Prepare for Impact: Measuring Large C&I Customer Response to DR Programs

Amy Buege and Michael Rufo, Itron, Inc.[1]
Michael Ozog and Dan Violette, Summit Blue Consulting, Inc.
Susan McNicoll, Pacific Gas and Electric, Inc.

ABSTRACT

This paper presents the results of an hourly load impact assessment of summer 2005 price responsive Demand Response (DR) programs targeted to large nonresidential customers. This impact assessment is one component of a larger overall statewide evaluation of the 2005 price responsive and reliability programs in California. The primary goals of this evaluation were to assess program marketing and implementation, and to analyze the load impacts attributable to these programs. Deriving hourly load impacts from the 2005 DR programs and evaluating methods to improve planning estimates of future impacts from DR programs were key research objectives necessary to inform key stakeholders on the range of load reduction they can count on from future DR program events.

This paper will discuss several methods used for calculating load reduction impacts for large C&I DR programs and identify strengths and weaknesses associated with each approach. It will also address the effect of an increase in the frequency of events in 2005 (resulting from changes to event triggers and summer 2005 weather/system conditions) with respect to peak load reductions. Technical issues encountered in calculating hourly load impacts for large C&I customers, whose load shapes are very heterogeneous and difficult to predict, will also be discussed.

Among the key findings from the impact assessment of the day-ahead DR programs were the following items: 1) Average impacts for each of the CPP and DBP programs were about 10 MW; however, impacts varied widely across event days and utilities. 2) 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. 3) The presence of a few large customers with highly unpredictable loads adds considerable uncertainty to the impact estimation process for the day-ahead programs. 4) 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.

Introduction

In 2002, the California Energy Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." Following this ruling, in Decision 03-06-032, the Commission authorized Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) to establish voluntary demand response (DR) programs for

[1] Formerly Quantum Consulting

large commercial and industrial (C&I) customers.[2] The goal underlying these DR programs was to provide California with greater flexibility in responding to periods of high peak electricity demand. Evaluating these programs allows us to quantify the overall performance of these programs during this past summer and provides insight into the range of load reduction system planners can expect from future events.

This paper presents selected findings from a comprehensive evaluation of the 2005 voluntary Critical Peak Pricing (CPP) tariff and Demand Bidding Program (DBP).[3] The overall evaluation consisted of four main components: a process evaluation focused on assessing the programs' procedures and processes, as well as participants' activity levels and satisfaction with the program experience; a market assessment which included a large quantitative survey focused on estimating DR potential, barriers and opportunities; a load baseline analysis, which systematically assessed the performance of different baseline estimation methods; and an impact evaluation, which estimated the load reductions realized from participants in 2005 CPP and DBP programs. This paper presents the methodology and key findings from the baseline analysis and impact evaluation. The results from the market and process evaluations of the CPP and DBP programs are available in the full evaluation report (see Quantum Consulting, 2006). Below, we present a brief summary of the 2005 CPP and DBP programs.[4]

CPP is a rate that includes increased peak prices during 6 or 7 hours (Noon to 6pm for PG&E and SCE, 11am to 6pm for SDG&E) for up to 12 "Critical Peak Pricing" days each year and reduced peak prices during non-critical-peak days. Specific prices in the tariff are applied based on participating customers "Otherwise Applicable Tariff" (OAT). Critical peak prices vary from 3 to 10 times OAT depending on the utility, and CPP customers are given day-ahead notice of critical peak pricing events. The DBP program provides opportunities for customers to promise or "bid" load reductions of at least 50 kW one day in advance of critical periods in return for payments based on actual load reduction performance. DBP incentive levels are determined by the day-ahead market price for power.[5]

Methodology

A key task in our evaluation of the 2005 CPP and DBP programs was to estimate the amount of peak load reduction these programs are capable of delivering in their current format and with current levels of participation. To estimate the load reduction resulting from a particular program, an estimate must be made of each customer's baseline, i.e. what a customer's load profile would have been in the absence of the program. The difference between a customer's baseline and their actual load on event days then yields an estimate of the program impacts.

Two general baseline estimation methods were employed in the 2005 CPP and DBP evaluation to calculate program impacts: the Representative Day approach and a multivariate statistical approach. The Representative Day approach requires calculating baselines for each event based on a series of recent "similar" days that serve as a proxy to the event day in question,

[2] Large C&I customers are those with annual peak demands of 200 kW or more.

[3] The scope of the 2005 evaluation also included the California Power Authority's Demand Reserves Partnership Program, as well as reliability programs, including traditional interruptible tariffs and the Base Interruptible Program. See Quantum Consulting (2006).

[4] For full program details, see Quantum Consulting (2006).

[5] 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, and the maximum DBP incentive is capped at $0.35/kW.

whereas the multivariate statistical approach uses regression techniques to estimate program impacts based on load data from the entire summer and variables representing event days, non-event days, weather, and various customer characteristics. In this sense, the multivariate regression approach estimates expected load impacts across all events, whereas the Representative Day approach estimates load impacts individually for each event. In this paper, we present only the impact results based on the Representative Day approach.[6]

Several different Representative Day baseline approaches were considered for the 2005 impact evaluation. These baselines included the 3-Day, 10-Day, 10-Day Adjusted, 8-Day Adjusted, and the Utility Coincident 3-Day baseline. All of these baseline methods are calculated by first selecting the most recent 10 similar days prior to the event (excluding weekends, holidays or other curtailment days) and then calculating the individual baselines as follows:

- The ***3-Day Baseline*** selects the three days with the highest overall load during the curtailment hours (from the 10 similar days) and averages the load for each hour of these three days.
- The ***10-Day Baseline*** averages the load for each hour of all 10 similar days.
- The ***10-Day Adjusted Baseline*** multiplies the 10-Day baseline by a scalar adjustment ratio, which shifts the 10-Day baseline up or down to align it with the customer's recent operating level, based on a series of calibration hours from the most recent similar day.
- The ***8-Day Adjusted Baseline*** is similar to the 10-Day adjusted but is based on the mid 8 days (after the highest and lowest days have been removed).
- The ***3-Day Utility Coincident Baseline*** is similar to the 3-Day baseline except the three high load days are the same for all program participants within a utility service territory and are based on the maximum utility coincident load during the 10 similar days.

These baselines were selected based on work previously conducted examining alternative baseline methodologies (CEC, 2003; Quantum Consulting, 2004), the recommendations from the evaluation oversight committee, and a review of the baselines currently employed for settlement in the 2005 CPP and DBP programs. The final impact estimates presented in this paper are based on the 10-Day Adjusted baseline. This baseline was shown to be the most accurate and least biased of the methods analyzed in the 2004 baseline analysis (see Quantum Consulting, 2004) and again proved to be the most accurate baseline method in the 2005 baseline analysis.

Counting estimated load differences. An additional factor that can affect the final program impact calculation under the Representative Day approach is which of the load differences are attributed to the program. Based on the results of the baseline analysis completed as part of the 2004 DR evaluation, it was evident that there is a moderate amount of uncertainty, both positive and negative, surrounding the baseline estimates. In the 2005 DR evaluation, we conducted

[6] Using a representative day approach can hide patterns of customer response that are linked to weather, price regimes, and customer-specific characteristics. In addition, these approaches can be significantly affected by short-term (day-to-day) fluctuations in a customer's load. Statistical models can isolate the impact of such factors on customer response behavior. However, the validity of using regression-based baselines for payment and reporting purposes depends upon 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. The impact results based on multivariate statistical regression are reported in the full evaluation report (Quantum Consulting, 2006).

further analysis of the variation in impacts resulting from alternative methods of counting load differences. Based on this analysis, we concluded the most appropriate approach is to count all load differences, whether they be positive (indicating a participant curtailed load for the event) or negative (indicating they increased consumption during the event).

Evaluation population and events. Hourly impacts were calculated for all 2005 CPP and DBP program events. Table 1 below provides the number of events called for the CPP and DBP programs at each of the utilities and the average number of participants (and bidders for DBP) across these events. This table shows that while the number of CPP events in 2004 and 2005 was comparable, the number of participants nearly doubled for all utilities except SCE, which continued to have only eight customers enrolled in the CPP program in 2005. For DBP, the number of events in 2005 was significantly higher than in 2004, however the percentage of participants placing bids for program events remained low (on average 14 percent of SDG&E, 7 percent of PG&E, and 5 percent of SCE participants placed bids for individual events). This low DBP bidding level makes calculating impacts the Non-Bidders contribute difficult since the noise associated with the baseline estimates for the large population of Non-Bidders tends to drown out the true program impacts of the Bidders. This potentially excludes some true program impacts from DBP non-bidding participants[7], however without specific event day information from each of the DBP participants quantifying this additional impact is difficult.

Table 1. CPP and DBP Program Events and Participants by Utility, 2004 vs. 2005

DR Program	Program Year	Utility					
		PG&E		SCE		SDG&E	
		Events	Avg Parts	Events	Avg Parts	Events	Avg Parts
CPP	2005	9	209	12	8	5	103
	2004	6	120	12	8	5	45
DBP[1]	2005	17	394 / 29	13	703 / 32	12	60 / 9
	2004	1	78 / n/a	2	515 / 26	3	36 / 7

[1] Average Parts Column for DBP Reflects Parts / Bidders

[2] The 2004 PG&E DBP Event was a day-of event which did not require bidding

Hourly Load Impact Reduction Results

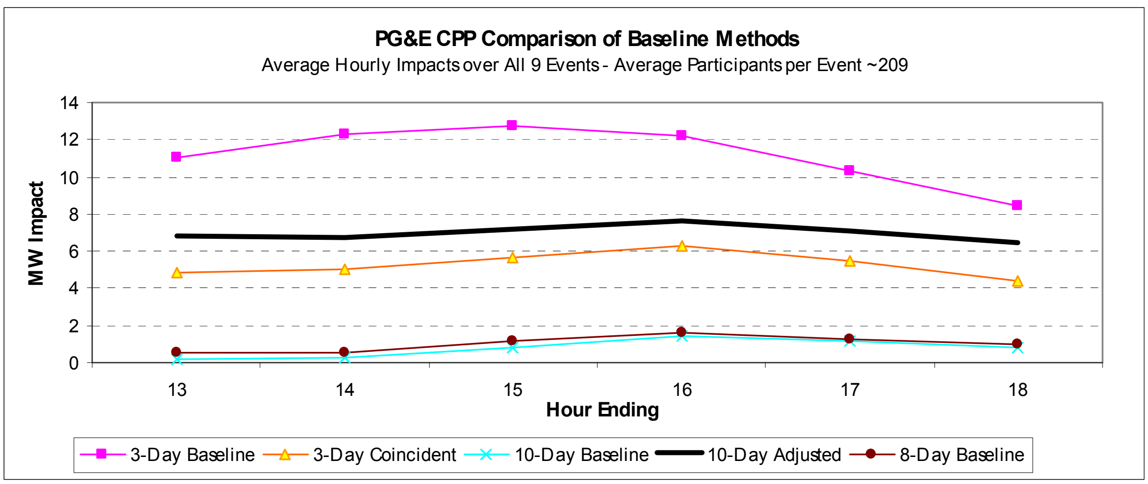
Below we present a summary of the impact analyses for PG&E's 2005 CPP and DBP participant population, followed by the overall hourly load impact reduction results for all three of the utilities. The complete detailed impact results for all three investor-owned utilities can be found in the final 2005 evaluation report (see Quantum Consulting, 2006).

Comparison of baseline methods. As discussed previously, the program impacts resulting from a Representative Day approach are a function of the specific baseline method selected for the analysis. If the baseline method is biased, the resulting impact estimates will be similarly biased. Figure 1 below shows the range in average hourly impacts for the 2005 PG&E CPP program as estimated using the 3-Day, 3-Day Coincident, 10-Day, 10-Day Adjusted and 8-Day baselines

[7] 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 actions despite not bidding for the event. See *Quantum 2006* for further details surrounding this survey.

methods. These impacts are simple averages across all CPP events (unadjusted for event frequency or other factors). This table illustrates the extent to which the program impacts estimated using the 3-Day baseline are significantly higher than those resulting from the alternative baseline methods. This result is consistent across all three utilities and the DBP program, as well as the findings from the baseline analysis conducted as part of the 2004 evaluation which found that the 3-Day baseline methodology had the most significant upward bias of all the baseline methodologies analyzed. In contrast, 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. Again, this result is consistent across program and utilities and confirms the findings of our 2004 baseline analysis. 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. Because we continue to believe the 10-Day Adjusted baseline is the most accurate of the Representative Day methods analyzed, the Representative Day impacts presented in this paper are based the 10-Day Adjusted baseline.

Figure 1. Comparison of Baseline Methods for PG&E CPP Participants



Average hourly program impacts. The individual customer level impact results are calculated for all program participants as the difference between the estimated customer specific representative day baseline and the actual load consumed by that customer during the event hours. Figures 2 and 3 below present the average hourly program impacts for the PG&E CPP and DBP events during the summer of 2005 (expressed as both the total MW reduction, as well as the percent load reduction). For the DBP program, the figure also includes the average bid realization rate for each event[8], which is the average hourly impact for the event divided by the average hourly bid. Figure 2 shows that the impact for the first CPP event (July 1st) was two to four times higher than the impacts for the remaining eight events despite the fact that this event was cancelled (and thus customers were not billed the higher critical peak period rate) due to late event notification. A hypothesis for this large reduction is that this event fell on July 1st, the Friday preceding the 4th of July holiday weekend, and thus some customers either already

8 The bid realization rate is missing for the first 7 PG&E DBP events since the bids were lost due to systems issues

planned to shut down early for the holiday weekend or decided to do so after finding out a CPP event was being called for that day. This figure also illustrates the time gaps that occurred between PG&E CPP events and how, although the load reductions resulting from consecutive events actually seemed to increase, the overall trend across the 2005 summer events was a decline in CPP program impacts. The lines Figure 3 shows that for the DBP program the bid realization rate across the last 10 events remained fairly consistent, between 70-85 percent, despite the large fluctuations in the associated MW and percent load reductions.

Figure 2. Average Hourly Program Impacts Across the 9 PG&E CPP 2005 Events Expressed as Total MW Reductions and Percent of Load Reduced

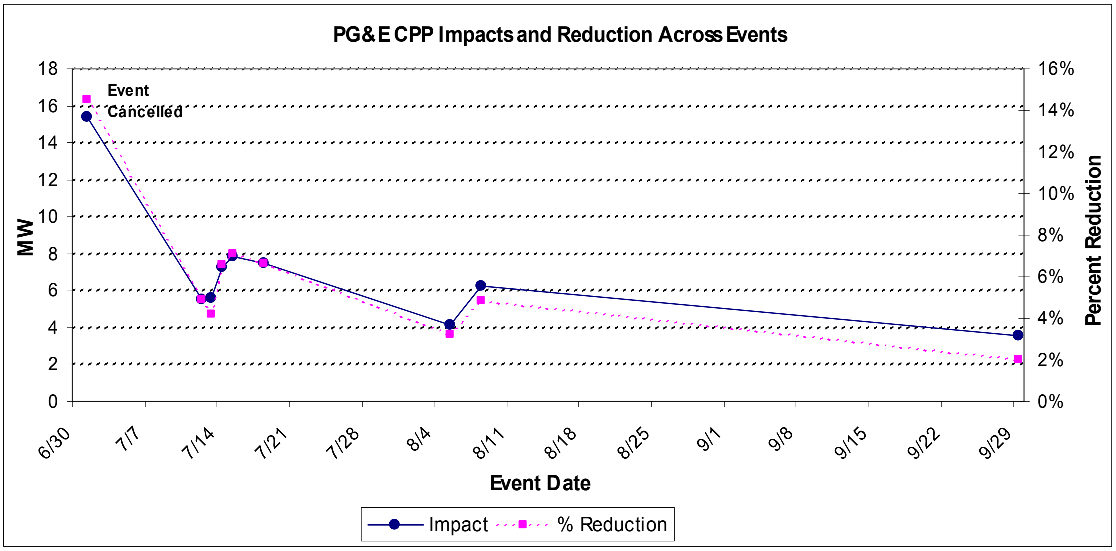


Figure 3. Average Hourly Program Impacts Across the 17 PG&E DBP 2005 Events 17 Expressed as Total MW Reductions and Percent of Load Reduced

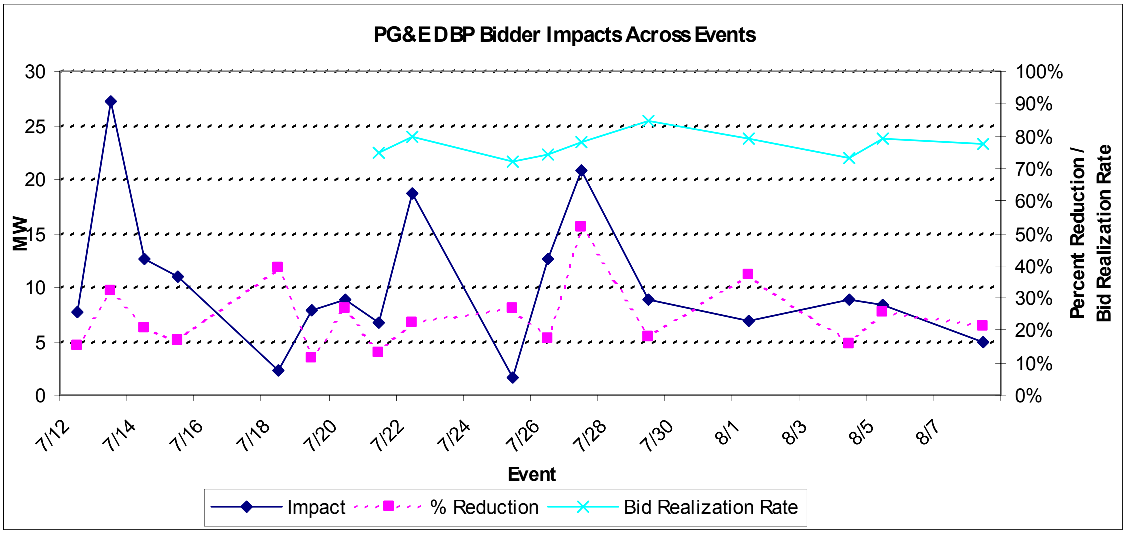
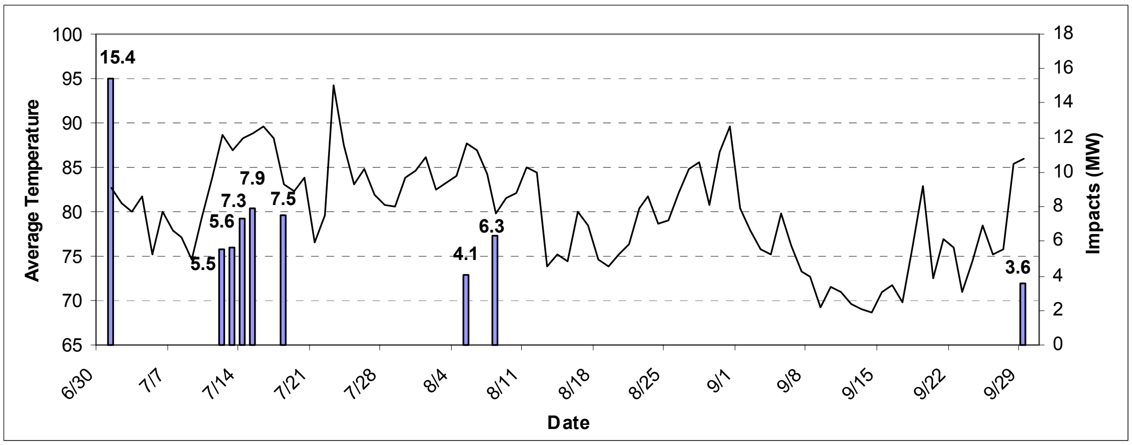


Figure 4 presents the average temperature across program participants during the event hours in parallel with the average hourly impacts for the 2005 CPP events. This figure displays the range of average temperatures across the 2005 summer and the correspondence between the average temperature during the event hours and the daily impact resulting from the programs. This figure also shows that while program impacts appear to increase across consecutive event days; the overall program impacts across the summer events did not increase despite the rise in the number of CPP participants (a 55 percent increase in participants between the first and last events[9]). The figure shows little correlation between the estimated impact for an individual CPP program event and the average temperature across the CPP participants for that event day.

Figure 4. PG&E Average Hourly CPP Impacts versus Average Temperature across all CPP Participants (during Event Hours)



Distribution of impacts across customers. Figure 5 presents the percentage of CPP and DBP participants achieving various levels of demand reduction for at least one 2005 event. The load reduction is calculated as the ratio of the estimated load drop over the estimated load based on the 10-Day Adjusted baseline. The figure shows that over half of PG&E CPP participants and four-fifths of DBP bidders were able to attain a 10 percent load reduction for at least one event in 2005, however, across all events for which a customer participated, only a quarter of CPP participants and 60 percent of DBP bidders were able to maintain this level of reduction. The DBP percent reductions are understandably higher since these averages are only calculated across events for which they placed bids and thus showed some sign of an intention to participate. Within the CPP program, our analysis found that the levels of load reduction demonstrated for one event cannot generally be relied upon for an entire summer of events. Within PG&E's service territory, nearly 80 percent of DBP Bidders, but only 22 percent of CPP participants, were able to reduce their load by more than 100kW for at least one event. On average, PG&E CPP participants reduced their load by 5.6 percent over all of 2005 events and DBP Bidders reduced their load by 22 percent (which, on average, was 41 percent of what they had bid).

---

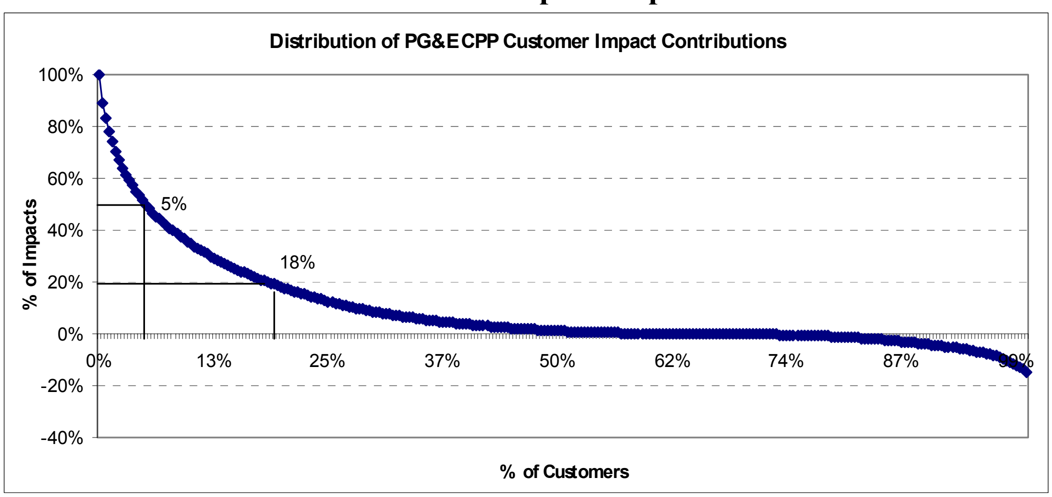
[9] This increase is attributable to both new participants enrolling in the program throughout the summer, as well different Zones for which the events were called (the 7/13 an d9/29 were the only events to be called in both PG&E zones).

Figure 5. Percentage of CPP and DBP Participants Attaining Various Load Reductions

Load Reduction	CPP Participants		DBP Bidders	
	For 1 Event	Across All	For 1 Event	Across All
5%	74%	38%	94%	77%
10%	55%	24%	81%	60%
25%	34%	9%	53%	37%
50%	18%	2%	36%	22%

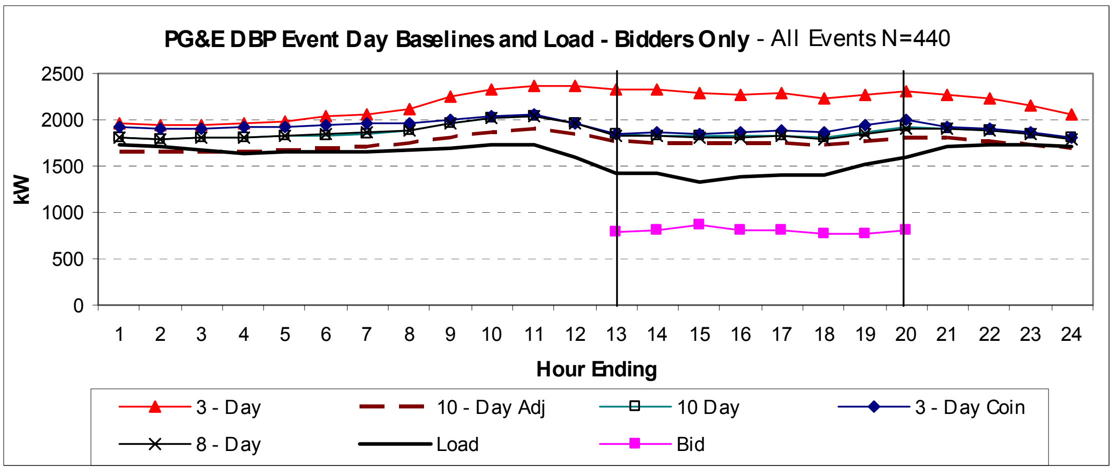
Figure 6 below shows the distribution of individual customer average hourly impacts across PG&E CPP participants based on the 10-Day Adjusted baseline. The figure shows that on average over the nine summer events, 5 percent of participants contributed roughly half of the overall *positive* program impacts and 18 percent contributed nearly 80 percent of these impacts. The impact contributions were very similar for the PG&E DBP program. Approximately one-third of the CPP participants contributed negative impacts, indicating they actually increased their consumption during the event, and thus impacts from about 75 percent of the program participants cancelled each other out.

Figure 6. Distribution of PG&E CPP Participant Impact Contributions for 2005 Events



Analysis of impact estimates for high-load high-variance customers. Although the 10-Day Adjusted baseline was shown to be the most accurate baseline, having the smallest bias and error magnitude, the 2004 baseline analysis identified a series of High-Load High-Variance (HLHV) customers for which none of the baseline methods could accurately predict their usage for a given event day. In the 2005 evaluation, these customers who displayed a high amount of variability in either their day-to-day load shape or average daily demand were explored in further detail to determine if there was an accurate way of identifying these customers and quantifying their effect on the overall program impact estimates. Figure 7 below presents the average daily-predicted load shapes based on the five baselines evaluated, as well as the average actual load shape, for all bidders across all 2005 PG&E DBP events. The vertical bars indicate the event start and end times for these events. This table illustrates how the baselines predict the daily load shape for DBP participant bidders over all event days and how the 10-Day Adjusted baseline most accurately predicts the actual load in the hours leading up to and 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 hours before and after the event period. The bid line in the figure below represents the average load a customer bid for a particular hour over all events. The average customer bid across all event hours was approximately 900 kW/hour, which was roughly half of their estimated base load using the 10-Day Adjusted baseline. One interesting finding was that although the average bid realization rate under the 10-Day Adjusted baseline was around 40 percent for the population of PGE DBP bidders, the bid realization rate under the over-predicted 3-Day baseline was very close to 100 percent. DBP participants place their bids the day prior to DBP events based on their predicted load from the 3-Day baseline, which indicates that the bias in the 3-Day method may have lead to significant free ridership.

Figure 7. Daily Load Shapes for All 2005 PG&E DBP Event Days – Bidders Only



To determine whether there were any customers for whom the 10-Day Adjusted baseline did not perform well, an algorithm was devised to identify HLHV customers. This algorithm was designed to flag all accounts for which the difference between their estimated average hourly impacts based on the 3-Day and 10-Day baselines for a particular event was greater than 50 percent of the average 10-Day baseline load for the DBP participants within the same service territory. Within the CPP program 4 percent of participants were flagged as HLHV for at least one event, and within the DBP 36 percent of bidders were flagged as HLHV. Figure 8 provides an example of a HLHV DBP customer whose load shape varies widely during the previous 10 similar days. On some days this customer's usage remains fairly consistent around 1.5 MW for the whole day. On other days it remains consistent but at levels closer to 3.5 MW and on other days it fluctuates over the course of the day between 1.5 and 3.5 MW. For this customer and this particular event day, the 10-Day Adjusted baseline is 1 MW lower than the 10-Day unadjusted which result from the lower average load during the 10-Day Adjusted calibration hours on the most recent "similar" day. This customer bid 2 MW per hour over the event period and it appears that their true program impact should be close to this hourly bid amount, although the 10-Day Adjusted baseline calculates an impact that is roughly half of that amount.

Figures 9 and 10 present the average daily-predicted load shapes versus the actual event day load shape for all 2005 DBP events for HLHV and Non-HLHV DBP participants. These figures illustrate how much less stable the population of HLHV customers is compared 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 shape fits a bit looser for the HLHV population. In all cases, the 3-Day baseline over-predicts the actual load.

Figure 8. Daily Load Shapes Associated with a Single Customer for the 10 Days Preceding the August 4th DBP Event and a Selection of Representative Day Baseline Estimates

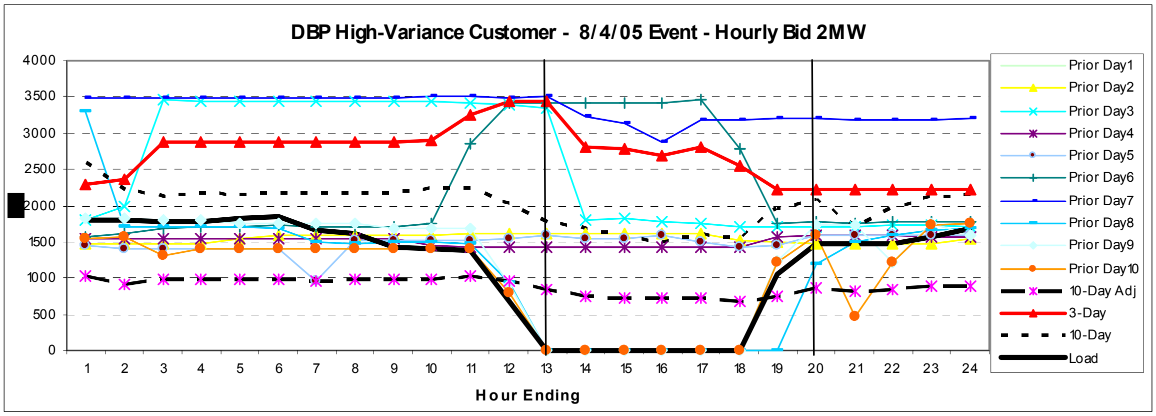


Figure 9. PG&E DBP High-Variance High-Load Customers

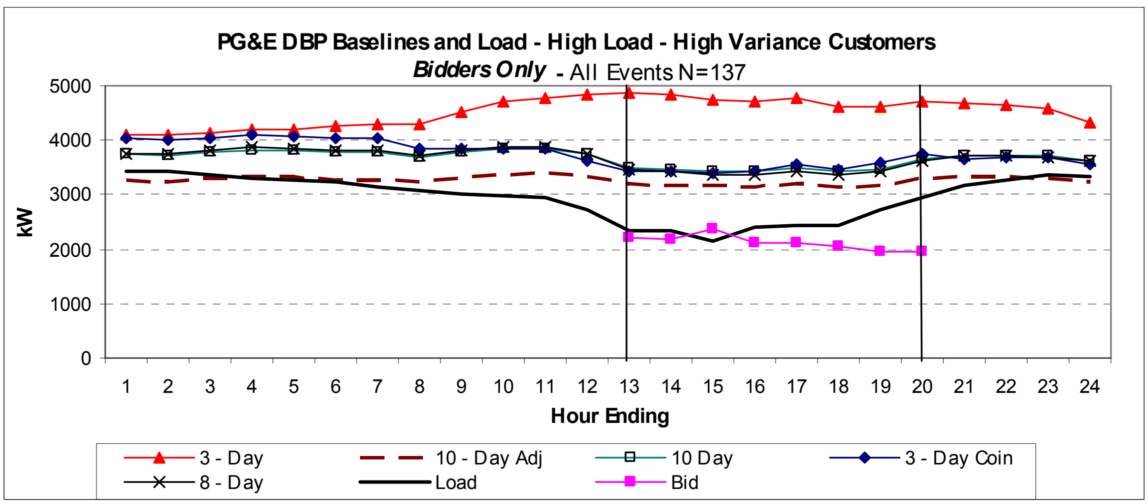
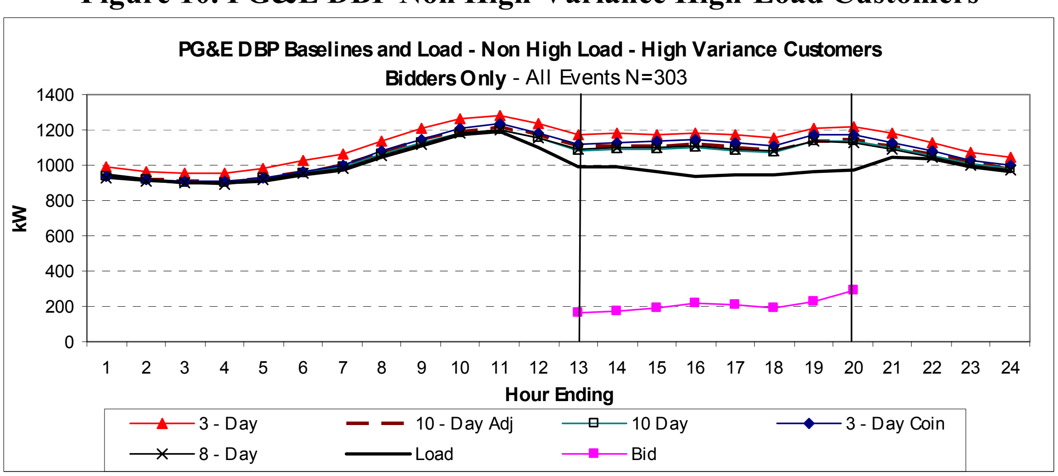
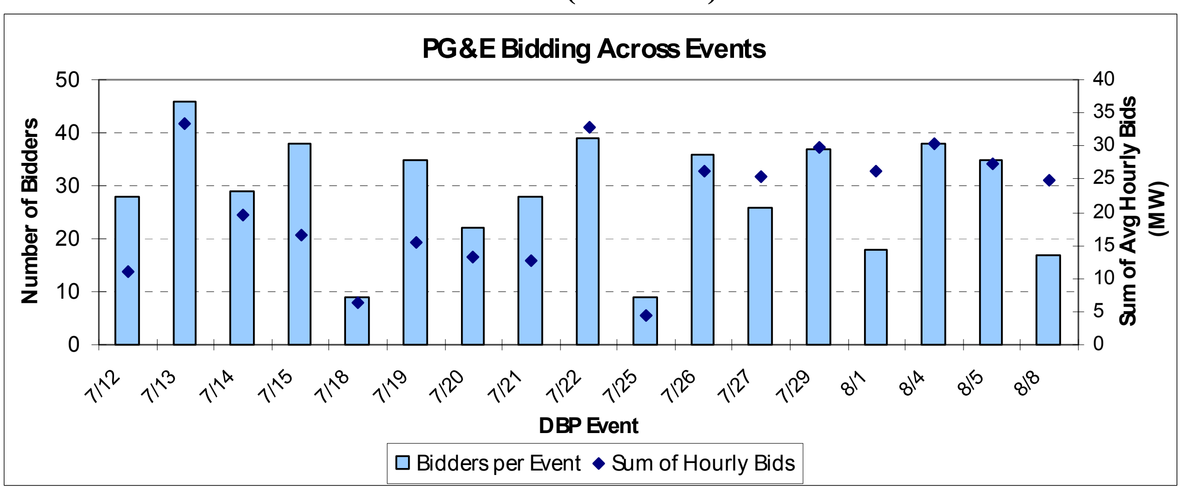


Figure 10. PG&E DBP Non High-Variance High-Load Customers



Analysis of DBP bidding trends. The 2005 evaluation also included an analysis of the bidding trends that occurred during the summer of 2005. Although DBP participation was relatively high, the number of DBP participants placing bids continued to be limited in 2005. The 2004 events were qualified because there were very few DBP events, and in some cases, the only events called were test events. However, in 2005, the number of DBP events called gave participants numerous opportunities to place bids. Throughout the course of the summer of 2005, approximately 18 percent of DBP participants placed a bid for at least one event, meaning 82 percent of enrolled DBP participants did not place a bid for any of the summer 2005 events. PG&E had the highest percentage of DBP participants placing for one or more events (37 percent), followed by SDG&E and SCE at 22 and 14 percent, respectively. When averaged over all events and all utilities, relatively few participants, 6 percent, placed bids in 2005. Across the three utilities, the bidding rate over all events ranged from 5 percent of participants for SCE, to 14 percent for SDG&E, and 7 percent for PG&E. Across all three utilities, between 20-30 percent of DBP participants who placed bids only bid on one event and on average a customer typically bid for approximately a third of the summer events. Figure 11 shows the variation in the number of bidders and the sum of the average hourly bids placed across the 2005 events with PG&E service territory. The figure illustrates how few PG&E participants placed bids for Monday events (July 18th/25th and August 1st/8th). One reason so few bids were placed for these Monday events was because PG&E triggered these events on Sunday afternoons and thus only customers operating 7 days a week were likely to receive the event notification in time to place a bid. PG&E was the only utility to call DBP events on Mondays based on a Sunday notification. SDG&E did not have any day-ahead events on Mondays during the summer of 2005 and SCE called one DBP event, however notified customers and accepted bids on the preceding Friday afternoon. This SCE event had slightly fewer bidders than the average across the other events.

Figure 11. Number of Bidders and Sum of Average Hourly Bids Across PG&E 2005 DBP Events (17 Events)



Summary

The impact evaluation confirmed that there were significant observable peak load reductions for active CPP and DBP participants in 2005. However, savings ranged widely from 3 percent up to 44 percent depending on utility, event, and program. This is largely due to two factors. First, some customers take action in one event but not another. Second, a small number of large customers with highly variable loads have a corresponding large affect on the estimate range of impact. Furthermore, predicting the baseline load for these high-load high-variance customers from one day to another is very difficult because their loads are not well correlated with weather, day of the week or other readily available parameters. Figure 11 presents a summary of the range of overall estimated program impacts for the CPP and DBP programs for the summer of 2005 across all utilities. The mean estimated impact for both CPP and DBP combined is roughly 22 MW (about 11 MW for each program). The quartile range is 13 MW to 29 MW indicating the wide range of impacts across events. For DBP, impacts are only associated with the subset of program participants that actually placed bids in 2005. We also estimated that less than 20 percent of CPP and DBP participants account for more than 80 percent of the estimated impacts associated these programs. These impacts can also be expressed in terms of reductions as percentages of estimated baseline loads. DBP impacts averaged roughly 12 percent of bidders' baseline loads, while CPP impacts averaged 7 percent of baseline loads.

Figure 12. Summary of Representative-Day Impact Results

Utility	Program Impact Ranges (MW)			
	CPP		DBP	
	Mean	75% / 25%	Mean	75% / 25%
PG&E	7.0	8.1 / 5.1	8.4	10.3 / 5.0
SCE	0.7	0.9 / 0.6	2.3	4.3 / -0.1
SDG&E	3.5	5.1 / 2.1	0.5	0.7 / 0.2
Statewide*	11.2	14.1 / 7.8	11.2	15.3 / 5.1

* Non-Coincident Statewide Impacts

Comparing results from the 2004 DR evaluation, which focused on the first-year program impacts, to those from the 2005 DR evaluation we found that CPP impacts increased as a result of the significant growth in participation. The average percent load reduction participants contributed remained steady between the two program years. Similar comparisons for DBP were difficult since the 2004 estimates were based on the results of a very limited number of events, the majority of which were test events, while in 2005 significantly more actual DBP events were called. However, despite the differences between program years, we found that the low DBP bidding rates seen in 2004 continued in 2005 and the estimated 2004 impacts fell within the range of the 2005 impacts. Readers are encouraged to review the complete impact results presented in the final evaluation report (Quantum Consulting, 2006).

References

CEC (2003). Protocol Development for Demand Response Calculation – Findings and Recommendations. Prepared by KEMA-Xenergy Inc. for the California Energy Commission.

Quantum Consulting, Inc. (2004). Working Group 2 Demand Response Program Evaluation – Program Year 2004, Final Report. Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. December.

Quantum Consulting, Inc. (2006). Working Group 2 Demand Response Program Evaluation – Program Year 2005, Final Report. Prepared by Quantum Consulting Inc. and Summit Blue Consulting, LLC. March.