that's basically an estimate."

The frequency of events, the nature of the trigger, and the severity of the penalty all caused aggregators to question the appropriateness of the baseline (since event days are excluded):

- "We had a customer who dropped all of their load, but because of how they were averaging using the 10 day baseline it looked like they hadn't. For example if we had 2.4 MW customer, on a hot day using 2.4 and they go to 0, but because they were called so many days, when you go back to before the events the baseline might be different. One client is a fruit processor; mid June, July, August and September are really busy for them, but they are not so busy in the first two weeks of June. So compared to that baseline they dropped less than 2.4 MW -- not a whole lot less but it was below the 95 percent. It's a very harsh penalty."

- "Hurricane Katrina led to a spike in gas price, which raised costs and caused the utilities to call DRP, even though it was mild weather. The problem with mild temperatures is that it's hard to shed weather dependent load, so customers' ability to perform is less and they get dinged."

While aggregators were satisfied with the nomination process, they raised several issues regarding problems with program enrollment and settlement. Comments about the enrollment process included:

- "At the beginning, even though meters were enrolled, we were not seeing data on a next day basis (on the APX site). We were getting some utilities that provided that data, other utilities were not getting that to APX. As someone who has to adjust on a daily basis, we were not able to make good decisions because we were not getting that data. That could go on for 10 days. Especially in June with a new customer, it would have been nice to see what they were doing, but as it was we had no idea what they were doing, we had to go by the seat of the pants."

- "We still had customers that took two months to get registered, it just wasn't getting done; sometimes there was something wrong with the meter or it was just other stuff. It wasn't the issue of synchronizing on monthly billing; it's just not a big priority for them (the utilities)."

- "All the TPOs [third party authorizations] ended up stretching it (the enrollment process) out; people got pulled in through June. It was difficult to get meter data from utilities because of the MDMA relationship with Hunt Power (which acquired the previous MDMA). Also the utilities were very slow in getting the TPOs OK, etc. so there was a big jam-up for weeks at a time; in June we still had them trickling in. Lots of people were frustrated that they weren't in earlier, specifically some industrial customers and college campuses. They were ready to get going."

There also appear to have been delays with the settlement/payment process, with a representative from CERS noting that they still had not received invoices requesting payment for July and August 2005 as of early February 2006.

The net effect of the many effects in the summer of 2005 was that a number of customers either dropped out of the program or stopped making monthly nominations. The many interruptions (and the fact that a number of events were called when the price did not reach $80/kW) caused the aggregators and customers to come up with an alternative approach to the design of the program in the years after DRP's expiration before the summer of 2007.

The program proposed by the CPA/aggregator group retains several fundamental elements of the current DRP program:

- Statewide consistency, with a single program across all utility territories
- A capacity payment, proposed at $15/kW per month for the months June through October
- Role of aggregators as vendors
- A separate agency to manage/implement program, which could be either CPA or the ISO

There are, however, other areas where the group offers significant changes:

- *Two participation options*. Option 1, "Reliability Program," would be called only when ISO Stage 2 Emergencies are announced. Option 2, "Peak Reduction Program," would be called at the discretion of the relevant IOU as an economic or peak reduction resource. The two options would differ on a number of key points:
  - The Reliability Program could be called from 8AM to 7PM on all business days (No weekends or holidays), while the Peak Reduction Program would operate from 11AM to 7PM on all business days.
  - The Reliability Program could be called for 1-3 hours or 1-6 hours as needed; the Peak Reduction Program could be called in a fixed block of 3 hours or 6 hours as determined by the relevant IOU.
  - The Reliability Program would be limited to 150 hours per year with no monthly maximum. The Peak Reduction Program would be limited to 24 hours per month and an annual cumulative maximum of 60 hours per year.
  - The Reliability Program would require 30-minute notification before curtailment and would be tied to the ISO stage 2 emergency notification. The Peak Reduction Program would require three-hour notification before curtailment and would be called at the discretion of the relevant IOU.
- *Aggregation across customers*. In line with the original program guidelines, the CPA/aggregator group proposes to allow customers to be aggregated into load blocks by Program (Reliability or Peak Reduction), by Product "blocks" (1-3, 1-6, 3 and 6 hours) and by demand zone or IOU service territory.

- A revised baseline calculated as the hourly average of the past 5 highest load program days of the last 10 program days, excluding curtailment days, with a calibration factor calculated from the three hours before notification

- A revised performance/penalty structure, with no payment for performance below 70 percent of nominated capacity, a basically linear payment between 70 percent and 130 percent of nominated capacity (except for a "shelf" between 95 and 105 percent of capacity simply deemed to be 100 percent compliant), and no additional payment for performance beyond 130 percent.

- Extension of the summer program through October, "because demands tend to remain high into this month in many areas of California and plants are taken offline for planned maintenance during this time."

The proposal also calls for a minimum three-year term as essential to incent customers to participate and to evaluate and measure program success.

The DRP working group recommendations described above were developed at least in part in response to participant reactions to program experience during the summer of 2005. Many of those participant reactions are reflected in results of the survey of program participants conducted in January 2006, discussed below.

10.3.3 Customer Survey

Four of the five aggregators provided contact names and telephone numbers, for a total of 32 DRP participants (of a total of 45 unique customers in August 2005, see Chapter 4). Telephone surveys were completed with 26 of these 32 participants, representing more than 80 percent of the sample – a very high rate of completion. The aggregators who provided the sample names also notified the customers that they would be called for a survey and asked them to respond to the survey, which helps explain the high response rate.

Of the 26 participants interviewed, 11 were college campuses, 6 were manufacturers or other industrial facilities, 5 were government/municipal facilities (including water and wastewater treatment plants), 2 were offices, one was a grocery store, and one was in transportation/ telecommunications/utilities sector. Respondents were evenly divided between those who had been in the program for 1or 2 years (50%) and those who had been in longer or did not know.

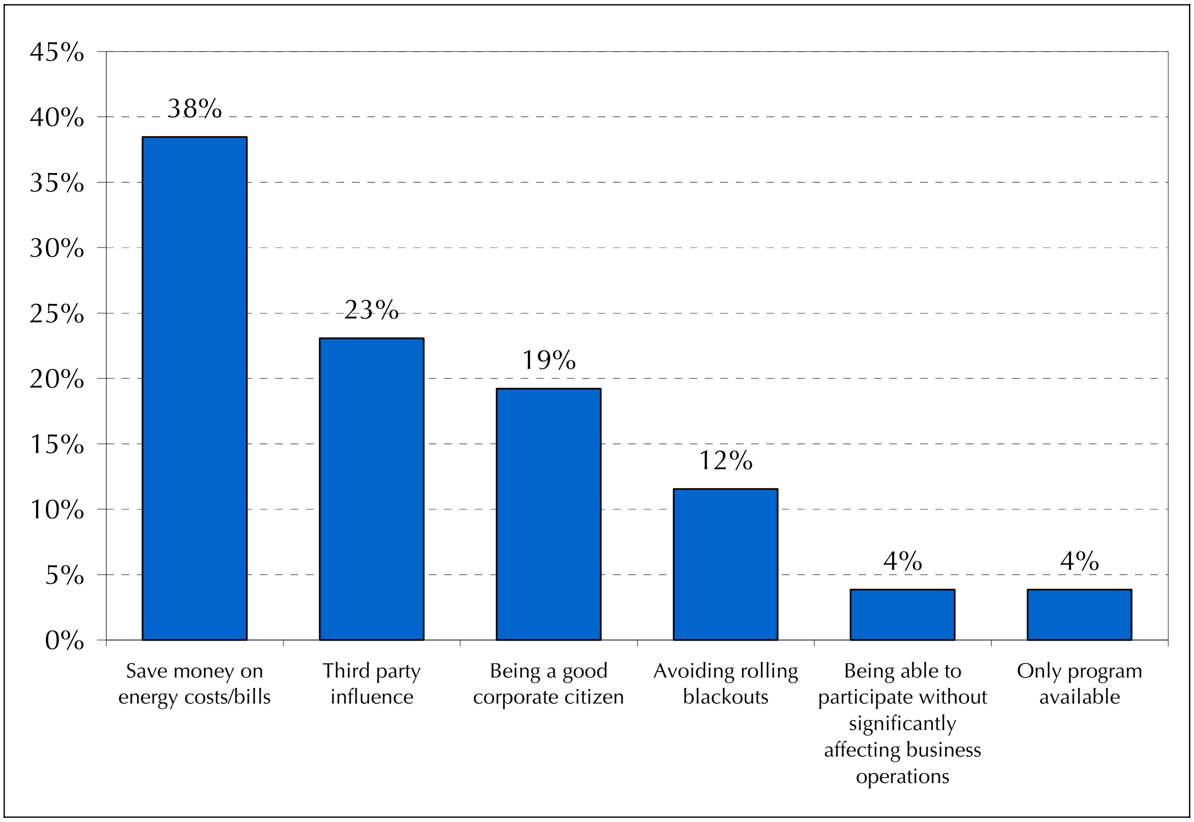
That the DRP program targets a different set of customers is reflected in the result that two-thirds (65%) of participants said they did not consider any other program before signing up for DRP, while 19 percent said they had considered BIP.

Due to the small customer population, the results presented below are unweighted, even though some respondents may have been responsible for multiple individual facilities. It should be noted that even though results may be presented quantitatively, they must be interpreted with caution because of the small size of the sample.

Reasons for Participation

The primary reasons given for program enrollment are shown below in Exhibit 10-1 and highlight the mix of motives that caused customers to sign up for DRP.

Exhibit 10-1
Reasons for DRP Participation

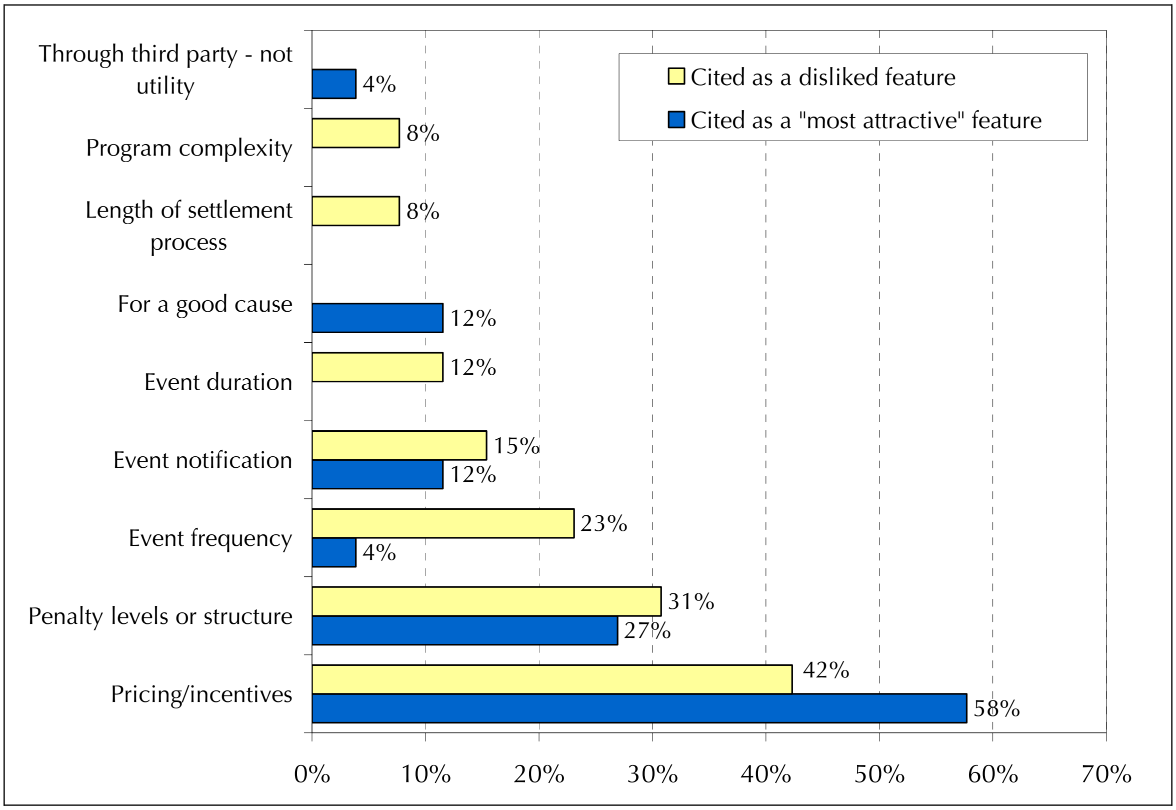


While saving money on energy was cited as the primary reason by 38 percent of respondents, the combination of "being a good corporate citizen" and "avoiding rolling blackouts" accounted for almost one-third of responses. More than one-fourth of respondents also cited third party influences, including not only aggregators, but also a government mandate for state agencies, decisions made at corporate headquarters, and decision made by the chancellor of a university campus.

Perceptions of Program Features

Exhibit 10-2 shows that when asked what features of the program they liked and disliked, the same features were perceived as either most attractive or disliked by different DRP customers.

Exhibit 10-2
Attractive and Disliked Features of DRP



While pricing and incentives were listed among the most attractive features by 58 percent of respondents, the remaining 42 percent cited them as disliked features. Several other features (penalties, event frequency, and event notification) were cited by some participants as attractive, but were disliked by more customers. A few features were only mentioned as disliked (event duration, length of the settlement process, and program complexity), while others were only mentioned in a positive light (program is for a good cause, offered through a third party).

A number of respondents offered comments regarding the specific features of the program that they disliked. Illustrative comments include:

- "There were abuses as to spot market prices driving program last year – we weren't even close to state kW and we were taking hits – we had weeks were we would get hit every day."

- “The baseline doesn’t work for office buildings; shedding is weather dependent and it doesn’t take that into account.”

- “Events were called almost daily and they were called on a price, not an emergency basis.”

- “They had events too frequently and for too short duration.”

- “Slow payment process - it can take almost a year to get your payment. Also, the variability of the outages. They are not consistent. The DRP program, they will call you 20 minutes before you go offline and they may ask you for 2 hours or 3 hours of curtailment and it's never the same. The length of time and the start time are not consistent. It makes it hard to plan.”

- “We were called several times when there wasn't a crisis situation. It was all about money. The way it was explained to me was that it was cheaper for the utility to have us go on the DRP program than to buy electricity from the open market. There was no crisis.”

- “This past summer I noticed and suspected game playing going on. When I went and looked at the ISO's webpage and I knew what the baseline was and what they needed and they had it and a couple hours later they called for a reduction. On their webpage it said they were fine.”

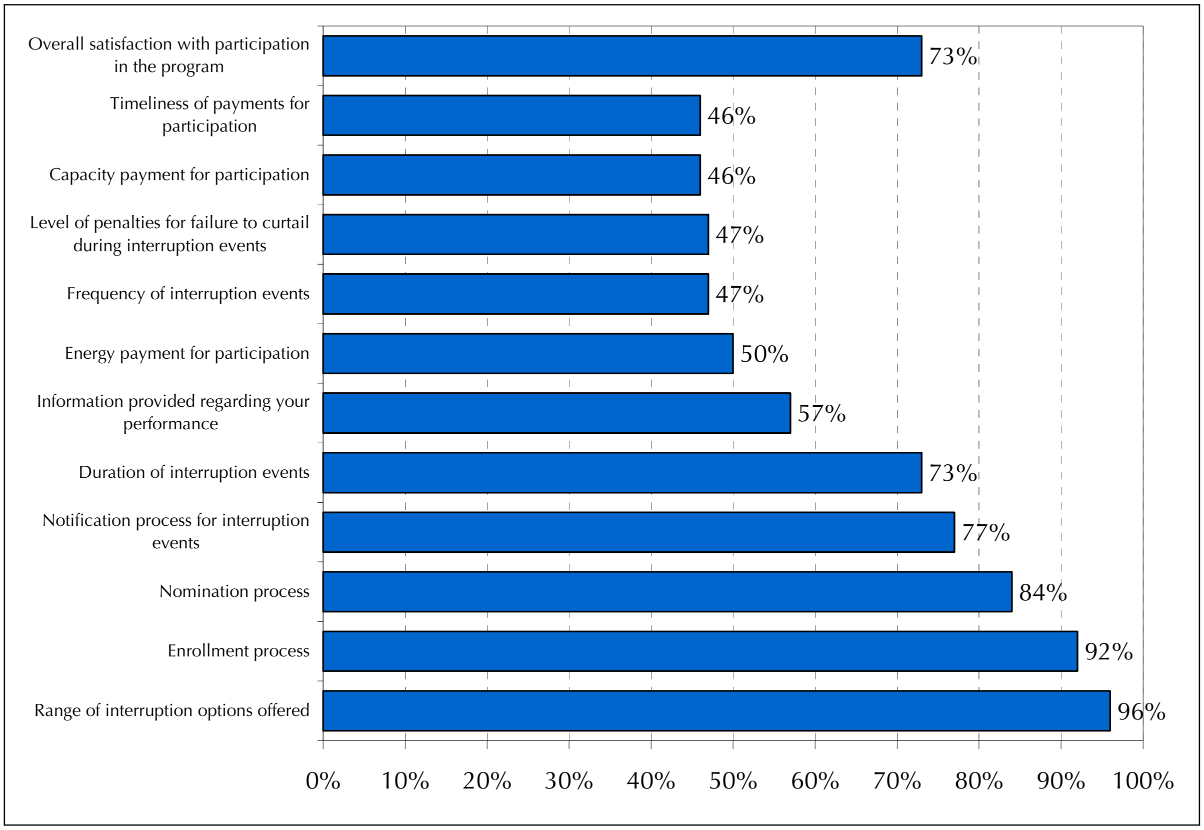
- “It seemed like we got into a situation where they were asking us to shed load above and beyond what we were willing to do. We were able to look at what the ISO was doing as far as statewide goes and it didn't look like there was a need for shedding and we were being asked to drop load. It didn't seem like the necessity was there for us to be asked to shed load.”

- “We weren't happy with anything. It was sold to us as a program that they would shed our load when there was an energy crisis in California, an actual shortage of energy. Instead, they did it based on the price of energy. We were misled.”

Program Satisfaction

Participants were also asked about their satisfaction with various elements of the program, using ratings of “very satisfied”, “somewhat satisfied”, “somewhat dissatisfied”, and “very dissatisfied.” Exhibit 10-3 shows the proportion of participants that reported to be “somewhat” or “very” satisfied with each program element and the program overall.

Exhibit 10-3
Satisfaction with DRP Program Elements



While almost three fourths of respondents said they were "somewhat" or "very" satisfied with their overall participation in the program, one-half or fewer were "somewhat" or "very" satisfied with a number of specific program elements, including their payment for participation (both the capacity and energy payments), the frequency of interruptions, the level of penalties, and the timeliness of payments for participation.

As indicated by aggregator responses and elaborated upon by customer comments, the high level of interruptions during the summer of 2005 appears to be responsible for much of the dissatisfaction with the program. In fact, given the high percentage of customers dissatisfied with many of the program elements, it is surprising that overall satisfaction with the program is not lower.

When customers who expressed dissatisfaction with the program overall were asked why they were dissatisfied, responses typically focused on the baseline calculations, the frequency or duration of events, and the complexity of the program. Comments included the following:

- "Because they used it as a price control rather than on an emergency basis."
- "It would be because the method by which curtailment was measured was not clear and was in dispute during whole summer 2005. It's still not resolved. Also the process by

which baseline is calculated – it excludes weekends, holidays, and other days where curtailments were called, so it doesn't reflect recent days."

- "The amount of time that we are down is equal to the amount of time that it takes us to come back up so it is not efficient for us."
- "The excessive curtailments with no explanations; payment levels too low; slow payments; lack of feedback on performance."
- "We got into it, we are State entity and as a State agency we were trying to do our part and when we get called to curtail when it is not necessary, when it is not a crisis, it is a huge inconvenience to our organization."
- "We want real time read-out so we can adjust the load shed. We felt like we were out of the loop; we need more feedback about participation afterward."

Future Participation Plans

The 73 percent of respondents somewhat or very satisfied corresponds exactly to the percentage that said they planned to remain on the program next year. In addition, 19 percent (five participants) said they were not planning to stay with the program, and two respondents (5%) said they did not know. Of the five that were not planning to remain in the program next summer, three said they would not be considering another DR program, one planned to close their plant, and one would look for a program "with no power scheduling."

Participants were also asked how likely they would be to stay with the program if the maximum number of hours of interruption were called. Since the 2005 interruptions were of the same order of magnitude as the maximum allowed by the program and almost three-fourths planned to re-enroll, it is not surprising that 57 percent of respondents said they would be very or somewhat likely to stay with the program even with the maximum curtailment scenario.

Some participants noted that the number of interruptions was more important than the total duration, since the 2-hour curtailments common in 2005 were seen as being more intrusive than fewer, longer curtailments.

Very few participants planned to participate in the TA-TI program. Although 21 of the 26 respondents said they are aware of the TA-TI program offered by their utility, only 5 of those said they planned to enroll in the program.

2005 Curtailment Experience

On average respondents recalled being interrupted about 17 times during the 2005 summer season. As a group DRP participants appear to be well prepared to handle curtailments: 85 percent (22 of 26) DRP participants said they have a pre-established curtailment strategy, and 80 percent said their curtailment actions are either wholly (42%) or partly (38%) centrally controlled.

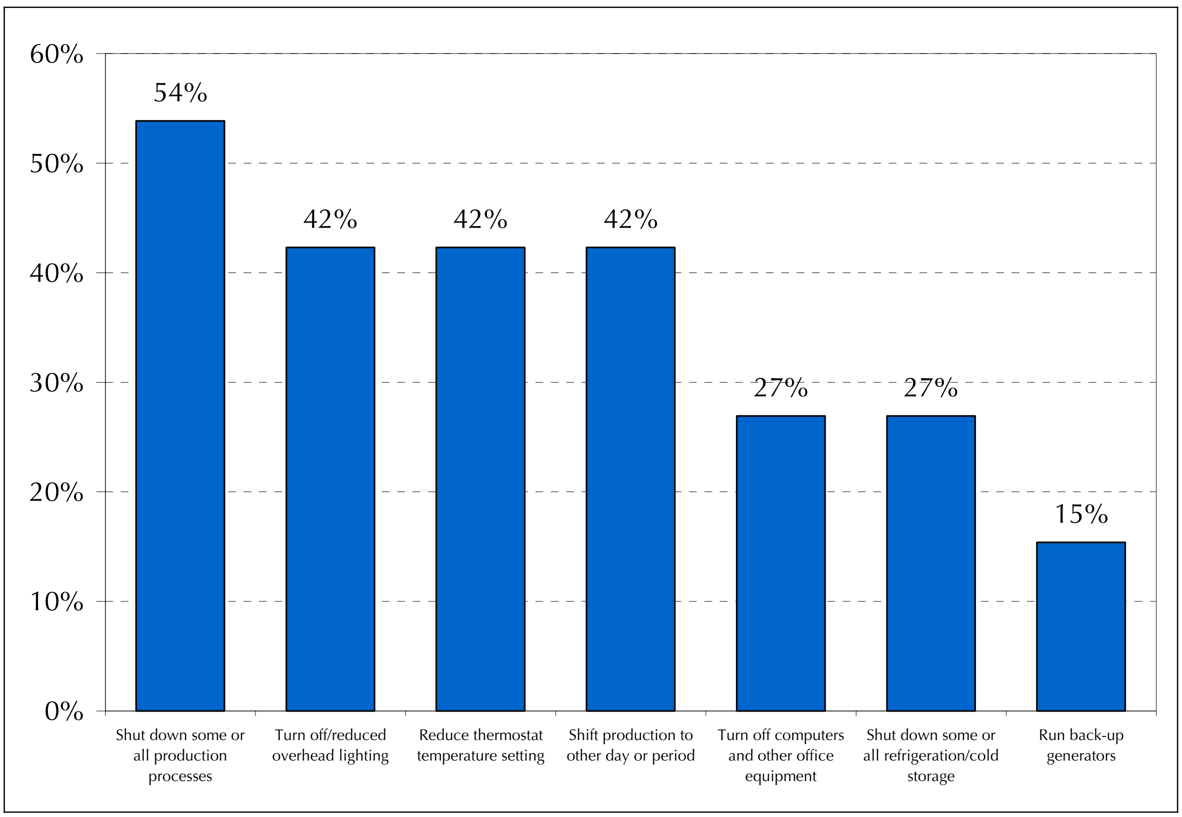
Overall, 65 percent of respondents said they have found it very (19%) or somewhat (46%) easy to curtail in the required time frame, while 35 percent have found it very (12%) or somewhat

(23%) difficult. Among the 19 respondents who found it easy, 10 cited the use of planning or automated controls, while 4 respondents noted that the controls were implemented by a third party (e.g., their aggregator), and 4 other respondents said curtailment did not affect their operations. Four respondents said they found it somewhat (rather than very) easy only because curtailment did indeed affect their operations.

The effect on operations was cited as the reason by four of the seven respondents who found curtailing difficult. Even more important, five of the seven attributed their difficulty to lack of capability or knowledge, suggesting that aggregators need to do more work with about 20 percent of all the customers interviewed. Difficulty in monitoring curtailments was cited by two respondents, and not knowing their baseline was also mentioned twice.

Exhibit 10-4 shows that the self-reported actions taken by DRP participants include most of the usual load shedding strategies, with a particular emphasis on production processes.

Exhibit 10-4
Curtailment Actions Taken



More than half of respondents said they shut down some or all of their production, while 42 percent (11 of the 26) mentioned each of the following: turning off overhead lighting, changing their thermostat setting, and shifting production to another day or period. Turning off computers and shutting down refrigeration were each mentioned by 7 participants, while 15 percent (4 respondents) met curtailments by running back-up generators.

These results help explain several issues that arose with the DRP program in 2005.

- First, with a majority of participants having production processes directly impacted by the curtailment events (either through shut-down or shifting), it is not surprising that multiple events on consecutive days should have a significant impact on operations and participant satisfaction.

- Second, the 42 percent of participants who allowed temperatures to rise to meet their curtailment obligation – in other words, those who count on shedding temperature-dependent load -- would have found it very difficult to curtail enough load if the baseline for the interruption day was determined by usage on relatively mild days.

- Finally, with 15 percent of respondents relying on backup generation, the multiple curtailments made it that much more likely that these customers would encounter regulatory limits on their generator usage that would limit their ability to respond.

One of the features of the DRP program that provides added flexibility is the ability to change nominations month to month and to make daily nominations if additional capacity is available.

- Among the participants interviewed, 11 of the 26 said they had changed their monthly nomination since they first enrolled in the program, with 3 respondents saying it had increased; 4 respondents saying that it had decreased, and the remainder saying that it varied from month to month. Three of those who had decreased their nomination said they had done so because baseline calculations made their previous nominations (which were based on hot weather) unattainable; others cited disruption to their business operations.

- Only three respondents said they recalled making daily nominations, including two who said they made daily nominations every month. Most respondents – 73 percent, or 19 of the 26 – said they had not made daily nominations, and 4 said they could not recall if they had done so.

10.4 SUMMARY AND KEY FINDINGS

The Unique Status of DRP among DR Programs Has Created Some Confusion among Utility Account Executives and Customers

Although utility program managers recognize that DRP can play a significant role in attaining DR objectives, they find it difficult to determine how to promote the program in the context of their broader product offerings. In-the-field account executives in particular are generally reluctant to do anything more than mention the program, both because DRP is not "their" program and because most details of the program are outside their control and they do not wish to interfere with the aggregators.

For their part, aggregators feel that the utilities tend to distance themselves from the program (for example, one aggregator stated that that DRP is "the red-headed stepchild" among utility programs). Ambiguity with regard to DRP has sometimes come to light when events are called and customers contact the utility. Utility reps may then point to DWR/CERS as having called the program, which is technically correct, even though CERS only initiates price-triggered events at the request of the utilities.

Modifications to the DRP Program Carried Forward into 2005, Combined with Market Conditions, Led to Frequent Program Events that Directly Affected Customer and Aggregator Perceptions of the Program

During 2004, DWR initiated a number of changes to the terms of the DRP program. Finalized during the summer of 2004 and carried forward into 2005, these changes significantly altered the risk-reward equation for program participants. Under the terms of the revised program, aggregators could no longer aggregate other than on an individual customer level, which limited their role to marketing the program and coordinating participation of individual customers.

The revised program also reduced capacity payments from DWR to CPA: from $15,000/MW to $12,000/MW per month (for 1-8 hour blocks) for the four summer months, with a corresponding decline in payments to aggregators and customers. In addition, the revised program allowed DWR to call events as short as one hour duration. While the timing and duration of potential interruptions created greater uncertainty for participants, performance criteria and penalties became more stringent, raising the possibility of significant downside risk from participation.

Combined with the program revisions, market conditions in 2005 were such that the program was called far more frequently than in previous years,[1] with some customers being called for the maximum number of events for multiple months.

The Frequency of DRP Events in 2005 Caused Concern among both Aggregators and Program Participants

The DRP program was designed to be triggered by either price or reliability issues, but in the perceptions of aggregators as well as customers the price-responsive aspect of the program is also seen as linked to system reliability. Consequently, neither aggregators nor customers were prepared for the program to be called based on a price trigger alone when there was no evidence of capacity shortages within the system.

While there were no actual capacity constraints to trigger the DRP program during the summer of 2005, the program was called on price frequently in 2005, with back-to-back events starting as early as June. All of these events were triggered at the request of the utilities because of price. Moreover, because events occurred on days that were not particularly hot (or had not been preceded by a number of hot days that established hot weather baseline usage), customers whose nominations were based on shedding weather-dependent load found it difficult to do so because their baseline had been determined by a series of mild days.

In addition, back-to-back interruptions of relatively short duration over a number of days severely impacted some industrial and other customers who planned to deal with curtailments by shifting production to other days. With these frequent, short interruptions, more than half

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[1] That is, prices often went or were predicted to go above $80/MW on a day-ahead basis.

the DRP program participants surveyed were somewhat or very dissatisfied with the number of program interruptions in 2005.

Despite Concerns about the Frequency of Interruptions in 2005 and Dissatisfaction with Some Program Elements, Most DRP Participants Said They Were Satisfied With the Program, and Plan to Stay With It

Almost three fourths of participants surveyed said they were somewhat or very satisfied with their overall participation in the DRP program. Customers who expressed dissatisfaction with the program overall typically attributed it to the baseline calculations, the frequency or duration of events, and the complexity of the program. At least half of survey respondents were dissatisfied with the capacity and energy payments, the frequency of interruptions, the level of penalties, and the timeliness of payments for participation.

Almost three fourths of respondents also said they planned to remain on the DRP program next year, and over half said they would be very or somewhat likely to stay with the program even if the maximum curtailments allowed under the program were called.

DRP Program Participation Was Motivated both By Bill Savings and By the Desire to Be Good Corporate Citizens and Help Avoid Blackouts

Saving money on energy was cited as the primary reason for enrollment in the DRP program by about a third of surveyed customers. However, non-financial motives were also important, with the combination of "being a good corporate citizen" and "avoiding rolling blackouts" also accounting for almost one-third of responses. Other external factors also played a significant role in encouraging participation. More than one-fourth of respondents cited third party influences, including aggregators, a government DR mandate for state agencies, decisions made at corporate headquarters, and decisions made by the chancellor of a university campus.

DRP Participants and Aggregators Often Perceive the Program to Be Driven Primarily By Capacity/Reliability Constraints Rather Than Price

While the terms of the program clearly state that it may be called either because of price or reliability, several aggregators noted that they were surprised by the number of purely price-driven events in 2005, and commented that this appeared to represent a change from previous years. Customer comments also emphasize the disconnect between the explicit price-responsive nature of the DRP program and the customer perception that events should be tied to system emergencies. As noted above, many customers signed up for the program at least in part to help address supply shortages, and several customers said they felt they had been misled by aggregators during the marketing effort.

Both Aggregators and Utilities Have Proposed Successor Programs to Take Effect when the Current Program Expires in May 2007

The aggregators and CPA have proposed a framework that retains several fundamental elements of the current program, including statewide consistency, a capacity payment (proposed at $15/kW/month) as well as an energy payment, marketing through third-party aggregators, and a separate organization to manage the program (which could be either CPA or the ISO). There are, however, other areas where the group proposes significant changes, including two participation options (a "Reliability Program," called only for ISO Stage 2 Emergencies and a "Peak Reduction Program" called at the discretion of the IOUs as an economic resource), aggregation across customers, a revised baseline, a revised penalty structure, and extension of the summer program through October.

The utilities envision the DRP program as requiring more commitment (along with greater compensation and penalties) than DBP, but greater flexibility (along with lower compensation and penalties) relative to BIP. The utility-proposed successor program also retains many of the DRP program features (e.g., aggregators, monthly nominations, capacity and energy payments, penalties for non-performance), but suggests changes in that: customers could participate directly with the utility as well as with an aggregator; the program would have an explicit temperature trigger rather than a price trigger; dispatch would truly be day-ahead; 1-3, 2-6, and 4-8 hour options would be offered; and the program would run June through October.

11. SUB-METERING SUMMARY

This chapter presents key findings from the sub-metering element of the 2004 and 2005 Working Group 2 (WG2) Demand Response (DR) Program Evaluation.

11.1 THE SUB-METERING ELEMENT OF WG2 EVALUATION OF 2004 AND 2005

The sub-metering element of the evaluation was established to provide a more in-depth understanding of DR program participant behavior - beyond what is revealed by analysis of revenue meter data, or by what can be learned about participants' DR strategies and behaviors from traditional survey methods. Key aspects of the sub-metering element of the evaluation are summarized below:

- **Twelve sites were included in the sub-metering portion of the 2004 evaluation**. These sites span each of the three primary price-responsive DR programs (i.e., CPP, DBP and DRP), a variety of business types and end uses, and each of the state's major investor-owned utilities (IOUs) (i.e., SCE, PG&E, SDG&E). As described below, data collection and analysis has been carried out for 11 of the 12 original sites for the summer of 2005.
- **Individual reports were prepared for each of the sub-metering sites as a part of the 2004 evaluation**. These individual reports detail the characteristics of each site, their DR strategies, the end uses monitored, and provide comparisons of revenue meter load reduction results with estimates developed from the sub-metering data. These full site reports were prepared to present site findings from participation in Summer 2004 programs. For the 2005 evaluation, analysis and findings have been prepared for sites participating in Summer 2005 programs, though individual site reports have not been prepared for 2005.
- **A 2004 summary report provides an integration of findings from across the 12 sites monitored**, as well as lessons learned from the sub-metering recruitment process. This chapter updates these findings by integrating results from the analysis of monitored sites participating in Summer 2005 programs.
- **Appendix J of the December 2004 final WG2 evaluation report provided a detailed summary of the methodology and procedures** used to design and implement the sub-metering project**.**

Specific elements of the sub-metering tasks across the 2004 and 2005 evaluation studies included:

- Developing a detailed screening process that resulted in a sample that includes a variety of customer types, programs, and DR strategies.
- Development and execution of detailed sub-metering plans for each of the study participants.
- Primarily remote (dial up) collection of sub-hourly equipment and circuit data.
- In-depth interviewing with each of the study participants.

- Analysis of individual equipment and circuit loads, as well as customer strategies and observed behavior.
- Preparation of a summary and individual site reports in 2004; preparation of this chapter as a final summary report for 2004 and 2005.

11.1.1 Why Sub-Metering?

Although many large customer demand response programs have been in existence for some time, the customer market for price-responsive DR is still in a relatively nascent stage. Few customers have a detailed understanding of the composition of their hourly loads or have the ability to easily and precisely control those loads. This is borne out by the results of the 2004 WG2 Evaluation, as well as other recent related research led by the California Energy Commission, the Public Interest Energy Research Program (PIER), Lawrence Berkeley National Laboratory, the Demand Response Research Center, and others.

Although much can and has been learned about how customers do or don't respond to DR program offerings through traditional evaluation approaches that do not include sub-metering customer loads, sub-metering offers a level of information and insight into customer activity that is difficult if not impossible to glean from other evaluation approaches. For example, using revenue meter data and customer self reports, the overall WG2 2004 Evaluation results provide a great deal of useful information on total program impacts as well as distributions of impacts across individual customers. However, information on the underlying sources of customer impacts, the sophistication and robustness of their DR implementation strategies, the degree to which they carried out their strategies, and the underlying reasons why they did or did not carry them out, is more limited. The sub-metering element of the evaluation was envisioned and designed to provide additional insights into these more detailed customer-specific issues.

The ability to analyze participants' loads at an equipment or circuit level provides significantly more information that can be used to enhance understanding of customers' DR strategies and their ability to effectively participate in DR events. The inclusion of sub-metering data in the analyses of participant performance is also useful to understanding how curtailed end uses contribute to load reductions at the revenue meter. Sub-metering data can be used to develop bottom-up estimates of DR impacts for monitored participants that can be compared to estimates of impacts measured by revenue-meter interval data. Comparing these results improves understanding of the relative accuracy of different revenue-meter impact estimation methods, which complements the results published in the December WG2 2004 Evaluation report.

Analysis of sub-metering data also significantly improves understanding of the strengths and weaknesses of customers' curtailment strategies and helps to illuminate barriers associated with the execution of these strategies. For example, the sub-metering data allows closer tracking and analysis of participants' actions over time. When conducted over multiple events in successive years, this analysis can yield a great deal of information about the *evolution* of customer's applied DR strategy.

While each sampled site reveals only one participant's experience, the integration of findings from this research reveals a number of findings that would likely not be obtainable by other means. These enhanced findings, when combined with the overall evaluation results, provide important input for program design and ongoing DR policy development. This research also makes significant contributions to DR research in the commercial and industrial sectors by adding twelve sub-metering sites to the small but growing number of in-depth case studies and monitoring projects carried out in related studies.[1] This combined body of work offers considerable potential for improving program offerings and enhancing the technical and organizational knowledge of active and prospective DR program participants.

11.1.2 Sub-Metering Study Objectives

Four broad objectives were initially identified for the sub-metering element of the 2004 WG2 Evaluation. These were to:

- Develop findings on what works and what doesn't to help improve program participation and forecasts of DR potential.
- Develop sub-metering-based estimates of DR impacts and compare with whole-meter estimates.
- Develop in-depth understanding of real and perceived end use service/demand response tradeoffs.
- Integrate results into the PIER DR Database.[2]

Building on the original project objectives, the following set of research questions were considered during the analysis process:

- What DR strategies work, which don't, and why? What are the weak points in the customers' participation processes? Are there differences in real and perceived effects of DR strategies? What are specific program, institutional, and technical barriers to event participation?
- What are the true costs and benefits of participation? What can be done to help customers bear the costs that prevent them from participation?

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[1] "Development and Evaluation of Fully Automated Demand Response in Large Facilities" Piette, M. A., O. Sezgen, D. Watson, N. Motegi, (Lawrence Berkeley National Laboratory), C. Shockman (Shockman Consulting), L. ten Hope (Program Manager, Energy Systems Integration CEC). CEC-500-2005-013. January 2005

"Measurement and Evaluation Techniques for Automated Demand Response Demonstration" Motegi, N., M.A. Piette, D.S. Watson, and O. Sezgen, Lawrence Berkeley National Laboratory. Proceedings, ACEEE 2004 Summer Study on Energy Efficiency in Buildings: Breaking out of the Box, August 22-27, 2004, Asilomar, Pacific Grove, CA. Washington D.C. American Council for an Energy-Efficient Economy. LBNL-55086. August 2004.

The Demand Response Research Center is currently operating a pilot project to examine Automated Critical Peak Pricing for Large Commercial facilities. For more information on this project and the above two citations, see http://drrc.lbl.gov/drrc.html

[2] PIER has developed a DR database that is intended as a repository for DR-related data collected through a variety of individual DR evaluation projects. This data can then be leveraged for further research by PIER and the Demand Response Research Center (see http://drrc.lbl.gov/)

- What are the successful manual and automated DR strategies? What level of automation is appropriate for different customer and end use types? Are customers actively seeking to automate? What are the primary constraints to improving automation?

- Do customers possess all the knowledge they need to carry out effective DR actions? What more do they need to know? Where might they obtain this knowledge? Are they aware that they may need more knowledge or tools to participate more effectively?

- What do customers understand about their baselines? How are they impacted by baseline estimates? What is the variability in their daily load shapes? Can they obtain baseline data when they need it? Do current baseline methods create opportunities for free riders? Are customers aware of that potential?

Sections 11.3 and 11.4 provide a summary of the key findings from this research. Section 11.3 summarizes the key findings drawn across the individual sub-metering site analyses, whereas Section 11.3 focuses on detailed situational and anecdotal findings of active, individual participants of the sub-metering sample. Overall, the sub-metering results address many but not all of the research questions listed above. This is primarily due to limitations in the study sample, monitoring approaches, and challenges with obtaining economic data related to the service impacts of DR participation.

11.2 ORIGIN AND CHARACTERIZATION OF THE SUB-METERING SAMPLE

The 2005 sub-metering sample is a continuation of the 2004 sample; no new sites were recruited in 2005, and one was eliminated due to a change in facility ownership. This section briefly describes the recruitment process carried out in summer 2004, and provides a status of the sub-metering sample and event monitoring at of the end of summer 2004 and 2005.

The following screening criteria were developed and applied to the spring 2004 population of CPP, DBP, and later, DRP, participants:

1. Customer had to be highly likely to opt-in for DR events.
2. Customer had to indicate they would shed multiple loads at a site.
3. Customer had to fit within our quota for a diverse mix of business types and customer sizes.
4. Customer had to fit within our quota for a mix of end uses and shed strategies.
5. Customer's characteristics had to enable cost-effective monitoring of loads and energy services of interest.

These criteria were intentionally biased in favor of a sample that included participants that are most likely to actually take DR actions and would utilize more complex DR strategies relative to participants who might only activate back-up generation or shut down one major type of load within their facility. Consequently, the first two criteria were applied as pass-fail decisions, whereas application of the third and fourth required considerably more scrutiny. Inherent in the third and fourth criteria was the intention to seek a reasonably representative distribution of the program population by utility and program.

The sub-metering recruitment and installation process, which did not begin in earnest until May 2004, was challenged by the need to have sub-metering equipment installed in time to capture DR events for the summer of 2004. The steps for recruiting customers into the sub-metering sample entailed obtaining participant lists from the utilities, conducting detailed telephone screening, carrying out on-site surveys, developing metering plans, and installing the monitoring equipment.

As shown in Exhibit 11-1, 19 sites made it through the initial telephone screening. Of these, seven were subsequently rejected for sub-metering. Very often candidates had either not developed a DR strategy at all or had not developed it to a level where it could be efficiently executed in the event of a day-ahead or day-of event notification. Others were uncertain of whether their intended curtailment strategy would meet minimum program requirements (e.g., achieving at the 100 kW minimum reduction for DBP events in 2004), whether participation would justify the costs, or whether load reductions could carried be out without significant disruptions to site operations or occupant comfort or productivity.

Exhibit 11-1
Distribution of 2004 Onsite Surveys and Installed Sites by Sector, Utility and Program

	Total	By Sector		By Utility			By Program		
	Sites	Com.	Ind.	PG&E	SCE	SDGE	DBP	CPP	DRP
Total Onsite Surveys Completed	19	10	9	7	8	4	13	5	1
Onsite Survey Sites Rejected	7	4	3	2	3	2	5	2	0
Metering Installations Completed	12	6	6	5	5	2	8	3	1
Installed Sites with Summer '04 Events Captured	6	2	4	3	2	1	2	3	1
Installed Sites with Summer '04 Events Not Captured	3	3	0	0	2	1	3	0	0
Installed Sites Not Participating in Summer '04 Events	3	1	2	2	1	0	3	0	0

Throughout the 2004 recruitment process, recruitment efforts were continuously redirected to attain a broad sample of sites across the three utilities, DR programs, customer types, and affected end uses. As a number of industrial facilities were among the first sub-metering sites recruited, the focus of recruitment was shifted to commercial and institutional sites. Exhibit 11-2 includes the final distribution of the sub-metering sample across these categories and indicates the number of sites in each category where sub-metering data was available from DR events in summer 2004. More details on the recruitment process itself can be found in Appendix J of the December WG2 2004 Evaluation report.

Once sites of the sub-metering sample were selected, sub-metering installations were planned and executed. The process by which metering installations were planned and executed is not discussed in this chapter, though it is described in detail in Appendix J of the December 2004 final WG2 Evaluation Report. Exhibit 11-2 provides a graphic example of how sub-load monitoring was carried at one of the sub-metering sites (Site 1). Similar diagrams were included in each of the 2004 Sub-metering Site Reports along with descriptions of the sites, the customer's DR strategy, the sub-metering approach, customer attitudes about the respective programs and their participation, as well as the analysis and findings from Summer 2004 events.

Exhibit 11-2
Graphical Example of Loads Monitored at one Sub-meter Site

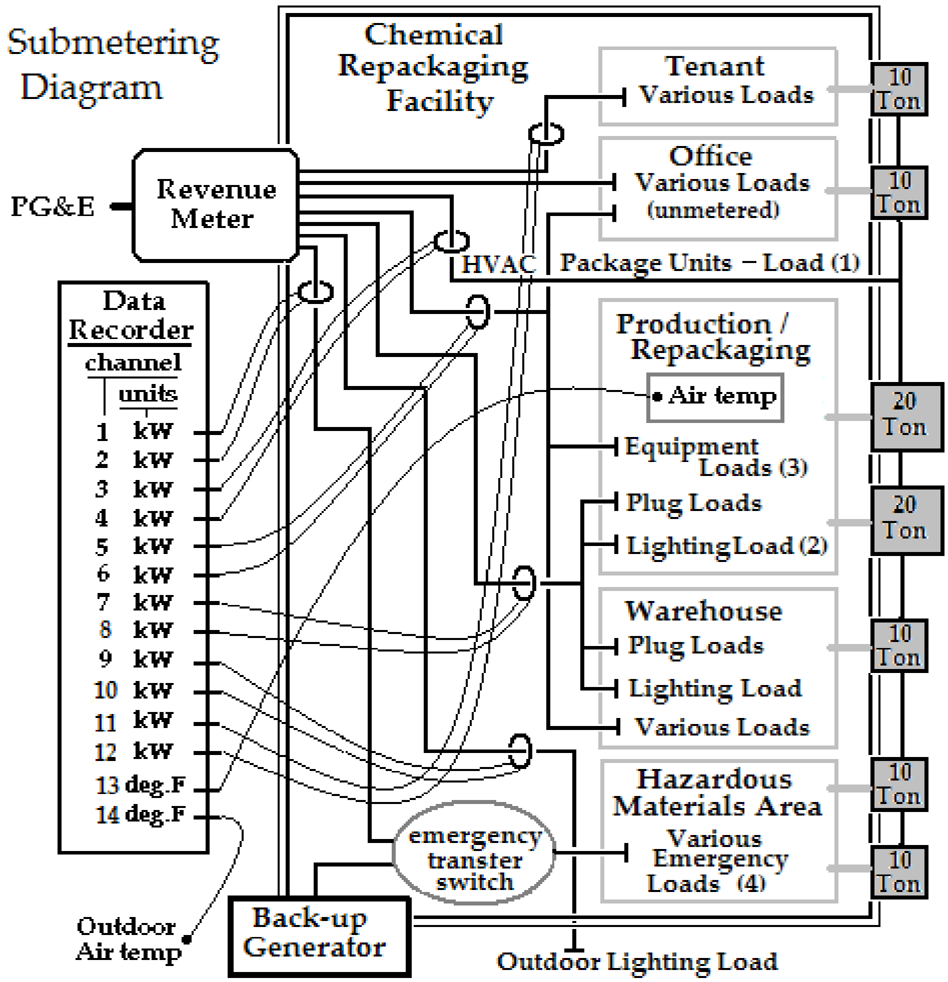

Exhibit 11-3 summarizes some of the key site characteristics of the sub-metering sample, along with metering installation and event dates in 2004. Given the timing and challenges of the recruitment and data collection process in the late spring and summer of 2004, it was fortunate that 2004 DR events were concentrated in the latter half of the summer. These circumstances allowed one or more of the 2004 DR events to be captured for half of the twelve sampled sites. Additional details on the site events analyzed in 2004 is included in Appendix J of the December WG2 2004 Evaluation report. Overall, the proportion of sub-metering customers that took action during 2004 DR events was many times higher than the rate of action found for the entire participant population.

Exhibit 11-3
Summary of Selected Sub-metering Site Characteristics and DR Event Monitoring in 2004

Customer	Utility & Program	Business Type & Size (1000 sq.ft.)	Curtailed End Uses (1: Primary EUs 2: Secondary EUs)	Level of Auto-mation	Instal-lation Date (2004)	Event Dates (2004)	Event Partic-ipation	Events Monit-ored
Installed Sites Participating in Summer 2004 - Events Captured (Sites 1 to 6)								
SITE 1: Product Repackaging Facility	PGE /CPP	Industrial / Packaging (64)	1: HVAC, Lighting 2: Process Equip.	Manual	7/30	8/27 9/8 9/9 9/10 10/13	NO NO YES YES YES	NO NO YES YES YES
SITE 2: Agricultural Product Processing, Packing & Cold Storage Facility #1	PGE /CPP	Industrial / Ag Process (250)	1: Cold Storage 2: Lighting, Process Equip.	Manual	6/11	8/27 9/8 9/9 9/10 10/13	YES YES YES YES YES	YES YES YES YES YES
SITE 3: Baking & Frozen Storage Facility	PGE /CPP	Industrial / Food Process (135)	1: Freezers 2: HVAC, Lighting, Process Equip.	Manual	6/24	8/27 9/8 9/9 9/10 10/13	YES YES NO NO YES	YES YES NO NO YES
SITE 4: Agricultural Product Processing, Packing & Cold Storage Facility #2	SCE /DBP	Industrial / Ag Process (174)	1: Cold Storage 2: Process Equip.	Manual	5/28	6/9 9/23	YES YES	YES YES
SITE 5: Multi-Building Office Complex #1	SCE /DBP	Commercial Office (1,000)	1: HVAC (AHUs) 2: Lighting, Fountain Pumps	Fully Autom-ated	8/13	6/9 9/23	YES YES	NO YES
SITE 6: Multi-Building Office Complex #2	SDGE /DRP	Commercial Office (278)	1: HVAC 2: Lighting, Elevators	Partially Autom-ated	8/27	9/28 (facility test)	YES	YES
Installed Sites Participating in Summer 2004 - Events Not Captured (Sites 7, 8 & 9)								
SITE 7: Multi-Building Office Complex #3	SCE /DBP	Commercial Office (192)	1: HVAC 2: Common Lighting	Partially Autom-ated	7/31	6/9 9/23	YES NO	NO YES
SITE 8: Office Building & Call Center	SDGE /DBP	Commercial Office (288)	1: HVAC 2: Lighting	Partially Autom-ated	8/26 installed; 9/23 data	5/03 6/30 9/7	NO YES NO	NO NO NO
SITE 9: University Campus	SCE /DBP	Institutional / Educ. (720)	1: HVAC 2: Lighting, Pumps, Freezers, etc.	Partially Autom-ated	Not Complete	6/9 9/23	YES NO	NO NO
Installed Sites Not Participating in Summer 2004 Events (Sites 10, 11 & 12)								
SITE 10: Glass Processing Facility	SCE /DBP	Industrial / Material Process (128)	1: Process Equip 2: Other Process Equip.	Manual	7/12	6/9 9/23	NO NO	N/A
SITE 11: Corporate Office & Laboratory	PGE /DBP	Commercial Office (242)	1: HVAC (AHUs) 2: Exhaust Fans	Partially Autom-ated	8/28	7/26	NO	N/A
SITE 12: Food Production & Frozen Storage Facility	PGE /DBP	Industrial / Food Process (70)	1: Freezers 2: Other Process	Manual	6/1	7/26	NO	N/A

2005 Sub-metering Sample

Exhibit 11-4 summarizes the *2005* participation status of the sub-metered sample and identifies the events included in the 2005 sub-metering analysis. One site was eliminated from the 2004 sample due to the inability to engage the new owners at a DRP facility (Site 6) that had changed ownership.

Exhibit 11-4
Summary Status of Sub-metering Sample and DR Event Monitoring in 2005

Customer	Total Program Events	Reported Event Participation	Dates of Events Analyzed	Site Status
Installed Sites Participating in Summer 2005 - Events Analyzed				
SITE 1: Product Repackaging Facility	9	8	7/1/05 7/15/05 8/8/05	Highly active CPP participant in 2005
SITE 2: Agricultural Product Processing, Packing & Cold Storage Facility #1	9	6	7/1/05 8/8/05 9/29/05	Highly active CPP participant in 2005
SITE 3: Baking & Frozen Storage Facility	9	4	7/14/05 8/8/05 9/29/05	Moderately active CPP participant in 2005
SITE 4: Agricultural Product Processing, Packing & Cold Storage Facility #2	13	10	7/19/05 7/21/05 8/5/05	Highly active DBP participant in 2005
SITE 8: Office Building & Call Center	12	1 (unspecified date)	7/28/05 8/4/05 8/5/05	Infrequent DBP participant in 2005; conducted curtailment testing in summer 2005 and intends to be active in 2006
SITE 11: Corporate Office & Laboratory	17	3	7/21/2005 (compared with 4 non-event days)	Participated in less than 20%of summer 2005 DBP events; Contact with site manager very limited; supporting qualitative data unavailable.
Installed Sites Participating in Summer 2005 - Events Not Analyzed				
SITE 9: University Campus	13	1	None	Customer reported participation in first 2005 DBP event only; Sub-metering capability constrained by incomplete tasks by customer's EMCS vendor.
Installed Sites Not Participating in Summer 2005 Events				
SITE 5: Multi-Building Office Complex #1	N/A	0	N/A	Facility Changed ownership early in 2005; Re-enrolled in DBP after last event of 2005.
SITE 6: Multi-Building Office Complex #2	N/A	0	N/A	Facility changed ownership in October 2004; dropped participation in DRP program.
SITE 7: Multi-Building Office Complex #3	N/A	0	N/A	Facility discontinued enrollment in DBP program in early 2005; May re-enroll for 2006.
SITE 10: Glass Processing Facility	13	0	N/A	Customer enrolled in DBP but unable to particpate in 2005 due to seasonal production requirements.
SITE 12: Food Production & Frozen Storage Facility	17	0	N/A	Customer enrolled in DBP, but unable to particpate in 2005 due to production requirements; Facility changing ownership (dropping enrollment) in early 2006.

Six sites in the 20-05 sample were not analyzed because they either did not enrolled in their respective programs during summer 2005 DR events (Sites 5, 6 & 7), did not participate in any 2005 events (Sites 10 & 12), or because sub-metering data was not available at the time of the event in which the customer (Site 12) participated.

11.3 KEY SUB-METERING FINDINGS

This section summarizes the key findings drawn across the complete range of individual sub-metering reports and analyses covering the summers of 2004 and 2005. Key findings are organized by categories related to the research questions outlined in Section 11.1.2.

11.3.1 Successful and Unsuccessful DR Strategies, Measures, and Practices

HVAC was the primary curtailed end use for commercial sites. There were only a few categories of curtailed end-uses within the sub-metering sample. In all six commercial sites, curtailment of HVAC systems was the primary, and often exclusive, source of load reductions. Each site tended to have a unique process for obtaining load reductions from their HVAC systems and had varying degrees of success. Only two of six commercial sites that actually curtailed HVAC system loads were unable to meet 2004 minimum (DBP) bid requirements of 100 kW through HVAC curtailments. One of the sites discontinued the program in 2005 due to their inability to meet the minimum bid requirement, and the site manager was unaware that the requirement had been reduced for 2005. Successful HVAC demand reductions from the remaining four commercial sites ranged between 100 kW and 460 kW in 2005. These impacts ranged from 6 to 31 percent of event-day peak loads and averaged 19 percent across the four sites. Sub-metering revealed how each type of curtailed HVAC equipment contributed to overall load reductions, and indicated which HVAC strategies worked well and which did not. Analysis of 2005 events at two sites indicated that customers had gained considerable knowledge about how to best execute their HVAC curtailment strategies.

Lighting impacts were minimal. Load reductions from secondary measures in the sampled sites of the commercial sector are small as compared with HVAC and are typically obtained from lighting and a host of other ancillary loads (e.g., elevators, fountain pumps, etc.). Lighting curtailments, if used at all, were typically confined to common areas, and often required separate, manual controls to activate curtailments (in 4 of 6 commercial sites). Building managers in this sample appeared reluctant to impact tenants with lighting sheds and were far more focused on managing complex HVAC systems during DR events. The potential for lighting reductions may have been limited in this sample by concerns over tenant and general occupant reaction and limited ability to remotely and precisely control lighting levels. The sub-metering results showed how rarely lighting measures where actually deployed during DR events despite the frequency with which they appeared in planned DR strategies.

Cold storage systems produced significant, successful curtailments. Based on the number of available cold storage sites during recruitment and observations from DR events, agricultural and food processing facilities with cold storage systems were generally successful program participants. These facilities tended to use their cold storage systems as the primary source of load reductions by cutting off compressors and letting product storage temperatures float for a limited period. Product temperatures were monitored in several of these cases and found to remain within the participants' identified tolerance levels. Cold storage system loads are typically manually controlled, and can often provide greater load reductions as an individual measure than those derived from multiple, manually-controlled process loads.

Moderate Batch Process Impacts. It is assumed that batch process industries have greater control over process equipment curtailments relative to their counterparts in continuous process industries, yet within the sub-metering sample, the use of batch process loads for curtailments was not as extensive as expected. All of the six industrial sites in the sub-metering sample utilized a form of batch processing, yet in all but one site, process load curtailment was not the primary end use by which load reductions were to be obtained. In five industrial sites, cold storage or HVAC system curtailments were the primary curtailed load, and in the only industrial site where all planned curtailments were process loads, no DR actions were taken in 2004 and 2005. For the customers in the sub-metering sample, daily (and seasonal) variability in process loads were often observed for individual pieces of equipment, thereby introducing considerable variability in the estimated baseline loads as seen at the revenue meter. In some cases, load impacts from the curtailment of a process load that was not operating during some or all baseline days would be measured at a lower value than the actual load impacts on the event day. For nearly all participating customers, the common expectation was that impacts would be roughly equivalent to the load reductions carried out on process equipment on the event day. However, baseline mechanics and circumstances of revenue meter loads (or individual subloads) for a given event day were not transparent to the customer, and measured impacts often deviated significantly from the expected (or actual) change in curtailed equipment loads on event days. In several instances, had the customer not acted, baselines methods would have penalized them with negative sub-load impacts.

Scheduling and daily production requirements were the primary obstacles to deploying process load curtailments. Yet, with enough notice and production flexibility, site managers were often effective in planning and deploying process load curtailments during DR events, but these efforts were rarely the primary contributor to load reductions at the revenue meter. For the first of several curtailments at one site, work shifts were actually modified in order to execute a curtailment of all available process loads. In this event, customer impacts exceeded their first, experimental bid by a factor of three. Yet, in successive events at this facility, work shifts were never again modified, and many of the process load curtailments were jettisoned as the customer came to rely more exclusively on cold storage system curtailments. This suggests that the customer did not find it worthwhile to significantly alter production schedules relative to program incentives.

Seasonality and work shifts significantly limited curtailment potential for some customers. In the analysis of successive DR events for commercial and industrial sites, it was observed that times of reduced facility demand were associated with reduced impacts. Seasonal production cycles and daily work shifts cycles tend to impact some process industries' (e.g., food production related) ability to shed load during certain summer months, during certain hours of DR events, or when summer peak loads otherwise occur. Seasonal shifts in production affect the extent to which load reductions can be obtained from these types of process loads. In peak production periods there is tendency to operate processes without interruption. Conversely, during periods of reduced production, process lines have a higher probability of being shut down. One agricultural processing and cold storage site obtained off-season load reductions that were less than a third of the load reduction observed during their peak season. For similar reasons, daily work shifts affect the ability to obtain load reduction potentials at certain times of the day. For example, in several cases, work shifts ended in early or mid-afternoon, and load reductions from process loads were eliminated or substantially diminished.

Limited use of Back-Up Generators. During recruitment, sites that planned to use only back-up generators (BUG) as their *exclusive* means of obtaining load reductions were eliminated as sub-metering candidates. Many of these sites were known to have successfully participated in DR events. Back-up generators were present in half of the commercial and industrial facilities in the sub-metering sample and some of these customers indicated they might be used during DR events in conjunction with other DR actions. In practice, however, there were no instances of their use during DR events in 2004, and only one instance in 2005 where a BUG was routinely used to diminish daily peak loads (not as a part of curtailment for DR events). These findings suggests that unregulated BUGs are typically used for daily load reduction, or for the regulated counterparts, are typically deployed as an exclusive DR measure, and may rarely be combined with other load shedding measures. One reason for this may be the complexity of synchronizing the integration of load shedding measures with onsite generation.

11.3.2 Effectiveness of Manual versus Automated Demand Response

Widely varying levels of automation among commercial and industrial sites. Levels of automation differed significantly between the commercial and industrial sectors. All of the six industrial sites in the sub-metering sample utilized manual controls to activate and control load reductions. The six commercial sites, primarily offices, were found to have varying levels of controls, primarily conventional energy management systems (EMCS), as discussed further below.

Industrial applications used manual controls. Manual curtailment of equipment loads in the sampled industrial batch process facilities was effective, particularly where there were fewer loads to control. There were no cases of automated controls applied among the sampled batch process industries, and it is assumed the daily, weekly and seasonal variability in the demand for process equipment services is incompatible with system automation.

Limited use of automated controls for HVAC. All of the commercial sites had EMCS systems for controlling HVAC systems, though the systems and their operators varied in their level of sophistication. However, many of these systems featured patch-worked integration with remnant legacy control systems, did not store or trend data points, and most did not include control of other building systems (e.g., lighting). The level of commercial building automation did not necessarily improve the probability or effectiveness of DR event participation within our sample. One customer with a moderately sophisticated EMCS needed assistance in determining how they could achieve a minimum bid of 100 kW and did not have the means to control their HVAC system in a comprehensive manner - thereby limiting their load reduction potential and the ability to participate. HVAC systems are complex, with design and control features that can counteract singular measures (e.g., raising chilled water temperature setpoints without controlling supply fans on air-handling units). Consequently, integrated HVAC system DR strategies that are pre-tested tend to be more effective. In 2005, two sites reported successful experimentation and testing of the EMCS systems in terms of refining and deploying their DR control strategies since 2004.

Virtually no use of automated systems for lighting. Among the six commercial sites, lighting DR measures were identified as secondary measures in the DR strategies of five sites. As discussed above, lighting measures were often on a manual or separately controlled, automated system (separate from HVAC EMCS), lacked precision (limited or no ability to *partially* reduce lighting within usage areas), were not often deployed in actual events, and were often confined to common areas. Lighting measures may not generate impacts commensurate with the time and attention required to execute curtailments in commercial buildings without significant improvement in centralized controls.

11.3.3 Constraints and Limitations on Participation

Commercial concerns over tenant and occupant impacts. Commercial office participants were particularly averse to impacting their tenants. Several of the commercial sites never actually experimented with HVAC curtailments prior to DR events, presumably out of aversion to possible tenant impacts and complaints. Others terminated HVAC curtailments prior to the end of DR events, thereby falling short of minimum DR bid requirements. Similarly, the few DR lighting measures that were seen in sub-metered events were typically undertaken in common (non-tenant) areas. Office HVAC DR measures were terminated or avoided altogether if they were likely to increase indoor temperatures to a point where tenant occupants would notice them. Notably, however, there was only one instance (in 2005) where a commercial site manager reported complaints of occupancy discomfort during a DR event in commercial sites, and complains about reduced lighting levels came from their own employees. In one industrial facility, a facility manager reported receiving complaints from their own employees about higher indoor temperatures on the production floor where temperature setpoints had been raised as a routine DR measure used in 2004 and 2005. Unlike his counterparts in commercial office sites, the facility manager felt complaints from their own employees were minor and had no bearing on production or worker productivity. This is consistent with the finding from the baseline survey in the overall 2004 WG2 Evaluation study that found commercial sector customers were much more concerned about occupant comfort impacts of DR than were industrial customers, especially when complaints came from tenants.

Limitations of the Notification Process. For several customers, the notification process was a significant barrier to participation. Site operations personnel are exceedingly busy managing industrial production on the plant floor or managing different aspects of commercial building operations. Many cases of non-participation in the monitored DR events were simply a function of the manager being unavailable to receive or respond to notifications. This was especially true with regard to the bidding process for the DBP programs, where day-ahead notifications only offered a small improvements over day-of notifications with regard to the customer's probability of participation. Especially for industrial participants, longer event notification (or bid window) periods are helpful, if not essential. Although there are cases of industrial process sites that need an hour or less to respond, the necessary changes to production schedules and work shifts more often take between 8 and 24 hours to plan. Curtailment of industrial processes were very much subject to the time between notifications and events, and the customer's flexibility to modify process and production lines during an event. The level of flexibility was determined by a host of factors, most notably production schedules and deadlines, interdependencies between processes within the plant, ease of (manual) control, adaptability of work shifts and other labor impacts. While there are cases of large and significant process load curtailments in our sample, there are a greater number of instances where process curtailments were not undertaken due to production requirements that could not be quickly rescheduled. Aside from longer advance notification, other improvements may be made to the process including a wider distribution of notifications to several individuals involved with site energy management. In addition, issues surrounding missed notifications appeared to diminish in 2005 due to the increased frequency of day-ahead events, and the total number of events, overall. Here it assumed that site managers made it a practice to anticipate and routinely check for notifications.

Declining institutional "memory" for executing DR strategies. Infrequent DR events appear to reduce the participants' probability of event participation and their ability to deploy a planned DR strategy during events. There were several instances where site energy managers incorrectly recalled which events they participated in or what measures they took during past events. This reinforces findings in the overall evaluation that the institutional "memory" for executing DR strategies erodes over time if there are no or very few opportunities for participation. Conversely, the increased frequency of DR events in 2005, appeared to increase event participation rates for most of the active sub-metering sites, and contribute to the refinement and routinization of DR strategies.

Diminishing trend in participation. For events in 2004 and 2005, the four commercial office sites that had an opportunity to participate in more than one DR event either did not participate in the latter events, or obtained load reductions that were lower than the prior event. One fully automated site deviated from its' automated, pre-programmed HVAC load reduction strategy and curtailed small loads that it had not previously indicated in its original DR strategy. The other two sites did not participate in the last event because they did not receive notifications in time to shed, or did not receive them at all.

Change in site ownership and staff erode participation. Change in site ownership or in the personnel responsible for operating DR strategies significantly erode the institutional capability to participate in DR events and deploy an effective DR strategy. Between 2004 and 2005, two commercial sites changed site ownership and consequently terminated enrollment in their respective DR programs (i.e. DRP, DBP). In the first of these instances (Site 6), the site energy manager responsible for the DR strategy was dismissed, and in the other (Site 5), one of two site managers involved in their DR strategy was retained. However, this site (5) did not re-enroll in the DBP program until after the last summer 2005 event. A third industrial participant (Site 12) lost the site manager (in summer 2004) who had championed DR program enrollment and participation in 2004; consequently, the site did not participate in DBP events in either year. Change in site personnel can also translate into missed notifications because contact information has not been updated or knowledge of the applied DR strategy is lost. At another site, event notifications were missed as they were sent only to contact points for the departed personnel.

Limited building operator knowledge of DR strategies. Based on observations of the candidate recruitment process and among sampled sites, building operators level of knowledge of how to operate DR measures and the likely impacts on energy services varies considerably, but it is often limited. Many candidates in the sub-metering recruitment process of 2004 were screened out because they were found to lack coherent DR strategies.

Limited ability to quantify costs of participation. Customers in the sample did not have any reliable and comprehensive process for the accounting of participation costs and benefits (incentives), and relied on a more intuitive assessment of the potential costs of disrupted production and tenant dissatisfaction. In one instance, a frozen food processing facility (Site 12) that did not participate in summer 2004 DR events, expressed a specific need to for a process or tool to help them assess the costs and benefits of curtailment actions specific to their facility. Among all the end-of-summer interviews conducted with site managers in 2004 and 2005, none of the site managers could begin to quantify the costs and benefits of event participation, though there was one instance where the site manager could definitively say that that bill credits of a specific event did not match the costs of participation. In this case, bill credits were less than expected and slow to appear, such that the feedback process for identifying benefits was significantly hampered by time and the lack of real-time knowledge about baseline conditions for the given event day (which would inform the customer's expectations of event impacts).

Need for assistance but not in form of 2004 Technical Assistance Program. Despite the general need for information on DR measures, costs and benefits, none of the sub-metering candidates or sampled sites were known to have utilized the Technical Assistance Program (TAP) in 2004 or 2005. Among the sampled sites, customers indicated they were either unaware of the program, felt they did not need it, believed that it would not address their specific information needs, or thought that there were prohibitive institutional constraints or financial risks associated with it. However, requests for advise on appropriate DR measures and strategies were commonly encountered throughout the sample recruitment process in 2004, and among five of the candidate sites that received onsite surveys. In that the sub-metering sample sought to identify the most probable program participants, it is posited that there is a considerable demand for technical assistance with developing and operating DR strategies in the program population. In 2005, most of the active sites had reported or otherwise exhibited self-directed refinement to their DR strategies; in two cases, very specific assistance was obtained from their utility (e.g. sub-load monitoring services)

11.3.4 Accuracy, Effectiveness, and Problems with Baseline Methods

The findings below refer to the two principal baseline load estimation methods described and analyzed in the 2004 WG2 Evaluation report. Readers unfamiliar with these baselines and issues associated with their accuracy should see Sections 6 and 7 of the 2004 WG2 Evaluation Report.

Sub-metering results reinforce finding that ten-day adjusted baseline method is more accurate than three-day method. The sub-metering results provide strong evidence that both the three-day and ten-day adjusted baselines can be inaccurate under different circumstances. However, the three-day baseline appears to be much less accurate on average than the ten-day adjusted method. The ten-day baseline was found to more closely track the trajectory of event-day loads in non-event hours for the revenue meter and sub-metered loads, especially among sites that deployed HVAC load curtailments. In many cases, the use of revenue meter data with the three-day settlement provides a false indication of impacts that is revealed by analyzing the sub-metered data. In all but a few instances, the three-day baseline overestimated load reduction impacts relative to absolute load reductions observed on the event days, and the ten-day adjusted baseline commonly measured smaller load impacts relative to the three-day. The ten-day baseline was subject to under-estimation of load impacts in cases where the customer initiated load reductions more than an hour in advance of the start of the event period. An inaccurate baseline creates opportunities for free riders when it consistently over-estimates event day loads. The sub-metering data provides evidence of possible free riding in a few cases where the customer had a good grasp of the mechanics of the three-day baseline calculation.

Three-day baseline method is affected by a large number of consecutive events in 2005. In the programs in which the active sub-metering sites participated in 2005, there were a large number of events relative to the number of events in 2004. For the vast majority of these 2005 events days, they were a part of a string of consecutive event days. Consequently, a large number of consecutive event days, led to the elimination of large blocks of days, and sometimes weeks, from the pool of available baseline days for event days, particularly those falling later in the month of July or early August (2005). While conducting the event analysis for these sites, it was not uncommon to encounter baseline days used in the three-day baselines that were three, four, and in one case more than five weeks ahead of the event day. When baseline days selected by the baseline algorithms are forced this far into the past by large numbers of consecutive event days, there is an increased risk that they are diminished in their ability to provide "predictive" load curves for what event day loads should look like in the absence of a curtailment. This risk is elevated for sites that have significant weekly or monthly variation in load patterns.

Customers' need to better understand baseline methods. Baseline methods are critical to assessing benefits of DR strategies, and among participants of the sub-metering sample, two customers expressed the specific need to better understand their baselines, or had a need to know what they looked like as a part of their process for taking action during DR events. Two of the sampled customers complained of delays in receiving bill credits, such that they experienced a very long delay in finding out how much they benefited from participation in a specific event. Customers need to understand how baseline methods are applied, especially for customers who intend to shed a small proportion of their total load; in these cases, unrecognized baseline inaccuracies may severely, and randomly, penalize or reward participating (or non-participating) customers. The need to better understand and gauge baselines was evident in the common discrepancies between load intended (bid) and actual load reductions. Improved baseline recognition could help participants consider not taking action when baselines are likely to work against them in terms of reducing incentives to where they do not justify actions taken. Alternately, baseline recognition may motivate participants to take action when the baseline will clearly capture the impacts of curtailments.

The baselines of sub-metered loads showed the variability of curtailed loads in terms of their contribution to revenue meter impacts, both within event periods and between events. The graphic comparison of baselines and event-day loads also revealed instances when end-uses intended for curtailment are not curtailed and actually detract from load reductions at the revenue meter. For HVAC loads, event day and baseline load comparisons are useful in terms of better understanding the effects of weather on HVAC curtailments. For example, there is one clear instance of a curtailed HVAC load that did not contribute significantly to the overall facility load reduction due largely to a mis-estimation of impacts associated with the three-day baseline method.

The comparison of event day and baseline loads also revealed instances when customers were unable to maintain curtailments on specific end uses and when specific loads were curtailed in advance of the DR event start times or other curtailed loads. In each case, sub-metered baselines provide key insights into challenges of curtailing specific end uses and the sequence of measures that the customer used in activating their DR strategy.

In cases where customers fully understand baseline mechanics and can obtain real-time baseline data, there is an alternate risk of exploiting free-ridership situations that arise from baseline methods, especially in the case of the three-day baseline method. In the 2004 sub-metering sample, there was one possible case of a fully-automated commercial site[3] where the site manager probably had the capability to observe the baseline for a late summer 2004 event in real time, and recognized a free-rider opportunity in bidding demand savings that would be estimated by the three-day baseline without taking significant action. In this instance, the customer bid and obtained a level of demand savings incommensurate with actions taken. This case is discussed further in section 11.4.5, below.

11.4 SELECTED FINDINGS FROM INDIVIDUAL SITES, FACILITY TYPES, AND NON-PARTICPATING SITES

This section brings forward key findings from the Summer 2004 and 2005 site analyses by focusing on detailed situational and anecdotal findings of active and non-active participants. This section also characterizes the constraints and successes of active participants, and how their DR strategies may have evolved over the summers of 2004 and 2005. This section also draws out broader conclusions about participating and non-participating facility types within the sub-metering sample (not previously addressed in Section 11.3), with an emphasis on the barriers to participation among the non-participants.

11.4.1 Product Repackaging Facility (Site 1)

Site 1 Description:

This facility is enrolled in PG&E's CPP Program and is primarily engaged in the repackaging of lubricants, epoxy resin, aerosols and other products. Product specifications are determined by customers and a large segment of the batch production operation is executed on a just-in-time basis. Facility production shifts are comprised of approximately 70 persons and typically extend from 7:00 AM to 3:30 PM during normal weekday operations. Just over half of the 63,760 total sq. ft. facility is conditioned floorspace, including a sixth of the building that is tenant occupied. The four remaining sections of this facility include office, production, warehouse and hazardous materials areas.

HVAC and batch processing loads are the most significant loads at the facility, and electric costs represent between 10% and 25% of the facility's total operating costs. The following itemizes each of the possible process, lighting and HVAC loads that could be curtailed during CPP events:

1) (2) 20 ton HVAC package units serving production/packaging area
2) Lighting in production/packaging area
3) Production/Packaging equipment
4) Emergency Equipment

[3] Within the sample, this customer had the most sophisticated EMCS, including pre-programmed, three-tiered DR curtailment sequence. The development of DR capabilities within this customer's EMCS were subsidized by the AB 970-funded Demand Reduction Program.

Preparing for a next-day curtailment requires that the site manager adjust production schedules and work shifts, which can take between 8 and 24 hours to plan. There are manual controls on all curtailed loads, and the customer has the capability to shift up to 45% of the facility's 350 kW total connected load to an emergency diesel back-up generator (BUG) that is required to power essential hazardous materials equipment in the event of utility power failure. Although the BUG is permitted to run it up to 300 hours per year, it was not used during any of the 2004 or 2005 events. Figure 11-2, above, provides a graphical representation of sub-metering at this facility.

Overall, this participant was among the most active in PG&E's CPP program in both 2004 and 2005 and reported being very satisfied with the program in both years. By the end of summer 2004, the site manager was well versed at responding to events, although he does not maintain a written curtailment plan. The customer was not completely satisfied with the process or the advance time given in the notification process, and the number of events called.

The customer did not utilize technical support from PG&E, but they expressed that they could have used assistance developing cost and bill savings estimates on some of their curtailment measures. The customer's main reason for participating in the CPP Program was the ability to obtain bill savings without significantly impacting plant production. While they were satisfied with the bill savings, they complained that bill credits are very slow to appear on their bills.

Key findings from this facility are as follows:

- The estimation of HVAC load impacts at this site is significantly affected by outdoor air temperatures; there are examples in 2004 and 2005 where both the three-day and ten-day adjusted baseline methods can be significantly biased in underestimating impacts. What is clear from the analysis (and perhaps not to the customer) is that on event days that are hotter than those used in the three days used in three-day baseline calculations, the customer must curtail HVAC equipment to avoid negative impacts from this sub-load, that have the potential to cancel or significantly diminish positive impacts derived from other curtailed sub-loads.

- Minor occupancy discomfort complaints were received as a result of raising thermostats by two degrees above the 78-degree (F) setpoints in the production area where HVAC loads were shed. The Safety Coordinator who curtails equipment did not feel that these employee complaints were significant and that elevated indoor temperatures during CPP events did not impact employee productivity. In order to obtain higher levels of demand savings in 2005, the site manager refined a strategy that allowed indoor temperatures to rise even higher during in 2005 events relative to those of 2004.

- Process equipment curtailments were second to HVAC loads in contributions to load reductions at the revenue meter, except in cases when HVAC impacts were underestimated by the three-day baseline method. Lighting curtailment was the third most important contributor to whole facility impacts. Non-curtailed tenant loads appear to randomly contribute or subtract from impacts seen at the revenue meter.

- The average whole-facility impacts of 2005 events were nearly 50% greater than the average for (fewer) Summer 2004 events. This suggests a process where the customer has refined their DR strategy over time, especially with regard to utilizing HVAC sub-loads. However, the summer 2005 impacts showed a tendency to diminish with later events, suggesting either customer fatigue with the frequent execution of manually operated DR strategies, or that there is a late summer bias in the use of three-day baselines against recording the full extent of HVAC sub-load impacts.

11.4.2 Agricultural Product Processing, Packing and Cold Storage Facilities (Sites 2 & 4)

Sites 2 and 4 are similar fruit processing facilities where product sorting, quality control, washing, processing, packing, and cold storage occur as a part of normal operations. Normal workday work shifts in both facilities start between 5:00 and 6:00 AM and end between 2:30 and 3:00 PM In each case, the facilities have been among the most active customers in their respective programs and the customer's satisfaction with the respective program structure and their process for event participation has been high because they can participate in DR events without significantly affecting operations.

Neither site maintains a written curtailment plan, though the DR strategies for these sites involve manual curtailment of one or more of their cold storage systems which can be carried out for limited periods of time without affecting stored fruit products. Selected process and lighting loads can also be curtailed during the normal work shift, which typically only occurs in the first half of the DR event periods.

Site 2 Description:

The facility is enrolled in PG&E's CPP Program. Seasonal production varies considerably as approximately 60 percent of the annual production occurs between the months of August to November. Approximately 170 persons occupy the facility during this peak season and occupancy falls to about 100 persons during other times. Some of the facility's production functions are being transferred to a site in Mexico and site employment is expected to drop by a third.

Electricity costs account for 15% to 20% of the site's total operating costs and bill savings and good corporate citizenship are the customer's primary motivations for program participation, There is approximately 250,000 total sq. ft. in seven buildings of which only three are involved in curtailments during DR events. Building 1, the main building, accounts for about half of the total facility floor space and houses a small main office (2,500 sq. ft.; the only conditioned space), packing, juicing, and other processing lines, and a small cold storage area (3,200 sq. ft.). The second and third buildings (at 32,000 and 7,200 sq. ft., respectively) are devoted to cold storage. In mid-summer 2005, the customer completed installation of a methane-fired back-up generator (BUG) that is now used on a daily basis in summer to reduce daily loads during peak hours, and is therefore not included in curtailment during DR events.

Site 4 Description:

The facility is enrolled in SCE's DBP Program. There is a total of 174,400 sq. ft. in three buildings at this facility. The first building is leased to a tenant and is not involved in the site's DR strategy. The second building (38,400 sq. ft.) is exclusively a cold storage facility, whereas the third, main building (100,000 sq. ft.) houses a front office, product washing room, a packaging and storage room on the first floor; the basement is primarily devoted to cold storage, and houses HVAC equipment and several additional non-curtailed loads. Approximately 90 persons occupy the facility during normal operations.

Regarding shedding of chiller loads for cold storage units, the customer initially indicated that maintaining the peak level of load curtailment would be unlikely beyond a two-hour period due to the temperature requirements of some types of agricultural product in cold storage. However, a combination of relaxing this assumption through testing, and minimizing service impacts of the chiller load sheds has allowed the shedding of (combined) chiller loads for up to eight hours in events of 2005.

Key findings from these facilities are as follows:

- Manual curtailment of cold storage loads were typically the primary contributor to whole-facility load impacts for both sites 2 and 4, and this type of curtailment provides a fairly consistent and manageable load reduction for the duration of longer event periods. This strategy is made possible because the stored agricultural products tolerate moderate temperature increases for several hours without consequence.

- Processing loads were significant contributors to whole facility load reductions, but become significantly less so during later segments of event periods after afternoon work shifts end. For both sites, the first response to an event in 2004 generated the largest average hourly impacts ever observed for each site in both years. In both cases, the sites were aided in their curtailment efforts by being at a point of their highest seasonal loads, and the entire menu of curtailable loads was deployed, as if to test the maximum potential for demand savings. In the case of Site 2, production lines were turned off and workers sent home for the duration of the event. This level of production line curtailment was never repeated by either site, suggesting that costs of forgone production are not matched by the level of program incentives, and a general lack of customer willingness to alter production schedule for the sake of DR.

- Site managers, while not maintaining a written curtailment plan, did reported a continuous process for refining the execution of their DR. In 2004, site managers did not initially exercise options to pre-cool or increase pre-curtailment loads, but these practices became more commonplace in 2005. Also, there was a higher degree of regularity in the practices and the patterns of sub-load shedding at both sites in 2005.

- Despite the ongoing refinement of DR strategies at these sites, the average event impacts decreased from 2004 to 2005. An example of strategy refinement was found in Site 4's routine process of shifting daytime loads to a smaller of two chillers – this reduced daily peak loads, thereby diminished the potential for curtailment in the combined chiller loads during events. This customer was in the DBP program, but indicated in an interview that they would probably practice demand response without bid incentives, just for the regular cost savings on their tariff. Similarly, Site 2, a CPP customer, brought a methane microturbine on line in summer 2005 to significantly diminish daily peak loads, thereby diminishing load shedding potential during events. In each case it is assumed that these very active customers knew what they were doing and were balancing the advantages of daily peak load reduction against demand response potential during events.

- For Site 2, application of the ten-day adjusted baseline curve almost always yielded a much lower figure for calculated impacts in 2005 (relative to the three-day baseline), whereas this was less often true for the fewer events of 2004. This is a case where the ten-day adjusted method, while typically yielding a more accurate measure of load reduction, in effect penalizes customers for premature curtailment on event days.

- Site managers at both sites customers indicated that they felt disadvantaged by the baseline in terms of resulting bill credits or bid payments, and that they would benefit from assistance with understanding the mechanics of baseline calculations. The Site 2 manager expressed the desire to view their loads in real time in order to predict or analyze the results of their curtailments during CPP events (PG&E's web-based Interact II load monitoring system only provided day-after load results). However, this customer was able to use the Interact system to monitor and adjust microturbine usage during daily peak loads. The Site 4 manager did use obtain assistance from SCE in 2005 for power monitoring that helped them to understand their sub-load affects on total facility loads.

- At both sites, there is a strong seasonal component in the customer's ability to deliver load reductions during DR events. Particularly with use of the three-day baseline, free rider opportunities arise when baseline days are drawn from their peak production season and corresponding events fall after the peak production period. The inverse is true when an event is early in a peak production season and baseline days are drawn from a period of lower production, unless a baseline adjustment is made (per the ten-day adjusted method).

11.4.3 Food Production and Frozen Storage Facilities (Sites 3 & 12)

Both of these facilities are engaged in baking and frozen storage operations within the PG&E service territory; Site 3 is enrolled in the CPP program, whereas Site 12 is enrolled in DBP. Each site operates multiple weekday shifts that spanning 20 to 22 hours each day. Similar to Sites 2 and 4 (discussed above), Sites 3 and 12 use manual controls to curtail cooling and process loads, and refrigeration loads are expected to provide the bulk of the load reduction during DR events.

Site 3 Description:

There are approximately 135,000 total sq. ft. in one large building, of which 75,000 sq. ft. is conditioned floorspace. The three main sections of the building include a warehouse & freezing section, a mixing and baking area, and a smaller packaging area. Company offices occupy about 10% of the total facility footprint. Approximately 200 persons occupy the facility during normal operations.

At this site, production schedules are constantly changing as they are determined largely by incoming product orders. The customer reported that it takes only 1 to 2 hours to shut down equipment, but between 8 and 24 hours to adjust production schedules and work shifts to accommodate equipment curtailments. Nonetheless, facility personnel were reasonably well prepared to participate in CPP events and they indicated that they were much more knowledgeable about carrying out a DR strategy and implementing load sheds as a result of being in the program in summer 2004. Despite the customer's indication that the notification process was very effective, they did not participate in all 2004 and 2005 events because they either missed notifications or were too busy managing production to participate in other CPP events.

The customer's motivation for program participation was more focused on avoid blackouts and being a good corporate citizen, than on bill savings. However, the customer was pleased with the bill savings that exceeded their expectations (approximately $13,000 in 2004 and $15,000 in 2005): The customer did complain that there were too many events in 2005 and that many of events were unnecessary.

Site 12 Description:

This 69,500 sq. ft. facility has two floors of which 95% of the floorspace is conditioned. The facility is housed within a single building that has a long axis on a north/south orientation. Major sections of the building include a freezer, production, packaging, warehouse and baking areas. A small office area accounts for less than 5 percent of the total building floorspace. Occupancy is typically 160 persons during normal work shifts, although summer manufacturing sometimes increases occupancy to 210 persons.

Site 12's primary load reduction strategy is to shut off several chiller compressors that serve the frozen storage area by raising temperature setpoints by 20 degrees (F) above the normal setpoint of –10 degrees. the frozen storage area is known to maintain adequate storage temperatures for up to 48 hours as long as freezer doors are not opened frequently. The customer has considered other process loads to be included in curtailments, including spiral freezers, battery chargers, conveyors, and water pumps. The plant also has a back-up generator, which was not planned to be used for curtailments.

The customer's primary reason for signing on to the DBP program was to have an opportunity to exploit bill savings if they could be obtained without disrupting plant operations. Although they admittedly do not have a thorough understanding of their internal costs and benefits of DR participation, they know that the economics of disrupting production relative to potential bill savings are generally unfavorable; the only possible exceptions would occur if they're given The customer was somewhat dissatisfied with the level of incentives offered by the program and did not feel the program was a particularly good fit for their type of operations. The site manager said, in retrospect, that they probably should not have signed on to the program and suggested that account representatives should be sure that the program is a good fit with customers before they are asked to enroll.

Key findings from these facilities are as follows:

- Like their counterparts in Sites 2 & 4, Sites 3 & 12 planned DR strategies that focused on curtailment cold storage systems as a main component of their overall DR strategy, supplemented by a menu of different process loads that could also be curtailed. Site 3 did not match the event response rate of Sites 2 & 4, and Site 12 has not participated in any events in 2004 or 2005. Site managers at Sites 3 & 12 have indicated that their production schedules keep them very busy and present a significant constraint on participation; they often miss or are unable to respond to event notifications. An attribute of Sites 3 & 12 that is different from Sites 2 & 4 is the process by which food is produced and immediately frozen. This is a more linear production processes that is more akin to a continuous processing facility, as compared to their agricultural batch processing counterparts in Sites 2 & 4. Site mangers at Sites 3 & 12 said that it takes them longer to adjust production schedules to accommodate DR actions, and in the case of Site 12, the time required prohibits event participation.

- Between 2004 & 2005, Site 3 made changes to the systematic use of processing equipment. Some of these changes affected the site's menu of curtailable loads. The best example of this change is as follows: In 2004, Site 3 used overhead lighting curtailment in a production area that was found to have adequate daylighting for workers to perform their tasks safely. In 2005, this CPP participant decided to make permanent the use daylighting in for 2005. This is but one example of how site managers initially identify curtailment options for DR that are later recognized to be more beneficial as routine (daily) load reductions. This is perhaps more common among participants in the CPP program, given the incentive to reduce daily peak loads that is inherent in the program's (TOU) tariff structure.

- Site 3 is located within a more moderate (Bay Area) climate zone within PG&E's service territory. On several event days in 2004 and 2005, outdoor temperatures were not unusually high, though higher temperatures across the broader service territory was a trigger for the CPP event. For the day of the event, the HVAC package units were never needed most of the preceding baseline days. Whether the customer realized this or not, their inactive HVAC sub-load was in effect created a "free rider" circumstance, in that it led to measurable and significant impacts on this sub-load without any curtailment action. While this spurious impact from HVAC loads is an affect of local climate conditions, it presents a situation where customers may begin to discern where sub-loads present free rider opportunities.

11.4.5 Active Commercial Office Participant Utilizing a High Level of Automation

Site 5 Description:

This facility is a multi-tenant office building and restaurant complex in a six-building campus totaling 1 million sq. ft. of conditioned floorspace. All buildings on the campus are corporate owned and leased to office and restaurant tenants. The customer was enrolled in SCE's DBP program in 2004 and the customer stated that obtaining bill savings was their primary reason for DBP participation, although they also mentioned the motive of doing their part to prevent rolling blackouts. Ownership of this facility changed early in 2005, and the facility was not re-enrolled in the DBP program until after the last event of summer 2005. Key findings from this facility are based on analysis of 2004 DBP events.

The two primary office buildings on the campus were utilized for curtailments in summer 2004. Each office tower includes approximately 300,000 sq. ft. of floorspace on among 15 floors, and normal weekday hours of operations for these buildings are between 8:00 AM and 6:00 PM. There are a total of 38 air-handling units assigned to separate floors of the two office towers. Housed in a separate building, a central plant includes two centrifugal chillers with a combined capacity of 1400 tons and two cooling towers. The site also has a 1.0 MW cogeneration plant installed two years ago, but it is not operated due to the high cost of natural gas. The facility also features real-time metering, a sophisticated communications infrastructure and Internet access to their online energy information system (EIS) used for trending and analyzing 15-minute interval data at the revenue meter level as well as for a large number of component demand, consumption, temperature and flow parameters used to track building operations.

The customer's capability to activate a pre-programmed, highly-automated curtailment of HVAC systems in the office towers was established in part through funding made available by State programs established by California Assembly Bill 970 and Senate Bill (SB) 5X in 2000 and 2001. Three different levels of demand response are activated by limiting the variable speed drives (VSD) for fans within designated air handling units (AHU) by 40, 60 or 80 percent, and by raising zone temperature setpoints, and lowering chiller temperature setpoints. Tests of the curtailment process were conducted successfully as a part of DR performance verification required by the state funded programs. As long as the Chief Engineer is present and can pass the notification on to his staff, curtailments can be activated within an hour of the receipt of notification for same-day events (all summer 2004 events were same-day events).

Key findings from this facility are based on two events in summer 2004:

- Analysis of the two 2004 events indicates that the ten-day adjusted baseline is a more appropriate baseline for this facility given that HVAC curtailments are central to the customer's strategy, and that the ten-day baseline curve closely tracks the trajectory of the event day loads in the hours on either side of the event period.

- For the first event, the customer utilized their standard pre-programmed HVAC curtailment strategy and actual impacts were considerably greater than what was bid by the customer. The customer had bid demand savings well below the load reductions that were credited to them. Larger than expected demand savings were attributed to the three-day baseline method which would have yielded demand savings had the customer not taken any action. It is likely that the customer was alerted to this discrepancy and used this information in their process for responding to the following event.

- For the latter of two 2004 events, the customer deployed reported DR measures not previously identified, including a reduction in common area lighting and the elimination of ornamental fountain pump loads (these loads were not monitored). It is not known why the customer deviated from their planned, fully automated HVAC-based DR strategy. However, the customer bid load reductions of 150 kW for all but the last hour of this event, for which 100 kW was bid. By use of the 3-day baseline, the customer was credited with average hourly impacts of about 120 kW, which is a larger load reduction than they were likely to obtain from the reported curtailed lighting and fountain pump loads. Comparisons between the load curves of the event day and the ten-day adjusted baseline indicates no significant DR actions (load reductions) taken during the event. Similarly, comparisons between the load curves of the event day and an alternative 3-day baseline (using two days immediately prior and one day following the event day) also indicates no curtailment in the event day load pattern. Given the underbid impacts of the first event, the analytical capabilities of the customer's EIS, and the known circumstances of this second event described above, it is plausible that the customer was aware of a free rider opportunity arising from the three-day baseline method (given results of the first event), and exploited this opportunity by bidding demand savings in this latter event beyond what could be obtained from the reported curtailed loads (if any action was taken at all).

11.4.6 Commercial Participants Experimenting with DR Strategies and Low Rates of Participation: Sites 6, 7, 8, 9, and 11

Nearly all of the active sites in the sub-metering have reported a fairly continuous process of gaining new knowledge from curtailments carried out in 2004 and 2005. HVAC and lighting are typically the largest loads in commercial offices, and the sample commercial relied heavily on HVAC system curtailments for their DR strategies, whereas curtailment of common-area lighting and other loads were sometimes included in DR measures. HVAC systems in commercial buildings are highly complex and require extensive knowledge and experimentation to obtain a desired curtailment result. Aside from being commercial office properties, Sites 6, 7, 8, 9 & 11 had significant differences in the configuration of their HVAC systems and their approaches to curtailing them. Site manager interviews and comparisons of sub-metering data between events in 2004 and 2005 often revealed modifications, refinements and the standardization of HVAC-based DR strategies over time. However, despite ongoing development of DR strategies, these sites exhibited a general pattern of limited (or no) program participation. This section identifies both the common and differential attributes of these sites and provides site descriptions and key findings that document the barriers, successes and the evolution of the customers' DR strategies.

Site 6 Description and Key Findings:

This customer is a multi-tenant office building with an occupancy of 570 persons and normal weekday hours of operations between 6:00 AM and 6:00 PM. The first of two buildings at this site is a 277,500 sq. ft 16-story office tower that where about 75 percent of the offices are leased (in 2004), and the second is a 3-story garage structure that also houses the central plant serving both buildings.

This facility was the only monitored participant in the DRP Program; the customer was enrolled in this program in late September 2004 by a designated Demand Reserves Provider (DRP aggregator) who had a long-standing relationship to the customer as an energy services provider that had previously planned and tested a preliminary DR strategy with the customer in the spring of 2002 (as a part of a state funded DR program funded by AB970). Shortly after confirmation of enrollment in the DRP program, the aggregator and the customer's Facility Energy Manager jointly planned and executed a September 28th test curtailment tin preparation for participation in the DRP program. This was to be the only example of a curtailment, as the facility changed ownership in October 2004 leading to the termination of the site energy manager and discontinuation of enrollment in the DRP program

DR strategy was to shed HVAC loads, with a possibility of shutting off freight elevators and lighting loads in common areas. Total impacts from all curtailed loads were expected to exceed 100 kW. The HVAC curtailment process involved shutting down a condenser water pump, resetting chilled water temperatures for chillers by 3 to 5 degrees (F), and manually reducing VSD fan speeds for unoccupied office suites to minimum speed settings. There is a 125 kW diesel backup generator at this facility that is not intended for use during DRP events. The facility has the real-time metering and communications infrastructure to support remote Internet access and analysis of their electric utility meter 15-minute interval data. However, only a few monitoring points within the buildings are trended for analytical and historical purposes.

Key findings from this site are as follows:

- Results of the 1.25-hour test curtailment in September 2004 showed positive (average) impacts of greater than 90 kW, and did not appear to significantly impact HVAC energy services. However, the sub-metering analysis revealed uncertain and erratic interactive behavior between the two curtailed chiller loads, suggesting a sub-optimal control strategy of the central plant. The pattern of cycling chiller loads presents challenges for not clear how a longer event would impact the control of the buildings' central plant systems and related cooling services in the office tower (Building 1).

- Late enrollment in 2004, the absence of DRP events in 2004, and the subsequent change in ownership explains the lack of participation in the DRP program. However, the management of DR program involvement by a third party service provider underscores the vulnerability of the customer's program participation to the relationship between the building owner and the service provider.

Site 7 Description and Key Findings:

This site is a 192,344 sq. ft. multi-tenant office facility consisting of two buildings, one with five stories and the other with three. There are approximately 600 occupants in both buildings during normal operating hours of 8:00 AM to 6:00 PM weekdays, although one tenant operates a call center that operates until 10:00 PM weekdays. The site's HVAC system consists of a single central plant comprised of two 220-ton chillers and a single cooling tower, and a main air-handling unit (AHU) for each of the two office buildings

The customer initially indicated that they are very well prepared to respond to SCE's Demand Bid notifications by curtailing various HVAC loads and lighting circuits serving common (non-tenant) areas. The site manager did not enlist tenant participation in their curtailment strategy, as he was very concerned about impacting tenants during curtailment. The planned DR measures at the site require less than an hour to carry out. Lighting measures are performed manually, whereas HVAC curtailment is automated by use of an energy management and control system (EMCS).

The customer's initially DR strategy was to start both chillers early on an event day and then shut one off at 4:00 PM. When one chiller is shut off, supply air and zone temperatures are expected to rise, thereby causing variable air volume (VAV) terminals to open and AHU supply fans to speed up to maintain static pressure at the increased flow. At the request of the customer, Quantum provided DR strategy assistance by suggesting that AHU fan speeds also be limited during curtailments to prevent increased loading, yet there was no way to limit the fan speeds. The site manager later realized that turning off one chiller caused the second chiller to be fully loaded, a undesirable condition if it lasts for more than two hours. Consequently, chiller curtailment measures were limited to a fewer number of hours. This ultimately rendered ineffective the customer's overall DR strategy as the utility's minimum bid requirements of 100 kW could not be met in the first of the summer 2004 events. when. Recognizing their inability to meet the 2004 minimum bid requirements, the customer did not bid in a second event of 2004, and discontinued program enrollment in 2005. Early in 2006, the customer realized SCE had reduced the minimum bid requirement to 50 kW for 2005and was considering re-enrolment in the DBP program for 2006.

Key findings from this site are as follows:

- As is common for tenant-occupied office facilities, one limitation on the customer's level of participation is their sensitivity to taking DR actions that might lead to occupancy discomfort. This constraint, in combination with a 100 kW minimum bid threshold for DBP participation, has led the customer to discontinue their program enrollment in 2005. Had the customer been informed that the minimum bid requirement was reduced to 50 kW for 2005, it is likely they would have continued program enrollment in that year.

- The initial facility manager who enrolled the customer in the DBP program left his position after the first of two DBP events. His replacement was located out of state, which left a building engineer at the site to carry out the DR strategy. The departing facility manager had set up multiple notification systems (i.e. email, phone, pager), though each was directed only to him. Failure to update notification contact information at the departure of the facility manager, meant that the site's building engineer didn't receive notifications for the latter of two 2004 DBP events. Although the customer was unlikely to bid for the latter event, the failure to maintain current notification contact information shows how customers can be inadvertently eliminated from the pool of potential program participants.

Site 8 Description:

This facility houses corporate offices and a call center in a 288,000 sq. ft., two-storey building served by two revenue meters. The building is fully owned by the corporate customer who operates a call center during three weekday shifts that extend beyond typical office building hours of operation and exhibit varying levels building occupancy:

1. 5:00 AM to 1:15 PM; (full occupancy: 1500 persons)
2. 1:00 PM to 9:00 PM; (partial occupancy: 1000 persons)
3. 8:50 PM to 12:00 AM (minimum occupancy: 100 persons)

The customer is enrolled in SDG&E's DBP Program and their DR strategy involves shutting off several rooftop package units (RTU) serving the first and second floors in both the east and west ends of the building. The customer also identified the possibility of curtailing various lighting and exhaust fan loads The facility also houses a 125 kW diesel backup generator at this facility which is not included in curtailments.

Key findings from this site are as follows:

- The site's June 30th, 2004 curtailment of more than 400 kW is among the largest impacts observed among all events of the sampled sites, both in absolute terms and as a proportion of total load. The customer did not participate in a second event for 2004. The customer continued to refine their DR strategy in 2005 but reported to have taken action for only one of the three events in which they bid (the utility did not record any bids), and did not bid on the remaining ten events in 2005. The site manager at Site 8 reported that they were actively working on refining and testing an automated strategy for shedding HVAC load, and several of the event days show positive impacts, though it is not definitively known if these are spurious or the result of the customer's tests.

- The site manager indicated that they frequently conducted DR strategy testing on non-event days. A review of sub-metering data shows that noticeable load drops from these tests sometimes occurred on the days used in three-day baseline calculations for event days. The effect of reduced loads on baseline days potentially diminishes calculated impacts. It is not known whether the site manager was aware of this outcome from his DR strategy testing, or if it contributed to his reluctance to bid on event days or to execute DR actions once bids had been placed. The potential negative impacts from DR strategy testing sheds some light on the question of whether customers should conduct test curtailments during the summer (when tests may provide more accurate simulations), when they potentially limit impacts obtained during events that occur in the following days or weeks.

- The single large building of this facility is served by two revenue meters. In the sub-metering analysis, it was noticed that one or two of the three BL days selected by the three-day baseline methods were different for the two revenue meters. There were also several instances where one of the buildings revenue meters showed positive impacts, and the other negative, for the same event day. These circumstances indicate a complex dynamic between building (HVAC) loads and building attributes (orientation, glazing, thermal mass, insulation, number of floors, etc.) and local climate conditions. These conditions suggest that the customer would need to fully understand the dynamics of building HVAC loads in order to maximize the effectiveness of their DR strategy.

- The site manager reported cases of employee complaints concerning reduced lighting levels during these curtailment tests. However, complaints were only received when he announced in advance that lighting levels would be reduced as a part a test. No complaints were received when tests were not announced.

Site 9 Description:

This facility is a recently established private university with approximately 720,000 sq. ft. of conditioned floorspace among the 18 buildings distributed across a 103-acre campus. Buildings on the campus include a library, recreation and student centers, six classroom and administrative buildings, 8 student resident buildings, a reception center and two smaller buildings used as an alumni center and guest residence. Building occupancy in campus buildings is substantially reduced from the second half of May, through June, July, and the first half of August when most of the student population is on summer break student population.

HVAC and lighting loads account for most of the sites total load and daily summertime peak loads between 1 and 2 megawatts. The campus central plant houses use one 800-ton centrifugal chiller and serves 15 of the 18 campus buildings. Among these 15 buildings there are a total of 26 air-handling units (AHUs). Most of the HVAC and lighting loads are controlled by use of a campus-wide Johnson energy management system with over 3000 control points. The Johnson system has been continuously expanded in 2004 and 2005 to include additional points and to trend data for key control points. The customer has an emergency back-up generator (BUG) that is not tied to any of the campus HVAC loads, and is not intended for use during DR events.

The primary component of the campus DR strategy is to reduce setpoints of variable frequency drives (VFD's) in most of the campus's air handlers. The site manager also stated that it was possible to raise space temperature setpoints from a normal of 73 degrees (F) to as high as 78 degrees (F). These measures would be made possible by reprogramming the Johnson energy management and control system (EMCS) and would allow for a fully automated process for responding to event notifications. The campus has additional loads that would require manual activation of curtailment. These loads include walk-in freezers and refrigerators, elevators, laundry equipment and several water fountain, irrigation, filter and pool pumps. Many of these loads are controlled by lighting panels in three separate buildings such that curtailment would require a person visiting three buildings separated by a total distance of approximately 300 yards.

The customer's primary motivations for participating in the DBP program are to obtain bill savings and avoid future blackouts. Yet, concerns about occupant comfort and productivity are the primary reasons that the customer may forego bidding for a given DBP event. Despite their claim of a high level of preparedness, the customer also expressed a desire for longer lead times in event notification whenever possible.

Key findings from this site include the following:

- Over the course of 2004 and 2005, the site managers at Site 9 are known to have been actively engaged in the development of their campus-wide EMCS system including steps to enable a highly-automated, pre-programmed DR strategy. Yet, this site only reported participation in one event for each summer; for the 2005 event, the customer did not come close to obtaining impacts commensurate with what they bid. Site managers reported being too busy to participate in events, most often due to activities related to management of energy service needs surrounding numerous routine and non-routine campus events (e.g. return of students, summer conferences, special sessions). A two-year effort to improve capabilities of a complex EMCS has made steady progress toward improving centralized control and management of energy services, but has not resulted in the customer's ability to participate in the DBP program. The lack of program participation may be partly attributed to activities surrounding efforts to expand campus-wide EMCS capabilities.

- Site managers reported that no action was taken for a September 23rd 2004 event, due to their preoccupation with managing energy services related to a returning student population. However, yet the three-day baseline method shows a large positive whole-facility impact of 310 kW, which is approximately twice the magnitude of impacts calculated by the ten-day adjusted baseline (at 164 kW), or impacts measured by the three-day baseline for the June 6th 2004 event (at 146 kW) in which the customer actively participated. Analysis of revenue meter for the September 23rd 2004 event, strongly suggests that DR actions were actually carried out, and that the ten-day adjusted baseline provides a far more accurate estimate of the actual load reductions observed for this event.

Site 11 Description:

This site is the customer's corporate headquarters and housing in both corporate offices and a pharmaceutical product research and development laboratory in three buildings. Weekday occupancy at the facility is approximately 400 persons and normal weekday operations occur between 6:00 AM – 7:00 PM. The facility has a total of 242,000 sq. ft. 95 percent of which is conditioned floor space.

DR measures are carried out in two of three buildings: Building 1 is comprised of office space, and Building 3 houses offices and labs, some of which have special space conditioning requirements. The customer's DR Strategy focuses on duty cycling of four air-handling units (AHUs) in Buildings 1 and 3. In turn, this is expected to unload one of two chillers housed in Building 3. The site has an emergency back-up generator (BUG) in Building 3 that is not used for DR events. Due to an unexplained loss of contact with site manager, only limited information is currently available regarding site conditions, DR program participation and customer attitudes.

A key finding from this site is as follows:

- There was only one possible event in which Site 11 had an opportunity to participate in 2004; The customer was not required to actively bid in PG&E 's DBP program of 2004, and there is some evidence that they attempted to curtail loads in the first hour of the event period; they did not reach the minimum bid requirement of 100 kW. On a later non-event day late in September, 2004, a sharp 1.5 hour load drop in AHU loads was observed, and it is presumed that this was a brief test curtailment (unconfirmed), where AHU loads were intentionally shut off, leading to a sharp rise in Chiller 1 loads for the same period. These instances show some experimentation with curtailments in 2004. The site is known to have actively bid for three of the 17 possible events in 2005. Although the DR strategy was devised in 2004, it was only after the first three DBP events of summer 2005, that the customer first bid and actively deployed their curtailment strategy for the full duration of an event. The customer bid on the fourth, sixth and eighth events, and the impacts of the first two events were approximately 30 percent of what was bid. In the last of these three events, the customer's bid was more modest, though impacts far exceeded what was bid and were much greater than impacts from the first two events combined. Baseline days were the same for all three events. Qualitative aspects of participation in these events is unavailable due to loss of contact with the site manager, though it is apparent that the customer was working to refine their DR strategy through two of the 2005 events before solving the problem of obtaining expected savings by managing loads of two chillers. Why the customer did not participate in the last nine events of 2005 is not known, but is suspected to be yet another case of a site manager too busy to participate in events.

11.4.7 Enrolled Non-participant: Continuous Processing Facilities: Glass

Site 10 Description:

This customer operates a chemical processing facility that processes sodium silicate into glass products. This site has a total of 120,000 sq. ft. in 12 buildings; 5,000 sq. ft. of the total floor space is administrative offices and is the only conditioned floorspace. There is an average of 12 workers on the site during normal operations. This facility uses large quantities of natural gas for glass melting furnaces. The electrical load is limited to process loads related to materials conveyance, air compressors, various pumps and mixers.

The customer was formerly enrolled in an SCE interruptible (I-6) program, and had a pre-established written list of demand response measures from which designated measures for the DBP program were selected. Components of the customer's planned DBP curtailment strategy include manually shutting down air compressors, glass transfer equipment motors, dissolver operations, various conveyors, mixers, fans and various tank farm pumps. The customer expects to be able to shed at least 100 kW from the manual control of these process loads without disrupting glass production or product quality.

For approximately 5.5 to 7 months per year, the plant operates at peak capacity, typically running shifts around the clock, seven days a week. Then, for the following six week period following peak operations, the plant operates eight hours a day and only on weekdays. In 2004, the peak operation period started in April, and ended in the middle of September. In 2005, a peak operation cycle began in June and ended in late November.

A key finding from this site is as follows:

- Site 10 did not participate in any of the two DBP events of 2004 or 13 events of 2005, although with a written DR strategy plan and prior experience with interruptible programs, they were reasonably prepared to participate in events. The site manager repeatedly cited being either too busy or unable to intervene in peak plant operations to curtail, and in the summers of 2004 and 2005, the plant was in the midst of a peak production cycle. Yet, the peak production cycles do not follow normal "seasonal" cycles related to an annual calendar. Given the irregularity of plant's production cycle, future event participation is likely if events occur when the plant is not in a peak production mode. Furthermore, The customer indicated that if they could go through the exercise of participating in a couple of events, it would make it much easier to execute strategy on a more frequent basis.