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2005/2006 PG&E Business Energy Coalition Evaluation

FINAL

Submitted to:

Pacific Gas & Electric Company
245 Market Street
San Francisco, California 94105

Submitted by:

Itron, Inc.
1111 Broadway, Suite 1800
Oakland, CA 94607
(510) 844-2800

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Executive Summary

This report presents the results of the 2005/2006 Pacific Gas and Electric Company's Business Energy Coalition Demand Response Evaluation, and provides feedback on the first two years of this pilot program.

1.1 Program Overview

The Business Energy Coalition (BEC) Program is a pilot demand response program that was ordered in Decision (D.) 05-01-056 and extended in (D.) 06-03-024. The program is an initiative between PG&E and major San Francisco business and civic leaders to demonstrate the load curtailment capabilities that exist within commercial customers within the San Francisco region of the PG&E service territory. The idea behind the BEC Program is to form a cooperative comprised of 25-35 large PG&E commercial customers that collectively commit to a reduce their load by a certain amount on event days.

This program is facilitated by The Energy Coalition (Program Manager) and is available to all PG&E bundled-service customer, Direct Access, and wholesale customers that have a minimum average monthly demand of 200 kilowatts (kW) and who are able to reduce their demand by a minimum of 200 kW. All program participants must have the required interval metering equipment installed and Internet access in place prior to participation in the BEC Program. The program is scheduled to terminate on December 31, 2008.

The BEC estimates each customer's committed load reduction by taking the difference between a customer's average peak demand and its firm service level (FSL). It is upon this committed load reduction that customers are paid. The FSL is designated by each customer with the approval of the BEC as the kW amount it can reduce down to for a given event. The average peak demand for each BEC participant is based upon a two-year average peak kW value calculated for each month between and including May through October for the 2005 and 2006 program years. The average peak demand is then set equal to the maximum of these six monthly two-year average values. An example of this calculation is shown below in Figure 1-1 for a hypothetical participant in program year 2006.

Figure 1-1: Methodology for Calculating A Customer's Average Peak Demand

PROJECT:	Example Participant
ADDRESS:	1234 Main Street

HISTORIC PEAK KW DEMANDS

AVERAGE PEAK - kW = 4,077

Year	May	June	July	August	September	October
2005	3,581	3,982	3,897	3,777	3,935	3,892
2004	3,459	3,610	3,725	3,906	4,218	4,047
2003						
2002						
2-Year Avg. =	3,520	3,796	3,811	3,842	4,077	3,970

1.2 Evaluation Objectives

The principal objectives of this evaluation include the following:

- Evaluating the 2005 and 2006 BEC Program impacts based on a variety of baseline methods currently used in California, as well as regression modeling techniques,
- Quantifying the load reduction impacts resulting from the BEC Program by hour, event, and program year, and comparing these results to the program goals and reported accomplishments,
- Assessing the effectiveness of the BEC program triggers, and
- Making recommendations regarding the load reduction estimation methodology that BEC should employ for program settlement and post-program evaluation.

1.3 Impact Evaluation Results

Table 1-1 below compares the evaluation-estimated impacts to the BEC estimated impacts, as well as the BEC Program goals. This comparison is made on an individual event basis as well as an event hourly weighted average basis for both of the program years. As this comparison shows, the Representative Day method (based on the 10-Day Adjusted baseline) provides the most conservative impact estimates (1.9 and 2.5 MW for 2005 and 2006, respectively). The regression based impacts (resulting from the aggregated daily load models) are one-third to two thirds higher than the Representative Day methods (2.4 and 4.1 MW, respectively). However, both of these evaluation methods result in impacts that are five to seven times smaller than the BEC reported impacts.

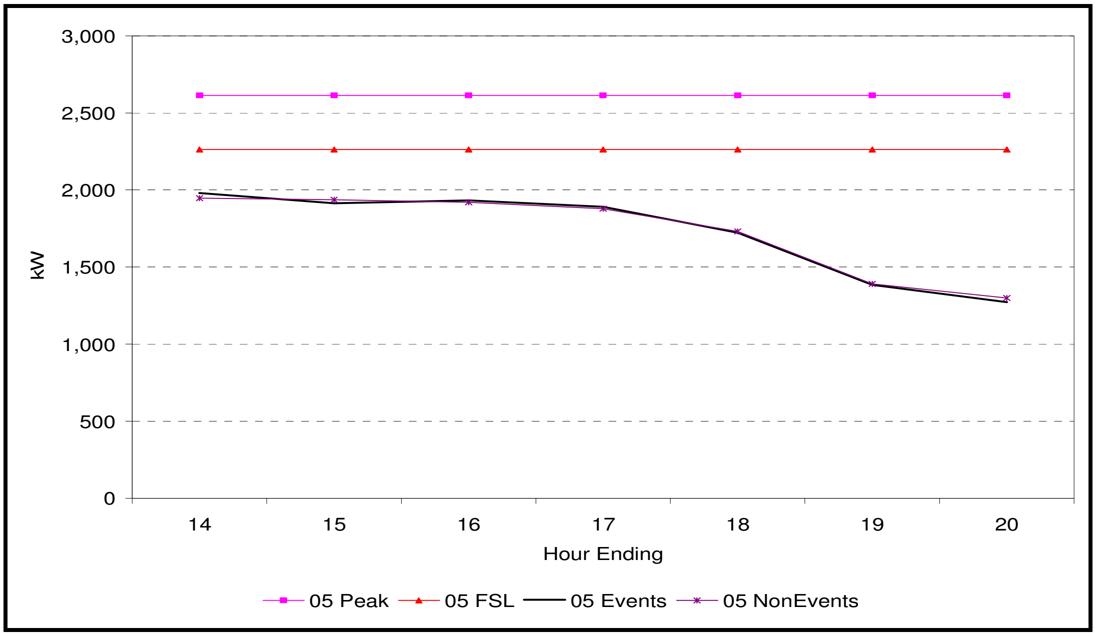
Table 1-1: Comparison of Estimated Impacts across Evaluation Methods and with PG&E Reported Impacts and Program Goals

Event Date	Average Hourly Impact (in MW)					
	Representative Day[1]	Regression[2]	PG&E Reported	BEC Reported	Program Goal	Goal Credit[3]
7/12/2005	2.7	3.2	7.1	7.1	10	6.0
7/13/2005	1.5	0.4	5.1	5.1	10	6.0
8/5/2005	2.7	2.9	16.5	16.5	10	6.0
8/8/2005	3.2	2.9	17.3	17.3	10	6.0
8/30/2005	1.3	5.3	14.6	14.6	10	6.7
9/28/2005	2.0	0.8	21.1	21.1	10	7.1
9/29/2005	0.6	1.9	20.6	20.6	10	8.8
2005 Avg.	**1.9**	**2.4**	**14.7**	**14.7**	**10**	**6.7**
6/22/2006	1.7	3.9	13.5	8.7	10	6.6
6/23/2006	9.7	3.2	22	17.1	10	6.6
7/17/2006	-3.0	5.4	20	15.5	15	7.2
7/18/2006	-3.2	3.2	20	17.3	15	7.9
7/21/2006	4.9	4.7	20	18.4	15	8.1
7/24/2006	2.8	3.7	17.8	16.1	15	8.6
7/25/2006	3.8	5.0	18.9	17.2	15	8.2
9/22/2006	3.9	3.9	20.5	20.8	15	10.3
2006 Avg.	**2.5**	**4.1**	**19.2**	**16.4**	**13.8**	**7.8**

1 Based on 10-Day Adjusted Baseline
2 Based on the Aggregated Daily Load Model
3 Sum of Estimated Reductions for "Active" Participants

Figure 1-2 below provides the average peak demand, firm service level (FSL), and event and non-event day loads for the summer of 2005 and illustrates the issues that result in the significant differences in estimated impacts between the current program impact estimation methods and the methods used in this evaluation that were presented in the table above. As this figure shows, the peak demand and FSL for the average program participant are substantially higher than their average non-event day load across the summer and these are what the BEC bases its estimated load impacts upon. Since the peak demand and FSL are set unrealistically high, it would seem that participants are being paid for load reductions that never occur.

Figure 1-2: Comparison of the Peak Demand, FSL, and Average Event and Non-Event Day Loads Across the Summer of 2005



1.4 Conclusions and Recommendations

The results of this evaluation show there are substantial issues with the methods currently used by the BEC Program to estimate event impacts. Although these methods (with modifications to the peak demand calculation) might still be reasonable for program settlement, as currently applied they grossly overstate the peak load reduction this program can realistically deliver on typical event days. Based upon the findings presented in this impact evaluation, there are significant advantages to using the Representative Day impact estimation methods and regression models instead. The Representative Day methods are easy to implement (they are currently used for impact estimation and program settlement for other PG&E DR programs) and are reasonably transparent to participants. However, they are not as robust at dealing with weather and day-of-week sensitivity issues that affect office and commercial buildings (which make up about 90% of the customers in this program) as the regression models are (which are more difficult to implement and less transparent to program participants).

Either of these alternatives are superior to the current method employed for program settlement and load impact estimation. The Representative Day methodology is relatively accurate and can be relied upon for program settlement purposes with a quick turnaround, while regression analysis provides a more robust analytical methodology which would be better to rely upon for post-program load reduction estimation purposes.

Based on the Findings and Conclusions, this evaluation makes the following recommendations:

1. Abandon the current method of estimating BEC program impacts and instead rely upon the set of Representative Day estimation methods for program settlement purposes. Rely upon the regression methodology for impact evaluation purposes only and ensure that the Representative Day method used continues to estimate program impacts as accurately as possible. Both of these methods are far superior to the estimation of impacts based upon the current average on-peak demand method used by the BEC Program. Program settlement for other PG&E demand response programs rely upon the Representative Day analysis and based upon this analysis, it can more reliably estimate program impacts of the BEC Program.

2. Based upon the findings from past demand response impact evaluations, the most accurate Representative Day method has proven to be the adjusted 10-Day method. Use this methodology to estimate the baseline demand of program participants. Incentive payments made to program participants should be based upon the impacts estimated based upon the adjusted 10-Day method rather than the current method which relies upon the difference between firm service level and peak demand. This current method exaggerates the load reduction occurring from the program.

3. Pro-rate incentives to program participants by paying them for actual performance in each event. The current scheme allows participants to receive payment for events that took place before they were enrolled in the BEC program.

2

Introduction

2.1 Background

The Business Energy Coalition (BEC) Program is a pilot demand response program that was ordered in Decision (D.) 05-01-056 and extended in (D.) 06-03-024. The program is an initiative between PG&E and major San Francisco business and civic leaders to demonstrate the load curtailment capabilities that exist within commercial customers located in the San Francisco region of the PG&E service territory. The idea behind the BEC Program is to form a cooperative comprised of 25-35 large PG&E commercial customers (primarily downtown office buildings and hotels) that can collectively commit to reduce their load by a given amount. This shared load reduction allows the customers to work together, so that on a given day if certain customers within the group cannot reduce their load, they can rely on their counterparts to reduce on their behalf.

The program is facilitated by The Energy Coalition (Program Manager) and is scheduled to terminate on December 31, 2008.

2.1.1 Program Overview

In 2005 and 2006, the BEC program was available to all PG&E bundled-service, Direct Access, and wholesale customers in sectors such as office, hospitality, and high-tech that have a minimum average monthly demand of 200 kilowatts (kW), and were able to reduce their demand by a minimum of 200 kW. Participants must take service on a PG&E demand time-of-use rate schedule and have the required interval metering equipment installed and Internet access in place prior to participation in the BEC Program.

The Energy Coalition was responsible for managing and enrolling customers on this pilot program. At the time of program enrollment, a customer must designate a Firm Service Level (FSL) that it will attempt to meet during program events, and must demonstrate to PG&E that they can meet the program's minimum requirements. An engineering and/or site assessment is provided for some customers to identify load that can be curtailed during program events to help determine each member's FSL. During a program event, each BEC participant should reduce its load to the prescribed FSL.

In the event of a program curtailment operation, PG&E will notify the Program Manager with as much advance notice as possible ranging from day-ahead to a minimum of an hour-ahead. The Program Manager will be notified by pager, e-mail, fax, and/or phone. The Program Manager is then responsible for notifying each of the customers participating in the program. Failure to receive a program operation notice does not release the Program Manager or each customer from its obligation to participate.

A program event may be triggered for actual or forecasted statewide or local shortages or emergencies throughout the pilot program period. Specifically, a program event may be issued when any of the following occur:

- The CAISO declares that electric service area known as NP15 spinning reserve level is below seven percent (7%),
- A Stage 2 emergency is issued by the California Independent System Operator (CAISO),
- The CAISO forecasted system load meets or exceeds 43,000 MW,
- The forecasted or actual temperature in San Francisco exceeds 78 degrees Fahrenheit, or
- The CAISO or PG&E declares a localized system emergency.

The committed load reduction will be evaluated as the difference between the two-year average of the group's coincident peak demand and the sum of each participant's FSL. The group's coincident peak demand may not exceed 10,000 kW (or 10 megawatts).

Program events will not exceed five hours per event, one event per day, five events per month, 25 hours per month, and 100 hours throughout the pilot period. Program events will be issued between 12 p.m. and 8 p.m., Monday through Friday, excluding holidays. The program will conduct a system test with each participant to assure energy reduction. In the event there are no actual curtailments, a two-hour test will be conducted every other month throughout the pilot program period.

Each program participant will receive an incentive payment of $50/kW annually based on the participant's committed load reduction. PG&E will pay half of this incentive payment to each participant at the end of October, and the balance will be paid in January. Non-performance penalties will be assessed on the group's load curtailment level (not on an individual participant basis). If the group fails to meet the group's established FSL, the group will draw from its Shortfall Reserve Fund to pay all CAISO charges, imbalance penalties, and other potential penalties. If the penalties/charges exceed the Shortfall Reserve Fund (SRF), the Energy Coalition will be responsible for any additional costs. Any outstanding balance in the SRF will be proportionately distributed to participants at the completion of the pilot program or, if applicable, carried over for an extended program.

2.2 Project Objectives

The principal objectives of this evaluation include the following:

- Evaluate 2005 and 2006 BEC program impacts based on a variety of baselines methods currently used in California.
  - This includes considering alternatives such as adjustments based on weather, pre- or post-period usage ratios and regression analysis.
- Quantify the load reduction impacts resulting from the BEC program.
  - Compare to goals and reported accomplishments.
  - Break out by hour, event, and program year.
- Assess the effectiveness of the BEC program triggers, including an analysis of the correlation between the program trigger and notification timing for an event, and the resulting program impact for that event.

2.3 Organization of Report

This report consists of five chapters and one appendix:

- **Section 1 (Executive Summary)** summarizes the high-level findings of the study and provides recommendations for future analysis.
- **Section 2 (Introduction)** provides an overview of the BEC Program and states the study objectives and report organization.
- **Section 3 (Impact Evaluation Methodology)** summarizes the methods and data sources used to calculate program impacts and details the participant population and program year events.
- **Section 4 (Impact Evaluation Results)** provides the final impact estimates based on Representative Day and regression methods and compares the evaluation impacts with program goals and reported accomplishments.
- **Section 5 (Findings, Conclusions, and Recommendations)** presents the findings and conclusions drawn from the analysis results. It also makes recommendations regarding the impact methodology BEC should rely upon to improve the accuracy of its estimates of load reduction garnered from the program.
- **Appendix A (Representative Day Baseline Event Day Load Shapes)** contains graphs of the event day load shapes (resulting from the actual event day load and the representative day baseline analysis) across all of the active BEC participants for each of the BEC event days in 2005 and 2006.

3

Impact Evaluation Methodology

This section presents the data requirements and methodology used to evaluate the impacts resulting from the 2005 and 2006 BEC Program. This section is broken into the following subsections.

- Summary of Data Sources for Impact Evaluation
- Summary of Evaluation Population and 2005/2006 Events
- Summary of Methods used for the Estimation of Impacts
  - Representative Day Approach
  - Multivariate Statistical Models

The purpose of the impact assessment is to provide independent third party evaluation-based estimates of the peak load reductions associated with the BEC program for events occurring during the summer of 2005 and 2006. The approach taken in this evaluation is to use multiple baseline methods to estimate and illustrate the 2005 and 2006 impacts. These methods, many of which are currently used in California, are described below. They include alternatives that make adjustments based on weather, pre- or post-period usage ratios, and regression analysis.

3.1 Summary of Data Sources for Impact Evaluation

The impact evaluation for the 2005 and 2006 BEC Program uses data from four primary data sources: interval meter billing data, program-specific event data, weather data, and participation data. 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.

3.1.1 Interval Meter Billing Data

PG&E provided Itron with a series of datasets containing interval meter data for BEC participants (for a few customers, quality billing data were not available; thus, interval meter data from PG&E's research group were used). Itron merged these datasets to create a unique interval meter database for BEC participants. This database included 15-minute interval meter billing data from May through October of 2005 and 2006 along with various account and meter identifiers used to link to the other data sources. In both 2005 and 2006, one participant was missing interval meter data for an event and was excluded from the impact estimates for those events. Since all participants are required to have interval meters installed in order to be eligible to participate, it is assumed that these missing data are a result of either an error in the files used by PG&E to identify participants or transmission difficulties between PG&E and an individual interval meter.

3.1.2 Program Event Data

Microsoft Excel databases were provided to Itron containing event information such as the event date, the period for which the event was called, the date of event notification (day-ahead or day-of), the event trigger (temperature, price, system emergency, etc.), and the BEC program estimate of load reductions resulting from each of the events.[1] Data were not available to confirm if a customer received the event notification, nor the actual time the event notification was sent out to program participants.

3.1.3 Weather Data

The hourly temperature and relative humidity data for each PG&E weather station were collected and appended to the interval meter data. These weather data were used to create variables, such as average temperature and average humidity during peak energy demand hours, for use in the regression modeling. Including weather variables in the regression specification helps inform the estimation of load on event days in the absence of the program by accounting for the day's climate conditions. The variables calculated from the weather data and considered in the econometric analysis included average peak temperature, average peak humidity, peak daily temperature, and peak daily humidity.

3.1.4 Participation Data

PG&E provided Itron with an Excel database containing the population of customers participating in the BEC Program for the 2005 and 2006 program years. For each participant, this database contained the customer's name and account identification numbers, their estimated peak demand for 2005 and 2006 (based on their peak loads from the two prior years), their Firm Service Levels (FSL) for 2005 and 2006, their estimated goal reduction (calculated as the difference between the peak demand and the FSL), and the incentive payment they received for each year they participated in the BEC Program. Additional

[1] The estimated load reductions provided to Itron from PG&E were based on the difference between the Peak Demand from the prior two years and actual event day load. These calculations were provided to PG&E from the Business Energy Coalition.

customer characteristics, such as size and business type, were determined from the participation data provided (based on the accounts' maximum demand in 2005 or 2006 and their NAICS code).

3.2 Summary of Evaluation Population and 2005/2006 Events

The impact assessment for the BEC 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 to the evaluation team.

Table 3-1 below provides a summary of all 2005 and 2006 BEC Program events, including the dates for which the events were called, the amount of notification given (day-ahead or day-of), the period of the event, the number of hours the event lasted, the event trigger, and the number of customers enrolled and able to participate in the event. There were two test events conducted for the BEC program; one was held on December 21, 2005 and another was to be held on June 22, 2006, but PG&E declared this an actual event day. Data regarding the test event in 2005 is not evaluated in this report as it was not made available to Itron during the evaluation process.

Table 3-1 illustrates that about one-third of the BEC events were called based on the temperature trigger (78 or 82 degrees) and the other two-thirds were called due to high California ISO forecasted demands. This table also shows that the population of participants that were enrolled and active in the BEC Program events in 2005 ranged from 12 for the first event of the year to 25 for the last event of the year. In 2006, the number of active participants ranged from 28 for the first event to 39 for the last event (one of the accounts was not included in the impact evaluation for the last event due to missing interval meter data).

Table 3-1: 2005 and 2006 BEC Event Summary

Program Year	Event Date	Notification Type	Event Period	Event Hours	Event Trigger	Event Participants
2005	Tuesday, July 12, 2005	Day-Of	2-6pm	4	CAISO Load Forecast	12
	Wednesday, July 13, 2005	Day-Of	1-6pm	5	CAISO Load Forecast	12
	Friday, August 05, 2005	Day-Ahead	2-6pm	4	CAISO Load Forecast	12
	Monday, August 08, 2005	Day-Ahead	2-6pm	4	CAISO Load Forecast	12
	Tuesday, August 30, 2005	Day-Of	2-6pm	4	Forecasted Temp > 82°	16*
	Wednesday, September 28, 2005	Day-Ahead	3-8pm	5	Forecasted Temp > 82°	18
	Thursday, September 29, 2005	Day-Ahead	3-8pm	5	Forecasted Temp > 82°	25
2006	Thursday, June 22, 2006	Day-Ahead	1-5pm	4	Forecasted Temp > 78°	28
	Friday, June 23, 2006	Day-Ahead	1-6pm	5	Forecasted Temp > 78°	28
	Monday, July 17, 2006	Day-Ahead	2-7pm	5	CAISO Load Forecast	29
	Tuesday, July 18, 2006	Day-Ahead	2-7pm	5	CAISO Load Forecast	30
	Friday, July 21, 2006	Day-Ahead	2-7pm	5	CAISO Load Forecast	31
	Monday, July 24, 2006	Day-Ahead	2-7pm	5	CAISO Load Forecast	32
	Tuesday, July 25, 2006	Day-Ahead	2-5pm	3	CAISO Load Forecast	30
	Friday, September 22, 2006	Day-Ahead	2-7pm	5	Forecasted Temp > 82°	38**

* There were 17 participants for this event but one was excluded due to missing interval meter data

** There were 39 participants for this event but one was excluded due to missing interval meter data.

3.3 Summary of Impact Estimation Methods

Both Representative Day and statistical methods were employed in the 2005 and 2006 BEC Program evaluation to calculate the program impacts. The first two subsections summarize the Representative Day approach, which requires calculating baselines for each event based on a series of recent "similar" days.[2] The following subsection describes how multivariate statistical regressions were developed to estimate impacts based on a series of weather, day type, and customer characteristics.

3.3.1 Representative Day Baselines Assessed

The description of the Representative Day baselines provided in this section is taken from the 2004 evaluation of the Nonresidential Day-Ahead and Reliability Demand Response Programs Final Report completed by Quantum Consulting.[3] These methodologies were also

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[2] Similar days exclude weekends, holidays, and any additional days during which a customer was paid to curtail their load.

[3] Quantum Consulting and Summit Blue Consulting. *Working Group 2 Demand Response Evaluation – Program Year 2004*. Prepared for Working Group 2 Measurement and Evaluation Committee. December 2004.

used in the Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs Final Report, also completed by Quantum Consulting.[4] A number of representative day baselines were assessed in these studies (i.e., 3-Day, prior day, 8-Day, 10-Day, and the 10-Day adjusted) and based upon the evaluation results, the 10-Day adjusted baseline was found to be the most accurate of the representative day methodologies as analyzed by Quantum Consulting.

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 baseline, and the 10-Day Adjusted baseline. Other Representative Day methods used for the 2005 DR evaluation (such as the Utility Coincident 3-Day baseline, the 8-Day adjusted baseline, and the DRP 8-Day baseline) were not used for this evaluation since the prior evaluation found the 10-Day adjusted baseline to be the most accurate[5] based on the baseline analysis performed as part of the 2004 WG2 DR program evaluation,[6] and the 3-Day baseline to be the one that yields the greatest load reduction. The 3-Day, 10-Day, and 10-Day adjusted baselines are described below.

Visual representations of these baseline methods for the summer 2005 events are displayed below in Figure 3-1. This figure compares the average estimated daily load shape across all participating BEC customers based on each of these baseline methods to the actual average load shape for the event days.

<u>3-Day Baseline</u>

The current baseline methodology being used for program settlement and reporting at PG&E for two of the primary DR programs (Critical Peak Pricing [CPP] and Demand Bidding Program [DBP]) 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

[4] Quantum Consulting and Summit Blue Consulting. Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs Final Report. Prepared for Southern California Edison Company and Working Group 2 Measurement and Evaluation Committee. April 2006.

[5] When compared to the 3-Day, the 10-Day, and the Previous Day baselines.

[6] The 2005 evaluation completed by Quantum Consulting and Summit Blue Consulting built upon the analysis methods used in the previous evaluation of the statewide large nonresidential day-ahead and reliability demand response programs.

and the load for each hour of these three days was averaged (by hour) to calculate an hourly 3-Day baseline estimate.

10-Day Baseline

An alternative baseline methodology used to calculate program impacts for the BEC program was the ***10-Day 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 the 10-Day baseline for each hour by averaging the hourly load over all of the last 10 similar days.

10-Day Adjusted Baseline

A second alternative baseline methodology used to calculate program impacts for the BEC program was the ***10-Day adjusted baseline***. As mentioned above, this baseline was found to be the most accurate of the various Representative Day baselines analyzed. The 10-Day adjusted baseline is calculated by applying a scalar adjustment to the 10-Day baseline described above. The scalar is used to calibrate the 10-Day baseline to the customer's recent operating level. The scalar adjustment is calculated based on a series of calibration hours and is computed as 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 12 p.m. until 3 p.m. on the most recent similar day.[7] Note that the calibration does not change the hours used to calculate the 10-Day baseline. The scalar adjustment is calculated in the following manner:

$$10\text{ - }Day\ Adjusted\ Baseline = Scalar\ Adjustment \times 10\text{ - }Day\ Baseline$$

where

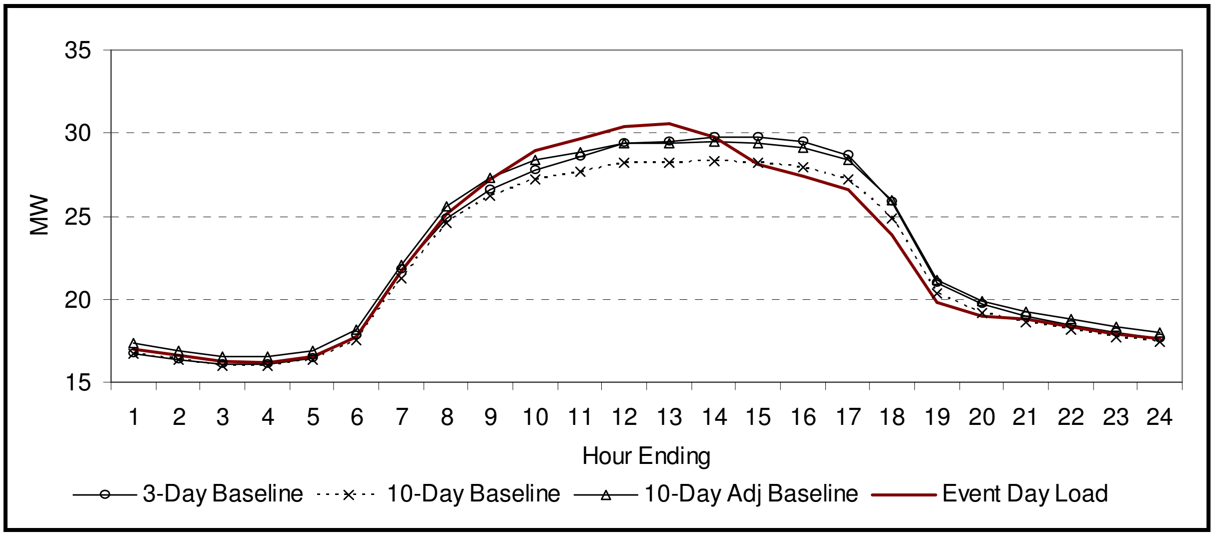
$$Scalar\ Adjustment = \frac{Average\ Load\ during\ Calibration\ Hours}{Average\ Load\ during\ same\ hours\ from\ the\ last\ 10\ similar\ days}$$

7 The scalar adjustment, based on a series of calibration hours from noon to 3 p.m., is multiplied by the 10-Day baseline for each participant to scale it to the customer's recent operating level during these hours on the day previous to an event. Average load during these calibration hours was used in an effort to represent load during an event pre-notification period that is similar enough to load on the event day had one not been called. For further information regarding the selection of these calibration hours, refer to Section 6 of Quantum Consulting and Summit Blue Consulting. *Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs Final Report*. Prepared for Southern California Edison Company and Working Group 2 Measurement and Evaluation Committee. April 2006.

Calculation of the 10-Day baseline is still based on actual event hours, while the scalar adjustment is used to reflect how similar the average peak load is during the calibration hours of the most recent non-event qualifying day. The scalar adjustment 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 an unrealistic level. This baseline was used to estimate the final program impacts for the BEC Program.

As mentioned earlier, Figure 3-1 presented below compares baselines from three of the Representative Day baseline methods (the 3-Day, the 10-Day, and the 10-Day adjusted baseline) with the average event day load across all seven of the 2005 BEC Program events

Figure 3-1: Comparison of Representative Day Baseline Methods based on 2005 BEC Program Events



3.3.2 Representative Day Approach Impact Methodology

The Representative Day methodology is based on constructing a baseline that seeks to represent the load for an individual customer on a "typical day" using load data from a series of non-event days preceding an event day. Once hourly baselines have been computed for all program participants for each of the event days, hourly event impacts can then be calculated as the difference between the baseline and the actual load for each hour of the event day. The overall program impact 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.

This summation used to calculate program impacts for the 2005 and 2006 BEC Program impact evaluations includes all differences (both positive and negative) 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.

3.3.3 Multivariate Regression Modeling Approaches

In addition to the described baselines above, regression analysis was used to estimate the impacts of the BEC Demand Response Program for 2005 and 2006. The econometric models developed for this evaluation were carried out as an ex post analysis of the total program impacts. Since the regression analysis is conducted after the fact, all pre- and post-event non-holiday, non-weekend weather and participant interval meter data were available for the analysis, thus improving the quality of the impact estimates. Another salient benefit of regression analysis is that it can be used to control for the effects of independent factors (such as weather and day-type) that affect energy consumption. Controlling for these factors helps ensure that any changes in load that would have occurred outside of the program, both increases and decreases, are accurately attributed to the program.

Conducting a post-program evaluation of impacts for the BEC DR program also provides an opportunity to compare impacts estimated through multivariate analysis to those calculated by taking differences in actual load and alternative baselines on event days. As described earlier, these differences are simplified calculations used by program managers to calculate real-time estimates, often for program settlement purposes. The baseline that generates impact estimates most similar to those based on regression analysis helps guide program managers in their choice of a baseline for real-time analysis. Providing ex-post feedback on the performance of alternative baselines based on regression analysis is the fundamental purpose of demand response program impact evaluation.

Several regression equations were specified in an effort to determine which factors have a statistically significant effect on energy consumption and what the magnitude of their effects are. The basic model structure is as follows:

$$AvgPeakLoad_t = f\left(AvgAMLoad_t, DayType_t, Weather_t, Month\right)$$

where

$AvgPeakLoad_t$	=	The daily average load across participants during the peak period hours for all days. The peak period used in this analysis is from 2 p.m. to 6 p.m.[8] Since the number of hours in a particular event differed by event day, a consistent set of hours is assumed to define the peak period for consistency purposes. For this analysis, a peak period from 2 p.m. to 6 p.m. is used because these hours were almost universally included in all events called under the BEC DR Program.
$AvgAMLoad_t$	=	Daily average consumption during the morning pre-event hours (hours ending 9 to 11). This captures daily operational differences across participants that are otherwise not known.
DayType	=	A series of day type indicator variables to capture differences in load levels primarily due to day-to-day intra-site activity differences. Since only non-holiday, non-weekend days are used in the analysis, the day type variables include Monday (*Mon*) capture potentially higher loads during the beginning of the business week and Friday (*Fri*) to capture potentially lower loads during the end of the business week.
Weather	=	A series of daily weather variables such as average peak temperature, average peak humidity, daily peak temperature, and daily peak humidity.
Month	=	A series of month indicator variables used to capture differences in load over the months May through October. Variables for the months of June through October are included in the analysis with May selected as the dummy variable to be omitted from the regression analysis. The coefficients for the monthly dummy variables describe usage relative to the month of May.

Past regression analyses used to quantify the impacts of demand response programs have firmly established that the variables presented above are related to daily average hourly peak load. As temperatures and humidity rise, energy consumption is expected to increase due to heavier reliance on air conditioning. Energy loads also fluctuate by day type, with businesses consuming far less energy on the weekends and holidays than on regular work weekdays. Since weekends and holidays are excluded from the dataset, these day type indicators are not present. Monday and Friday day type variables were included in various regression specifications however. Morning load, the average load during the hours of 9 a.m. to 11 a.m.

[8] Average peak load is calculated for each day in the dataset and is equal to the sum of hourly load across all participants between 2 and 6 p.m. and then divided by four to arrive at an average hourly peak load value for each day in the dataset.

on any given day, is used to capture daily operational differences that are otherwise not known.

Two multivariate analyses were used to estimate program impacts. Both relied on a dataset in which the hourly loads of the participants are summed for each day in the dataset, which include all non-holiday, non-weekend days from May through October for 2005 and 2006. In other words, each record represents a day and contains values for hourly temperature (*temp1–temp24*), hourly relative humidity (*humid1–humid24*), hourly load (*hrload1–hrload24*), and average hourly peak load for all participants.

Aggregated Daily Load Model

The first model is an aggregated daily load model in which the daily average peak load of all program participants was regressed on a set of independent variables that included weather, day type, month, and indicators for the 15 event days that occurred in 2005 and 2006.[9] The coefficients estimated for each of the event day indicator variables are interpreted as the average load reduction that occurred due to the event, excluding the other factors that were included in the regression specification.

The following represents the regression model used for this part of the analysis:

$$\begin{aligned} AvgPeakLoad_t = {} & \beta_0 + \beta_1 AvgPeakTemp_t + \beta_2 AvgPeakHumidity_t + \beta_3 AvgAMLoad_t + \\ & \beta_4 Event72105 + \beta_5 Event71305 + \beta_6 Event80505 + \beta_7 Event80805 + \\ & \beta_8 Event83005 + \beta_9 Event92805 + \beta_{10} Event92905 + \beta_{11} Event62206 + \\ & \beta_{12} Event62306 + \beta_{13} Event71706 + \beta_{14} Event71806 + \beta_{15} Event72106 + \\ & \beta_{16} Event72406 + \beta_{17} Event72506 + \beta_{18} Event92206 + \beta_{19} Mon + \beta_{20} Fri + \\ & \beta_{21} June + \beta_{22} July + \beta_{23} Aug + \beta_{24} Sept + \beta_{25} Oct \end{aligned}$$

where

t	=	date, from May 1, 2005 through Oct 31, 2005 and May 1, 2006 through Oct 31, 2006.
$AvgPeakLoad_t$	=	the daily average hourly load across all participants between 2 p.m. and 6 p.m.
$AvgPeakTemp_t$	=	the daily average temperature in the San Francisco area between the hours of 2 p.m. and 6 p.m.

9 Only one participant of 43 was excluded due to incomplete interval data.

$AvgPeakHumidity_t$	=	the daily average relative humidity in the San Francisco area between the hours of 2 p.m. and 6 p.m.
$AvgAMLoad_t$	=	the daily average load of participants between 9 a.m. and 11 a.m.
*Event**** *	=	a set of dummy variables that denotes whether an event is called on a particular day (i.e., the value of Event71205 is equal to 1 on July 12, 2005 to indicate that an event was called on that day).
Mon	=	a dummy variable to denote whether a date falls on a Monday or not.
Fri	=	a dummy variable to denote whether a date falls on a Friday or not.
June, July, Aug, Sept, Oct	=	a set of dummy variables to denote whether a date is in the months of June, July, August, September, and October, respectively.

Two regression specifications were initially estimated. The first included all of the variables presented in the equation above, and the second included all of the variables except for the month indicators (*June* through *Oct*). Because coefficients of similar magnitude were estimated across the two specifications, the regression that includes all of the variables listed in the equation above was selected for presentation and it is discussed in detail in Section 3.5.2. The weather variables included in the above equation, daily average peak temperature and daily average peak humidity, were selected based upon their statistical significance. In addition to testing the equation with these variables, daily peak temperature and daily peak humidity were included in different specifications, but neither was as significant as their average peak counterparts in this part of the analysis. The Durbin Watson statistic was calculated for the regression and it indicated the presence of first order serial correlation. The selected regression equation corrected for this and relied upon maximum likelihood estimation to generate estimated coefficients.

Daily Backcasting Model

The second regression method used to estimate load reductions attributable to the program relied upon a load estimation model that is similar in structure to models used for load forecasting. In this case, however, it is used for backcasting. This method used an aggregated daily load model to simulate peak period load on event days assuming no event had been declared. This is accomplished by removing event days from the dataset, estimating a model, and then using the results from the model to simulate the load on the event days. The differences between the actual event day peak load values (the values removed from the dataset) and the predicted peak load values (those values simulated using the model results) are taken to represent estimated load reductions for each event. The following equation is the regression model used for the daily load model backcasting analysis:

$$AvgPeakLoad_t = \beta_0 + \beta_1 AvgPeakTemp_t + \beta_2 AvgPeakHumidity_t + \beta_3 AvgAMLoad_t + \beta_4 Mon + \beta_5 Fri + \beta_6 June + \beta_7 July + \beta_8 Aug + \beta_9 Sept + \beta_{10} Oct$$

By design, the daily backcasting model used in the analysis is virtually identical to the aggregate daily model specification, with the exception the presence of event day indicators. The event day indicators are excluded from the daily backcasting model because it is used to simulate the average peak hourly load on event days. The estimated coefficients from the regression specification and the estimated savings for each event derived from this analysis are presented in Section 4.2.

Based upon the methodologies described in this section, estimated load reductions from BEC events were calculated and are presented in Section 4.

4

Impact Evaluation Results

This section presents the estimated program impacts resulting from the Representative Day and regression modeling methodologies. These estimated impacts are presented by individual event, event hour, and overall for the program year. The relationship between these estimated impacts and the event trigger (temperature versus system load), the average temperature on the day of the event, and notification given for the event (day-ahead versus day-of notification) are also presented.

4.1 Representative Day Impact Estimates

In this section, estimates of peak load reductions for the BEC Program resulting from the Representative Day methods are presented. The final impacts estimates are based on the 10-Day adjusted baseline and include all differences between the baseline and actual event day load (both positive and negative impacts).

4.1.1 Average Hourly Program Impacts

To ascertain how the BEC program performed throughout the summer of 2005 and 2006 we calculated the average hourly program impact across all BEC participants who were enrolled and active for each of the events. Figure 4-1 and Figure 4-2 presents the average hourly program impacts for each event based on the 10-Day Adjusted baseline (expressed as both the total MW reduction, as well as a percent load reduction).

Figure 4-1 shows the impacts for the 2005 BEC events fluctuated between 0.6 and 3.2 MW, which amounted to between a 1 and 14% load reduction. The average impact based on the 10-Day adjusted baseline was 1.9 MW. Events that occurred the day immediately after an event had much lower impacts than the preceding day (46% lower for the July 13 event and 72% lower for the September 29 event). It is also interesting to note that the number of active BEC participants increased from 12 customers for the first four events, to 16, then to 18 and finally to 25 for the last event (which coincidentally had the lowest impact and the fourth event, with only 12 participants, had the highest impact).

Figure 4-1: Average Hourly Program Impacts Across the 2005 BEC Events

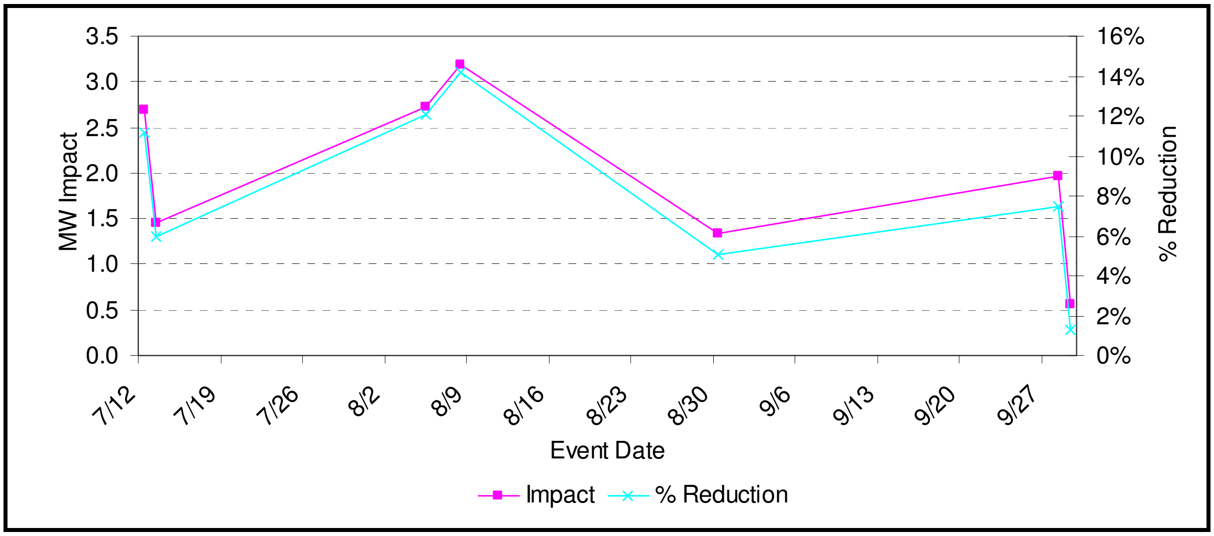
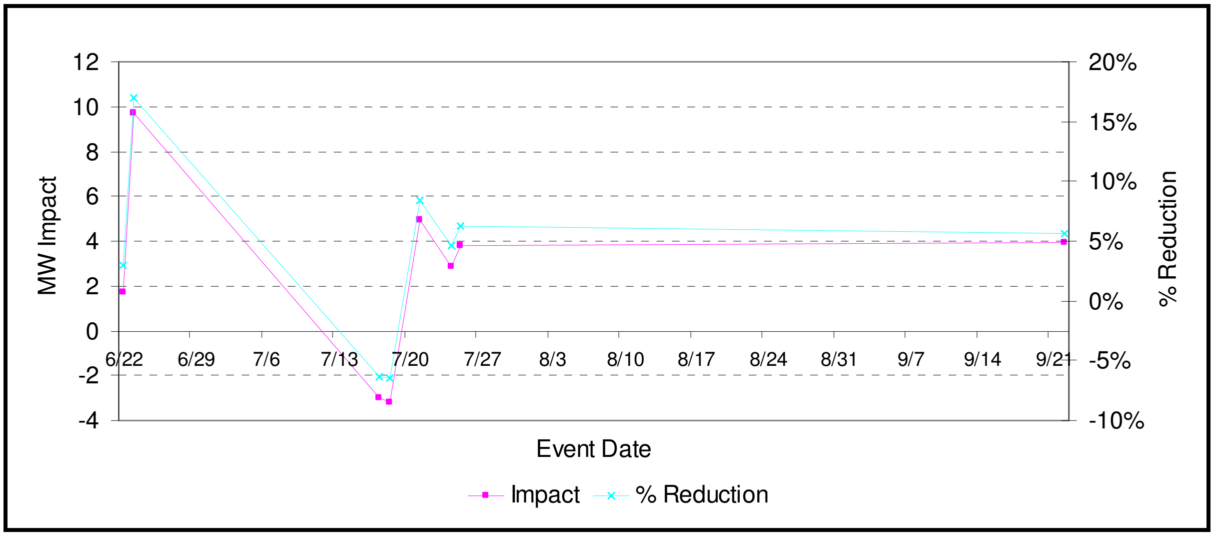


Figure 4-2 shows the impacts for the 2006 BEC events, which ranged from a negative 3.2 MW to 9.7 MW, and these impacts represented a negative 6 to 17% load reduction. The average impact across all 2006 events based on the 10-Day adjusted baseline was 2.5 MW. The event with the highest impact was the June 23 event (9.7 MW), which interestingly included the same 28 participants as the previous days event (June 22), however, the impact for the June 22 event was only 1.7 MW. The difference in the magnitude of these impacts on these two consecutive days may be partially explained by the fact that June 22nd was a Thursday while June 23rd was a Friday in 2006. The weekend effect may explain the larger demand reduction that occurred on the June 23 event. The number of active BEC participants increased throughout 2006 from 28 customers for the first two events, to 38 customers for the last event.

Figure 4-2: Average Hourly Program Impacts Across the 2006 BEC Events



4.1.2 Hourly Program Impacts

Itron also examined how, on average, the BEC program performed over the course of the event hours, as well as the hours leading up to and following an event. 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. Figure 4-3 and Figure 4-4 present the estimated hourly impacts for each of the BEC events occurring during the summer of 2005 and 2006, based on the 10-Day adjusted baseline. While the hourly impacts for the summer of 2006 events remain fairly consistent across all event hours, the hourly impacts for the 2005 events seem to fluctuate.

Figure 4-3: Hourly Program Impacts for each of the 2005 Events (7 Events)

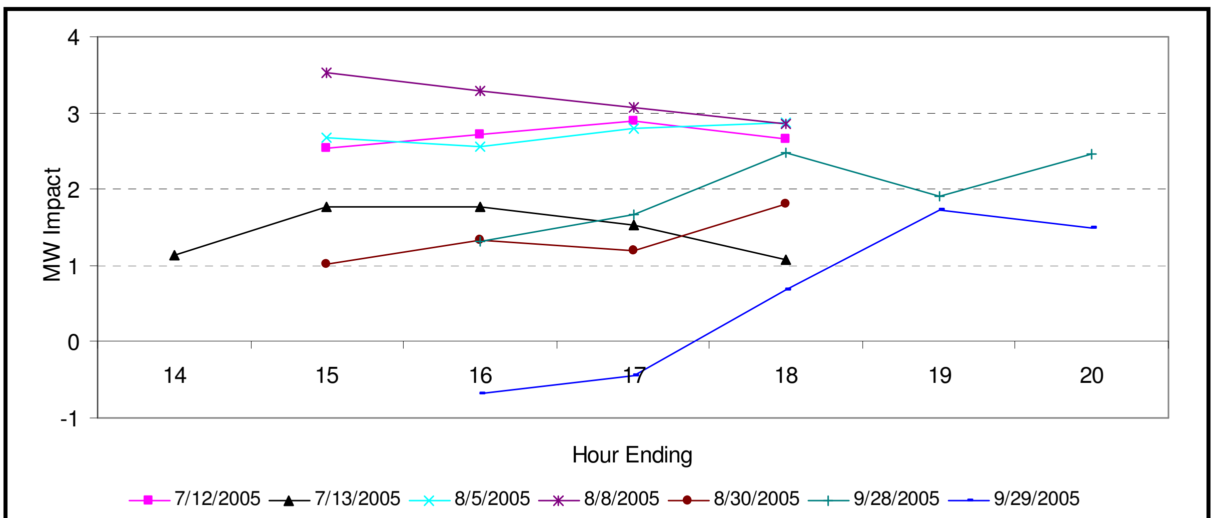
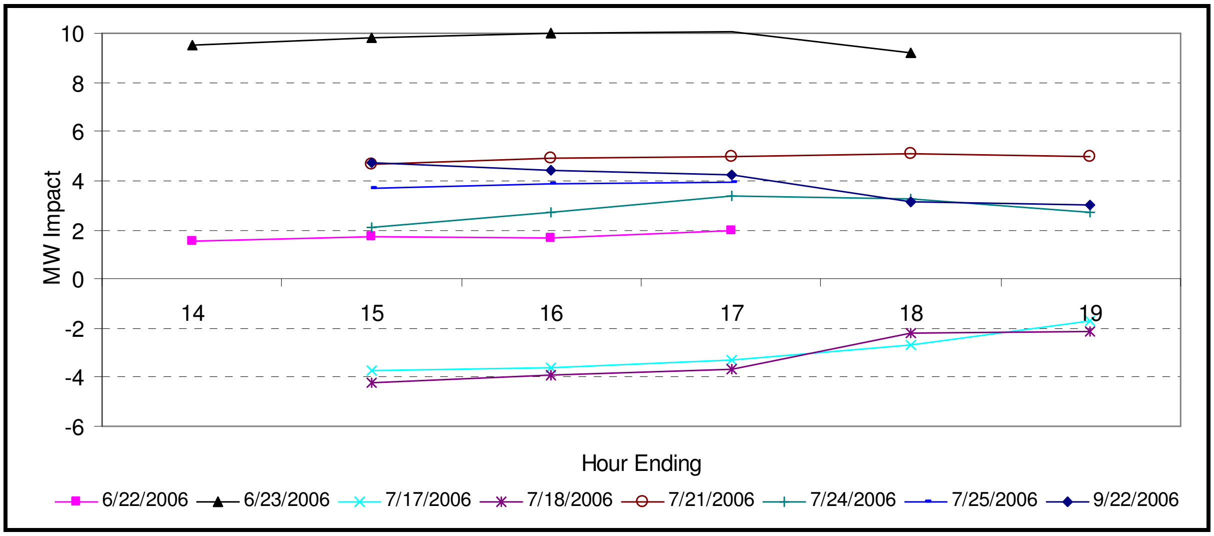


Figure 4-4: Hourly Program Impacts for each of the 2006 Events (8 Events)



4.1.3 Yearly Program Impacts

Table 4-1 below presents a summary of the estimated impacts, percent load reduction and impact per participant for each of the 2005 and 2006 events, along with the average across the program year events. The percent load reduction shown in this table is calculated as the sum of the estimated impacts across all active BEC participants divided by the sum of the estimated load of these participants in the absence of the program (based on the 10-Day adjusted baseline). This table shows that although the average impact estimated for the 2006 events was larger than for the 2005 events (2.5 MW versus 1.9 MW, respectively), the percent load reduction, and impact per participant was higher in 2005 than in 2006.

Table 4-1: Summary of Yearly Program Impacts[10]

Program Year	Event Date	BEC Participants	Estimated Impact (MW)	% Load Reduction	Impact per Part (MW)
2005	7/12/05	12	2.7	11%	0.22
	7/13/05	12	1.5	6%	0.12
	8/5/05	12	2.7	12%	0.23
	8/8/05	12	3.2	14%	0.27
	8/30/05	16	1.3	5%	0.08
	9/28/05	18	2.0	7%	0.11
	9/29/05	25	0.6	1%	0.02
	2005 Average	**15**	**1.9**	**8%**	**0.13**
2006	6/22/06	28	1.7	3%	0.06
	6/23/06	28	9.7	17%	0.35
	7/17/06	29	-3.0	-6%	-0.10
	7/18/06	30	-3.2	-6%	-0.11
	7/21/06	31	4.9	8%	0.16
	7/24/06	32	2.8	5%	0.09
	7/25/06	30	3.8	6%	0.13
	9/22/06	38	3.9	6%	0.10
	2006 Average	**31**	**2.5**	**4%**	**0.08**

An examination of the event impacts depicted in Figure 4-1 through Figure 4-4 and the estimated impacts using the 10-Day Adjusted baseline methodology shows a relatively small demand reduction impacts on September 29, 2005, July 17, 2006, and July 18, 2006. Though the estimated impacts on these days are relatively small (even negative for the events in 2006), the average peak temperature and relative humidity on these days do not deviate from those on the other event days. Table 4-2 presents event day average peak temperature and humidity between the hours of 12 – 6pm and it is clear that these event days are not outliers. The small estimated impacts on these days are instead an artifact of the use of similar day baseline methodologies, such as the Adjusted 10-Day. While these baselines are simple to calculate and therefore useful for settlement purposes, the individual event day impacts are greatly influenced by the energy demand of the participants on assumed "similar" days. If their energy demands are not typical of "similar" days to the event, then these data can greatly affect the estimated impacts. This is further supported by the econometrically

[10] Percent load reduction for this table is calculated as the sum of the estimated impacts across all active BEC participants divided by the sum of the estimated load of these participants in the absence of the program based on the 10-Day adjusted baseline. This differs from the method used in Table 3-5, which is the mean of each participants individual percent load reduction.

estimated impact results presented in later in this section. As shown in Table 4-11, the estimated impacts using the Adjusted 10-Day baseline are presented alongside the impacts estimated using a regression model. The econometrically estimated impacts on these event days are similar to the impacts on the other event days and are not similar to the impacts estimated using the Adjusted 10-Day baseline technique.

Table 4-2: Average Peak Temperature and Humidity on BEC DR Event Dates in 2005 and 2006

Event Date	Average Peak Temperature	Average Peak Humidity
7/12/2005	73	55
7/13/2005	66	68
8/5/2005	71	57
8/8/2005	62	76
8/30/2005	82	21
9/28/2005	71	63
9/29/2005	**76**	**45**
6/22/2006	80	37
6/23/2006	68	62
7/17/2006	**79**	**39**
7/18/2006	**75**	**52**
7/21/2006	80	39
7/24/2006	78	53
7/25/2006	77	54
9/22/2006	76	17

4.1.4 Distribution of Impacts Across Participants

Itron next examined the estimated program impacts that individual participants achieved for BEC events. Table 4-3 presents the percentage of BEC participants achieving various levels of demand reduction for at least one hour of one event during the summers of 2005 or 2006. 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 in both 2005 and 2006 more than 50% of active BEC participants were able to achieve at least a 10% load reduction for at least one hour of an event, however less than 5% of these participants ever reduced their load by more than 50%.

Table 4-3: Percent of Participants Reaching Various Load Reduction Levels for at Least One Event Hour in 2005 or 2006

Load Reduction	Percentage of Participants	
	2005	2006
5%	65%	58%
10%	50%	55%
25%	12%	18%
50%	4%	3%

The analysis performed found that the largest hourly load drop achieved by a program participant in 2005 was 2,120 kWh and in 2006 was 977 kWh. Sixty-two percent of participants were able to reduce their load by more than 100 kW during at least one hour of a 2005 event and this number climbed to over 82% of participants across the 2006 events.

Table 4-4 below displays the levels of load reductions BEC participants averaged over the 2005 or 2006 events for which they were considered "Active." The comparison of Table 4-3 and Table 4-4 illustrates that while a large proportion of BEC Program participants were able to make various levels of load reductions for a particular hour of an event, these levels of load reduction could not generally be relied on across the entire summer of events.

Table 4-4: Percent of Participants Reaching Various Average Load Reduction Levels Across all 2005 or 2006 Events

Load Reduction	Percentage of Participants	
	2005	2006
5%	15%	25%
10%	12%	13%
25%	4%	0%
50%	0%	0%

Table 4-5 below shows that although the maximum hourly load reduction across all active BEC participants was close to 50%, the average peak load reduction achieved was 2.5% in 2005 and 3.8% in 2006. This indicates that the average customer is shedding only a small percentage of their estimated base load for each event. Comparing this average hourly load reduction for each participant to the overall percent load reductions presented in Table 4-1 above (8% in 2005 and 4% in 2006) gives an indication of how the premise of this program (where impacts are aggregated across a group of customers and thus it is not all customers have to participate in all events) played out during the first two years of program events. This is further described below.

Table 4-5: Average and Maximum Hourly Load Reductions Across all 2005 and 2006 Events

Program Year	Event Hours	Average Hourly Load Reduction	Maximum Hourly Load Reduction
2005	483	2.5%	50%
2006	1142	3.8%	52%
All	1625	3.4%	52%

Figure 4-5 and Figure 4-6 below present the distribution of BEC participants' average hourly impacts across all 2005 and 2006 BEC 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%. Figure 4-5 shows that on average across the 2005 program events, one participant provided nearly 70% of the overall *positive* program impacts (this customer dropped out of the program in 2006) and 50% of participants contributed negative impacts, meaning they actually increased their consumption during the event hours. Figure 4-6 shows that in 2006 a larger percentage of program participants contributed to the overall program load reduction. On average across the 2006 program events, 20% of the active participants provided more than 60% of the overall *positive* program impacts and only 25% contributed negative impacts.

Figure 4-5: Distribution of Average BEC Participant Impact Contributions Based on Average Hourly Impact per Participant across all 2005 Events

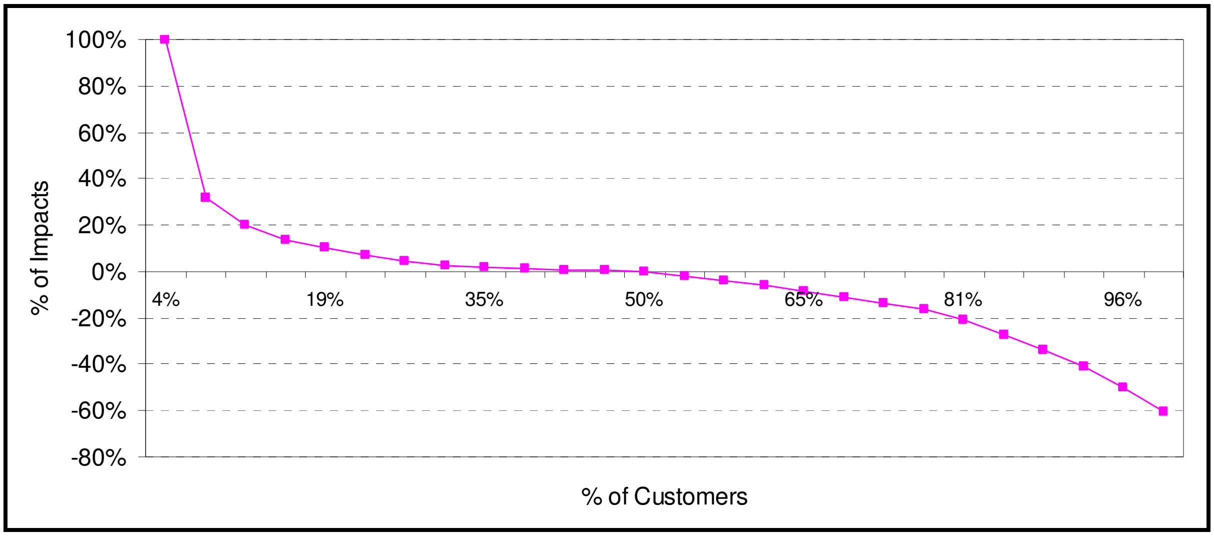
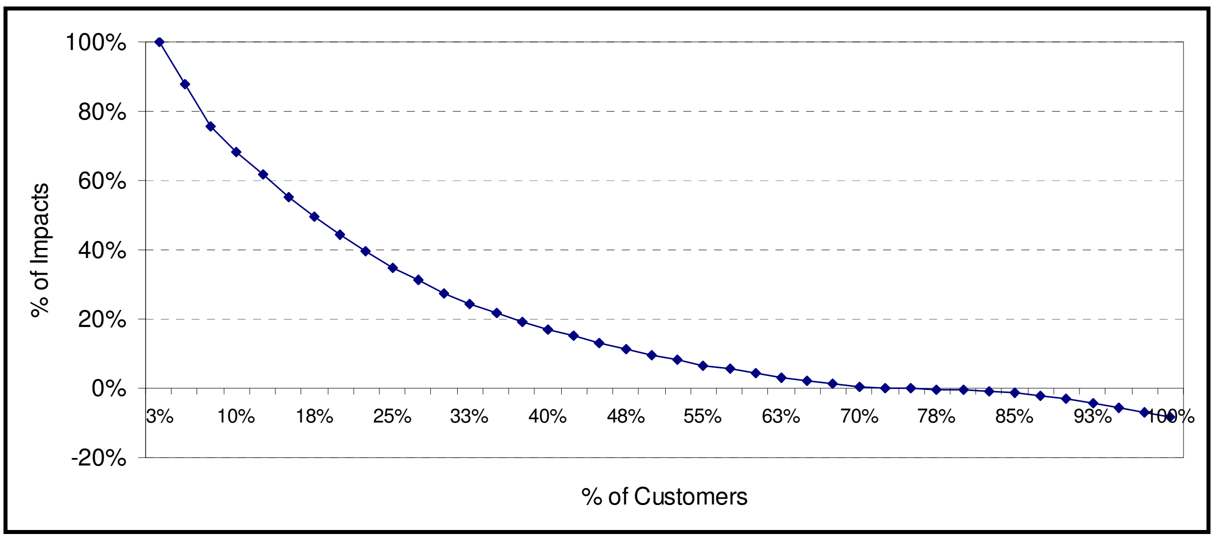


Figure 4-6: Distribution of Average BEC Participant Impact Contributions Based on Average Hourly Impact per Participant across all 2006 Events



4.1.5 Relationship between Estimated Impact Event and Event Attributes

Analysis was completed to determine if a relationship existed between the overall percent load reduction achieved by the participants within an event and various event attributes. Table 4-6 below shows the average percent load reduction for each of the 2005 and 2006 events (the average load reduction across all events was 6%). This table also shows there was little difference in average impact between the average estimated program impacts resulting from events called on the day prior to an event (day-ahead) versus events called on the same day as the event (day-of). The average estimated impact across the three same day events was 6% compared to the average for the 12 day-ahead events which 7%. Analysis of the relationship between the event trigger (CAISO forecasted load or forecasted temperature) again shows that event trigger had little impact on the resulting estimated impact. Itron also looked at whether events falling on certain days of the week had higher or lower average impacts. Itron found that on average events occurring on Fridays had larger impacts than events falling on other days of the week (11% versus 4% respectively). Due to the small number of events this calculation was based upon, this difference was not statistically significant.

Table 4-6: Average BEC Event Impact versus Notification Timing, Event Trigger, and Event Day Weekday

Event Date	% Load Reduction	Notification Type	% Load Reduction		Event Trigger	% Load Reduction		% Load Reduction	
			Day-Of	Day-Ahead		Load	Temp	Friday	Non-Friday
7/12/05	11%	Day-Of	11%		Load Forecast	11%			11%
7/13/05	6%	Day-Of	6%		Load Forecast	6%			6%
8/5/05	12%	Day-Ahead		12%	Load Forecast	12%		12%	
8/8/05	14%	Day-Ahead		14%	Load Forecast	14%			14%
8/30/05	5%	Day-Of	5%		Temperature		5%		5%
9/28/05	7%	Day-Ahead		7%	Temperature		7%		7%
9/29/05	1%	Day-Ahead		1%	Temperature		1%		1%
6/22/06	3%	Day-Ahead		3%	Temperature		3%		3%
6/23/06	17%	Day-Ahead		17%	Temperature		17%	17%	
7/17/06	-6%	Day-Ahead		-6%	Load Forecast	-6%			-6%
7/18/06	-6%	Day-Ahead		-6%	Load Forecast	-6%			-6%
7/21/06	8%	Day-Ahead		8%	Load Forecast	8%		8%	
7/24/06	5%	Day-Ahead		5%	Load Forecast	5%			5%
7/25/06	6%	Day-Ahead		6%	Load Forecast	6%			6%
9/22/06	6%	Day-Ahead		6%	Temperature		6%	6%	
Average	**6%**		**7%**	**6%**		**6%**	**7%**	**11%**	**4%**

4.2 Regression Analysis Impact Estimates

This subsection presents the results of the regression analysis used to estimate the impacts of the BEC Demand Response Program for 2005 and 2006. As stated in subsection 3.3.3, econometric estimation allows for the control of non-programmatic changes in energy consumption that occur throughout the period over which the BEC demand response program operates. This allows for a more refined estimate of program impacts.

4.2.1 Aggregated Daily Load Model Results

First, an aggregated daily load model was developed to estimate the average load reduction that occurred on BEC event days in 2005 and 2006. This and all subsequent equations discussed in this section were estimated using the maximum likelihood estimation technique and they all were corrected for first order serial autocorrelation.[11] Variables to control for weather, day type, average load during the morning hours, monthly indicator variables, and day type indicators were included in the regression along with dummy variables for each of the 15 events called during the summer months of 2005 and 2006 for the BEC program. Table 4-7 presents the results estimated from the selected regression specification of the aggregated daily load model.

In Table 4-7, the estimated coefficients for each of the variables included in the regression, the standard errors, t-values, and p-values (Pr > |t|) are presented. Positive coefficients are interpreted as having a positive relationship with the dependent variable, with the opposite being true of negative coefficients. For example, as average peak temperature rises by one degree Fahrenheit, daily average peak load increases by 404 kW, holding all other variables included in the equation constant. The event dummy variables all have negative coefficients, which is expected since daily average peak load is expected to be lower on event days than non-event days. Standard errors of the estimated coefficients are also presented in the table below. They represent the standard deviations of the sampling distributions of the estimated coefficients. The larger is the standard error, the greater is the spread of values about the estimate.

It is important to note that only coefficients deemed to be statistically significant can be interpreted as having a positive or negative relationship to the dependent variable. Statistical significance of an estimated coefficient is indicated by the size of an estimate's t-value, as long as the data comes from a population that is normally distributed. The t-value to test that a coefficient is statistically significantly different from zero depends upon the size of the sample used in the estimation, the type of t-test used (one-or two-tailed) and the required degree of confidence (generally a 95% level is used). As long as the sample size is large enough and a 95% probability of accuracy is acceptable, t-values equal to or greater than 1.96 indicates statistical significance. P-values, as indicated by the values in the last column of Table 4-7, are also a test of statistical significance of estimated coefficients. The p-value is defined as the probability of obtaining a result at least as extreme as a given data point, given the null hypothesis (which, in this case is that the estimated coefficients are statistically significantly different from zero). The smaller is the p-value, the more statistically significant is the estimated coefficient.[12]

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[11] The Durbin Watson statistic for the aggregate daily load model was initially equal to 1.45 when the regression was estimated using Ordinary Least Squares and no AR(1) correction. Once the correction was applied, the DW statistic was equal to 2.19.

[12] For further information on hypothesis testing and statistics, see Kennedy, P. *A Guide to Econometrics*, The MIT Press: Cambridge, 1992.

Table 4-7: Regression Results from the Aggregated Daily Load Model (Dependent Variable = Daily Average Peak Load)

Variable	Estimated Coefficient	Standard Error	t-value	Pr > |t|
Intercept	5459	2759	1.98	0.049
APTemp	403.87	30.88	13.08	<.0001
APHumid	34.50	10.87	3.17	0.0017
AvgAMLoad	0.539	0.035	15.45	<.0001
Event71205	-3235	1034	-3.13	0.002
Event71305	-420	1031	-0.41	0.6841
Event80505	-2882	1029	-2.8	0.0055
Event80805	-2883	1030	-2.8	0.0056
Event83005	-5264	948.49	-5.55	<.0001
Event92805	-832.85	1024	-0.81	0.4171
Event92905	-1919	1023	-1.88	0.062
Event62206	-3876	1072	-3.62	0.0004
Event62306	-3236	1027	-3.15	0.0018
Event71706	-5400	1043	-5.18	<.0001
Event71806	-3163	1023	-3.09	0.0022
Event72106	-4667	1066	-4.38	<.0001
Event72406	-3685	1169	-3.15	0.0018
Event72506	-4973	1058	-4.7	<.0001
Event92206	-3858	980.79	-3.93	0.0001
Mon	-179.70	160.67	-1.12	0.2645
Fri	-985.74	157.03	-6.28	<.0001
June	-137.86	391.91	-0.35	0.7253
July	-492.87	427.49	-1.15	0.2501
Aug	-512.70	408.89	-1.25	0.2112
Sept	504.73	413.53	1.22	0.2235
Oct	1096	396.98	2.76	0.0062
Adjusted R-squared = 0.93 Durbin Watson statistic = 2.19				

As these results show, the relationships between average peak consumption to average peak temperature, average peak humidity, morning consumption, and the day type indicator *Fri* are as expected. With the exception of *Fri*, all of these variables are positively related to average peak consumption. Average peak consumption on Fridays is expected to be lower than other days, since businesses often close early on Fridays in anticipation of the weekend. What was not expected was the negative coefficient estimated for the day type indicator *Mon*, although this result was not statistically significant. The monthly dummy variables show that relative to the month of May (the base month that was omitted from the regression analysis to avoid matrix over-identification), energy loads were lower in June, July, and August, but higher in September and October. However, of the monthly dummy variables, the only one showing statistical significance is the indicator for the month of October.

The coefficients of greatest interest are those estimated for each of the event day indicators. As expected, the coefficients are all negative (to indicate a reduction in load on event days) and are generally statistically significant. The only events for which the estimated coefficients are not significant at the 5% level are the events held on July 13, 2005, September 28, 2006, and September 29, 2006. Aside from these three event days, the estimated load reductions range from a low of 2.8 MW (on August 5, 2005 and August 8, 2005) to a high of 5.4 MW (on July 17, 2006), with most of the coefficients equal to or greater than 3 MW. If the coefficients for all of the 15 events are averaged to give an indicator of the program impacts, we find the average load reduction per event is just over 3.35 MW. This estimate of average load reduction per event should be taken as an indicator, since, as noted earlier, three of the coefficients estimated were statistically insignificant at the 5% level. Table 4-8 below presents the estimated load reductions for each event; these are the coefficients presented in the regression results above.

Table 4-8: Regression Estimated Load Reductions by Event for the 2005 and 2006 BEC DR Program in kW (coefficients of Event Day Indicators)

Event	Load Reductions
7/12/2005	3,235
7/13/2005	420*
8/5/2005	2,882
8/8/2005	2,883
8/30/2005	5,264
9/28/2005	833*
9/29/2005	1,919*
6/22/2006	3,876
6/23/2006	3,236
7/17/2006	5,400
7/18/2006	3,163
7/21/2006	4,667
7/24/2006	3,685
7/25/2006	4,973
9/22/2006	3,858
AVERAGE	**3,353**

* Insignificant at the 5% level

4.2.2 Daily Backcasting Model Results

The aggregate backcasting models also yielded estimated load reductions by events. The backcasting analysis was carried out by removing actual daily average hourly peak loads that were observed on event days, predicting simulating average hourly peak loads on these days through regression analysis, (assuming no event occurred) and taking the difference of these predicted load values from actual average peak load. By removing actual peak loads, which are expected to be lower due to participants' response to BEC events, the model results can be used to simulate what average peak loads would have been on those days if there had not been an event. Results from this analysis are presented in Table 4-9.

Table 4-9: Estimated Load Reduction for BEC Demand Response Program Events Using Aggregate Daily Load Model Backcasting (in kW)

Event Date	Predicted Avg Peak Load	Actual Avg Peak Load	Load Reduction by Event
7/12/2005	80,260	83,577	3,317
7/13/2005	78,480	79,072	591
8/5/2005	73,497	76,166	2,669
8/8/2005	70,458	72,755	2,297
8/30/2005	81,022	86,301	5,278
9/28/2005	81,573	82,428	855
9/29/2005	82,988	84,965	1,977
6/22/2006	82,588	86,658	4,070
6/23/2006	70,904	74,349	3,445
7/17/2006	78,202	83,624	5,422
7/18/2006	77,918	81,179	3,261
7/21/2006	78,183	82,891	4,708
7/24/2006	81,382	85,063	3,681
7/25/2006	79,755	84,561	4,806
9/22/2006	75,234	78,574	3,340
AVERAGE:	**78,163**	**81,478**	**3,314**

The average load reduction per event from the daily backcasting model is just slightly lower than that estimated from the aggregate load model presented earlier. In the daily backcasting model, the average load reduction is estimated to equal 3.31 MW while it is equal to 3.35 MW when the aggregate daily load model is used. In both cases, the event estimated to yield the largest load reduction (approximately 5.4 MW) occurred on July 17, 2006 while the smallest load reduction occurred on July 13, 2005 based on the estimates calculated from both regression models. The regression specification used to simulate average peak load values using the daily backcasting model was presented in Section 3.4.3 and the regression results are shown below in Table 4-10.

Table 4-10: Daily Backcasting Regression Model Used to Simulate Average Peak Load on Event Days (Dependent Variable = Average Peak Load)

Variable	Estimated Coefficient	Standard Error	t-value	Pr > |t|
Intercept	5022	2757	1.82	0.0698
APTemp	399.93	30.88	12.95	<.0001
APHumid	33.98	10.87	3.13	0.002
AMCons	0.55	0.03	15.84	<.0001
Mon	-172.83	162.21	-1.07	0.2878
Fri	-975.08	158.56	-6.15	<.0001
June	-171.89	377.99	-0.45	0.6497
July	-474.67	413.01	-1.15	0.2516
Aug	-505.13	393.81	-1.28	0.2009
Sept	492.88	397.60	1.24	0.2164
Oct	1087	381.49	2.85	0.0048
Adjusted R-sq.= 0.93 Durbin Watson statistic = 2.2				

Based upon the multivariate regression analyses, a conclusion can be drawn that load reductions did indeed occur due to the BEC demand response program. The total load reduction that occurred on an event ranged from approximately half a MW to greater than 5 MW. On average, the load reduction per event was equal to approximately 3.3 MW.

4.3 Comparison to BEC Program Impact Estimation Methods

This section presents the methodology used in 2005 and 2006 by the BEC Program to calculate the impact resulting from a BEC Program event. It then compares the estimated event-level impacts resulting from this methodology to the evaluation estimated program impacts presented above (based on the Representative Day and Regression Modeling methods), as well as to the BEC Program goals.

4.3.1 Calculation of BEC Reported Program Impacts

In order to calculate a participant's load reduction for any given event it is necessary to know the customer's peak demand and FSL for the program year, as well as their actual load during the event time period. The method used to calculate a customer's yearly peak demand and determine their FSL are described below.

Peak Demand Calculation

Upon signing up for the BEC Program, the average peak demand (kW) is calculated for each participant. To calculate this peak demand it is necessary to gather the participant's monthly peak kW readings from the previous two years for all months from May to October. After these data have been collected, a two-year average peak kW is calculated for each month. The average peak demand is then set equal to the maximum of these six monthly two-year average values. An example of this calculation is shown below in Figure 4-7 for a hypothetical participant in Program Year 2006.

Figure 4-7: Methodology for Calculating a Participants Peak Demand

PROJECT: Example Participant
ADDRESS: 1234 Main Street

HISTORIC PEAK KW DEMANDS

AVERAGE PEAK - kW = 4,077

Year	May	June	July	August	September	October
2005	3,581	3,982	3,897	3,777	3,935	3,892
2004	3,459	3,610	3,725	3,906	4,218	4,047
2003						
2002						
2-Year Avg. =	3,520	3,796	3,811	3,842	4,077	3,970

For the summers of 2005 and 2006, the average event and non-event day loads were substantially lower than the peak demand estimated using the methodology. As we will show, this resulted in over-estimation of event impacts.

Firm Service Level

After a participant's peak demand has been set, the customer must designate a FSL that they will attempt to reduce their load to during program events. According to PG&E Schedule E-BEC, "An engineering and/or site assessment may be provided to identify load that can be curtailed during program events." This assessment, though not necessarily provided to all BEC program participants, is used to help determine a customer's FSL.

Committed Load Reduction vs. Curtailment

Once a participant's peak demand and FSL have been agreed upon, the customer's committed load reduction is calculated as the difference between their peak demand and their FSL. It is important to note here that a customer's committed load reduction for an event is different from the customer's curtailment for an event. Suppose, for instance, that a participant has a peak demand of 2,000 kW and a FSL of 1,500 kW. The delta between these two values is the participant's committed load reduction (500 kW). Further, suppose that on the day of the event the customer's load is 1,700 kW. If this customer reduces their load during the event by 200 kW, they will achieve their FSL, which means their actual curtailment is 200 kW while there committed load reduction (on which they are paid) is 500 kW.

Assuming a participant's base load was close to their peak demand, the average BEC participant would have had to reduce their load by 14% in 2005 and by more than 11% in 2006 to achieve reach their FSL. In comparison, Table 4-5 above showed that the average peak load reduction achieved in 2005 was 2.5% and in 2006 was 3.8%. This indicates that the average customer is being paid for significantly more load than they are actually shedding.

BEC Incentive Payments

A customer's committed load reduction is important since it is based on this committed load reduction that participants receive incentive payments for their participation in the BEC Program. For the 2005 and 2006 BEC Program, customers received annual incentive payments of $50/kW based on their committed load reduction. Because the participants in this program function as a group, it is necessary to calculate the committed load reduction across all active program participants to determine if the group has achieved its committed load reduction. According to PG&E Schedule E-BEC, the committed load reduction for the group of BEC participants is calculated "as the difference between the two-year average of the group's coincident peak demand, and the sum of each participant's FSL." If the group of program participants is unable to reduce their load to the groups established FSL, non-performance penalties are assessed. A Shortfall Reserve Fund (SRF) is set up containing $25/kW based on the groups committed load reduction, and if the penalties assessed exceed the moneys in the SRF the Energy Coalition is responsible for any additional costs. If there is a balance left in the SRF after all penalties have been assessed the remaining balance is distributed proportionately to the BEC Program participants.

According to the data Itron received from PG&E for the 2005 and 2006 BEC Program events, participants of the BEC Program were paid out incentives based upon their individual enrolled loads. Total incentive payments in 2005 were equal to $769,350 (for the 10.26 MW of enrolled load) and in 2006, they were equal to $778,700 (for the 15.6 MW enrolled). While incentive payments were made based on enrolled load, during 2006 the participants were out of compliance in 6 out of the 8 events based on an hourly compliance standard. In other words, the average hourly reduction made by BEC Program participants did not meet the group's load reduction commitment for at least one hour in each of six events (out of a total of 8 events in 2006). Total penalties are still under negotiation between PG&E and the BEC.

It is interesting to note that any customer enrolled in the BEC Program for at least one event during a particular program year received the annual incentive payment of $50/kW plus a percentage of any additional monies left over in the SRF. This meant that in 2005, all 25 program participants were paid the full annual incentive payment, although seven participants were not fully active until the final event of the year. In 2006, 39 participants were paid the full incentive, despite the fact that nearly a quarter of them only participated in the last event of the year. It is possible that by not pro-rating a participant's annual incentive payments it might provide potential enrollees with an incentive to wait until the end of summer to register for the BEC program.

BEC Estimated Impacts

Participant and overall BEC Program impacts were calculated by the Business Energy Coalition for each event and then provided to PG&E for reporting purposes. BEC calculates a participant's impact by first calculating the participant's average consumption across the event hours of a specific event. This average consumption is then subtracted from their estimated peak demand (as described above), which results in their reduction from peak (i.e. their estimated impact). The sum of these peak reductions across all active program participants provides the BEC Program's estimate of event impact.

It is important to note that method of calculating an estimated event impact is, in principal, quite a bit different from the best-practice methods used in this evaluation to estimate program impacts. The reduction from peak estimate represents a load reduction from a fixed peak value, whereas the other methods attempt to estimate what the load would have been in the absence of the program and then estimate the impact as the delta between this estimated load and the actual event day load.

Relationship Between Committed Load Reduction, FSL, and Actual Customer Loads

Figure 4-8 and Figure 4-9 below provide the average peak demand, FSL and event and non-event day loads across the summers of 2005 and 2006. These figures allow us to gain a better understanding of the relationship between these peak demand and FSL estimates and an average participant's daily consumption. As Figure 4-8 shows, on average across all active BEC Program participants, the average load on event versus non-event days is nearly identical. This is understandable considering Table 4-5 above showed that the average hourly load reduction on an event day was 2.5%, which on a load of 2,000 kW would be only 50 kW. This figure also shows that for the average participant, the peak demand and FSL are substantially higher than its average non-event day load across the summer. This indicates that these values are set unrealistically high and thus participants are being paid for load reductions that never occur. Finally, this figure shows that, on average, a participant's consumption begins to naturally decline around hour ending 17 (4 p.m.), which makes sense since the majority of customers participating in this program are office buildings and thus the occupant load would naturally start to reduce at this time, and thus calculating impacts from a uniformly set peak level leads to over inflated impacts in the late afternoon hours.

Figure 4-8: Comparison of the Peak Demand, FSL, and Average Event and Non-Event Day Loads Across the Summer of 2005

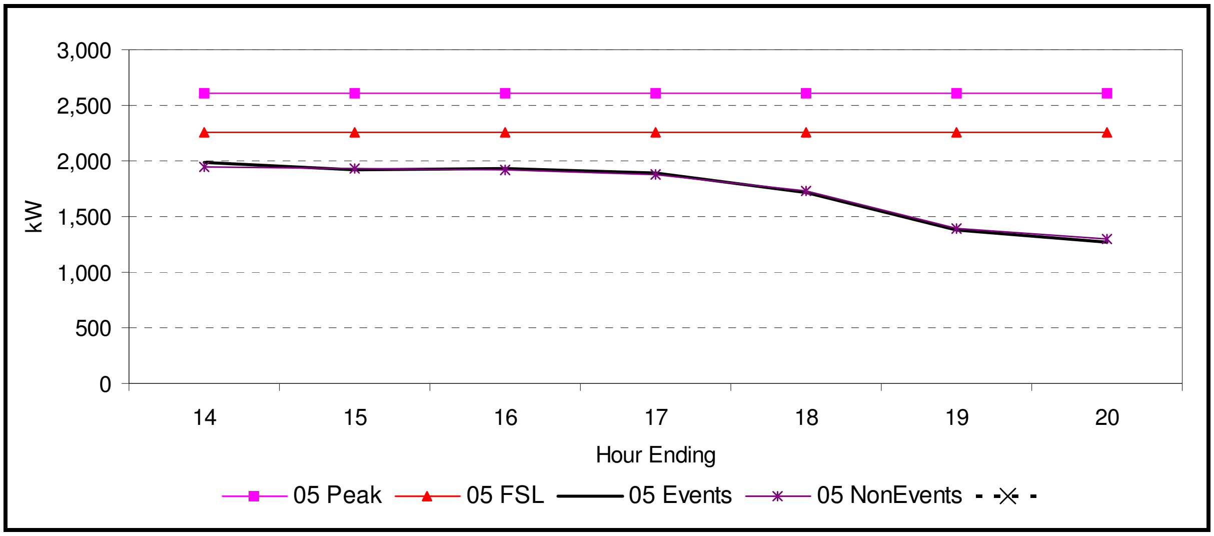


Figure 4-9 is very similar to Figure 4-8 but for the summer of 2006. It is interesting to note that in 2006, the average load on an event day even with BEC Program curtailment was actually higher than the average load on a non-event day. Even with curtailment on event days, this result makes sense when we consider the average temperature on event days relative to non-event days. On event days, the average temperature was over 78 degrees, while the average for non-event days was more than 10 degrees lower (67 degrees). It is not too surprising that when the temperature is much higher, use of air conditioning would be higher, even if those are days on which events are called. Use of energy on these days without an event would likely be even higher had no event been called.

Figure 4-9: Comparison of the Peak Demand, FSL, and Average Event and Non-Event Day Loads Across the Summer of 2006

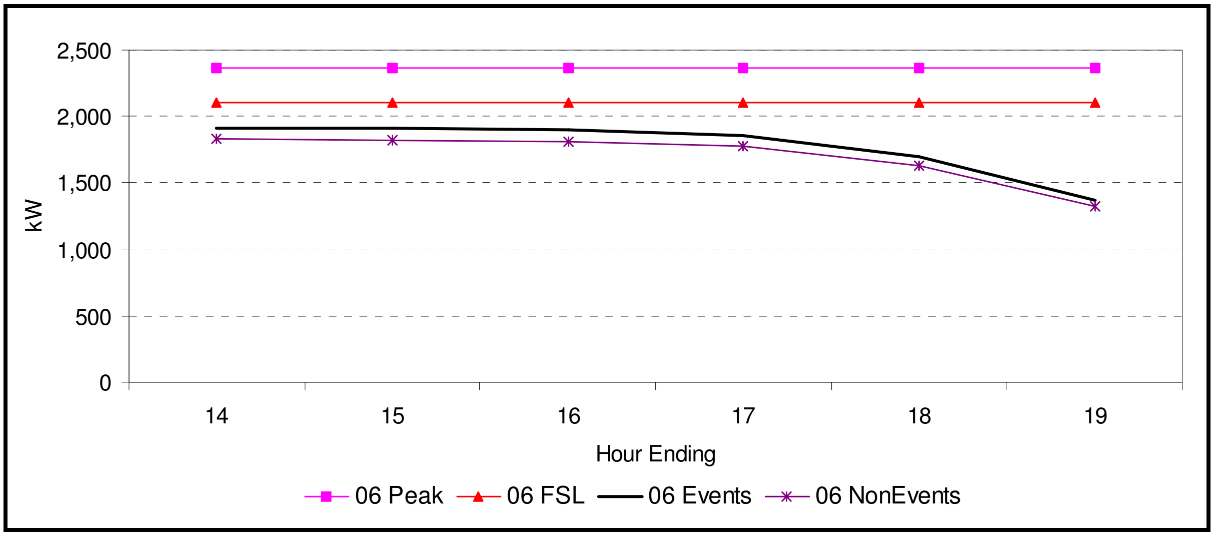
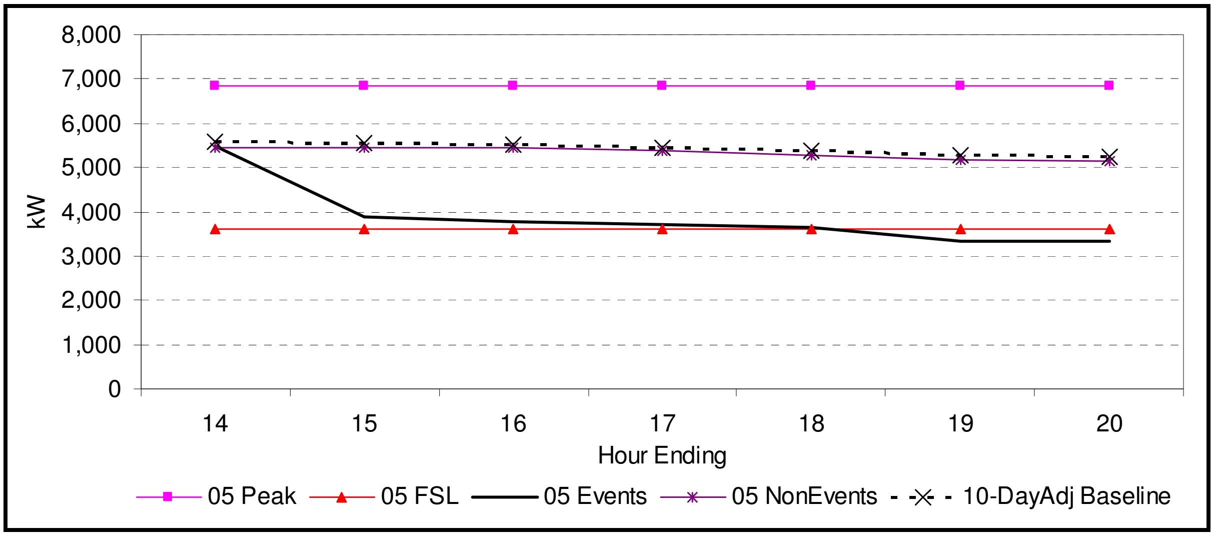


Figure 4-10 shows the average peak demand, FSL, event and non-event day loads and the 10-Day adjusted baseline for one 2005 BEC Program participant. This participant contributed 70% of the total 2005 event impacts. This figure is interesting for a number of reasons. First it shows, for this customer, how the 10-Day adjusted baseline is nearly identical to the load on non-event days, which is precisely what a Representative Day baseline should do (i.e. predict the customer load in the absence of the program). Secondly, it shows that across all the 2005 events, this customer did make substantial load reductions on event days (1.5 to 2 MW on average). Finally, it shows that even for this large customer, the peak demand is set more than 1 MW greater than their average load for the summer. The maximum hourly consumption for this customer across the entire summer of 2005 was 6,414 kW, which is 424 kW lower than their peak demand of 6,838 kW as calculated by the BEC program (and would result in an additional payment of nearly $32,000).

Figure 4-10: Comparison of the Peak Demand, FSL, Average Event and Non-Event Day Loads, and 10-Day Adjusted Baseline for the BEC Participant with the Largest Load Reduction



4.3.2 Comparison of Evaluation Estimated Impacts to BEC Program Goals and Reported Accomplishments

Table 4-11 compares the evaluation-estimated impacts to the BEC estimated impacts, as well as the BEC Program goals, on both an individual event basis as well as on an event hourly weighted average basis for both of the program years. As this comparison shows, the Representative Day method (based on the 10-Day adjusted baseline) provides, on average, the most conservative impact estimates across both summers (1.9 and 2.5 MW for 2005 and 2006, respectively). The regression-based impacts (resulting from the aggregated daily load models) are approximately one-third to two-thirds larger than the Representative Day methods (2.4 and 4.1 MW, respectively); however, both methods result in impacts that are approximately five to six times smaller than the BEC Program reported impacts.

The table below contains a column for both the PG&E Reported and BEC Reported impacts. It might seem redundant to present both PG&E's and BEC's impacts, since BEC provides PG&E with the estimated impacts for this program that PG&E then files with the CPUC in their monthly report on the Interruptible and Outage Programs. In 2005, as one would expect, these values are equal, however the 2006 impacts differ since months after the report had been filed with the CPUC, BEC recalculated the event impacts after clearing up some reporting issues. As this table shows, the magnitude of the difference between these impacts is small when compared to the difference between these numbers and the estimated impacts resulting from this evaluation. This table also contains a Program Goal column and Goal Credit column. The Program Goal came from the BEC, whereas Goal Credit is calculated as the difference between the Peak Demand and FSL for all active participants for an event.

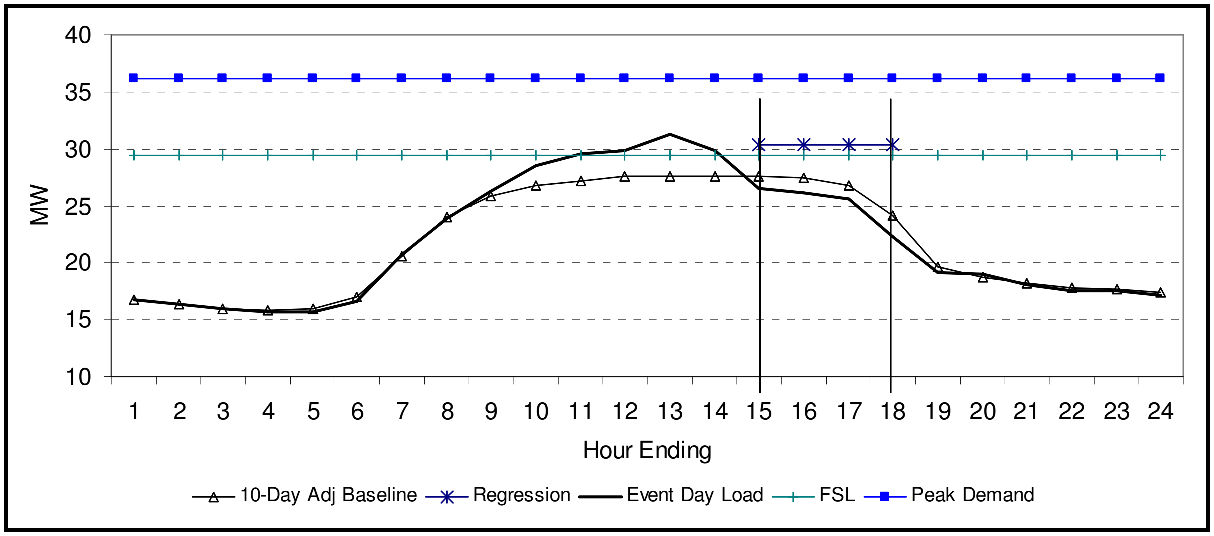
Table 4-11: Comparison of Estimated Impacts across Evaluation Methods and with PG&E Reported Impacts and Program Goals

Event Date	Average Hourly Impact (in MW)					
	Representative Day[1]	Regression[2]	PG&E Reported	BEC Reported	Program Goal	Goal Credit[3]
7/12/2005	2.7	3.2	7.1	7.1	10	6.0
7/13/2005	1.5	0.4	5.1	5.1	10	6.0
8/5/2005	2.7	2.9	16.5	16.5	10	6.0
8/8/2005	3.2	2.9	17.3	17.3	10	6.0
8/30/2005	1.3	5.3	14.6	14.6	10	6.7
9/28/2005	2.0	0.8	21.1	21.1	10	7.1
9/29/2005	0.6	1.9	20.6	20.6	10	8.8
2005 Avg.	**1.9**	**2.4**	**14.7**	**14.7**	**10**	**6.7**
6/22/2006	1.7	3.9	13.5	8.7	10	6.6
6/23/2006	9.7	3.2	22	17.1	10	6.6
7/17/2006	-3.0	5.4	20	15.5	15	7.2
7/18/2006	-3.2	3.2	20	17.3	15	7.9
7/21/2006	4.9	4.7	20	18.4	15	8.1
7/24/2006	2.8	3.7	17.8	16.1	15	8.6
7/25/2006	3.8	5.0	18.9	17.2	15	8.2
9/22/2006	3.9	3.9	20.5	20.8	15	10.3
2006 Avg.	**2.5**	**4.1**	**19.2**	**16.4**	**13.8**	**7.8**

1 Based on 10-Day Adjusted Baseline
2 Based on the Aggregated Daily Load Model
3 Sum of Estimated Reductions for "Active" Participants

Figure 4-11, Figure 4-12, and Figure 4-13 illustrate for three individual event days some of the differences apparent in Table 4-11 between the impact estimation methods. Figure 4-11 shows the peak demand, FSL, event day load, 10-Day adjusted baseline and regression-estimated load across all active BEC participants for the August 30, 2005 event. For this event, the average hourly impact was estimated to be 1.3 MW based on the Representative Day method, 5.3 MW based on the aggregated daily load regression model, and 14.6 MW based on the BEC peak demand definition. Looking at this figure, it appears that some pre-cooling began about three hours prior to the start of the event, causing the event day load to spike around noon, before participants began curtailing their load. This event was triggered by high temperatures (greater than 82 degrees) and notification for this event was provided on the day-of the event. Because this was a day-of event, the adjustment used for the 10-Day adjusted baseline was based on the prior day's load and looks to underestimate what the actual load for this day would have been in the absence of the program (based on the separation of the event day load and baseline estimate around 9 a.m.). Because the regression model includes variables to capture the effect of temperature and humidity, it estimates a load that appears to be more in line with what the load would have been in the absence of the program. The figure also shows how BEC calculated such a large impact for this event using the peak demand estimation method. For this event, it seems that the regression model provides the most accurate estimation of the actual program impact (5.3 MW).

Figure 4-11: Comparison of Estimated Impacts Methods – 8/30/05 Event



Similar to Figure 4-11, Figure 4-12, and Figure 4-13 show the peak demand, FSL, event day load, 10-Day adjusted baseline and regression-estimated load across all active BEC participants for the events called on June 23, 2006 and July 17, 2006. Both events were called on the day prior to the event. The June event was triggered by temperatures greater than 78 degrees, while the July event was triggered by the CAISO load forecast. The June event also fell on a Friday and was a consecutive event, meaning an event was called on the prior day as well (June 22, 2006). Generally, loads are expected to be lower on Fridays as businesses might begin shutting down earlier in anticipation of the weekend. An examination of Figure 4-12 shows an impact of 9.3 MW based on the 10-Day adjusted baseline methodology and an average load reduction of 3.2 MW when the drop in load is estimated through the daily aggregate regression model. The BEC estimated impact was 17.1 MW. In this figure, the regression estimated average load reduction is smaller than what is estimated using the 10-Day adjusted baseline method. This is opposite of what was seen in Figure 4-11. Again, the impacts estimated using the regression method is likely a better assessment of the impact since this event occurred on a Friday and, in absence of the program, one would expect a smaller impact since lower loads are generally observed on Fridays. In fact, an examination of the regression coefficient on the day type indicator for Friday is -986, indicating that, on average, load is generally 1 MW lower on Fridays, all else equal. Since the 10-Day adjusted baseline does not account for the day of the week, it leads to the conclusion that it might over-predict the impact for this event. Figure 4-13 below is similar to Figure 4-12; however, it also contains the event day load from the previous days event (6/22/06). As this exhibit shows, the load shape is very similar, but the magnitude of the load is approximately 10 MW higher despite their being the same exact participants.

Figure 4-12: Comparison of Estimated Impacts Methods – 6/23/06 Event

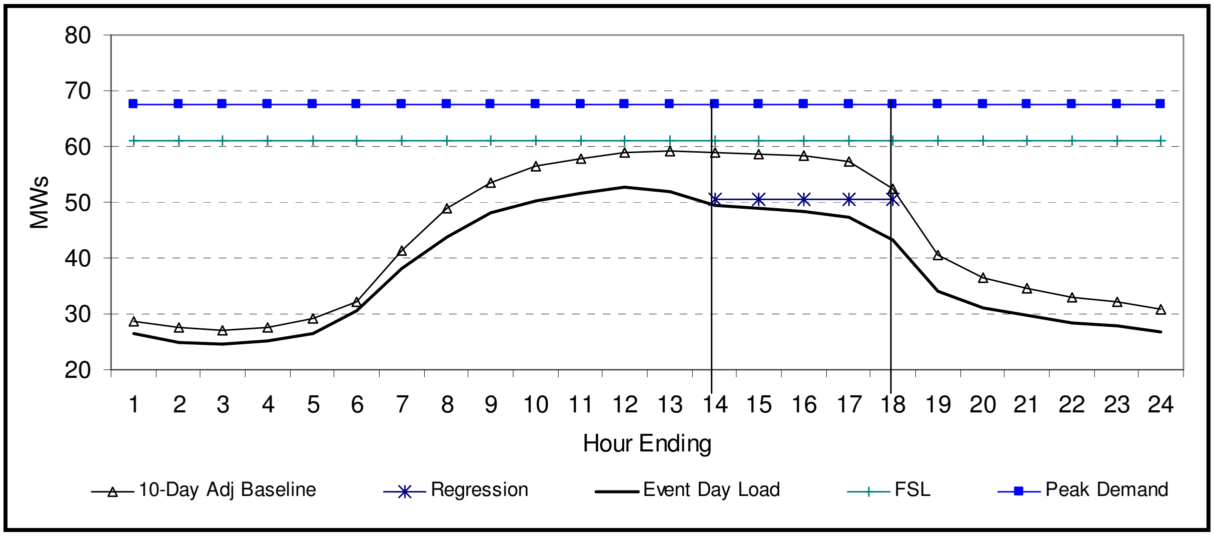
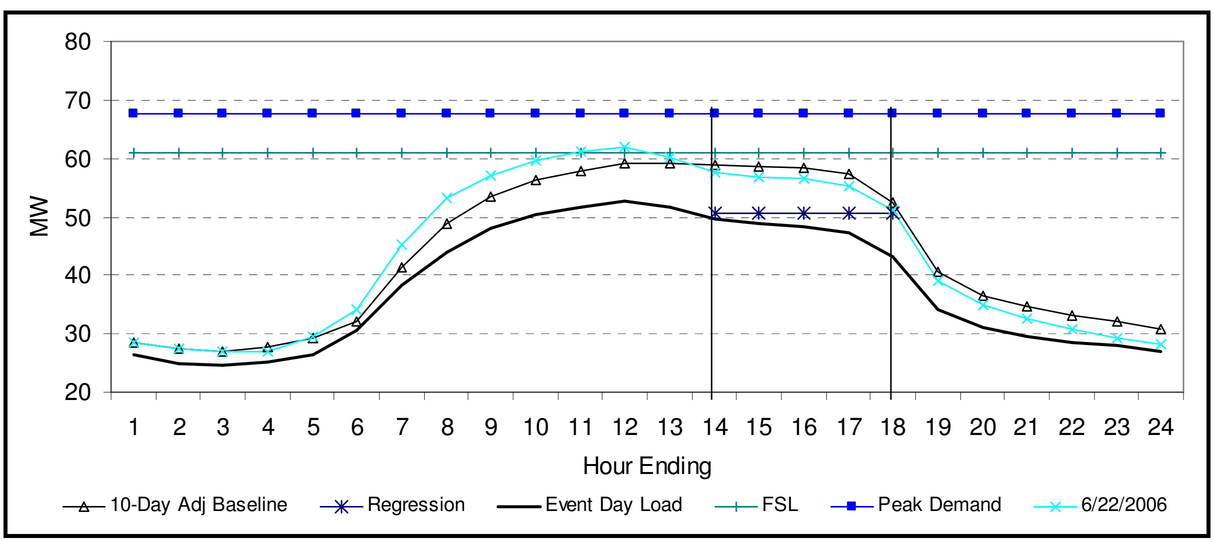
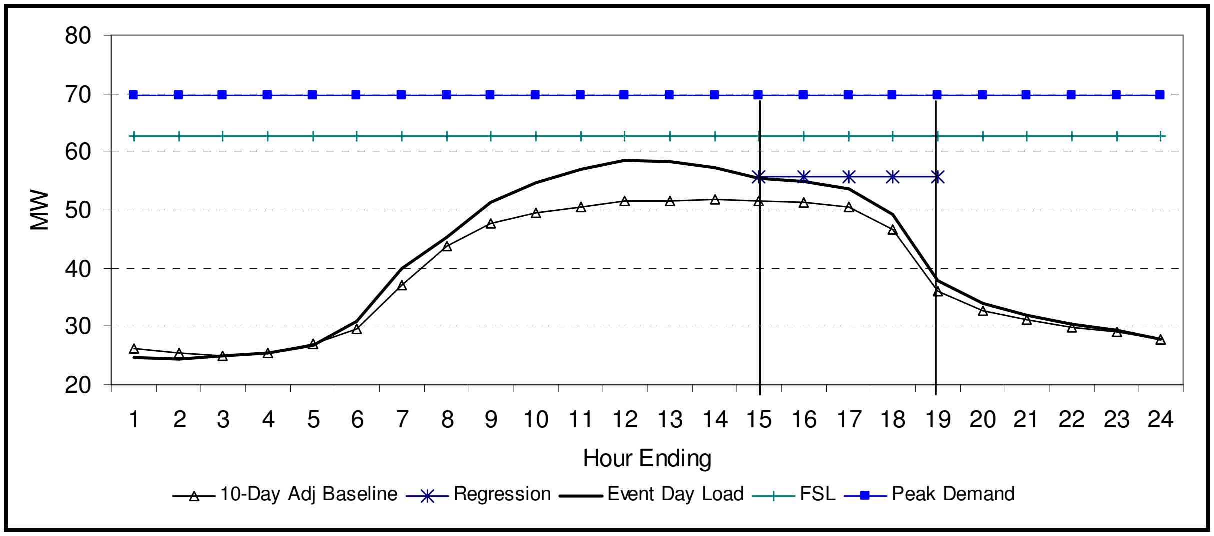


Figure 4-13: Comparison Estimated Event Day Load for Friday 6/23 Event versus Thursday 6/22 Event



The estimated impacts associated with the July 17, 2006 event, presented in Figure 4-14, are estimated at -3.0 MW using the 10-Day adjusted baseline methodology, 5.4 MW using the daily aggregate regression model, and 15.5 MW as estimated by BEC. In this case, the 10-Day adjusted method estimates a load increase during the event hours. These impacts are similar to those estimated for the following day event (7/18/06). For these two events, the average temperature between the hours of 11 a.m. and 8 p.m. were 77 and 75 degrees, compared to the average temperature during these hours for the 10 days used to create the 10-Day adjusted baseline, which was 65 degrees. This illustrates another limitation of the 10-Day adjusted baseline for customers, such as office buildings, that tend to be more weather sensitive. Although an adjustment is applied to this baseline in an attempt to bring the load more in line with recent load levels, the July 17 event fell on a Monday and was called with a day-ahead trigger. Thus, the day used to adjust the baseline was Friday, July 14, which had an average temperature of 62 degrees during the hours of 11 a.m. to 8 p.m.

Figure 4-14: Comparison of Estimated Impacts Methods – 7/17/06 Event



5

Findings, Conclusions, and Recommendations

This section discusses some of the salient findings made from the impact evaluation of the PY 2005-06 BEC demand response program. After the findings are presented, a list of recommendations are made regarding the methods to use when estimating load reductions on event days for program settlement and post-program evaluation purposes.

5.1 Findings

The following findings were made based on the analysis results presented in this study:

- While a large proportion of BEC Program participants were able to make various levels of load reductions for a particular hour of an event, these levels of load reduction could not generally be relied on across the entire summer of events. In fact, the average peak load reduction achieved by program participants was 2.5% in 2005 and 3.8% in 2006. This indicates that the average customer is shedding only a small percentage of their estimated base load for each event.

- For the summers of 2005 and 2006, the average event and non-event day loads were substantially lower than the peak demand estimated using the BEC's load reduction methodology. Using peak demand, as defined under the BEC program, leads to large over-estimations of event impacts, especially when compared to the Representative Day approach and the regression modeling methodology.

- Assuming a participant's base load was close to their peak demand, the average BEC participant would have had to reduce their load by 14% in 2005 and by more than 11% in 2006 to achieve reach their FSL. However, as mentioned in the first bullet, average peak load reduction achieved in 2005 was 2.5% and in 2006 was 3.8%. This indicates that the average customer is being paid for significantly more load than they are actually shedding.

- According to the data Itron received from PG&E for the 2005 and 2006 BEC Program events, the group's FSL was achieved for all events and thus no performance penalties were assessed. The resulting payment per participant was $75/kW and the total incentive payments in 2005 were $769,350 (for the 10.26 MW of enrolled load) and in 2006 were $1,168,050 (for the 15.6 MW enrolled). Essentially, the BEC program was paying out incentives based upon over-estimations of load reductions since these impacts were based upon BEC's definition of peak demand.

- An artifact of the 2005-06 BEC incentive payment scheme was that any customer enrolled in the BEC Program for at least one event during a particular program year received the annual incentive payment of $50/kW plus another $25/kW for the summers of 2005 and 2006 since no performance penalties were assessed. As a result, all 25 program participants in 2005 were paid the full annual incentive payment, even though seven of the participants were not fully active until the final event of the year. Likewise, 39 participants in 2006 were paid the full incentive, despite the fact that nearly a quarter of them only participated in the last event of the year. By not pro-rating a participant's annual incentive payments, the BEC incentive payment scheme provides potential enrollees with an incentive to wait until the end of summer to register for the BEC program.

- Based upon a comparison of BEC's impact estimates with those estimated using the Representative Day and regression analysis approaches, Itron finds that the average on peak demand and FSL are substantially higher than its average non-event day load across the summer. This indicates that these values are set unrealistically high and thus participants are being paid for load reductions that never occur.

5.2 Conclusions

Evaluating the PY2005-06 BEC program provided a unique opportunity to compare different methodologies of estimating the load reduction impacts for program events. Under the Representative Day approach, a number of baselines were calculated (such as the 3-Day, prior day, and 10-Day adjusted) and the differences between these baselines and actual event day loads were calculated and taken as estimates of program impacts. Regression analysis techniques were also employed to estimate program impacts that take into account variations in day type and weather. The load impacts estimated using these methodologies were in stark contrast to the impacts estimated by the BEC. The approach used by the BEC was to take the difference between a firm's highest average monthly on-peak demand[13] and its actual load on event days.

Based on the findings presented in this section and the results discussed in this evaluation report, it is apparent that there are significant issues with the methods currently used by the

[13] See Section 4.3.1 for a description of the calculation.

BEC to estimate event impacts. Although these methods (with modifications to the peak demand calculation) might still be reasonable for program settlement, as currently applied they grossly overstate the peak load reduction this program can realistically deliver on typical event days. Based upon the findings presented in this impact evaluation, there are significant advantages to using the Representative Day impact estimation methods and regression models instead. The Representative Day methods presented in this analysis are easy to implement (they are currently used for impact estimation and program settlement for other PG&E DR programs) and are reasonably transparent to participants. However, they are not as robust at dealing with weather and day-of-week sensitivity issues that affect office and commercial buildings (which comprise about 90% of the customers in this program) as the regression models are (which are more difficult to implement and less transparent to program participants). Either of these alternatives are superior to the current method employed for program settlement and load impact estimation.

5.3 Recommendations

Based on the Findings and Conclusions above, this evaluation makes the following recommendations:

1. Abandon the current method of estimating BEC program impacts and instead rely upon the set of Representative Day estimation methods for program settlement purposes. Rely upon the regression methodology for impact evaluation purposes only and ensure that the Representative Day method used continues to estimate program impacts as accurately as possible. Both of these methods are far superior to the estimation of impacts based upon the current average on-peak demand method used by the BEC Program. Program settlement for other PG&E demand response programs rely upon the Representative Day analysis and based upon this analysis, it can more reliably estimate program impacts of the BEC Program.

2. Based upon the findings from past demand response impact evaluations, the most accurate Representative Day method has proven to be the adjusted 10-Day method. Use this methodology to estimate the baseline demand of program participants. Incentive payments made to program participants should be based upon the impacts estimated based upon the adjusted 10-Day method rather than the current method which relies upon the difference between firm service level and peak demand. This current method exaggerates the load reduction occurring from the program.

3. Pro-rate incentives to program participants by paying them for actual performance in each event. The current scheme allows participants to receive payment for events that took place before they were enrolled in the BEC program.

Appendix A

Representative Day Baseline Event Day Load Shapes

This appendix contains graphs of the sum of the event day load shapes (resulting from the actual event day load and the representative day baseline analysis) across all of the active BEC participants for each of the BEC event days in 2005 and 2006. Each graph indicates the event date, the number of participants participating in the event, the sum of the FSLs for these participants and the goal reduction across these participants (the delta between the Peak Demand and FSL). The horizontal bars on each graph represent the start and end times of the event.

Figure A-1: July 12, 2005 Event

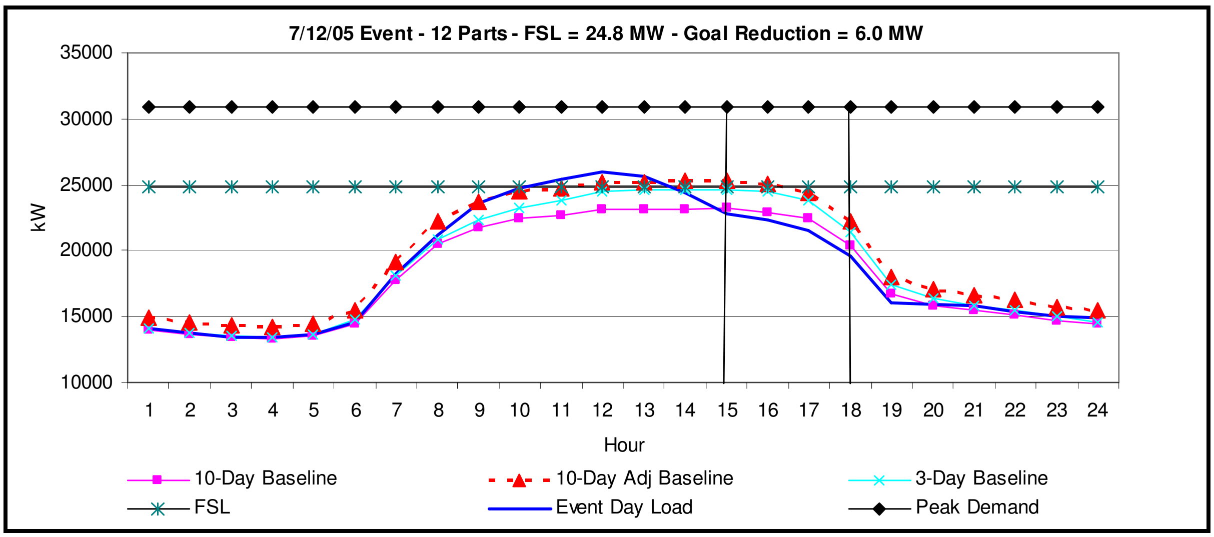


Figure A-2: July 13, 2005 Event

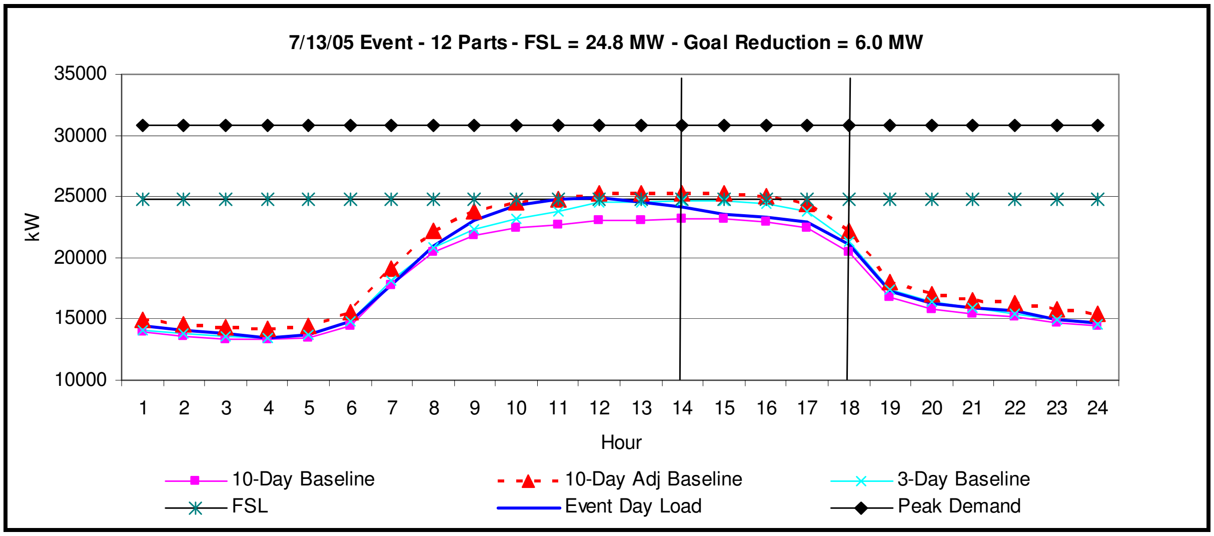


Figure A-3: August 5, 2005 Event

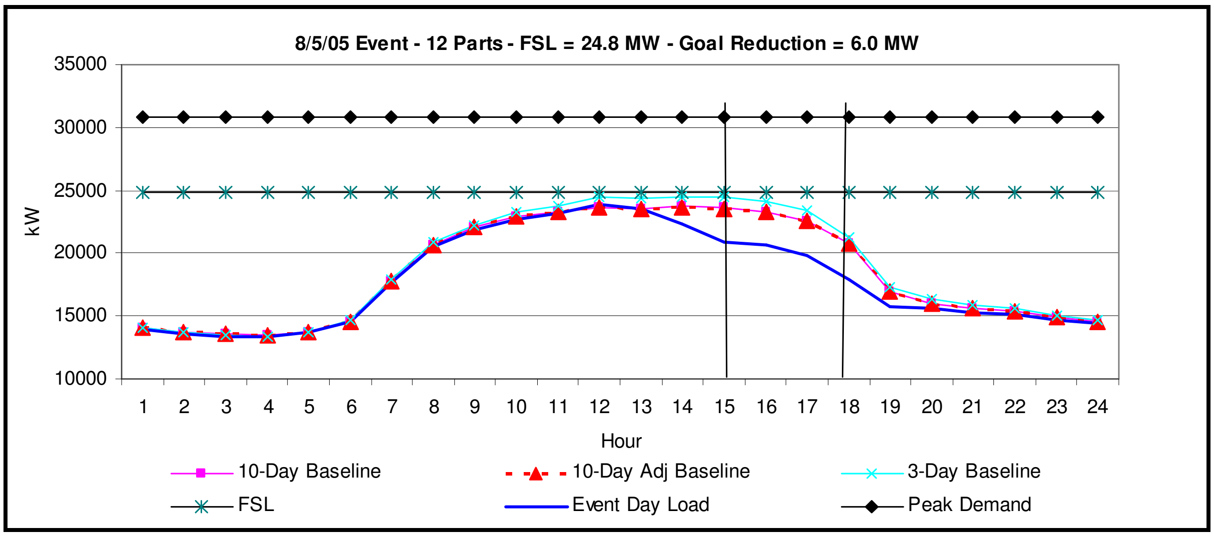


Figure A-4: August 8, 2005 Event

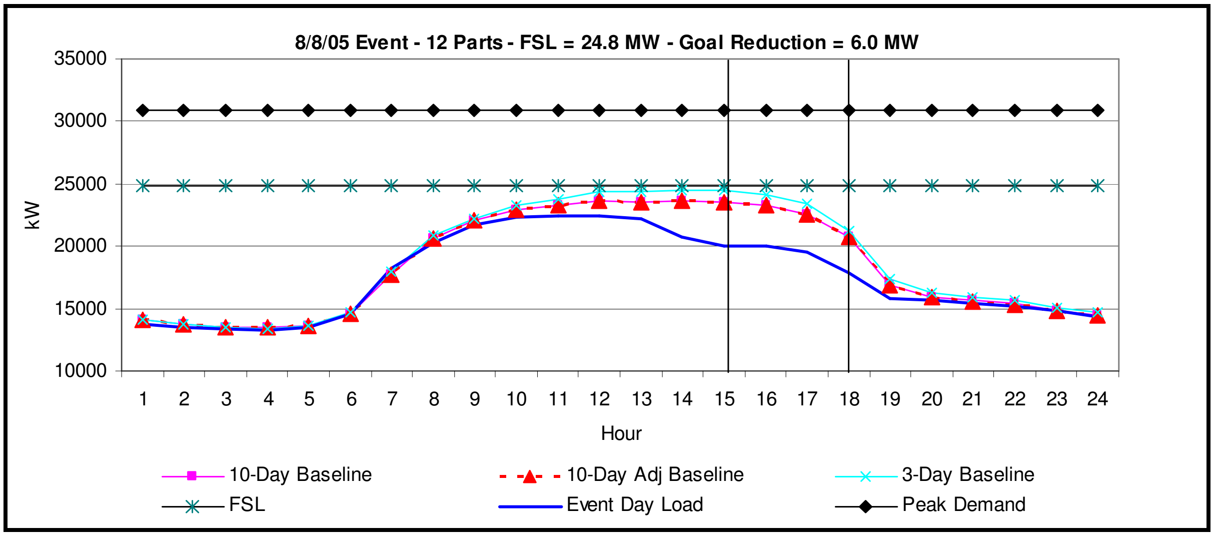


Figure A-5: August 30, 2005 Event

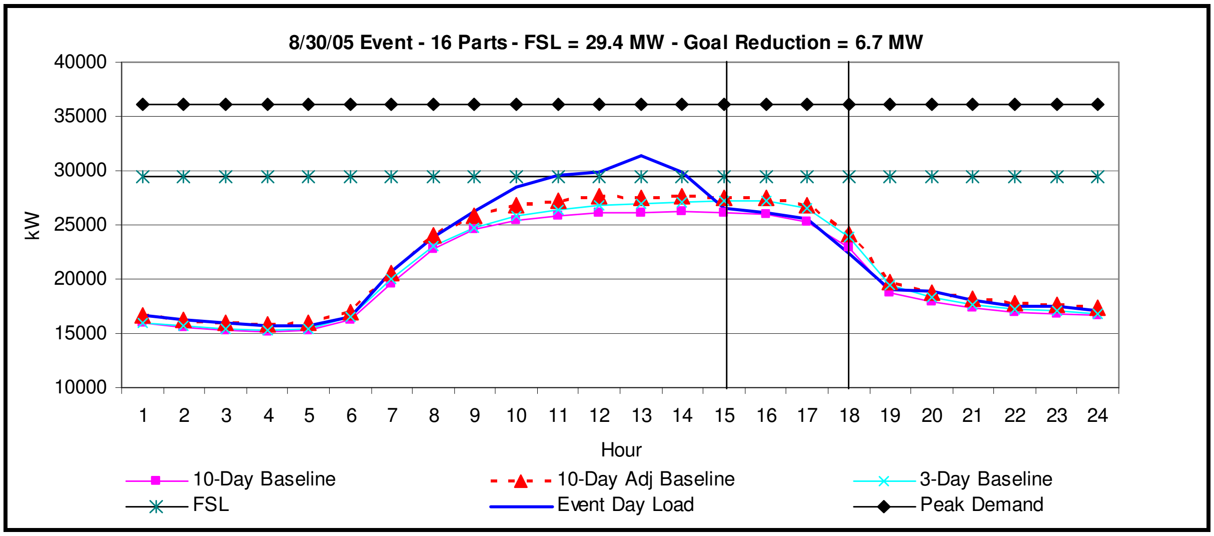


Figure A-6: September 28, 2005 Event

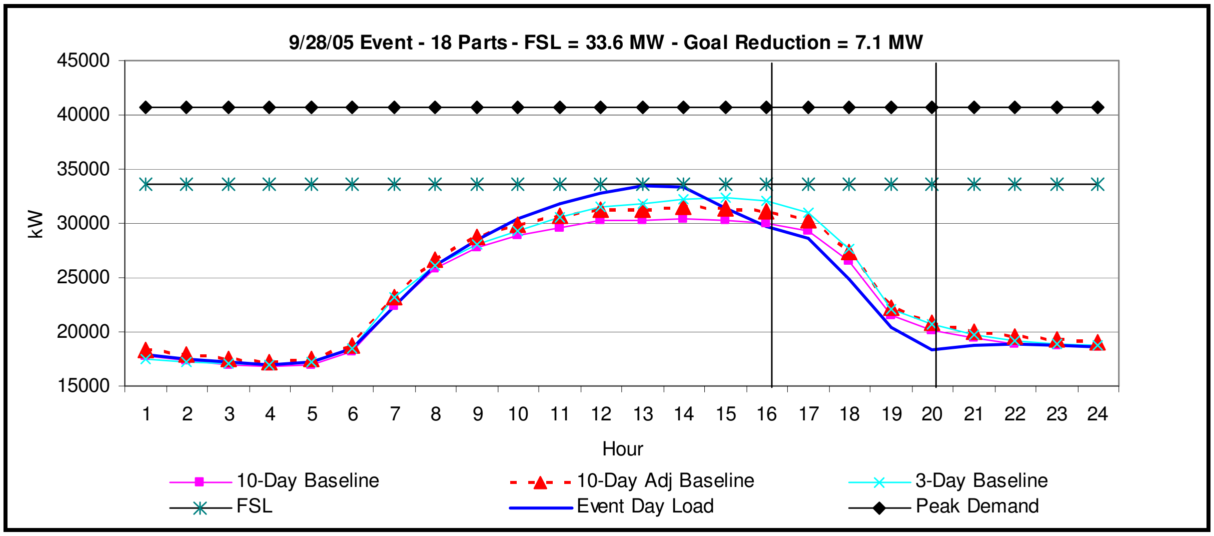


Figure A-7: September 29, 2005 Event

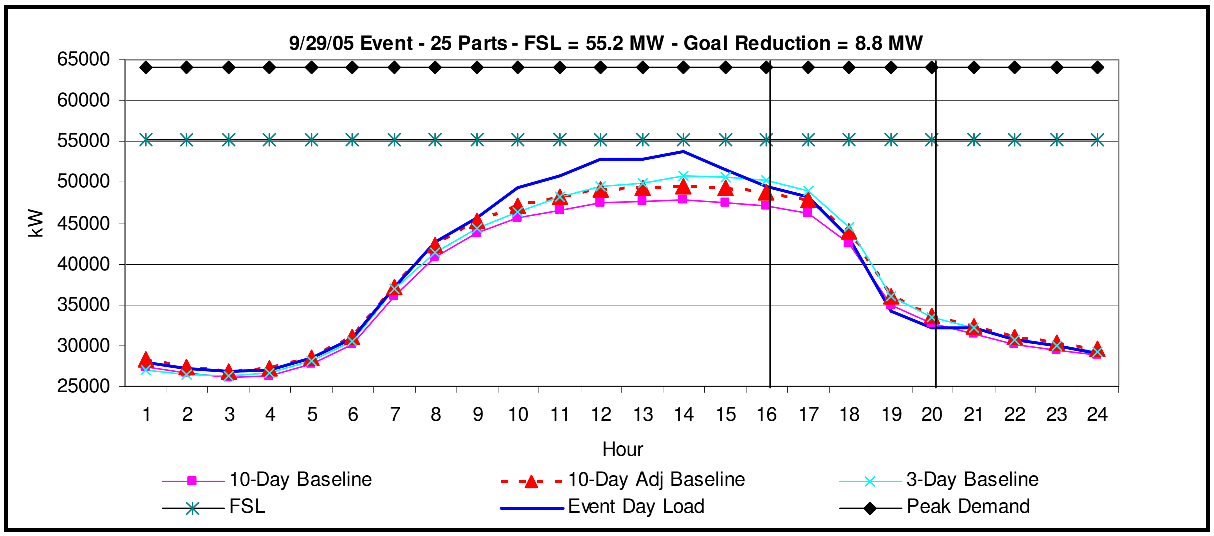


Figure A-8: All 2005 Events

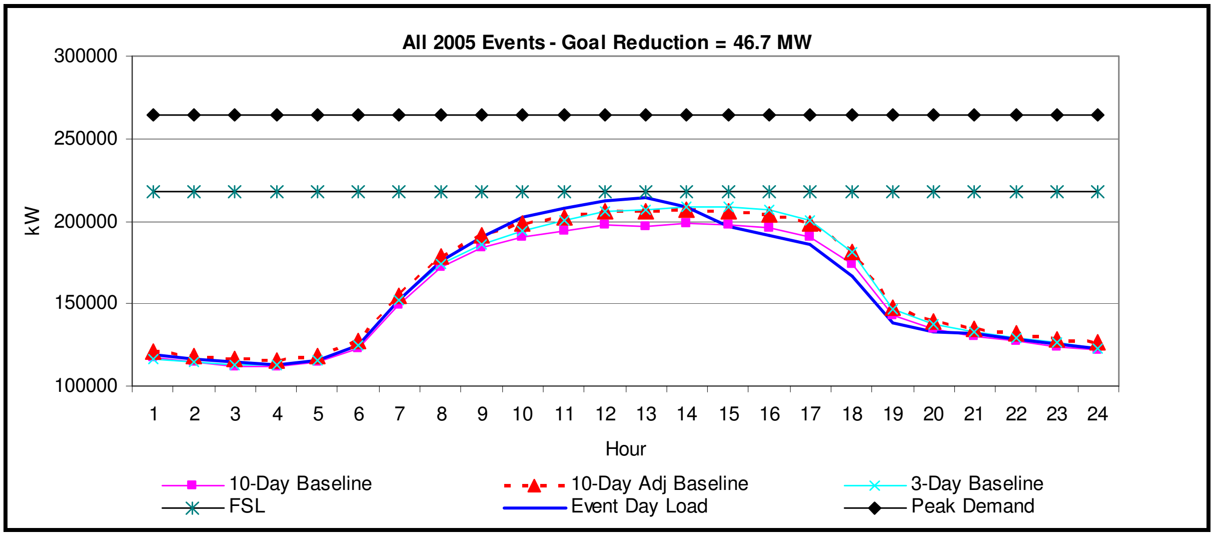


Figure A-9: June 22, 2006 Event

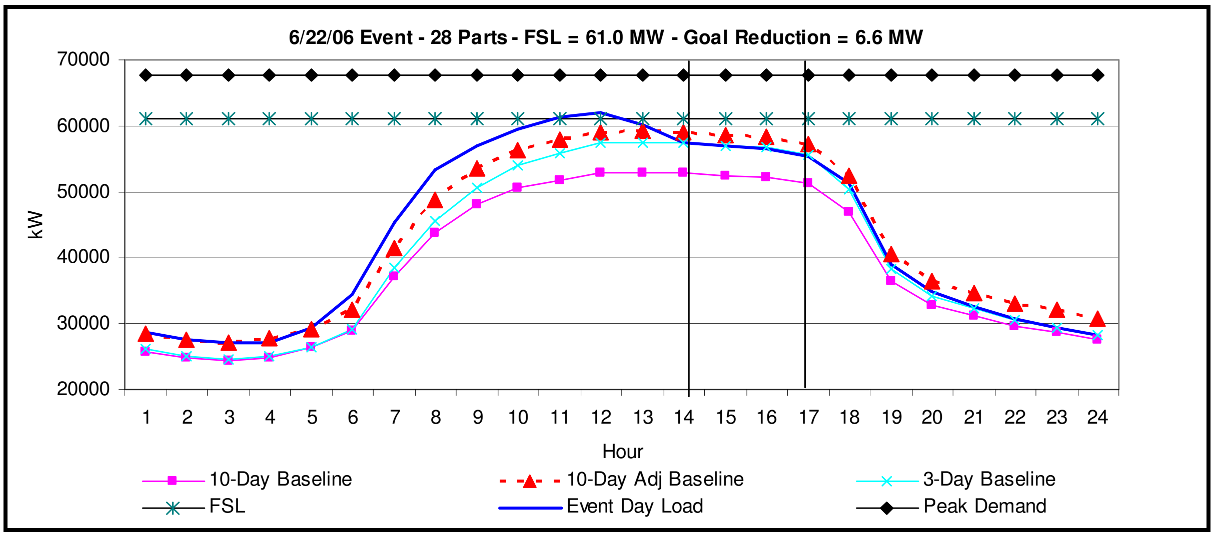


Figure A-10: June 23, 2006 Event

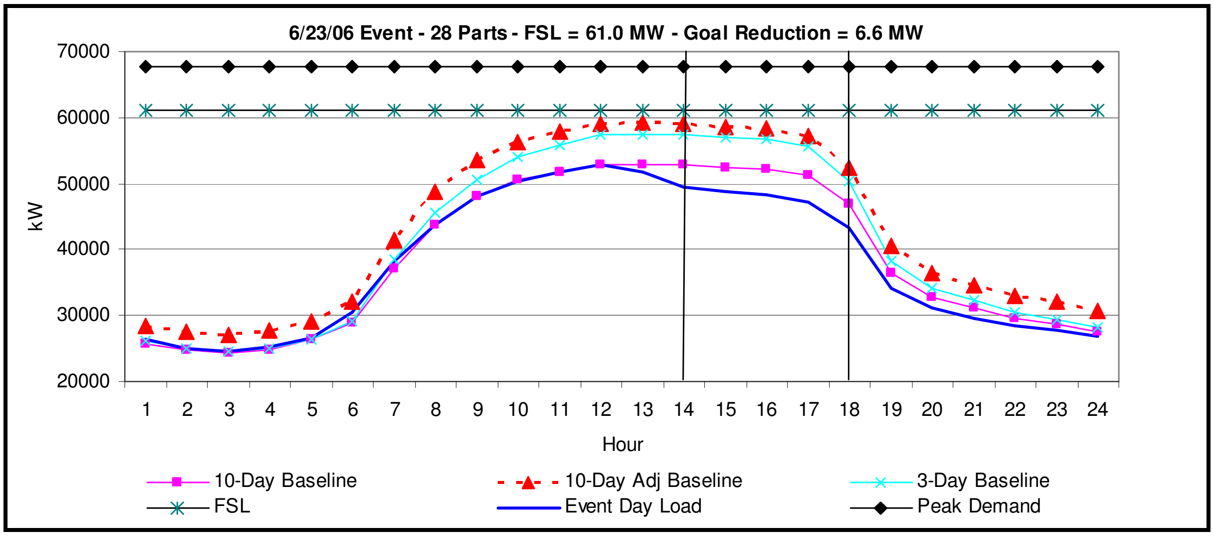


Figure A-11: July 17, 2006 Event

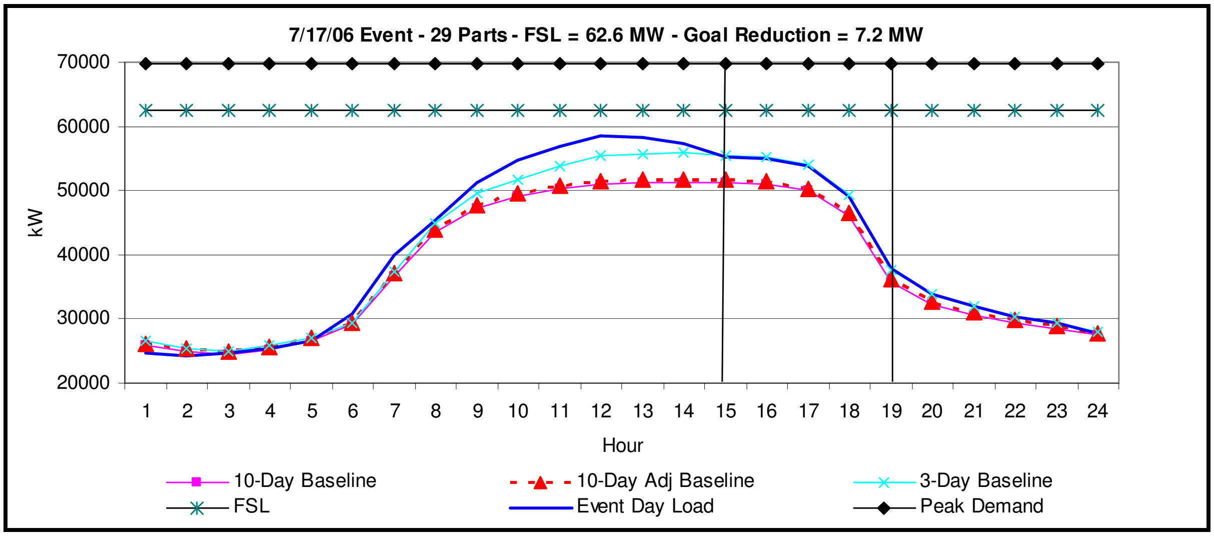


Figure A-12: July 18, 2006 Event

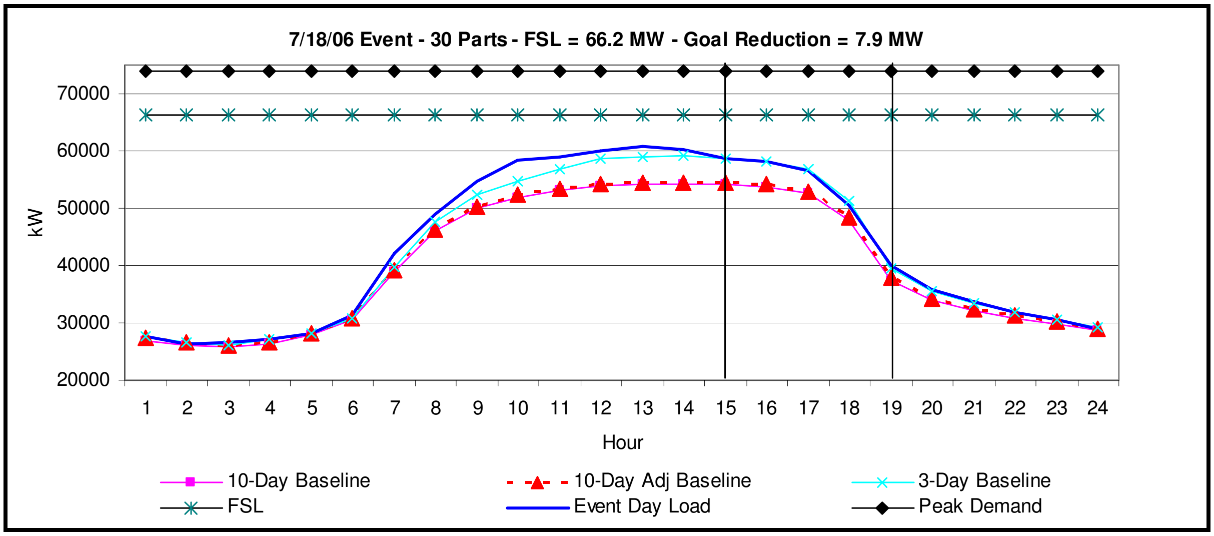


Figure A-13: July 18, 2006 Event

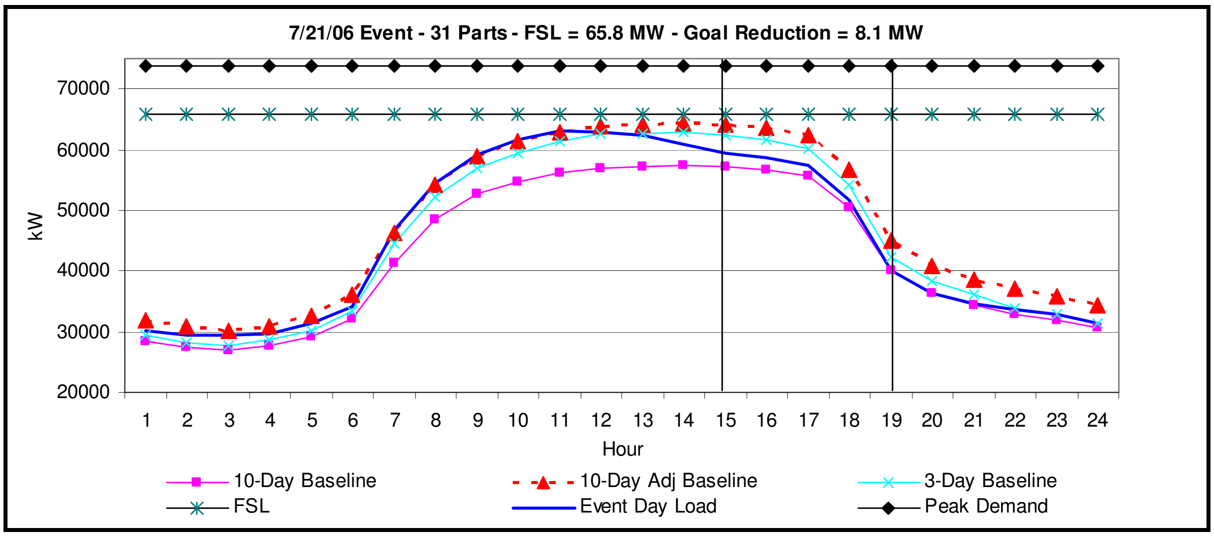


Figure A-14: July 24, 2006 Event

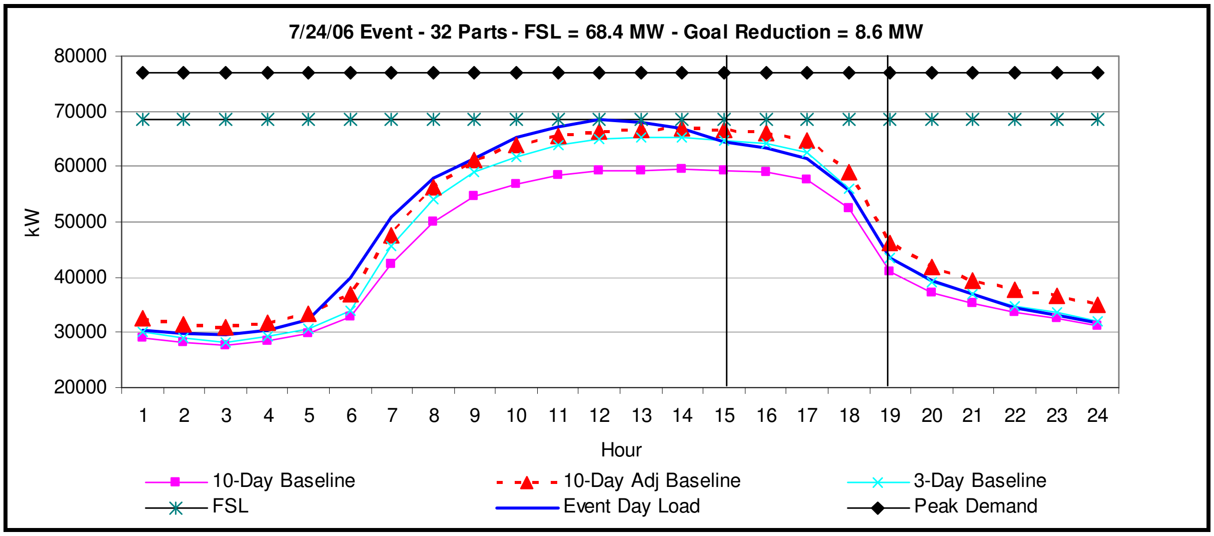


Figure A-15: July 25, 2006 Event

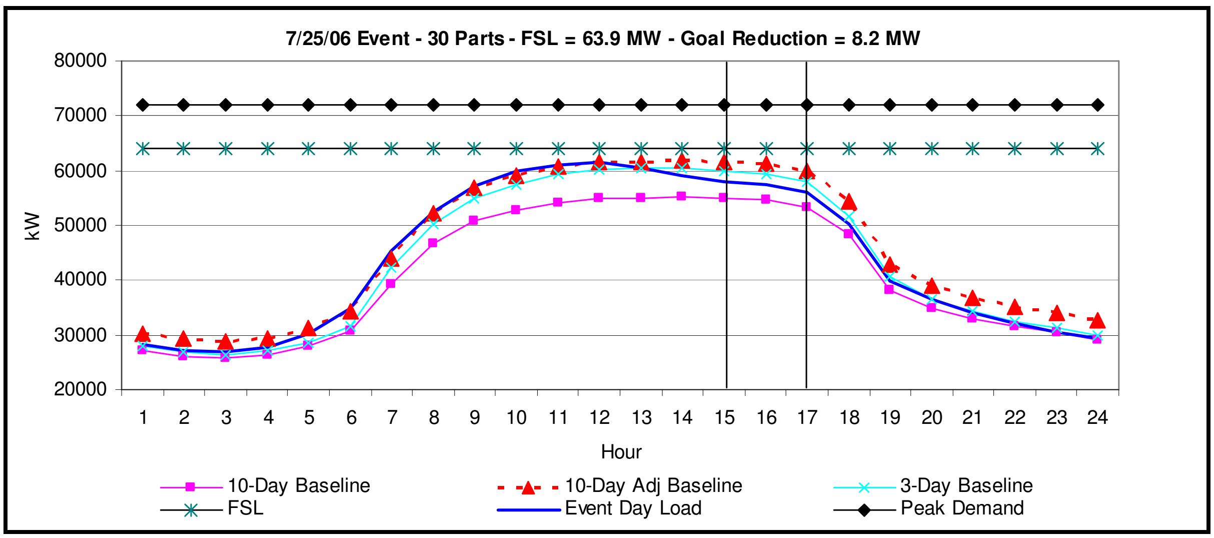


Figure A-16: All 2006 Events