FREEMAN, SULLIVAN & CO.

A MEMBER OF THE FSC GROUP

CALMAC ID: PGE0319

2012 Load Impact Evaluation of California's Statewide Base Interruptible Program

Prepared for:
Southern California Edison Co.
Pacific Gas & Electric Co.
San Diego Gas & Electric

April 1, 2013

Prepared by:
Stephen S. George, Ph.D.
Josh Schellenberg, M.A.
Aimee Savage, B.A.

Freeman, Sullivan & Co.
101 Montgomery St., 15th Fl
San Francisco, CA 94104
fscgroup.com

The FSC Group

Table of Contents

1 Executive Summary

Each of California's three major investor-owned utilities, Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E), offer the Base Interruptible Program (BIP). Although minor differences in the tariffs exist across the three utilities, for all three, BIP is a tariff based, emergency-triggered demand response (DR) program that the utilities can dispatch for California Independent System Operator (CAISO) system warnings, CAISO emergencies and local emergencies. Customers enrolled in BIP receive incentive payments in exchange for committing to reduce their electrical usage to a contractually-established level referred to as the Firm Service Level (FSL). Participants who fail to reduce load down to or below their FSL are subject to a substantial financial penalty assessed on a kWh basis. In addition, PG&E and SDG&E participants who fail to reduce load down to or below their FSL have their FSL reset up to their energy usage during the event, thus lowering their capacity payment in future months. As of January 2013, enrollment in BIP equaled 647 accounts for SCE, 266 accounts for PG&E and 11 accounts for SDG&E.

One of the most important issues facing the statewide BIP program is the cap on emergency DR programs that was adopted in 2010 by the utilities, CAISO and the California Public Utilities Commission (CPUC).[1] This cap limits the growth of emergency DR programs to a certain percentage of the recorded all-time coincident CAISO peak load. For 2012, the limit was 3% with a 10% tolerance band. The cap will gradually lower to 2% of CAISO peak load without a tolerance band from 2016 onwards. A specific portion of the cap is allocated to each utility. Considering that SCE is near its allocation of the cap, BIP enrollment is projected to remain constant throughout the ex ante forecast period (2013-2023). SDG&E BIP enrollment is also expected to remain constant. PG&E expects enrollment in its BIP program to increase over the next couple years, reaching 312 participants by the end of 2014 and then enrollment is assumed to remain constant thereafter.

This report documents the ex post and ex ante load impact estimates associated with BIP for all three of California's major investor-owned utilities. Ex post estimates are provided for 2012 events. Ex ante estimates are provided for the years 2013 through 2023.

1.1 Ex Post Load Impact Estimates

This report provides ex post load impact estimates for events called in 2012. Each utility called a territory-wide test BIP event in 2012. SCE called a test event on September 26 from 3 PM to 5 PM. PG&E implemented a test event on August 10 from 3 PM to 5 PM. SDG&E called a BIP test event on September 14 that lasted from 1 PM to 5 PM.

SCE held a system-wide test event with 24-hour advance notice for BIP on September 26 from 1 PM to 5 PM. Overall, 667 customers participated in the event. The aggregate load drop during the event period was 573 MW. This represents nearly a 74% reduction relative to the estimated reference load of 776 MW. From 4 PM to 5 PM, aggregate load lowered to 139 MW and customers provided 93% of the expected load reduction given the aggregate FSL of 90 MW.

PG&E's system-wide BIP test event was held on August 10 from 3 PM to 5 PM. The event included all of the 252 customers that were enrolled in BIP at that time. The aggregate load drop during the

[1] CPUC Rulemaking 07-01-041, Phase 3, Appendix A. February 2, 2010.

event period was 221 MW. This represents roughly an 80% reduction relative to the reference load of 277.9 MW. On aggregate, customers provided nearly 100% of the expected load reduction given the aggregate FSL of 56.7 MW.

SDG&E called a BIP event on September 14 that lasted from 1 PM to 5 PM for all customers. All customers received 30-minute notice of the event. In total, 11 customers participated in the event. The aggregate load drop from 1 PM to 5 PM was 0.84 MW. This represents roughly a 29% reduction relative to the reference load of 3.0 MW. The 1 PM to 5 PM aggregate load of 2.1 MW was substantially higher than the aggregate FSL of 0.5 MW. SDG&E BIP customers under performed during this event, providing only 34% of the 2.5 MW reduction that participants needed in order to be in compliance.

1.2 Ex Ante Load Impact Estimates

BIP is a large, statewide emergency resource that is expected to experience modest growth over the next few years. Figure 1-1 shows the amount of DR available from 2013 through 2023 by utility. For the August monthly peak day in a 1-in-2 weather year, the program is projected to deliver 864 MW in 2013. By 2015, the aggregate load impact is expected to grow by 6% to 915 MW. This growth is a result of increased enrollment among PG&E BIP customers and load growth among SCE and PG&E participants. From 2015 through 2023, the aggregate load impact remains the same. In each forecast year, around 69% to 71% of the aggregate load reduction comes from SCE, 29% to 31% from PG&E and the remaining 0.1% from SDG&E. These results are not significantly different under 1-in-10 weather year conditions because BIP customers are not weather-sensitive on average.

Figure 1-1: 2013-2023 Aggregate Load Impacts by Utility and Forecast Year
August Monthly Peak Day in a 1-in-2 Weather Year

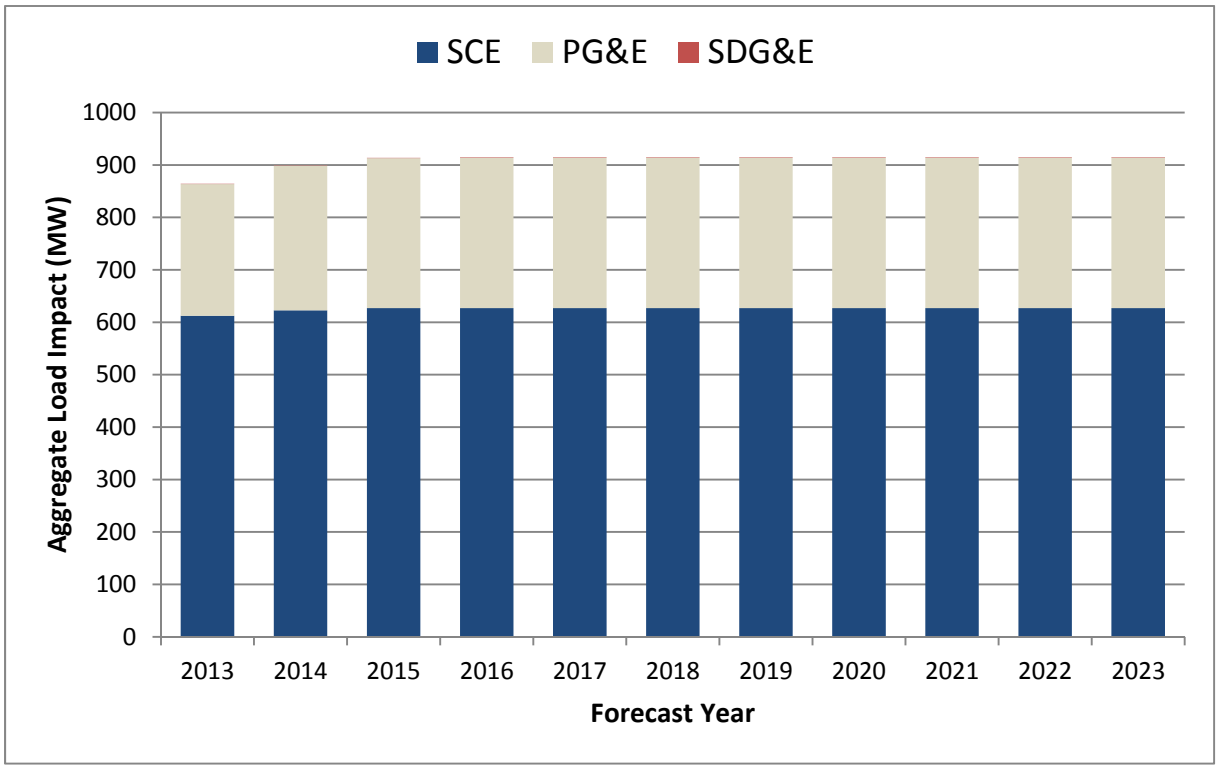
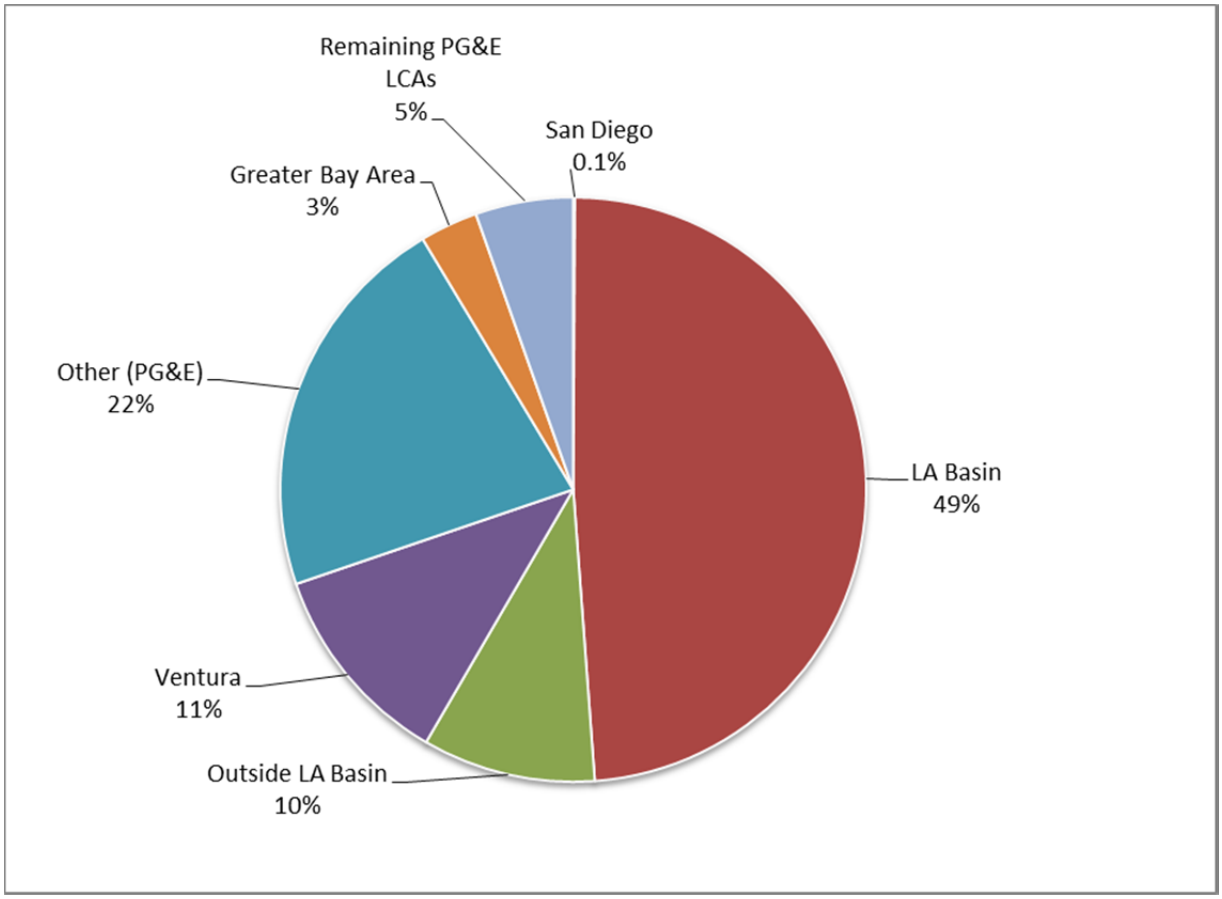


Figure 1-2 shows the distribution of statewide aggregate load impacts in 2015 by local capacity area (LCA). LCAs are CAISO-designated planning regions in which utilities must meet local resource adequacy requirements. For a typical event day in a 1-in-2 weather year in 2015, the statewide aggregate load impact is 907 MW. The LA Basin LCA in SCE's service territory comprises 49% of the statewide aggregate load impact. PG&E's Other LCA is the only area outside of SCE's territory that provides more than 3% of the statewide aggregate load impact.

Figure 1-2: Distribution of 2015 Statewide Aggregate Load Impacts by Local Capacity Area
Typical Event Day under 1-in-2 Weather Conditions
Total Statewide Aggregate Impact = 907 MW



2 Introduction and Program Summary

This report documents the 2012 ex post load impact estimates for California's statewide Base Interruptible Program (BIP) and provides ex ante load impact estimates from 2013 through 2023. Each of California's three major investor-owned utilities, Southern California Edison (SCE), Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E), offer the BIP program. Although minor differences in the tariffs exist across the three utilities, for all three, BIP is a tariff based, emergency-triggered demand response (DR) program that the utilities can dispatch for California Independent System Operator (CAISO) system warnings, CAISO emergencies and local emergencies. Customers enrolled in BIP receive incentive payments in exchange for committing to reduce their electrical usage to a contractually-established level referred to as the Firm Service Level (FSL). Participants who fail to reduce load down to or below their FSL are subject to a substantial financial penalty assessed on a kWh basis.

Until recently, the state's IOUs could only operate BIP when the CAISO determined that system-wide conditions reached a Stage 2 emergency (e.g., when operating reserves are less than 5%) or on a test-event basis. At the request of the CAISO, the California Public Utilities Commission (CPUC) ruled[2] that the three utilities must modify their tariffs. The revised tariffs allow the utilities to call BIP after CAISO has publicly issued a warning notice and has determined that a stage 1 emergency is imminent when it has exhausted all other options to prevent further degradation of its operating reserves. The other triggering conditions for BIP (local emergencies, Stage 2 alerts or test events) remain.

This report provides ex post load impact estimates for events called in 2012. Each utility called a BIP event in 2012. SCE called a test event on September 26 from 3 PM to 5 PM. PG&E implemented a test event on August 10 from 3 PM to 5 PM. There was one test event held for SDG&E's BIP program in 2012. That event occurred on September 14 and lasted from 1 PM to 5 PM.

Ex ante impact estimates for all three programs are also provided for a 1-in-2 weather year and a 1-in-10 weather year from 2013 to 2023. The load impact estimates presented here are intended to conform to the requirements of the California Public Utilities Commission (CPUC) Demand Response Load Impact Protocols.[3]

2.1 Cap on Emergency DR Programs

One of the most important issues facing the statewide BIP program is the cap on emergency DR programs that was adopted in 2010 by the utilities, CAISO and CPUC.[4] This cap limits the growth of emergency DR programs to a certain percentage of the recorded all-time coincident CAISO peak load. For 2012, the limit was 3% with a 10% tolerance band. The cap will gradually lower to 2% of CAISO peak load without a tolerance band from 2016 onwards. The cap is allocated to each utility as follows:

- PG&E: 400 MW;
- SCE: 800 MW; and
- SDG&E: 20 MW.

[2] CPUC resolution E-4220. January 29, 2009.

[3] CPUC D.08-04-050 issued on April 28, 2008 with Attachment A.

[4] CPUC Rulemaking 07-01-041, Phase 3, Appendix A. February 2, 2010.

If a utility exceeds its cap, the CPUC may reduce the amount of resource adequacy credit allocated towards emergency DR programs or ask the utility to modify the program in order to reduce enrollment.

Although there are other emergency DR programs run by the utilities, this cap has the largest impact on BIP because it comprises more than half of the state's emergency DR resources. As a result, each utility will need to closely monitor BIP enrollment in order to maximize the potential of this important resource, but not exceed the cap.

2.2 Overview of SCE's BIP Program

SCE's BIP program is designed for customers and aggregators with demands of 200 kW and above. The program includes 2 notification options: option A with a 15-minute notification lead time and option B with a 30-minute notification requirement. Interruption events for an individual BIP customer or aggregated group are limited to a single 6-hour event per day, and no more than 180 hours per calendar year. An interruption event may be called at any time during the year.

SCE's I-6 program was a predecessor interruptible tariff designed for large customers with demands of 500 kW and above. The I-6 tariff has been closed to new enrollment since 1996. Starting in 2006, SCE began transitioning I-6 customers to BIP. The transition was complete by the end of 2008. As of January 2013, SCE had 647 service accounts enrolled in the BIP program, of which nearly 88% were in the 30-minute notification option. As indicated in Table 2-1, the largest number of accounts is from the manufacturing sector (58% of the total).

Table 2-1: Number of Accounts in SCE's BIP Program by Industry

Industry	Number of Accounts
Agriculture, Mining & Construction	56
Manufacturing	377
Wholesale, Transport & Other Utilities	64
Retail Stores	41
Offices, Hotels, Finance & Services	36
Schools	68
Institutional/Government	5
Total	**647**

SCE's service territory includes three CAISO local capacity areas (LCA).[5] The vast majority of service accounts (552 out of the 647 BIP accounts) are in the LA Basin LCA; 73 are located in the Ventura LCA and the remaining 22 are in the Outside LA Basin LCA.

[5] Local capacity area (or LCA) refers to a CAISO-designated load pocket or transmission constrained geographic area for which a utility is required to meet a Local Resource Adequacy capacity requirement. There are currently three LCAs within SCE's service territory, seven in PG&E's service territory and one in SDG&E's service territory. In addition, PG&E has many accounts not located within any specific LCA. These accounts are categorized here as being in the "Other" LCA region.

In the ex ante analysis, it is assumed that enrollment remains the same from 2013 through 2023. Considering that SCE is close to its cap on emergency DR programs, they do not plan to actively recruit new BIP customers.

There was one test event held for SCE's BIP program in 2012. That event occurred on September 26 and lasted for two hours, from 3 PM to 5 PM. Section 4.1 summarizes the ex post results for this event.

2.3 Overview of PG&E's BIP Program

Customers can enroll in PG&E's BIP program either directly or through an aggregator. The program is designed for customers with minimum average monthly demand of at least 100 kW. Customers enrolled in PG&E BIP are notified at least 30 minutes in advance of an event. Previously, there was an option B with a 4-hour notification lead time, but it is no longer offered. At the time option B was discontinued, all PG&E BIP customers were enrolled in the 30-minute notification option. Curtailment events for an individual BIP customer or an aggregated group of customers are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

As January 2013, there were 252 accounts[6] enrolled in PG&E's BIP program. Since the end of 2011, the number of participants has grown by 22 accounts. Table 2-2 shows the distribution of service accounts by industry grouping. As in SCE's BIP program, the largest number of accounts comes from the manufacturing sector (35% of the total).

Table 2-2: Number of Accounts in PG&E's BIP Program by Industry

Industry	Number of Accounts
Agriculture, Mining & Construction	42
Manufacturing	89
Wholesale, Transport & Other Utilities	40
Retail Stores	33
Offices, Hotels, Finance, Services	18
Schools	19
Institutional/Government	11
Total	**252**

Table 2-3 shows the distribution of PG&E BIP accounts across LCAs within PG&E's service area. Most BIP participation comes from the Other and Greater Bay Area LCAs.

[6] Officially, PG&E refers to these as "service agreements," but in order to be consistent with the terminology used for SCE and SDG&E, "accounts" is used.

Table 2-3: Number of Service Accounts in PG&E's BIP Program by LCA

LCA	Number of Accounts
Greater Bay Area	65
Greater Fresno	18
Humboldt	11
Kern	20
Northern Coast	19
Other	89
Sierra	7
Stockton	23
Total	**252**

PG&E expects enrollment in its BIP program to increase over the next few years. Enrollment peaks at 312 participants in 2014 and remains constant until end of the ex ante forecast period (2023).

There was one event for PG&E's BIP program in 2012. The system-wide test event occurred on August 10 and lasted for two hours, from 3 PM to 5 PM. Section 5.1 summarizes the ex post results for this event.

2.4 Overview of SDG&E's BIP Program

SDG&E BIP is a voluntary program that offers participants a monthly capacity bill credit in exchange for committing to reduce their demand to a contracted FSL on short notice during emergency situations. Non-residential customers who can commit to curtail 15% of monthly peak demand with a minimum load reduction of 100 kW are eligible for the program. Customers in BIP are notified no later than 30 minutes before the event. Previously, there was an option B with a 3-hour notification lead time, but it is no longer offered. Incentive payments are $12 per kW during May through October and $2 per KW during all other months. Curtailment events for an individual BIP customer are limited to a single 4-hour event per day, no more than 10 events per month and no more than 120 event hours per calendar year. A curtailment event may be called under BIP at any time during the year.

Participation in SDG&E's program has been relatively low. There was one participant in 2006 and three in 2007. Participation grew from 3 to 20 participants in 2008, but fell to 19 participants as of January 2010. By the end of 2010, there were 21 accounts enrolled in SDG&E BIP and enrollment remained at that level through the end of 2011. However, by May of 2012, enrollment dropped to 11 accounts and remained flat until the end of 2012. The current distribution of accounts by industry is shown in Table 2-4. There is only one LCA in SDG&E's service territory.

Table 2-4: Number of Service Accounts in SDG&E's BIP Program by Industry

LCA	Number of Accounts
Agriculture, Mining & Construction	2
Manufacturing	3
Wholesale, Transport & Other Utilities	1
Retail Stores	3
Offices, Hotels, Finance, Services	2
Total	**11**

Enrollment in SDG&E's BIP program is expected to remain stable over the next few years.

There was one event held for SDG&E's BIP program in 2012. That event occurred on September 14 and lasted for four hours, from 1 PM to 5 PM.

2.5 Report Structure

The remainder of this report is organized as follows. Section 3 discusses the methodology for the ex post and ex ante evaluations. Sections 4, 5 and 6 include the ex post and ex ante load impact estimates for each utility and Section 7 contains recommendations for improving the program. All of the required ex post and ex ante hourly load impact tables are included in the electronic appendices.

3 Methodology

This section discusses the methodology that was used to develop ex post and ex ante load impact estimates for BIP. It covers the regression model development and assessment of its accuracy.

3.1 Model Development

For DR resources that have numerous events, regression analysis can be used to estimate the typical (absolute or percentage) load reduction associated with events as a function of event-day conditions (e.g., weather, day-of-week, etc.). These regression models can then be used to predict either ex ante or ex post impacts as a function of the conditions that occurred on those historical days or that are expected to occur on future days on which program events are most likely to be called.

With DR resources for which there is little event history like BIP, this regression-based method cannot be used to predict load reductions because there is not enough empirical event data for estimating the impact coefficients. However, for ex ante load impact estimation purposes, regression analysis can be used to predict the reference load (i.e., the load that would occur in the absence of a program event), and the expected load reductions from those customers given their FSL. For ex post load impact estimation purposes, regression analysis can be used to predict the reference load for the historical event day; the actual metered load for that day can be subtracted from the reference load to estimate the load impact.

For ex ante analysis, the estimated load reduction for BIP is a function of:

- Forecasted load in the absence of a DR event (i.e. the reference load);
- The participant's FSL; and
- Over/under performance relative to the FSL.

The reference load is estimated using the regression model discussed below. Over/under performance, which is a measure of how well customers perform during BIP events relative to the FSL, is determined for each industry using historical event data. Although the number of events is too small to be used in a regression to predict the load with DR, it can be used to adjust load relative to the FSL. By subtracting the estimated load with DR from the reference load, the ex ante load impact can be estimated.

The regression models used to predict reference loads were developed with the primary goal of accurately predicting the average customer load given time-of-day, day-of-week, month and temperature. Given that all BIP customers are on TOU rates, rate-period variables were also included in the model specification. The estimated models were based on one year of hourly load data for each customer. Individual regressions with all 24 hours included were run for each customer.

The dependent variable in the regression model was the kW load in each hourly interval for each participant. The regression model contained hundreds of variables, consisting largely of shape and trend variables (and interaction terms) designed to track variation in load across days of the week and hours of the day. Weather variables were tested and had significant impacts for certain customers. Binary variables representing when the underlying TOU rates changed during the day and season were also included to capture the change in load due to price variation. The regression model is as follows:

$$kW_t = A + B \times SummerOn_t + C \times SummerMid_t + D \times SummerOff_t + E \times WinterMid_t + \sum_{i=1}^{24}\sum_{j=1}^{5} F_{ij} \times Hour_i \times DayType_j + \sum_{i=1}^{24}\sum_{j=1}^{12} G_{ij} \times Hour_i \times Month_j + \sum_{i=1}^{24} H_{ij} \times Hour_i \times TotalCDH_t + \sum_{i=1}^{24} I_{ij} \times Hour_i \times TotalCDHsqr_t + \sum_{i=1}^{24} J_{ij} \times Hour_i \times TotalHDH_t + \sum_{i=1}^{24} K_{ij} \times Hour_i \times TotalHDHsqr_t + \sum_{i=1}^{24} L_i \times Hour_i \times Other\_Eventday_t + \sum_{i=1}^{24}\sum_{j=1}^{2} M_{ij} \times Hour_i \times BIP\_Eventday_j + e_t$$

Table 3-1: Variable Descriptions

Variable	Description
kWt	hourly BIP customer load at time t
A	estimated constant term
B through Mij	estimated parameters
SummerOnt, SummerMidt, SummerOfft and WinterMidt	binary variables that indicate which TOU rate block is in effect for each hour
Houri	series of binary variables for each hour, which is interacted with all of the remaining variables because each has an impact that varies by hour
DayTypej	series of binary variables representing five different day types (Mon, Tues-Thurs, Fri, Sat, Sunday/Holiday)
Monthj	series of binary variables for each month
TotalCDHt	total number of cooling degree hours (base 70) per day
TotalCDHsqrt	total number of cooling degree hours per day squared
TotalHDHt	total number of heating degree hours (base 70) per day
TotalHDHsqrt	total number of heating degree hours squared
Other_Eventdayt	binary variable for event days from other DR programs
BIP_Eventdayj	binary variable representing each BIP event day;7
et	error term

Load was significantly lower in recent years for many BIP customers due to changes in overall economic conditions. If these conditions were not accounted for in the model, there would be a

[7] SCE and SDG&E had one event during the time period included in the estimation, whereas some PG&E BIP participants had two events.

downward bias in the forecasted reference load for the ex ante analysis, assuming that economic growth rebounds from recent years. Each utility had its own assumptions concerning the economic recovery and its effect on BIP load in the ex ante analysis:

- SCE: BIP load is assumed to increase by 1.5% per year from 2013 through 2014 and then reach a steady state from 2015 through 2023;
- PG&E: BIP load is assumed to increase by 1% per year from 2013 through 2015 and then reach a steady state from 2016 through 2023; and
- SDG&E: BIP load is assumed to remain the same. With so few customers in the program, it is difficult to determine whether a customer experienced a decline in load due to the economic downturn or had a permanent change in their business practices.

For SCE, the load growth assumption is based on an analysis of recent trends in aggregate BIP load. PG&E used its internal economic forecast for large business customers to project how BIP load will change from 2013 through 2023.

3.2 Model Accuracy and Validity Assessment

Although regressions were run for each individual customer in the BIP program, what matters most is that the reference loads for all customers combined, or for selected groups of customers (e.g., industry types, LCA) are accurate. The regressions are not as accurate at the individual customer level, but when aggregated, overestimates and underestimates generally balance each other out and the resulting aggregate reference load is more accurate. Given that load impacts are calculated as the difference between the reference load and the FSL (after factoring in over/under performance), any error in the estimated reference load would cause an error in the estimated load impact.

3.2.1 Out-of-Sample Validation

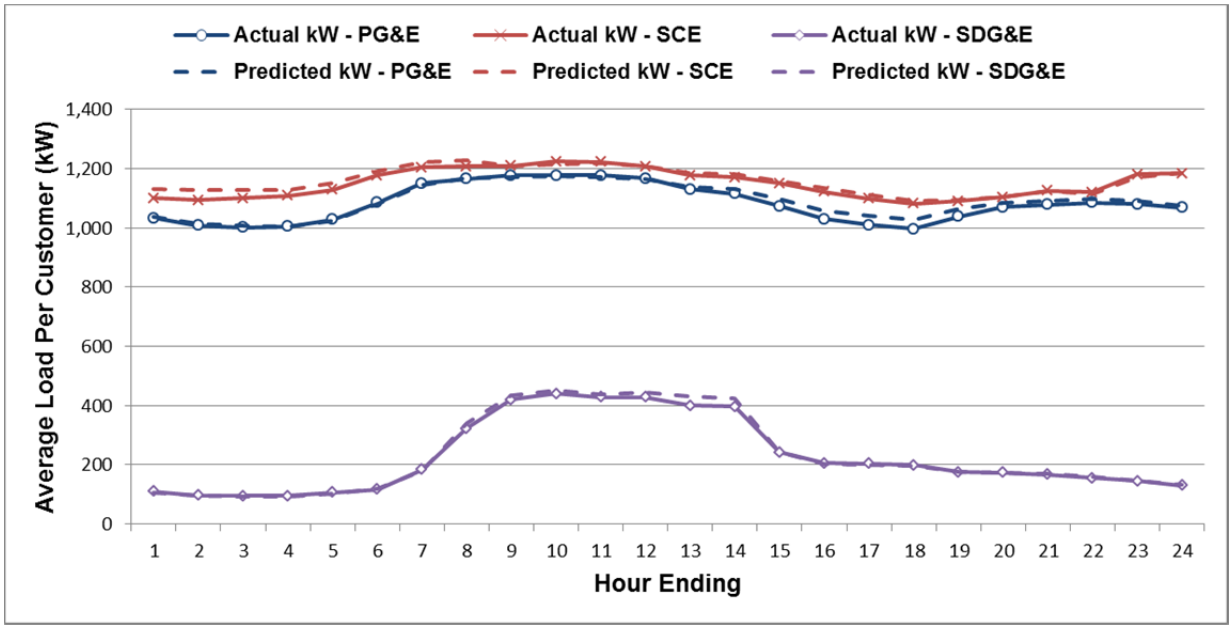
Considering that BIP events are usually called on high system load days, it is important that the model predicts accurately on these days. In the first test of model accuracy, a series of out-of-sample validations is conducted. Rather than running the model on all of the available load data, a group of three randomly selected high system load days is withheld from the estimation. Although these three days are not included in the estimating sample, the model is used to predict load on those days. This process is repeated three times so that, in total, out-of-sample predictions of load are generated for the top nine system load days for each customer.

This validation process most closely aligns with what is expected of the model in the ex post and ex ante analyses. In the ex ante analysis, the model is used to simulate the reference load and load with DR under 1-in-2 and 1-in-10 weather year scenarios. The ex post analysis estimates load reductions by predicting what load would have been if an event was not called. In both of these analyses, out-of-sample predictions are generated for scenarios in which actual, unperturbed load data is not available. Therefore, out-of-sample validation using randomly selected high system load days is a logical test to determine which model is most accurate.

Figure 3-1 shows the results of the out-of-sample validation for the average of the top nine system load days for each customer. As seen in the figure, the model accurately predicts load on high system load days even if those days are not included in the estimating sample. The difference between actual and predicted load did not exceed 8.0% in any hour for each utility, and was below 4.0% in most

instances. More importantly, the percentage error is low during the afternoon when events are most likely to be called. Between 1 PM and 6 PM, the SCE model very slightly over predicts by 0.1%, the PG&E model over predicts by less than 2.5% and the SDG&E model is over by 0.5%. Considering that BIP customers typically drop more than 70% of their load during events, an error up to 2.5% during event hours will have little effect on the accuracy of the load impact estimates.

Figure 3-1: Actual v. Predicted Average Load by Utility
Out-of-Sample Validation for Top 9 System Load Days[8]



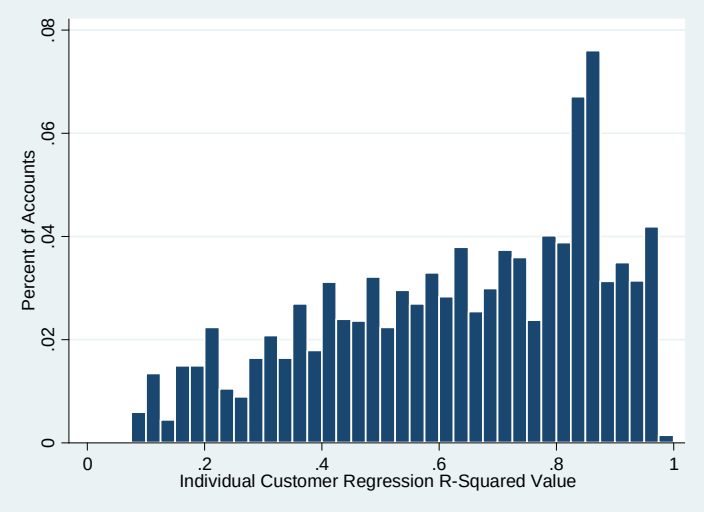
3.2.2 Goodness of Fit Measures

Although regressions were estimated at the individual customer level, from a program standpoint, the focus is less on how the regressions perform for individual customers than it is on how the regressions perform for the average participant and for specific customer segments. Individual customers exhibit more variation and less consistent energy use patterns than the average participant population. Likewise, the regressions are better at explaining the variation in electricity consumption and load impacts for the average customer (or average customer within a specific segment) than for individual customers. Put differently, it is more difficult to fully explain how a customer from a specific industry behaves on an hourly basis than it is to explain how the average customer in that industry behaves on an hourly basis. Because of this, we present measures of the explained variation, as described by the R-squared goodness-of-fit statistic, for the individual regressions, for specific customer segments and for the average customer overall.

Figure 3-2 shows the distribution of R-squared values from the individual customer regressions for SCE BIP customers. Roughly half of the individual customer regressions had R-squared values above 0.6, which suggests that the model predicts well for most SCE BIP customers.

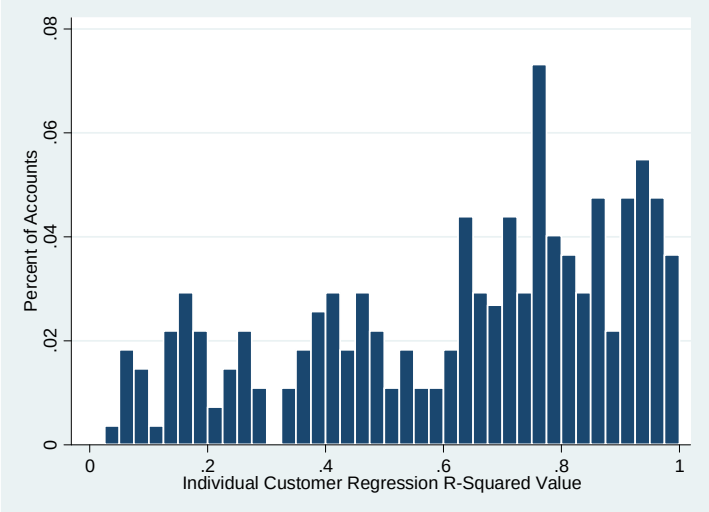
[8] Note that there are two lines for each utility in the graph, but due to the small error between estimated and actual values, it is difficult to distinguish the two lines. A table of the hourly values for each utility is provided in Appendix A.

Figure 3-2: Distribution of R-squared Values from Individual Regressions for SCE BIP Customers



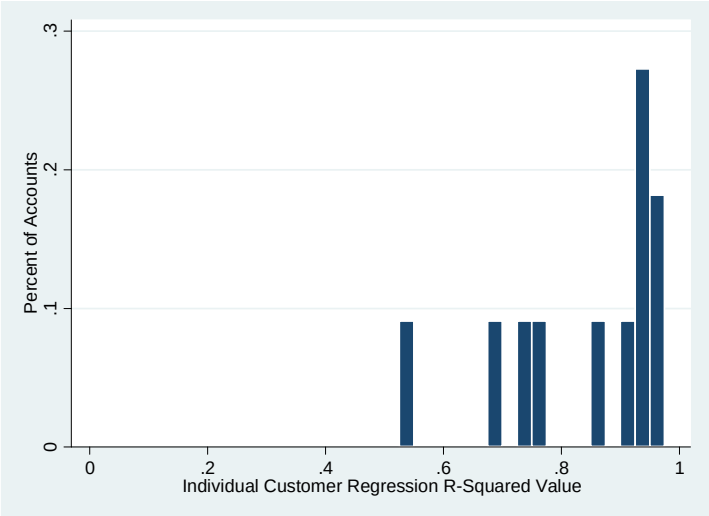
For PG&E BIP customers, the distribution of R-squared values from the individual customer regressions is more variable, as shown in Figure 3-3. About 68% of the individual customer regressions had R-squared values above 0.5. This result suggests that the model explains most of the variation in load for the majority of PG&E BIP customers. The lower one-third of all PG&E individual regressions had R-squared statistics below 0.5. The difference in the distribution of R-squared values between the utilities is primarily a function of the difference in industry mix. PG&E has a relatively large portion of BIP customers in the wholesale, transport & other utilities segment, which has load that is more difficult to explain.

Figure 3-3: Distribution of R-squared Values from Individual Regressions for PG&E BIP Customers



As shown in Figure 3-4, the model has relatively high R-squared values for SDG&E BIP customers. All individual customer regressions have an R-squared value above 0.5.

Figure 3-4: Distribution of R-squared Values from Individual Regressions for SDG&E BIP Customers



In order to estimate the average customer R-squared values for each industry, LCA or the program as a whole, the regression-predicted and actual electricity usage values were averaged across all customers for each date and hour. This process produced regression-predicted and actual values for the average customer, which enabled the calculation of errors for the average customer and the calculation of the R-squared value. The R-squared values for the average participant and for the average customer by segment were estimated using the following formula:[9]

$$R^2 = 1 - \frac{\sum_t (y_t - \hat{y}_t)^2}{\sum_t (y_t - \bar{y})^2}$$

Table 3-2: Variable Descriptions

Variable	Description
y_t	actual energy use at time t
$\hat{y}_t$	regression predicted energy use at time t
$\bar{y}$	average energy use across all time periods

Table 3-3 summarizes the amount of variation explained by the regression model by industry and utility. For all customers, SCE and PG&E have an aggregate R-squared value of 0.6 and 0.7, which means that the model explains 60% and 70% of variation in aggregate BIP load for each utility. As

[9] Technically, the R-squared value needs to be adjusted based on the number of parameters and observations from each regression. Given that the number of observations per regression was typically over 8,000, the effects of the adjustment were anticipated to be minimal. As a result, the unadjusted R-squared is presented in order to avoid the complication of tracking the number of observations and parameters from each individual regression.

suggested by the histograms above, SDG&E BIP customers have a higher R-squared of 0.84. Retail stores have the highest aggregate R-squared value for each utility, ranging from 0.95 for SCE to 0.99 for PG&E. In general, customers in the wholesale, transport & other utilities segment have usage that is relatively more difficult to explain, which is why their aggregate R-squared value is relatively low.

Table 3-3: Aggregate R-Squared Values by Industry and Utility

Industry	SCE	PG&E	SDG&E
Agriculture, Mining & Construction	0.36	0.73	0.81
Manufacturing	0.55	0.64	0.73
Wholesale, Transport & Other Utilities	0.35	0.46	0.94
Retail Stores	0.95	0.99	0.98
Offices, Hotels, Finance & Services	0.89	0.91	0.96
Schools	0.92	0.82	
Institutional/Government	0.71	0.96	
All Customers	**0.60**	**0.70**	**0.84**

Table 3-4 shows the aggregate R-Squared values by LCA. The explained variation varies from 36% to 86% across LCAs. Only 2 of the LCAs have an R-squared value below 0.5 – SCE's Outside LA Basin LCA (0.39) and PG&E's Kern LCA (0.36). As shown in Table 3-3, the model has a relatively low R-squared value for agriculture, mining & construction and wholesale, transport & other utilities customers. These two industries comprise a large part of the customer mix in the Outside LA Basin and Kern LCAs, respectively, which explains why the R-squared is relatively low.

Table 3-4: Aggregate R-Squared Values by LCA

Utility	Local Capacity Area	R-Squared
SCE	LA Basin	0.60
	Outside LA Basin	0.39
	Ventura	0.57
PG&E	Greater Bay Area	0.87
	Greater Fresno	0.76
	Humboldt	0.79
	Kern	0.36
	Northern Coast	0.85
	Other	0.55
	Sierra	0.86
	Stockton	0.86
SDG&E	San Diego	0.84

3.3 Over/Under Performance Adjustment

In addition to estimating the reference load for the ex ante load impacts, historical event day behavior was analyzed and incorporated into the ex ante results to adjust for over/under performance. For most DR programs, the ex post impacts from previous events are applied to the ex ante estimates. For example, if a customer provided a load reduction of 500 kW on average, the typical event day on an ex ante basis would show a load reduction of roughly 500 kW for that customer. For BIP, similar *performance* relative to the FSL is expected, not similar *reductions*. Consider a BIP customer that provided an average load reduction of 500 kW with an average reference load of 800 kW during event hours. Assume that this customer had an FSL of 300 kW and with an average load reduction of 500 kW; this customer fully complied with its FSL obligations. Since this customer fully complied, it is expected that this customer would fully comply in future events. Therefore, if the predicted reference load for a typical event day is 950 kW, an impact of 650 kW would be expected (950 kW – 300 kW FSL). If we applied the same 500 kW reduction from previous events, the estimated load with DR would be 450 kW (950 kW – 500 kW), which would suggest that the customer substantially under complied relative to its FSL of 300 kW. If a customer did not under comply in previous events, it is not expected that it would under comply on an ex ante basis. Therefore, the ex ante impacts are based on the estimated reference load and the FSL after adjusting for over/under performance.

Over/under performance is calculated at the industry level in the SCE and PG&E ex ante analysis. Therefore, a customer in a given industry is assumed to perform similar to the recent historical performance of customers in its industry. The SDG&E ex ante analysis focuses on over/under performance at the program level because there are so few customers in each industry category. Therefore, SDG&E BIP customers are assumed to perform similar to the recent historical performance of the overall program. This over/under performance adjustment in the ex ante analysis is necessary simply because there is limited (if any) event history for individual customers. Because very few actual BIP events have been called since 2006 (the exception being annual tests events), we only have historical performance data for one to three BIP events for most BIP program participants. Furthermore, this analysis does not consider the performance data of customers on interruptible programs that existed prior to BIP. As such, conclusions about such customer's performance should not be drawn from this particular analysis.

The over/under performance analysis is conducted separately for each utility in this year's evaluation. Prior to 2011, the statewide BIP evaluations pooled SCE and PG&E historical event data together in order to develop the over/under performance estimates that were incorporated into the ex ante analysis. Now that SCE and PG&E have applied test event protocols that simulate peaking conditions, each utility has its own historical event data to incorporate into the ex ante analysis. Considering that each utility now has recent data for events under these conditions, it is possible to estimate over/under performance based on utility-specific event data, which improves the accuracy of the ex ante results because there are differences in the design and customer mix between the two BIP programs. If SCE or PG&E call an actual systemwide BIP event in the near future, that data can be pooled with the recent test event data for each utility because the event conditions from the customer perspective are similar. In fact, as in the recent test events that simulated peaking conditions, customers performed very well during the last actual systemwide BIP event for SCE and PG&E in 2006.

4 SCE Load Impact Analysis

This section includes 2012 ex post load impact estimates and 2013-2023 ex ante load impact estimates for SCE's BIP program. The discussion of load impacts provided below focuses on the high level, average and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the protocols, including uncertainty adjusted estimates, can be found in the electronic appendices titled, "SCE 2012 BIP Ex Post Load Impact Tables" and "SCE 2012 BIP Ex Ante Load Impact Tables."

4.1 Ex Post Load Impact Estimates

SCE held a systemwide test event for 667 BIP participants on September 26 from 3 PM to 5 PM, which was the second SCE BIP event since 2009. Although participants are required to respond within 15 to 30 minutes for actual BIP events, 24-hour advance notice was provided for this test event. In the 24-hour advance notice, the exact timing of the event was not provided. SCE started providing final notification of the event at 3 PM on September 26 and customers were required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option. Customers were instructed to curtail load until 5 PM.

Figure 4-1 shows the average load impact per customer in each hour on September 26. As seen, the average load drop over the two-hour event period was 859 kW. There were also significant load impacts after the event, as the average participant load slowly ramped back up after the event and was still nearly 12% below the reference load at the end of the day.

Figure 4-2 shows the aggregate load impact in each hour of the day. The aggregate load drop during the event period was 573 MW. This represents nearly a 74% reduction relative to the reference load of 775.8 MW. From 4 PM to 5 PM, aggregate load lowered to 139 MW and customers provided 93% of the expected load reduction given the aggregate FSL of 89.5 MW.

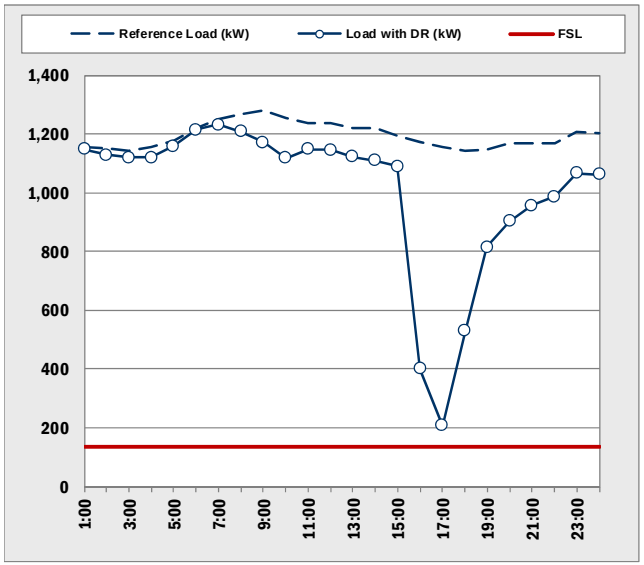
Figure 4-1: Average Ex Post Load Impact (kW) per Participant for SCE BIP Event (September 26, 2012)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Wednesday, September 26, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	667
Average FSL (kW)	134.2



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1155.1	1147.4	7.7	61.9	-46.1	-14.3	7.7	29.8	61.6
2:00	1150.8	1128.4	22.4	61.4	-31.1	0.5	22.4	44.4	76.0
3:00	1143.5	1119.8	23.7	60.9	-29.9	1.8	23.7	45.7	77.4
4:00	1153.2	1120.2	33.0	60.6	-20.6	11.1	33.0	54.9	86.6
5:00	1178.4	1158.4	20.0	60.6	-33.6	-2.0	20.0	41.9	73.5
6:00	1219.0	1214.6	4.5	60.4	-49.1	-17.4	4.5	26.4	58.0
7:00	1250.6	1231.2	19.4	61.3	-34.3	-2.6	19.4	41.4	73.2
8:00	1268.3	1208.7	59.6	63.3	5.7	37.6	59.6	81.6	113.5
9:00	1278.5	1171.5	107.0	66.5	53.1	84.9	107.0	129.1	160.9
10:00	1252.0	1117.9	134.1	70.6	80.4	112.1	134.1	156.0	187.8
11:00	1238.1	1148.2	89.8	74.6	36.6	68.1	89.8	111.6	143.0
12:00	1235.8	1146.4	89.5	77.1	36.4	67.7	89.5	111.2	142.5
13:00	1220.9	1121.9	98.9	79.4	45.8	77.2	98.9	120.6	152.0
14:00	1219.3	1108.9	110.4	80.4	57.4	88.7	110.4	132.1	163.4
15:00	1192.9	1090.3	102.6	79.6	49.8	81.0	102.6	124.2	155.4
16:00	1171.2	400.0	771.2	78.0	718.4	749.6	771.2	792.8	824.0
17:00	1154.9	207.9	947.0	75.7	894.2	925.4	947.0	968.6	999.8
18:00	1140.4	529.5	610.9	72.4	558.2	589.3	610.9	632.5	663.7
19:00	1147.4	815.9	331.4	69.6	278.6	309.8	331.4	353.0	384.2
20:00	1166.1	902.7	263.5	68.1	210.6	241.9	263.5	285.1	316.3
21:00	1169.6	956.6	212.9	67.3	160.0	191.3	212.9	234.6	265.9
22:00	1166.3	986.6	179.7	66.3	126.8	158.1	179.7	201.4	232.6
23:00	1208.5	1067.1	141.4	65.6	87.7	119.4	141.4	163.3	195.0
0:00	1201.1	1062.4	138.7	64.4	85.2	116.8	138.7	160.6	192.2

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	28,681.8	24,162.5	4,519.3	57.8	4258.2	4412.4	4519.3	4626.1	4780.4

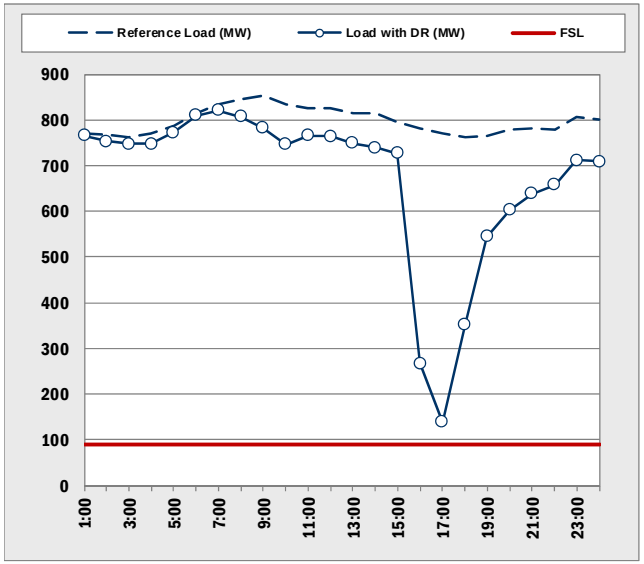
Figure 4-2:Aggregate Ex Post Load Impact (MW) for SCE BIP Event (September 26, 2012)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Wednesday, September 26, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	667
Aggregate FSL (MW)	89.5



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	770.4	765.3	5.2	61.9	-30.7	-9.5	5.2	19.8	41.1
2:00	767.6	752.6	15.0	61.4	-20.8	0.3	15.0	29.6	50.7
3:00	762.7	746.9	15.8	60.9	-19.9	1.2	15.8	30.5	51.6
4:00	769.2	747.2	22.0	60.6	-13.7	7.4	22.0	36.6	57.8
5:00	786.0	772.7	13.3	60.6	-22.4	-1.3	13.3	27.9	49.1
6:00	813.1	810.1	3.0	60.4	-32.7	-11.6	3.0	17.6	38.7
7:00	834.2	821.2	13.0	61.3	-22.9	-1.7	13.0	27.6	48.8
8:00	846.0	806.2	39.8	63.3	3.8	25.1	39.8	54.5	75.7
9:00	852.8	781.4	71.4	66.5	35.4	56.7	71.4	86.1	107.3
10:00	835.1	745.7	89.4	70.6	53.6	74.8	89.4	104.1	125.2
11:00	825.8	765.9	59.9	74.6	24.4	45.4	59.9	74.4	95.4
12:00	824.3	764.6	59.7	77.1	24.3	45.2	59.7	74.1	95.1
13:00	814.3	748.3	66.0	79.4	30.5	51.5	66.0	80.5	101.4
14:00	813.3	739.6	73.6	80.4	38.3	59.2	73.6	88.1	109.0
15:00	795.6	727.2	68.4	79.6	33.2	54.0	68.4	82.8	103.7
16:00	781.2	266.8	514.4	78.0	479.2	500.0	514.4	528.8	549.6
17:00	770.3	138.7	631.6	75.7	596.4	617.2	631.6	646.1	666.9
18:00	760.7	353.2	407.5	72.4	372.3	393.1	407.5	421.9	442.7
19:00	765.3	544.2	221.1	69.6	185.9	206.7	221.1	235.5	256.2
20:00	777.8	602.1	175.7	68.1	140.5	161.3	175.7	190.2	211.0
21:00	780.1	638.1	142.0	67.3	106.7	127.6	142.0	156.5	177.3
22:00	777.9	658.1	119.9	66.3	84.6	105.4	119.9	134.3	155.2
23:00	806.1	711.8	94.3	65.6	58.5	79.6	94.3	108.9	130.1
0:00	801.1	708.6	92.5	64.4	56.8	77.9	92.5	107.1	128.2

	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	19,130.8	16,116.4	3,014.4	57.8	2840.2	2943.1	3014.4	3085.6	3188.5

Table 4-1 shows the average load impact per customer across the event period by industry group and Table 4-2 shows the aggregate impact by industry. The overall results for all customers were primarily driven by participants in the manufacturing sector, which accounted for 57.4% of event participants and 65.7% of the aggregate load reduction. The agriculture, mining & construction segment was the only other industry group to provide more than 7.1% of the aggregate load reduction. Although customers in this segment accounted for less than 9% of event participants, they comprised 19.5% of the aggregate load reduction because agriculture, mining & construction customers had the highest reference load per customer (over 2.3 MW) and largest percent load reduction (84.1%). Retail stores and schools had the lowest event performance, providing less than 55% of the expected load reduction.

Table 4-1: Average Customer Load Impact by Industry for September 26, 2012 SCE Event

Industry	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	57	2332.4	370.4	1962.0	141.3	89.5
Manufacturing	383	1313.8	331.2	982.6	151.8	84.6
Wholesale, Transport & Other Utilities	73	759.2	203.7	555.6	107.2	85.2
Retail Stores	39	468.4	254.6	213.8	76.4	54.5
Offices, Hotels, Finance & Services	41	838.2	378.6	459.5	222.3	74.6
Schools	68	398.0	192.7	205.3	22.1	54.6
Institutional/Government	6	750.6	227.4	523.2	330.2	124.4
All Customers	**667**	**1163.1**	**304.0**	**859.1**	**134.2**	**83.5**

Table 4-2: Aggregate Load Impact by Industry for September 26, 2012 SCE Event

Industry	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Agriculture, Mining & Construction	57	132.9	21.1	111.8	84.1	19.5
Manufacturing	383	503.2	126.9	376.3	74.8	65.7
Wholesale, Transport & Other Utilities	73	55.4	14.9	40.6	73.2	7.1
Retail Stores	39	18.3	9.9	8.3	45.6	1.5
Offices, Hotels, Finance & Services	41	34.4	15.5	18.8	54.8	3.3
Schools	68	27.1	13.1	14.0	51.6	2.4
Institutional/Government	6	4.5	1.4	3.1	69.7	0.5
All Customers	**667**	**775.8**	**202.8**	**573.0**	**73.9**	**100.0**

Tables 4-3 and 4-4 show the breakdown of load impacts by LCA. Although customers in the LA Basin LCA had the lowest average load reduction per customer (699.3 kW), this LCA accounted for 68.8% of the aggregate load reduction because 564 of 667 event participants were located there. Customers in

the Outside LA Basin LCA provided the largest average load reduction per participant (3,160.8 kW) and highest percent load reduction (82.7%). As a result, this area accounted for 13.2% of the aggregate load reduction even though only 3.6% of event participants were in that LCA.

Table 4-3: Average Customer Load Impact by Local Capacity Area for September 26, 2012 SCE Event

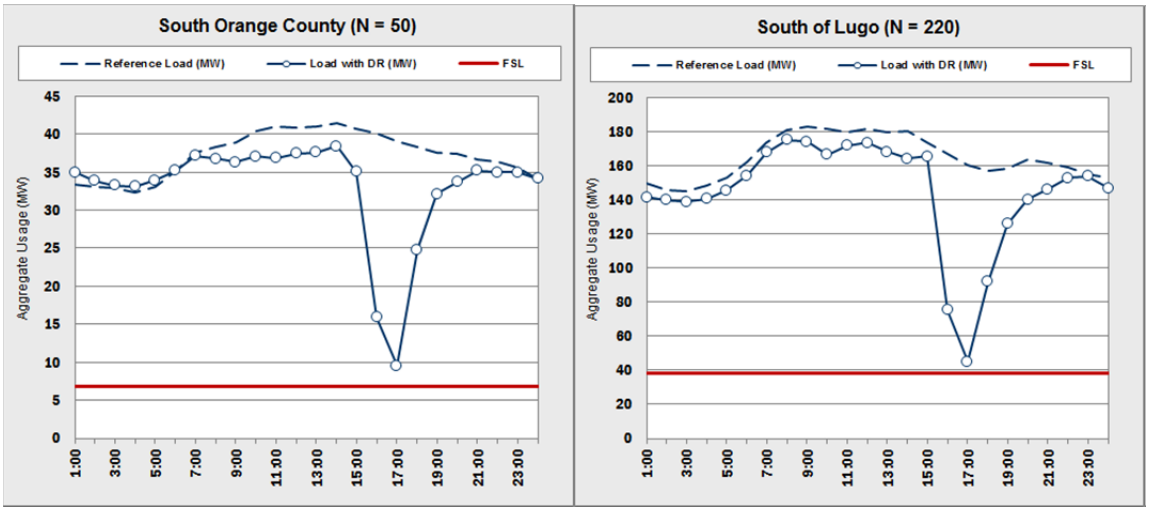
Local Capacity Area	Number of Customers	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
LA Basin	564	986.9	287.6	699.3	132.2	81.8
Outside LA Basin	24	3821.2	660.4	3160.8	268.4	89.0
Ventura	79	1613.5	312.6	1300.8	107.9	86.4
All Customers	**667**	**1163.1**	**304.0**	**859.1**	**134.2**	**83.5**

Table 4-4: Aggregate Load Impact by Local Capacity Area for September 26, 2012 SCE Event

Local Capacity Area	Number of Customers	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
LA Basin	564	556.6	162.2	394.4	70.9	68.8
Outside LA Basin	24	91.7	15.9	75.9	82.7	13.2
Ventura	79	127.5	24.7	102.8	80.6	17.9
All Customers	**667**	**775.8**	**202.8**	**573.0**	**73.9**	**66.7**

Due to the temporary closure of the San Onofre Nuclear Generating Station (SONGS), there was an additional requirement for this year's load impact evaluations – estimate load impacts for areas that were affected by the SONGS closure, which were the South Orange County and South of Lugo areas. Figure 4-3 shows the aggregate load impact for each hour of the event day in these areas. The aggregate hourly impact from 3 PM to 5 PM was 26.8 MW for the 50 South Orange County BIP participants and 103.7 MW for the 220 South of Lugo BIP participants. This represents a 68% and 63% reduction respectively. As shown by the figures and aggregate load impact estimates, BIP is a substantial resource in both of these supply constrained regions.

Figure 4-3: Average Ex Post Load Impact (kW) per Participant in South Orange County and South of Lugo for SCE BIP Event (September 26, 2012)



4.2 Over/Under Performance Analysis

For SCE's over/under performance analysis, data for the 2011 and 2012 SCE test events was used. Table 4-5 shows the results of the over/under performance analysis by industry for SCE BIP customers. A value over 100% means that customers in that industry over performed whereas a value under 100% means that customers in that industry under performed. For all industries combined, customers provided 92% of the expected load reduction given their FSL during the events. This performance level differs from the reported performance in Table 4-1 and Table 4-3 because it accounts for the specific 15-minute time intervals for which each individual customer was required to respond. For its BIP events, SCE starts providing final notification in the first event hour and customers are required to curtail load within 15 or 30 minutes of receiving notification, depending on their BIP program option. After identifying the specific intervals for which each individual customer was required to respond, participants achieved 92% performance overall. This is similar to the reported performance for the final hour of the 2012 event (94%) because nearly every customer was required to respond by 4 PM and was instructed to curtail load until 5 PM.

Performance varies substantially by industry. Customers in the agriculture, mining & construction and manufacturing segments underperform slightly during the events, which drives much of the overall result for all customers. Retail stores and schools generally underperform, providing less than 70% of the expected load reduction.

Although the main purpose of this exercise was to determine over/under performance by industry during the event hours, it also provided information on electric load during pre-event and post-event hours, which was incorporated into the ex ante estimates. As a result, SCE ex ante load impact estimates show moderate load reductions in the pre-event hours. After the event, aggregate load does not return to the level of the reference load until the end of the day or later. This means that there are substantial load impacts after the event ends.

Table 4-5: SCE BIP Over/Under Performance Percentages by Industry and Event Hour 2011 and 2012 SCE Systemwide BIP Events

Industry	% Over/Under Performance		
	Hour Before Event	During Event	Hour After Event
Agriculture, Mining & Construction	54.2	98.6	62.7
Manufacturing	52.0	94.1	66.5
Wholesale, Transport & Other Utilities	51.5	90.9	48.0
Retail Stores	32.2	65.0	37.3
Offices, Hotels, Finance & Services	42.0	78.9	50.3
Schools	35.7	69.5	53.9
Institutional/Government	35.0	111.0	68.0
All Customers	**50.4**	**92.0**	**62.5**

4.3 Ex Ante Load Impact Estimates

SCE projects that BIP enrollment will remain constant throughout the ex ante forecast period (2013-2023). Although enrollment does not change, ex ante load impact estimates increase slightly over time due to load growth. As discussed in Section 3.1, SCE BIP load is assumed to increase by 1.5% per year from 2013 through 2014 and then reach a steady state from 2015 through 2023. This 1.5% annual increase is applied to the estimated reference load, which in turn leads to a proportional increase in load impacts.

Figures 4-4 and 4-5 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2015. Impacts are reported for 2015 because it is the year in which BIP load growth reaches a steady state through 2023. For a 1-in-2 typical event day, the estimated load impact for the average participant is 971.8 kW from 1 PM to 6 PM. This represents an 82.3% impact relative to the average reference load of 1,180.3 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is nearly identical to that of a 1-in-2 weather year because BIP customer usage is not sensitive to temperature.

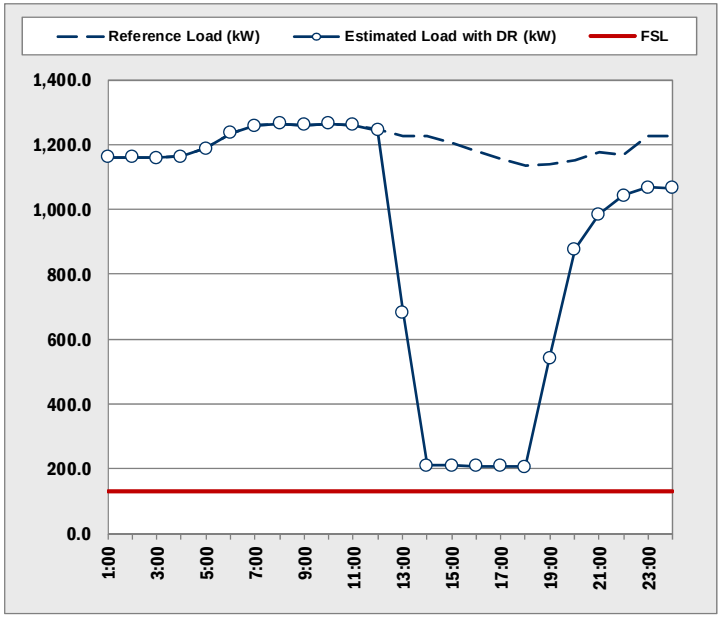
Figure 4-4: SCE BIP Average Load Impact (kW) per Customer in 2015 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	647
Average FSL (kW)	130.2
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	971.8
% Load Impact (1-6pm)	82.3%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1161.0	1161.0	0.0	69.2	-54.6	-22.3	0.0	22.3	54.6
2:00	1160.1	1160.1	0.0	68.1	-54.4	-22.3	0.0	22.3	54.4
3:00	1157.9	1157.9	0.0	66.8	-54.3	-22.2	0.0	22.2	54.3
4:00	1163.8	1163.8	0.0	66.2	-54.3	-22.2	0.0	22.2	54.3
5:00	1187.4	1187.4	0.0	65.4	-54.4	-22.3	0.0	22.3	54.4
6:00	1234.5	1234.5	0.0	65.0	-54.5	-22.3	0.0	22.3	54.5
7:00	1259.0	1259.0	0.0	65.5	-54.4	-22.2	0.0	22.2	54.4
8:00	1263.6	1263.6	0.0	68.9	-54.4	-22.3	0.0	22.3	54.4
9:00	1261.0	1261.0	0.0	74.4	-54.5	-22.3	0.0	22.3	54.5
10:00	1264.0	1264.0	0.0	79.6	-54.3	-22.2	0.0	22.2	54.3
11:00	1261.0	1261.0	0.0	83.9	-54.1	-22.1	0.0	22.1	54.1
12:00	1246.9	1243.1	3.8	87.1	-50.2	-18.3	3.8	26.0	57.9
13:00	1227.3	681.7	545.7	89.5	491.7	523.6	545.7	567.7	599.6
14:00	1226.4	209.7	1016.7	91.1	962.8	994.6	1016.7	1038.8	1070.6
15:00	1204.0	209.5	994.5	91.8	940.6	972.5	994.5	1016.6	1048.4
16:00	1179.1	208.2	970.9	91.8	917.1	948.9	970.9	993.0	1024.8
17:00	1156.1	207.7	948.4	90.8	894.6	926.4	948.4	970.4	1002.2
18:00	1135.7	207.1	928.7	88.5	874.8	906.6	928.7	950.7	982.5
19:00	1137.1	542.5	594.6	85.4	540.7	572.5	594.6	616.6	648.4
20:00	1152.0	876.2	275.9	81.6	222.0	253.8	275.9	297.9	329.8
21:00	1174.6	984.9	189.7	77.5	135.8	167.6	189.7	211.8	243.6
22:00	1166.7	1041.8	124.9	75.0	70.9	102.8	124.9	147.0	178.9
23:00	1225.2	1067.7	157.5	73.1	103.0	135.2	157.5	179.8	212.0
0:00	1226.2	1065.0	161.2	71.3	106.8	138.9	161.2	183.4	215.6

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	28,830.6	21,918.1	6,912.5	212.3	6647.1	6803.9	6912.5	7021.1	7177.8

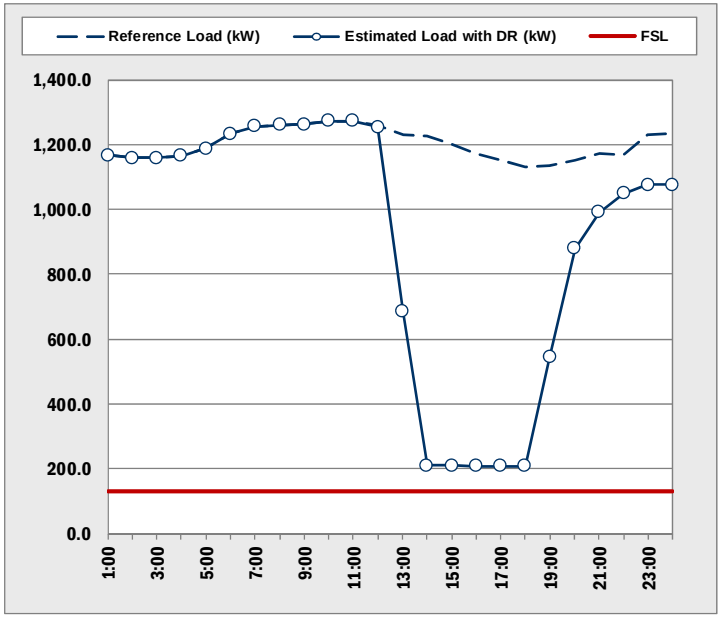
Figure 4-5: SCE BIP Average Load Impact (kW) per Customer in 2015 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	647
Average FSL (kW)	130.2
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	967.0
% Load Impact (1-6pm)	82.3%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1166.2	1166.2	0.0	76.0	-54.8	-22.4	0.0	22.4	54.8
2:00	1159.2	1159.2	0.0	74.5	-54.7	-22.4	0.0	22.4	54.7
3:00	1159.7	1159.7	0.0	73.6	-54.6	-22.3	0.0	22.3	54.6
4:00	1164.7	1164.7	0.0	72.8	-54.5	-22.3	0.0	22.3	54.5
5:00	1188.5	1188.5	0.0	72.2	-54.7	-22.4	0.0	22.4	54.7
6:00	1232.3	1232.3	0.0	71.8	-54.8	-22.4	0.0	22.4	54.8
7:00	1255.9	1255.9	0.0	72.0	-54.6	-22.4	0.0	22.4	54.6
8:00	1260.0	1260.0	0.0	74.6	-54.7	-22.4	0.0	22.4	54.7
9:00	1262.0	1262.0	0.0	78.9	-54.7	-22.4	0.0	22.4	54.7
10:00	1272.4	1272.4	0.0	82.9	-54.6	-22.3	0.0	22.3	54.6
11:00	1273.2	1273.2	0.0	86.1	-54.3	-22.2	0.0	22.2	54.3
12:00	1257.8	1254.9	2.9	88.5	-51.4	-19.3	2.9	25.1	57.1
13:00	1228.7	684.9	543.8	90.6	489.6	521.6	543.8	566.0	598.0
14:00	1224.3	209.9	1014.4	92.3	960.1	992.2	1014.4	1036.6	1068.7
15:00	1200.1	209.4	990.6	93.0	936.5	968.5	990.6	1012.8	1044.7
16:00	1174.0	208.7	965.3	92.6	911.3	943.2	965.3	987.4	1019.4
17:00	1149.6	207.9	941.7	91.3	887.7	919.6	941.7	963.8	995.8
18:00	1130.0	207.2	922.8	89.1	868.8	900.7	922.8	944.9	976.8
19:00	1134.6	544.5	590.0	85.9	536.0	567.9	590.0	612.2	644.1
20:00	1150.2	879.1	271.1	81.7	217.1	249.0	271.1	293.2	325.2
21:00	1171.8	991.3	180.6	78.1	126.5	158.4	180.6	202.7	234.7
22:00	1167.9	1049.3	118.6	76.0	64.5	96.5	118.6	140.8	172.8
23:00	1231.9	1076.6	155.4	74.2	100.8	133.0	155.4	177.7	210.0
0:00	1233.9	1075.0	159.0	73.1	104.2	136.6	158.9	181.3	213.7

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	28,849.1	21,992.8	6,856.2	261.9	6589.7	6747.2	6856.2	6965.3	7122.7

Table 4-6 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM to 9 PM for the November through March monthly peak days. The change in peak period timing does not affect SCE BIP customers substantially because they have a relatively flat load shape. Load impacts are lower during the November through March time period because usage is relatively low during those months, not because of the change in peak period timing. Aggregate load impacts are lowest for the December monthly peak day, which is likely due to the holiday season when many manufacturing facilities operate at less than full capacity.

Once load growth reaches a steady state in the 2015 to 2023 time period, the program is expected to be capable of delivering up to 659.5 MW, which occurs during the October monthly peak under 1-in-10 weather conditions. As a result of load growth, aggregate load impacts for the 1-in-2 typical event day grow from 614.2 MW in 2013 to 628.8 MW in 2015-2023.

Table 4-6: SCE BIP Aggregate On-Peak Load Impacts (MW) for Each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2013	2014	2015-2023
1-in-2	Typical Event Day	1-6 PM	614.2	624.5	628.8
	January Peak	4-9 PM	574.8	584.5	594.3
	February Peak	4-9 PM	572.8	582.4	591.3
	March Peak	4-9 PM	617.3	627.6	636.3
	April Peak	1-6 PM	602.8	612.9	620.5
	May Peak	1-6 PM	618.8	629.2	636.2
	June Peak	1-6 PM	612.8	623.1	629.1
	July Peak	1-6 PM	618.0	628.3	633.5
	August Peak	1-6 PM	612.5	622.7	627.0
	September Peak	1-6 PM	627.4	637.9	641.4
	October Peak	1-6 PM	640.8	651.5	654.2
	November Peak	4-9 PM	607.0	617.1	618.8
	December Peak	4-9 PM	542.8	552.0	552.8
1-in-10	Typical Event Day	1-6 PM	611.1	621.3	625.6
	January Peak	4-9 PM	590.0	599.9	609.9
	February Peak	4-9 PM	566.3	575.8	584.7
	March Peak	4-9 PM	595.5	605.4	613.8
	April Peak	1-6 PM	608.0	618.2	626.0
	May Peak	1-6 PM	621.5	631.9	639.0
	June Peak	1-6 PM	617.6	627.9	634.0
	July Peak	1-6 PM	613.2	623.5	628.6
	August Peak	1-6 PM	607.6	617.7	622.0
	September Peak	1-6 PM	626.9	637.3	640.8
	October Peak	1-6 PM	646.0	656.8	659.5
	November Peak	4-9 PM	610.3	620.4	622.2
	December Peak	4-9 PM	556.1	565.4	566.2

Table 4-7 provides the 2015-2023 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. The LA Basin LCA provides a 441.9 MW aggregate load impact, which accounts for 70.3% of the total for all customers. The Outside LA Basin LCA has the largest average load impact per customer (3,943.9 kW). As a result, the Outside LA Basin LCA accounts for 13.8% of the total aggregate load impact even though it has less than 4% of the total number of customers. The remaining 16.4% of the total aggregate load impact is located in the Ventura LCA.

Table 4-7: 2015-2023 Average and Aggregate Load Impacts by LCA
Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

LCA	Number of Customers	Reference Load (kW)	Load with DR (kW)	Avg. Load Impact (kW)	Aggregate Load Impact (MW)	% of Aggregate Load Impact
LA Basin	552	1,002.8	202.2	800.6	441.9	70.3
Outside LA Basin	22	4,341.2	397.3	3,943.9	86.8	13.8
Ventura	73	1,614.4	201.5	1,412.9	103.1	16.4
All Customers	**647**	**1,180.3**	**208.4**	**971.8**	**628.8**	**100.0**

5 PG&E Load Impact Analysis

This section includes 2012 ex post load impact estimates and 2013-2023 ex ante load impact estimates for PG&E's BIP program. The discussion of load impacts provided below focuses on the high level, average and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the protocols, including uncertainty adjusted estimates, can be found in the electronic appendices titled, "PG&E 2012 BIP Ex Post Load Impact Tables" and " PG&E 2012 BIP Ex Ante Load Impact Tables."

5.1 Ex Post Load Impact Estimates

The ex post load impact estimates presented in this section are for PG&E's system-wide BIP test event that occurred on August 10 from 3 PM to 5 PM. It was a test event that included all of the 252 customers that were enrolled in BIP at that time. Figure 5-1 shows the average load impact per customer in each hour of the event day. As seen, the average load drop over the two-hour event period was 877.0 kW. In the hour prior to the event, the average load reduction equaled 407.2 kW, and in the first hour after the event, load was still more than 470 kW below the reference load.

Figure 5-2 shows the aggregate load impact in each hour of the day. The aggregate load drop during the event period was 221.0 MW. This represents roughly an 80% reduction relative to the reference load of 277.9 MW. On aggregate, customers provided nearly 100% of the expected load reduction given the aggregate FSL of 56.7 MW.

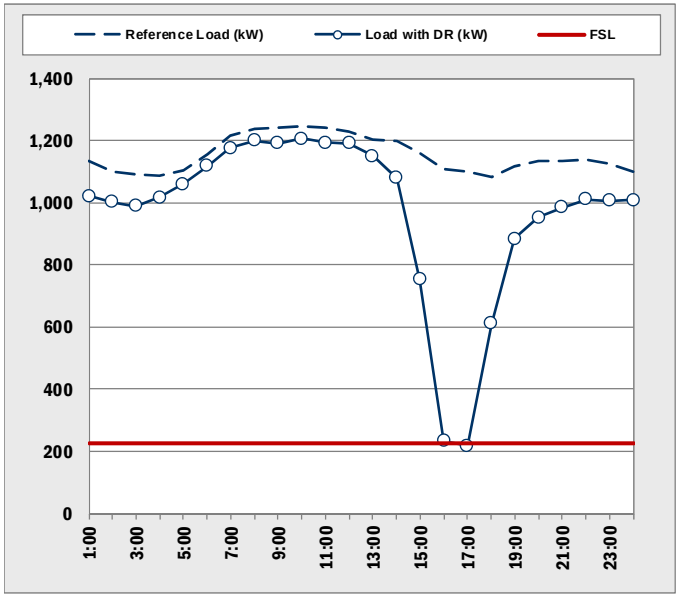
Figure 5-1: Average Ex Post Load Impact (kW) per Participant for PG&E BIP Event (August 10, 2012)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Friday, August 10, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	252
Average FSL (kW)	225.2



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1132.1	1021.5	110.6	72.8	61.7	90.6	110.6	130.6	159.5
2:00	1100.7	1002.3	98.4	71.4	49.6	78.4	98.4	118.3	147.2
3:00	1088.8	987.8	101.1	70.0	52.2	81.1	101.1	121.0	149.9
4:00	1088.1	1016.5	71.6	69.1	22.8	51.6	71.6	91.5	120.3
5:00	1105.4	1058.9	46.5	68.1	-2.3	26.5	46.5	66.5	95.3
6:00	1155.4	1118.3	37.2	66.9	-11.9	17.1	37.2	57.2	86.2
7:00	1216.4	1176.3	40.1	66.5	-9.2	19.9	40.1	60.3	89.4
8:00	1234.7	1199.2	35.5	68.3	-13.6	15.4	35.5	55.7	84.7
9:00	1240.0	1190.6	49.4	72.1	0.3	29.3	49.4	69.5	98.5
10:00	1244.2	1205.7	38.5	76.6	-10.5	18.5	38.5	58.6	87.6
11:00	1239.4	1192.5	46.9	80.8	-2.1	26.9	46.9	67.0	96.0
12:00	1228.7	1190.2	38.6	84.3	-10.2	18.6	38.6	58.5	87.3
13:00	1200.5	1149.0	51.5	87.7	2.8	31.6	51.5	71.4	100.2
14:00	1196.6	1078.4	118.2	90.8	69.7	98.3	118.2	138.1	166.7
15:00	1159.3	752.1	407.2	92.5	358.7	387.3	407.2	427.0	455.7
16:00	1108.0	233.5	874.5	93.7	826.0	854.7	874.5	894.4	923.0
17:00	1097.9	218.4	879.5	94.0	830.9	859.6	879.5	899.4	928.2
18:00	1081.9	611.0	470.9	93.0	422.3	451.0	470.9	490.8	519.5
19:00	1117.1	884.5	232.6	90.7	184.0	212.7	232.6	252.5	281.2
20:00	1134.5	951.3	183.2	86.1	134.4	163.2	183.2	203.2	232.0
21:00	1134.3	984.2	150.1	81.1	101.3	130.1	150.1	170.0	198.8
22:00	1139.4	1009.6	129.9	77.6	81.1	109.9	129.9	149.8	178.6
23:00	1124.8	1006.6	118.1	74.7	69.4	98.2	118.1	138.1	166.9
0:00	1101.1	1009.2	91.9	72.2	43.1	72.0	91.9	111.9	140.8

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	27,669.3	23,247.4	4,421.9	231.9	4182.8	4324.1	4421.9	4519.8	4661.1

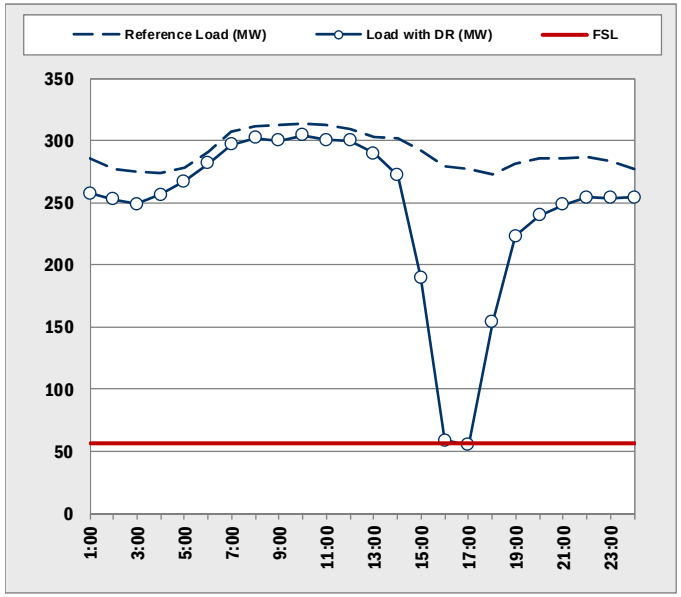
Figure 5-2: Aggregate Load Impact (MW) for PG&E BIP Event (August 10, 2012)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Friday, August 10, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	252
Aggregate FSL (MW)	56.7



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	285.3	257.4	27.9	72.8	15.5	22.8	27.9	32.9	40.2
2:00	277.4	252.6	24.8	71.4	12.5	19.8	24.8	29.8	37.1
3:00	274.4	248.9	25.5	70.0	13.2	20.4	25.5	30.5	37.8
4:00	274.2	256.2	18.0	69.1	5.7	13.0	18.0	23.1	30.3
5:00	278.6	266.8	11.7	68.1	-0.6	6.7	11.7	16.7	24.0
6:00	291.2	281.8	9.4	66.9	-3.0	4.3	9.4	14.4	21.7
7:00	306.5	296.4	10.1	66.5	-2.3	5.0	10.1	15.2	22.5
8:00	311.2	302.2	9.0	68.3	-3.4	3.9	9.0	14.0	21.3
9:00	312.5	300.0	12.4	72.1	0.1	7.4	12.4	17.5	24.8
10:00	313.6	303.8	9.7	76.6	-2.6	4.7	9.7	14.8	22.1
11:00	312.3	300.5	11.8	80.8	-0.5	6.8	11.8	16.9	24.2
12:00	309.6	299.9	9.7	84.3	-2.6	4.7	9.7	14.7	22.0
13:00	302.5	289.5	13.0	87.7	0.7	8.0	13.0	18.0	25.3
14:00	301.5	271.8	29.8	90.8	17.6	24.8	29.8	34.8	42.0
15:00	292.1	189.5	102.6	92.5	90.4	97.6	102.6	107.6	114.8
16:00	279.2	58.8	220.4	93.7	208.1	215.4	220.4	225.4	232.6
17:00	276.7	55.0	221.6	94.0	209.4	216.6	221.6	226.7	233.9
18:00	272.6	154.0	118.7	93.0	106.4	113.7	118.7	123.7	130.9
19:00	281.5	222.9	58.6	90.7	46.4	53.6	58.6	63.6	70.9
20:00	285.9	239.7	46.2	86.1	33.9	41.1	46.2	51.2	58.5
21:00	285.8	248.0	37.8	81.1	25.5	32.8	37.8	42.8	50.1
22:00	287.1	254.4	32.7	77.6	20.4	27.7	32.7	37.7	45.0
23:00	283.4	253.7	29.8	74.7	17.5	24.7	29.8	34.8	42.1
0:00	277.5	254.3	23.2	72.2	10.9	18.1	23.2	28.2	35.5

	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	6,972.7	5,858.3	1,114.3	231.9	1054.1	1089.7	1114.3	1139.0	1174.6

Table 5-1 shows the average load impact per customer across the event period by industry group and Table 5-2 shows the aggregate impact by industry. Among the seven industry groups included in Table 5-1, customers in the agriculture, mining, & construction, schools, manufacturing, and wholesale, transport & other utilities segments had the highest performance during the event. All of these industries achieved performance of 100% or above (i.e., reduced load below their FSL). The performance for retail stores was substantially lower, only providing 10.5% of the expected load reduction. Customers in the manufacturing and wholesale, transport & other utilities segments provided the largest percentage load drop (around 90% of the reference load). In aggregate, the manufacturing sector provided 62.2% of the total load reduction on the event day. This result is consistent with the 2009, 2010 and 2011 ex post evaluations, where manufacturing customers provided around 65% of the aggregate load reduction for the past three annual test events.

Table 5-1: Average Customer Load Impact by Industry for August 10, 2012 PG&E Event

Industry	Number of Customers[10]	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Agriculture, Mining & Construction	41	1088.0	347.2	740.9	347.4	100.0
Manufacturing	85	1807.9	189.5	1618.4	214.3	101.6
Wholesale, Transport & Other Utilities	47	627.7	53.5	574.3	197.3	133.4
Retail Stores	30	215.8	200.5	15.2	71.3	10.5
Offices, Hotels, Finance & Services	17	2241.3	821.3	1419.9	619.2	87.5
Schools	19	110.6	76.6	34.0	107.4	1040.3
Institutional/Government	13	268.2	203.5	64.7	24.2	26.5
All Customers	**252**	**1103.0**	**225.9**	**877.0**	**225.2**	**99.9**

Table 5-2: Aggregate Load Impact by Industry for August 10, 2012 PG&E Event

Industry	Number of Customers[10]	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Agriculture, Mining & Construction	41	44.6	14.2	30.4	68.1	13.7
Manufacturing	85	153.7	16.1	137.6	89.5	62.2
Wholesale, Transport & Other Utilities	47	29.5	2.5	27.0	91.5	12.2
Retail Stores	30	6.5	6.0	0.5	7.1	0.2
Offices, Hotels, Finance & Services	17	38.1	14.0	24.1	63.4	10.9
Schools	19	2.1	1.5	0.6	30.7	0.3
Institutional/Government	13	3.5	2.6	0.8	24.1	0.4
All Customers	**252**	**277.9**	**56.9**	**221.0**	**79.5**	**100.0**

Tables 5-3 and 5-4 show the breakdown of load impacts by LCA. Six of the eight LCAs within PG&E's service territory had 25 or fewer accounts enrolled in BIP at the time of the event. Around 35% of all accounts were located in the Other LCA and 26% in the Greater Bay Area LCA. Almost half of the

[10] Although the total number of customers is the same as in Table 2-2 (enrollment by industry as of January 2013), the distribution of customers by industry is slightly different because the customer mix changed since the August 2012 event.

customers in the manufacturing segment were located in the Other LCA. This concentration of manufacturing customers explains why the average load reduction in the Other LCA was more than 965 kW higher than in any of the other areas. As a result, the Other LCA accounted for nearly 75% of the aggregate load reduction. This result is consistent with the 2009, 2010 and 2011 ex post evaluations, where customers in the Other LCA provided around 70% of the aggregate load reduction for the past three annual test events.

Percent load reductions and performance relative to the FSL vary substantially by LCA. With performance above 100%, customers in the Other, Sierra and Stockton LCAs complied with their FSL. In the Northern Coast LCA, customers under performed substantially with performance around 66%. The remaining LCAs had performance around 85%.

Table 5-3: Average Customer Load Impact by Local Capacity Area for August 10, 2012 PG&E Event

Local Capacity Area	Number of Customers[11]	Reference Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
Greater Bay Area	66	647.1	242.0	405.1	173.0	85.5
Greater Fresno	16	322.5	130.4	192.1	100.6	86.6
Humboldt	7	434.0	92.6	341.4	25.7	83.6
Kern	25	671.6	262.1	409.4	187.8	84.6
Northern Coast	19	599.6	365.3	234.2	245.5	66.2
Other	89	2090.7	240.6	1850.1	339.2	105.6
Sierra	8	908.0	25.7	882.2	109.5	110.5
Stockton	22	251.1	141.7	109.4	141.8	100.1
All Customers	**252**	**1103.0**	**225.9**	**877.0**	**225.2**	**99.9**

Table 5-4: Aggregate Load Impact by Local Capacity Area for August 10, 2012 PG&E Event

Local Capacity Area	Number of Customers[11]	Reference Load (MW)	Load with DR (MW)	Load Reduction (MW)	% Load Reduction	% of Aggregate Load Reduction
Greater Bay Area	66	42.7	16.0	26.7	62.6	12.1
Greater Fresno	16	5.2	2.1	3.1	59.6	1.4
Humboldt	7	3.0	0.6	2.4	78.7	1.1
Kern	25	16.8	6.6	10.2	61.0	4.6
Northern Coast	19	11.4	6.9	4.5	39.1	2.0
Other	89	186.1	21.4	164.7	88.5	74.5
Sierra	8	7.3	0.2	7.1	97.2	3.2
Stockton	22	5.5	3.1	2.4	43.6	1.1
All Customers	**252**	**277.9**	**56.9**	**221.0**	**79.5**	**100.0**

[11] Although the total number of customers is the same as in Table 2-3 (enrollment by LCA as of January 2013), the distribution of customers by LCA is slightly different because the customer mix changed since the August 2012 event.

5.2 Over/Under Performance Analysis

For PG&E's over/under performance analysis, data was pooled across the annual systemwide PG&E BIP test events from 2010 to 2012. This data included three different event days. The 2010 test event for PG&E provided data for 187 PG&E customers and data for 221 customers was included from the 2011 test event. Finally, this year's over/under performance analysis was updated with 252 customers that participated in the 2012 PG&E system-wide test event. PG&E's over/under performance analysis and ex ante load impact estimates incorporate data for multiple years because these three test events were consistently called under peaking conditions during the summer, which is reflective of the conditions for which BIP load reductions would most likely be needed.

After pooling the event data, the load shape pattern was determined for each industry and incorporated into the ex ante load impact estimates. Table 5-5 shows the results of the over/under performance analysis by industry for PG&E BIP customers. A value over 100% means that customers in that industry over performed whereas a value under 100% means that customers in that industry under performed. For all industries combined, customers provided 97.0% of the expected load reduction given their FSL in the first hour of the event and 98.5% in the last hour of the event.

Performance varies substantially by industry. Customers in the agriculture, mining & construction and wholesale, transport & other utilities segments over perform by more than 8% during event hours. Retail stores under perform substantially, providing less than 15% of the expected load reduction. The largest BIP industry (manufacturing) under performs slightly, which drives much of the overall result for all customers.

Although the main purpose of this exercise was to determine over/under performance by industry during the event hours, it also provided information on electric load during pre-event and post-event hours, which was incorporated into the ex ante estimates. As a result, PG&E ex ante load impact estimates show moderate load reductions in the pre-event hours. After the event, aggregate load does not return to the level of the reference load until the end of the day or later. This means that there are substantial load impacts after the event ends.

Table 5-5: PG&E BIP Over/Under Performance Percentages by Industry and Event Hour
PG&E Systemwide BIP Events from 2010-2012

Industry	% Over/Under Performance			
	Hour Before Event	First Hour of Event	Last Hour of Event	Hour After Event
Agriculture, Mining & Construction	67.6	108.1	109.2	73.6
Manufacturing	44.5	97.4	98.6	65.7
Wholesale, Transport & Other Utilities	44.9	119.6	120.6	57.8
Retail Stores	-2.0	10.7	14.2	6.5
Offices, Hotels, Finance & Services	26.0	87.4	90.4	37.5
Schools	34.2	77.0	97.5	99.4
Institutional/Government	2.4	36.3	36.7	16.0
All Customers	**43.4**	**97.0**	**98.5**	**61.1**

5.3 Ex Ante Load Impact Estimates

PG&E expects enrollment in its BIP program to increase over the next few years. Enrollment peaks at 312 participants in 2014 and then remains stable until the end of the ex ante forecast period (2023).

BIP load growth as the economy improves is another source of variation in ex ante load impacts throughout the forecast period (2013-2023). As discussed in Section 3.1, PG&E BIP load is assumed to increase by 1.0% per year from 2013 through 2015 and then remain steady through 2023. This pattern is consistent with PG&E's internal economic forecast of average load for large business customers. The 1.0% annual increase is applied to the estimated reference load, which in turn leads to a proportional change in load impacts.

Figures 5-4 and 5-5 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for 2016-2023. For a 1-in-2 typical event day, the estimated load impact for the average participant is 883.2 kW from 1 PM to 6 PM. This represents a 78.4% impact relative to the average reference load of 1,126.5 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is very similar to that in a 1-in-2 weather year. The average load impact across the event period is 894.7 kW, which is 1.3% more than in the 1-in-2 weather year. Reasons for the larger 1-in-10 load impacts are discussed below.

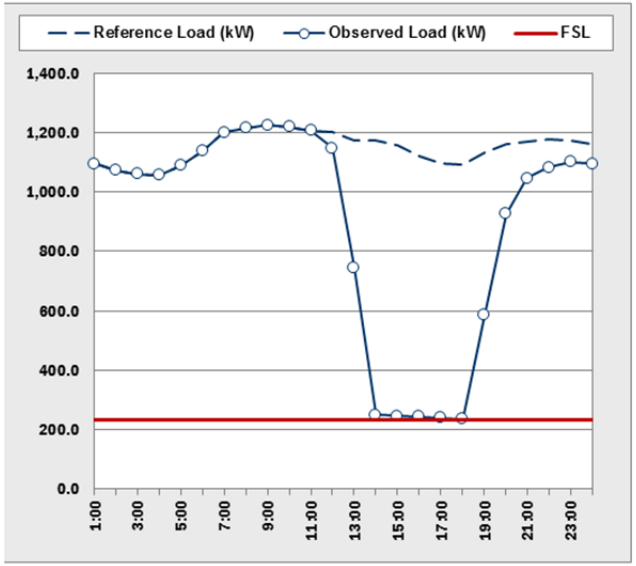
Figure 5-4: PG&E BIP Average Load Impact (kW) per Customer in 2016-2023 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2016-2023
Day Type	Typical Event Day
Customer Characteristic	All Customers
Demand Category	All

TABLE 2: Output

Number of Accounts	312
Average FSL (kW)	234.0



Note: 1 to 6pm is the event window for the Typical Event Day.

Hour Ending	Reference Load (kW)	Observed Load (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1095.4	1095.4	0.0	71.1	-1.2	-0.5	0.0	0.5	1.2
2:00	1072.1	1072.1	0.0	66.3	-1.2	-0.5	0.0	0.5	1.2
3:00	1060.8	1060.8	0.0	64.8	-1.2	-0.5	0.0	0.5	1.2
4:00	1056.2	1056.2	0.0	63.6	-1.2	-0.5	0.0	0.5	1.2
5:00	1088.9	1088.9	0.0	62.8	-1.2	-0.5	0.0	0.5	1.2
6:00	1137.4	1137.4	0.0	62.2	-1.2	-0.5	0.0	0.5	1.2
7:00	1200.1	1200.1	0.0	62.3	-1.2	-0.5	0.0	0.5	1.2
8:00	1214.5	1214.5	0.0	65.9	-1.2	-0.5	0.0	0.5	1.2
9:00	1224.0	1224.0	0.0	71.6	-1.2	-0.5	0.0	0.5	1.2
10:00	1218.3	1218.3	0.0	77.0	-1.2	-0.5	0.0	0.5	1.2
11:00	1206.0	1206.0	0.0	82.1	-1.2	-0.5	0.0	0.5	1.2
12:00	1202.5	1147.3	55.3	86.7	54.1	54.8	55.3	55.7	56.4
13:00	1174.3	745.1	429.2	90.0	428.0	428.7	429.2	429.7	430.4
14:00	1174.6	249.9	924.7	92.6	923.5	924.2	924.7	925.2	925.9
15:00	1155.6	246.7	908.9	94.6	907.7	908.4	908.9	909.4	910.1
16:00	1118.3	243.9	874.4	95.5	873.2	873.9	874.4	874.9	875.6
17:00	1094.3	239.8	854.5	95.2	853.3	854.0	854.5	854.9	855.6
18:00	1089.9	236.2	853.6	94.0	852.5	853.1	853.6	854.1	854.8
19:00	1132.8	584.8	548.0	91.3	546.8	547.5	548.0	548.5	549.2
20:00	1162.2	925.7	236.4	87.0	235.3	236.0	236.4	236.9	237.6
21:00	1169.8	1047.2	122.6	81.7	121.5	122.2	122.6	123.1	123.8
22:00	1178.4	1083.7	94.7	77.6	93.5	94.2	94.7	95.2	95.9
23:00	1174.3	1100.8	73.5	74.9	72.3	73.0	73.5	73.9	74.6
0:00	1160.3	1094.9	65.4	72.9	64.2	64.9	65.4	65.9	66.6

	Reference Energy Use (kWh)	Observed Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	27,560.9	21,519.6	6,041.3	245.9	6035.5	6038.9	6041.3	6043.6	6047.0

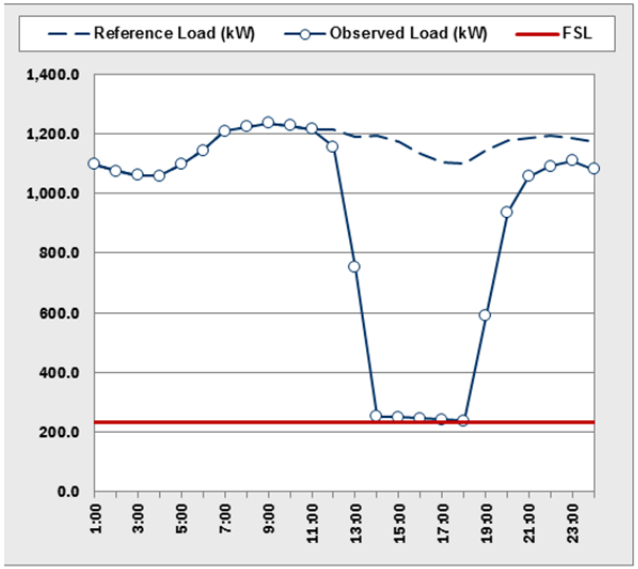
Figure 5-5: PG&E BIP Average Load Impact (kW) per Customer in 2016-2023 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2016-2023
Day Type	Typical Event Day
Customer Characteristic	All Customers
Demand Category	All

TABLE 2: Output

Number of Accounts	312
Average FSL (kW)	234.0



Note: 1 to 6pm is the event window for the Typical Event Day.

Hour Ending	Reference Load (kW)	Observed Load (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1096.7	1096.7	0.0	75.2	-1.3	-0.5	0.0	0.5	1.3
2:00	1073.7	1073.7	0.0	73.9	-1.3	-0.5	0.0	0.5	1.3
3:00	1059.7	1059.7	0.0	72.7	-1.3	-0.5	0.0	0.5	1.3
4:00	1058.6	1058.6	0.0	71.4	-1.3	-0.5	0.0	0.5	1.3
5:00	1096.4	1096.4	0.0	70.5	-1.3	-0.5	0.0	0.5	1.3
6:00	1143.4	1143.4	0.0	69.6	-1.3	-0.5	0.0	0.5	1.3
7:00	1208.0	1208.0	0.0	69.4	-1.3	-0.5	0.0	0.5	1.3
8:00	1222.4	1222.4	0.0	71.9	-1.3	-0.5	0.0	0.5	1.3
9:00	1234.8	1234.8	0.0	77.1	-1.2	-0.5	0.0	0.5	1.2
10:00	1226.1	1226.1	0.0	81.6	-1.2	-0.5	0.0	0.5	1.2
11:00	1215.7	1215.7	0.0	85.8	-1.3	-0.5	0.0	0.5	1.3
12:00	1212.1	1156.4	55.7	89.7	54.5	55.2	55.7	56.2	57.0
13:00	1189.0	751.6	437.4	93.1	436.1	436.9	437.4	437.9	438.6
14:00	1193.7	252.6	941.2	95.6	939.9	940.6	941.2	941.7	942.4
15:00	1171.7	249.4	922.3	97.1	921.1	921.8	922.3	922.8	923.5
16:00	1131.4	246.6	884.8	98.2	883.6	884.3	884.8	885.3	886.0
17:00	1104.3	242.1	862.2	98.3	861.0	861.7	862.2	862.7	863.5
18:00	1100.6	237.8	862.8	97.3	861.6	862.3	862.8	863.3	864.0
19:00	1145.0	589.9	555.1	94.8	553.9	554.6	555.1	555.6	556.3
20:00	1175.2	937.1	238.1	90.8	236.8	237.6	238.1	238.6	239.3
21:00	1184.4	1055.9	128.5	86.4	127.3	128.0	128.5	129.0	129.8
22:00	1192.7	1090.8	101.9	83.1	100.6	101.4	101.9	102.4	103.2
23:00	1186.6	1108.1	78.5	80.6	77.2	77.9	78.5	79.0	79.7
0:00	1171.1	1080.1	91.1	78.8	89.8	90.6	91.1	91.6	92.4

	Reference Energy Use (kWh)	Observed Energy Use (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	27,793.3	21,633.8	6,159.5	323.9	6153.4	6157.0	6159.5	6162.0	6165.7

Table 5-6 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM to 9 PM for the November through March monthly peak days. Throughout the forecast period (2013-2023), the program is expected to be capable of delivering up to 298.3 MW, which occurs during the June monthly peak under 1-in-10 weather conditions in 2016-2023. As in the typical event day estimates, the aggregate impacts are higher in a 1-in-10 weather year than in a 1-in-2 weather year for many months. This trend is driven by the weather variables in the model because other factors do not change by weather year within each day type and forecast. The 1-in-10 weather patterns are generally more extreme (hotter in the summer and colder in the winter), which lead to a slight increase in load.

Table 5-6: PG&E BIP Aggregate On-Peak Load Impacts (MW) for Each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2013	2014	2015	2016-2023
1-in-2	Typical Event Day	1-6 PM	239.0	262.8	274.1	275.4
	January Peak	4-9 PM	197.2	216.8	235.5	238.2
	February Peak	4-9 PM	203.9	224.0	241.8	244.3
	March Peak	4-9 PM	202.2	222.1	238.3	240.5
	April Peak	1-6 PM	234.4	257.3	274.4	276.6
	May Peak	1-6 PM	230.7	253.0	268.1	270.0
	June Peak	1-6 PM	247.1	271.8	285.2	286.9
	July Peak	1-6 PM	241.6	265.6	277.0	278.4
	August Peak	1-6 PM	251.0	275.8	285.9	287.0
	September Peak	1-6 PM	249.7	273.4	281.6	282.5
	October Peak	1-6 PM	239.6	262.3	268.6	269.1
	November Peak	4-9 PM	231.2	252.8	257.4	257.6
	December Peak	4-9 PM	232.1	253.7	256.7	256.7
1-in-10	Typical Event Day	1-6 PM	242.1	266.2	277.6	279.0
	January Peak	4-9 PM	197.1	216.7	235.4	238.0
	February Peak	4-9 PM	204.0	224.1	241.9	244.4
	March Peak	4-9 PM	202.4	222.3	238.5	240.7
	April Peak	1-6 PM	236.3	259.3	276.5	278.7
	May Peak	1-6 PM	234.3	257.0	272.3	274.2
	June Peak	1-6 PM	257.0	282.7	296.5	298.3
	July Peak	1-6 PM	242.9	267.1	278.5	279.9
	August Peak	1-6 PM	253.4	278.4	288.6	289.7
	September Peak	1-6 PM	251.9	275.7	284.1	284.9
	October Peak	1-6 PM	241.2	264.0	270.4	270.9
	November Peak	4-9 PM	232.8	254.6	259.2	259.4
	December Peak	4-9 PM	232.7	254.4	257.5	257.5

Table 5-7 provides the 2013 and 2016-2023 average and aggregate load impact estimates by LCA for a typical event day under 1-in-2 weather conditions. The average load impact per customer increases from 860.8 kW in 2013 to 883.2 kW in 2016-2023 because of the forecasted increase in BIP customers' reference load. Throughout the forecast period, aggregate load impacts are primarily concentrated in PG&E's Other LCA. In 2013, the Other LCA accounts for 71.7% of aggregate impacts and 71.5% in 2016-2023. Although this LCA accounts for around 37% of the total number of customers in each time period, the majority of aggregate impacts are concentrated there because customers in the Other LCA provide the largest average load reduction. In 2013 and 2016-2023, Other LCA customers provide an average load reduction of over 1,600 kW, whereas the average load impact for each of the remaining LCAs does not exceed 910 kW. The Greater Bay Area LCA comprises the second largest share of aggregate load impacts, accounting for 10.6% in 2013 and 2016-2023. Although enrollment growth rates are projected to be different across the LCAs, the general composition of the program is expected to remain similar with over 80% of aggregate impacts in the Other and Greater Bay Area LCAs.

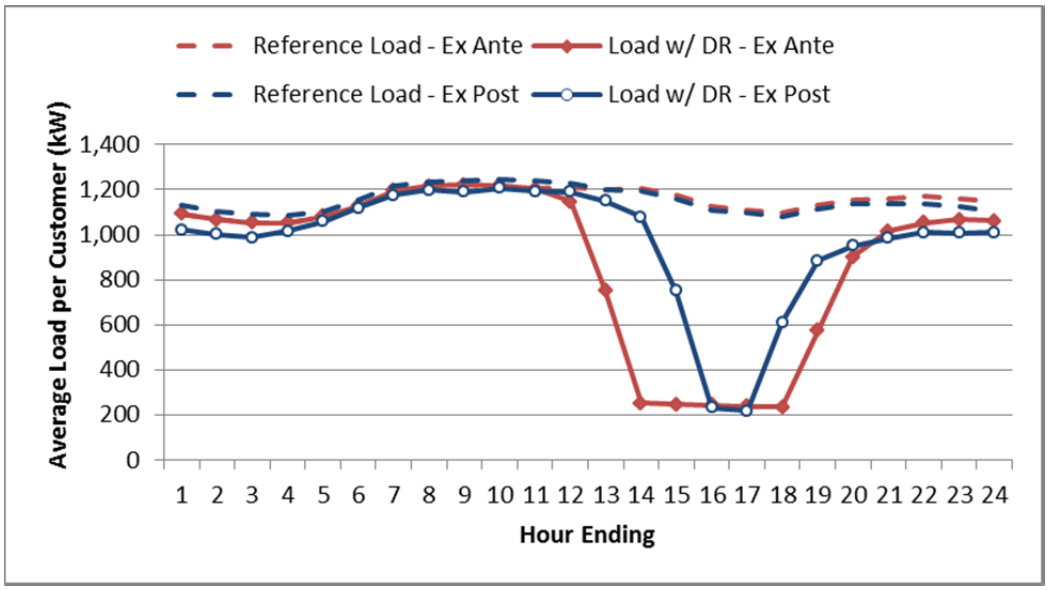
Table 5-7: 2013 and 2016-2023 Average and Aggregate Load Impacts by LCA
Typical Event Day under 1-in-2 Weather Conditions, 1 PM to 6 PM

Forecast Year	LCA	Number of Customers	Reference Load (kW)	Load with DR (kW)	Avg. Load Impact (kW)	Aggregate Load Impact (MW)	% of Total Aggregate Load Impact
2013	Greater Bay Area	64	628.3	231.0	397.3	25.2	10.6
	Greater Fresno	14	517.5	119.3	398.2	5.4	2.3
	Humboldt	11	427.0	70.1	357.0	4.0	1.7
	Kern	27	748.3	213.7	534.6	14.6	6.1
	Northern Coast	28	534.0	242.5	291.6	8.2	3.4
	Other	103	1998.1	333.9	1664.2	171.3	71.7
	Sierra	8	1011.3	105.0	906.3	7.0	2.9
	Stockton	23	238.5	98.1	140.4	3.3	1.4
	All Customers	**278**	**1102.8**	**242.0**	**860.8**	**239.0**	**100**
2016-2023	Greater Bay Area	72	641.5	233.2	408.3	29.2	10.6
	Greater Fresno	15	530.1	119.1	411.1	6.3	2.3
	Humboldt	13	441.3	71.1	370.2	4.6	1.7
	Kern	31	766.2	214.6	551.5	17.1	6.2
	Northern Coast	32	546.8	243.4	303.3	9.7	3.5
	Other	115	2044.4	335.1	1709.3	196.9	71.5
	Sierra	9	1028.6	106.5	922.1	7.9	2.9
	Stockton	26	243.4	99.1	144.3	3.7	1.4
	All Customers	**312**	**1126.5**	**243.3**	**883.2**	**275.4**	**100**

The ex ante load impact estimates reported in this section closely align with the ex post load impact estimates presented in Section 5.1. The 2012 systemwide BIP test event occurred on August 10, during moderate system load conditions that are comparable to the 1-in-2 August peak in the 2013 ex ante estimates. Figure 5-5 compares these two estimates and shows that the average hourly impact is similar during the event period (3 PM to 5 PM in the ex post estimates and 1 PM to 6 PM in the ex ante estimates). Although the average reference load is nearly identical from 3 PM to 5 PM, the load

reduction is slightly higher in the 2012 ex post estimates because event performance is slightly higher. Considering that the over/under performance analysis also factors in the 2010 and 2011 events, the ex ante estimates show slightly lower performance than the 2012 ex post estimates. Outside of the 2013 August peak 1-in-2 ex ante estimates, the load impacts do not align as closely with the ex post because the month is different and in the later years, enrollment and load growth lead to higher impacts.

Figure 5-5: Comparison of 2012 Ex Post Estimates and 2013 August Peak 1-in-2 Ex Ante Estimates



Another useful comparison for the ex ante load impact estimates is to those of last year's evaluation. In general, the per-customer ex ante load impact estimates are nearly the same in this year's evaluation. For example, the 2013 August peak load impact estimate for a 1-in-2 weather year was 202.6 MW in last year's evaluation. With 227 customers projected to be in the program, this was an average load impact of 892.5 kW per customer. In this evaluation, there is a projected 280 customers in August 2013, but the monthly peak load impact estimate for a 1-in-2 weather year is higher at 251.0 MW. This is an average load impact of 898.0 kW per customer, which is less than 1% higher than the estimate in last year's evaluation. This increase is primarily due to a change in the BIP enrollment mix over the past year. Last year's ex ante analysis was based on a set of customers with an average on-peak load of 1,011.6 kW. In this year's evaluation, the set of customers in the ex ante analysis had an average on-peak load of 1,059.5 kW.

6 SDG&E Load Impact Analysis

This section includes 2012 ex post load impact estimates and 2013-2023 ex ante load impact estimates for SDG&E's BIP program. The discussion of load impacts provided below focuses on the high level, average and aggregate impacts. The remainder of the hourly ex post and ex ante load impact estimates that are required by the protocols, including uncertainty adjusted estimates, can be found in the electronic appendices titled, "SDG&E 2012 BIP Ex Post Load Impact Tables" and "SDG&E 2012 BIP Ex Ante Load Impact Tables."

6.1 Ex Post Load Impact Estimates

SDG&E called a BIP event on September 14 that lasted from 1 PM to 5 PM for all customers. All customers received 30-minute notice of the event. In total, 11 customers participated in the event.

Figures 6-1 and 6-2 show the average load impact per customer and aggregate impacts in each hour on September 14. The event period is highlighted in the figures. As seen in Figure 6-1, the average load drop per customer from 1 PM to 5 PM was 76.2 kW. Figure 6-2 shows that the aggregate load drop from 1 PM to 5 PM was 0.84 MW. However, the results varied substantially by hour. The load reduction was 2.4 MW from 1 PM to 2 PM, but only 0.28 MW from 2 PM through 5 PM. Overall, the load impact represents roughly a 29% reduction relative to the reference load of 3.0 MW. The 1 PM to 5 PM aggregate load of 2.1 MW was substantially higher than the aggregate FSL of 0.5 MW. BIP customers under performed during this event, providing only 34% of the 2.5 MW reduction that participants needed in order to be in compliance.

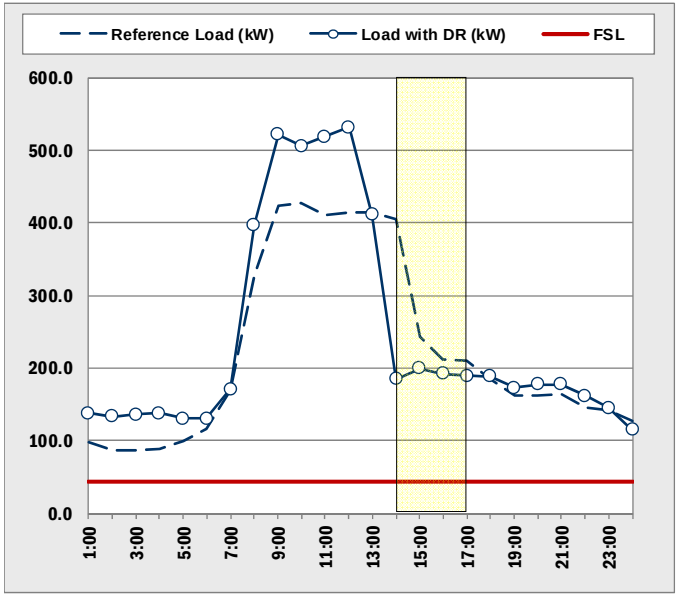
Figure 6-1: Average Ex Post Load Impact (kW) per Participant for SDG&E BIP Event (September 14, 2012)

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Event	Friday, September 14, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	11
Average FSL (kW)	42.9



Hour Ending	Reference Load (kW)	Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	96.9	137.4	-40.4	66.9	-103.5	-66.3	-40.4	-14.6	22.7
2:00	87.3	132.8	-45.5	66.5	-107.9	-71.0	-45.5	-20.0	16.9
3:00	86.6	135.9	-49.3	65.8	-111.0	-74.5	-49.3	-24.0	12.5
4:00	88.4	137.2	-48.8	64.6	-110.3	-74.0	-48.8	-23.6	12.7
5:00	100.3	130.4	-30.1	64.5	-92.1	-55.5	-30.1	-4.7	31.9
6:00	116.4	130.6	-14.2	64.3	-75.3	-39.2	-14.2	10.8	46.9
7:00	168.5	170.5	-2.0	64.9	-64.3	-27.5	-2.0	23.5	60.3
8:00	326.9	397.5	-70.6	69.9	-142.0	-99.8	-70.6	-41.3	0.9
9:00	424.0	520.9	-96.9	78.1	-178.4	-130.2	-96.9	-63.5	-15.4
10:00	427.5	505.3	-77.9	86.7	-156.5	-110.1	-77.9	-45.7	0.7
11:00	410.3	518.5	-108.2	86.7	-180.3	-137.7	-108.2	-78.7	-36.1
12:00	414.1	531.7	-117.6	90.4	-190.3	-147.3	-117.6	-87.9	-44.9
13:00	413.8	410.9	2.9	92.4	-71.2	-27.4	2.9	33.2	77.0
14:00	405.5	184.9	220.7	95.2	145.3	189.8	220.7	251.5	296.0
15:00	243.4	199.6	43.8	94.5	-20.1	17.7	43.8	70.0	107.7
16:00	212.1	192.1	20.0	93.0	-48.6	-8.1	20.0	48.1	88.6
17:00	209.8	189.3	20.5	92.9	-45.9	-6.7	20.5	47.7	86.9
18:00	184.6	188.0	-3.5	91.8	-67.3	-29.6	-3.5	22.6	60.3
19:00	161.8	172.4	-10.6	86.4	-72.0	-35.7	-10.6	14.5	50.7
20:00	161.4	177.3	-15.9	83.4	-77.1	-40.9	-15.9	9.1	45.3
21:00	164.5	177.0	-12.6	79.3	-73.8	-37.6	-12.6	12.5	48.6
22:00	144.7	161.7	-17.1	78.4	-78.2	-42.1	-17.1	7.9	44.0
23:00	142.1	144.6	-2.5	76.5	-63.5	-27.4	-2.5	22.5	58.5
0:00	127.4	114.7	12.7	75.8	-48.8	-12.5	12.7	37.9	74.2

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,318.4	5,761.4	-443.0	261.5	-769.0	-576.4	-443.0	-309.6	-117.0

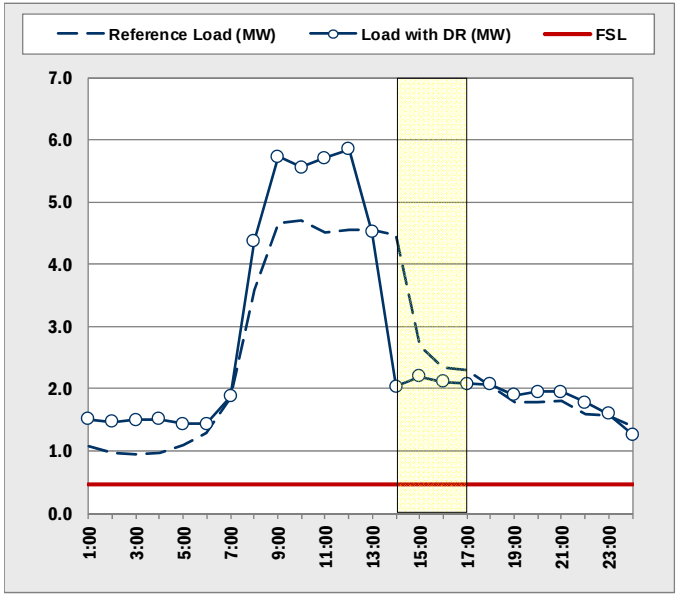
Figure 6-2: Aggregate Load Impact (MW) for SDG&E BIP Event (September 14, 2012)

TABLE 1: Menu options

Type of Results	Aggregate
Event	Friday, September 14, 2012
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	11
Aggregate FSL (MW)	0.5



Hour Ending	Reference Load (MW)	Load with DR (MW)	Load Impact (MW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	1.1	1.5	-0.4	66.9	-1.1	-0.7	-0.4	-0.2	0.2
2:00	1.0	1.5	-0.5	66.5	-1.2	-0.8	-0.5	-0.2	0.2
3:00	1.0	1.5	-0.5	65.8	-1.2	-0.8	-0.5	-0.3	0.1
4:00	1.0	1.5	-0.5	64.6	-1.2	-0.8	-0.5	-0.3	0.1
5:00	1.1	1.4	-0.3	64.5	-1.0	-0.6	-0.3	-0.1	0.4
6:00	1.3	1.4	-0.2	64.3	-0.8	-0.4	-0.2	0.1	0.5
7:00	1.9	1.9	0.0	64.9	-0.7	-0.3	0.0	0.3	0.7
8:00	3.6	4.4	-0.8	69.9	-1.6	-1.1	-0.8	-0.5	0.0
9:00	4.7	5.7	-1.1	78.1	-2.0	-1.4	-1.1	-0.7	-0.2
10:00	4.7	5.6	-0.9	86.7	-1.7	-1.2	-0.9	-0.5	0.0
11:00	4.5	5.7	-1.2	86.7	-2.0	-1.5	-1.2	-0.9	-0.4
12:00	4.6	5.8	-1.3	90.4	-2.1	-1.6	-1.3	-1.0	-0.5
13:00	4.6	4.5	0.0	92.4	-0.8	-0.3	0.0	0.4	0.8
14:00	4.5	2.0	2.4	95.2	1.6	2.1	2.4	2.8	3.3
15:00	2.7	2.2	0.5	94.5	-0.2	0.2	0.5	0.8	1.2
16:00	2.3	2.1	0.2	93.0	-0.5	-0.1	0.2	0.5	1.0
17:00	2.3	2.1	0.2	92.9	-0.5	-0.1	0.2	0.5	1.0
18:00	2.0	2.1	0.0	91.8	-0.7	-0.3	0.0	0.2	0.7
19:00	1.8	1.9	-0.1	86.4	-0.8	-0.4	-0.1	0.2	0.6
20:00	1.8	2.0	-0.2	83.4	-0.8	-0.5	-0.2	0.1	0.5
21:00	1.8	1.9	-0.1	79.3	-0.8	-0.4	-0.1	0.1	0.5
22:00	1.6	1.8	-0.2	78.4	-0.9	-0.5	-0.2	0.1	0.5
23:00	1.6	1.6	0.0	76.5	-0.7	-0.3	0.0	0.2	0.6
0:00	1.4	1.3	0.1	75.8	-0.5	-0.1	0.1	0.4	0.8

	Reference Energy Use (MWh)	Energy Use with DR (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	58.5	63.4	-4.9	261.5	-8.5	-6.3	-4.9	-3.4	-1.3

Table 6-1 shows the average load impact per customer for all customers. The 11 event participants span across 5 different industry categories[12] and there are 3 of fewer customers within each category, so impacts for specific industries are excluded due to confidentiality. Table 6-2 shows the aggregate impacts. Customers provided a 28.5% load reduction, which is well short of the 84% load reduction that participants needed in order to reduce usage to the FSL.

Table 6-1: Average Customer Load Impact for September 14, 2012 SDG&E Event

Customer Category	Number of Customers	Hour Ending	Ref. Load (kW)	Load with DR (kW)	Load Reduction (kW)	Average FSL (kW)	Performance (%)
All Customers	11	14	405.5	184.9	220.7	42.9	60.9
		15	243.4	199.6	43.8	42.9	21.9
		16	212.1	192.1	20.0	42.9	11.8
		17	209.8	189.3	20.5	42.9	12.3
		Avg.	**267.7**	**191.5**	**76.2**	**42.9**	**33.9**

Table 6-2: Aggregate Load Impact for September 14, 2012 SDG&E Event

Customer Category	Number of Customers	Hour Ending	Ref. Load (MW)	Load with DR (MW)	Load Reduction (MW)	Average FSL (MW)	Performance (%)
All Customers	11	14	4.46	2.03	2.43	0.47	60.9
		15	2.68	2.20	0.48	0.47	21.9
		16	2.33	2.11	0.22	0.47	11.8
		17	2.31	2.08	0.23	0.47	12.3
		Avg.	**2.94**	**2.11**	**0.84**	**0.47**	**33.9**

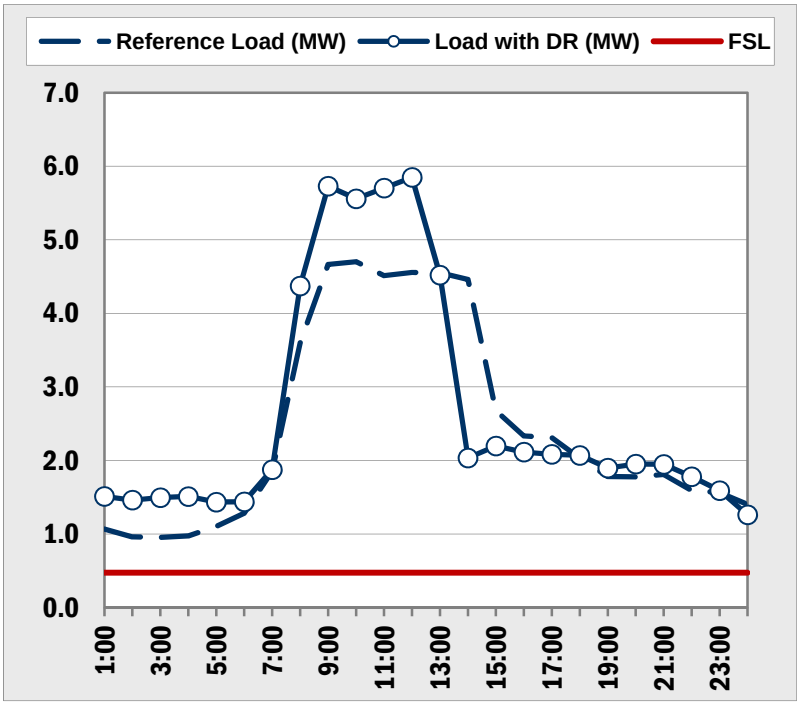
6.2 Over/Under Performance Analysis

For SDG&E's over/under performance analysis, data for the 2012 BIP event was used. Data for multiple years was not pooled together, as in SCE's and PG&E's over/under performance analysis. No new customers joined or left the program since the 2012 event. Therefore, SDG&E's over/under performance analysis is based on data for the 11 customers who experienced the 2012 BIP event

Figure 6-3 shows the aggregate load impacts for the 2012 SDG&E BIP event for customers that are still enrolled in the program. Considering that all of the BIP customers were in Option A, curtailment was required from 1 PM to 5 PM. Among the 11 customers that are still enrolled in the program, the aggregate hourly impact during the event period was 0.8 MW and performance was 33.9%. Considering that these customers are identical to the current program, the 33.9% performance value is what was used for the ex ante analysis.

[12] Agriculture, Mining & Construction, Manufacturing, Wholesale, Transport & Other Utilities, Retail Stores and Offices, Hotels, Finance & Services

Figure 6-3: Aggregate Load Impact (MW) for 2012 SDG&E BIP Event for Customers that are Currently Enrolled in the Program (As of Dec 2012)



6.3 Ex Ante Load Impact Estimates

Figures 6-4 and 6-5 show the reference load and estimated load with DR for the average customer on a typical event day based on 1-in-2 and 1-in-10 year weather conditions for the year 2015. For a 1-in-2 typical event day, the estimated load impact for the average participant is 72.7 kW from 1 PM to 6 PM. This represents a 28.3% impact relative to the average reference load of 255.9 kW. Based on 1-in-10 year weather conditions, the load impact pattern over the event period is very similar to that in a 1-in-2 weather year because BIP customer usage is not sensitive to temperature. The average load impact across the event period is 72.2 kW.

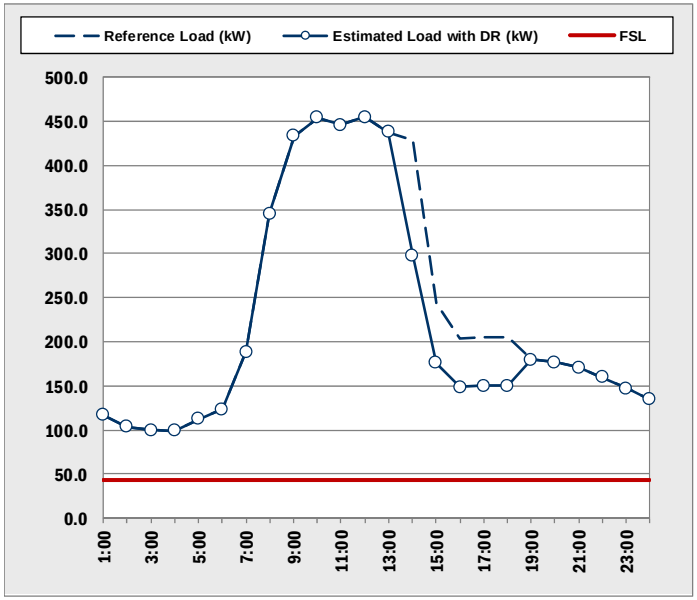
Figure 6-4: SDG&E BIP Average Load Impact (kW) per Customer in 2015 for a Typical Event Day Based on 1-in-2 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-2
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	**11**
Average FSL (kW)	**42.9**
Proxy Date	**N/A**
Average Load Impact (kW) (1-6pm)	**72.7**
% Load Impact (1-6pm)	**28.3%**



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	117.0	117.0	0.0	68.4	-59.9	-24.5	0.0	24.5	59.9
2:00	103.2	103.2	0.0	67.9	-59.9	-24.5	0.0	24.5	59.9
3:00	99.9	99.9	0.0	67.5	-59.9	-24.5	0.0	24.5	59.9
4:00	98.8	98.8	0.0	67.0	-59.9	-24.5	0.0	24.5	59.9
5:00	112.5	112.5	0.0	66.8	-59.9	-24.5	0.0	24.5	59.9
6:00	123.0	123.0	0.0	66.5	-59.9	-24.5	0.0	24.5	59.9
7:00	188.8	188.8	0.0	66.9	-60.3	-24.7	0.0	24.7	60.3
8:00	345.2	345.2	0.0	70.3	-62.3	-25.5	0.0	25.5	62.3
9:00	433.7	433.7	0.0	75.2	-63.1	-25.8	0.0	25.8	63.1
10:00	454.7	454.7	0.0	79.4	-64.0	-26.2	0.0	26.2	64.0
11:00	446.5	446.5	0.0	82.6	-64.5	-26.4	0.0	26.4	64.5
12:00	454.9	454.9	0.0	82.5	-64.9	-26.6	0.0	26.6	64.9
13:00	437.7	437.7	0.0	82.1	-64.7	-26.5	0.0	26.5	64.7
14:00	429.0	298.1	130.9	81.6	65.6	104.2	130.9	157.7	196.2
15:00	243.8	175.7	68.1	81.3	7.4	43.3	68.1	93.0	128.8
16:00	203.2	148.8	54.3	80.8	-6.0	29.6	54.3	79.1	114.7
17:00	205.4	150.3	55.1	79.3	-5.0	30.5	55.1	79.7	115.2
18:00	205.0	150.0	55.0	76.9	-5.1	30.4	55.0	79.6	115.1
19:00	179.9	179.9	0.0	75.0	-60.0	-24.6	0.0	24.6	60.0
20:00	176.7	176.7	0.0	72.8	-60.0	-24.5	0.0	24.5	60.0
21:00	170.7	170.7	0.0	71.2	-60.0	-24.5	0.0	24.5	60.0
22:00	159.4	159.4	0.0	70.5	-60.0	-24.5	0.0	24.5	60.0
23:00	147.4	147.4	0.0	69.5	-59.9	-24.5	0.0	24.5	59.9
0:00	134.2	134.2	0.0	68.9	-60.0	-24.5	0.0	24.5	60.0

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,670.7	5,307.2	363.5	111.4	63.3	240.6	363.5	486.3	663.6

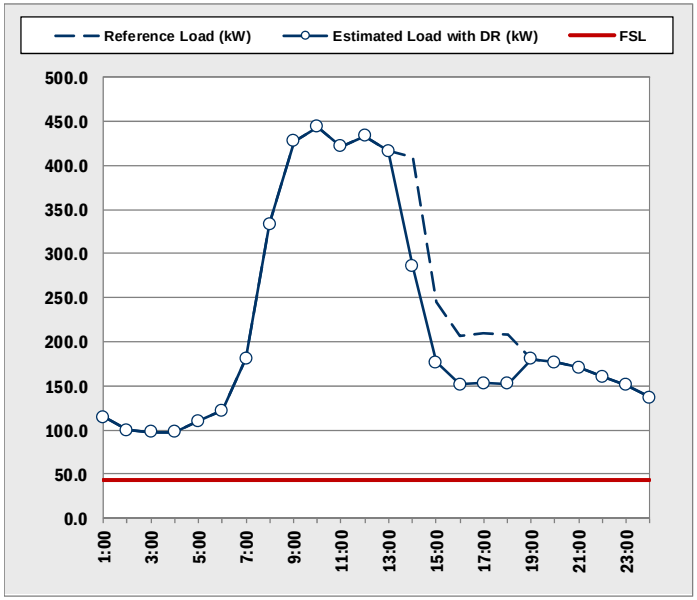
Figure 6-5: SDG&E BIP Average Load Impact (kW) per Customer in 2015 for a Typical Event Day Based on 1-in-10 Year Weather Conditions

TABLE 1: Menu options

Type of Results	Average Enrolled Account
Weather Year	1-in-10
Forecast Year	2015 - 2023
Day Type	Typical Event Day
Customer Characteristic	All Customers

TABLE 2: Output

Number of Accounts	11
Average FSL (kW)	42.9
Proxy Date	N/A
Average Load Impact (kW) (1-6pm)	72.2
% Load Impact (1-6pm)	28.2%



Hour Ending	Reference Load (kW)	Estimated Load with DR (kW)	Load Impact (kW)	Weighted Temp (F)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
1:00	114.6	114.6	0.0	71.9	-60.0	-24.6	0.0	24.6	60.0
2:00	100.0	100.0	0.0	71.4	-60.0	-24.5	0.0	24.5	60.0
3:00	97.6	97.6	0.0	70.8	-60.0	-24.5	0.0	24.5	60.0
4:00	97.2	97.2	0.0	70.2	-60.0	-24.5	0.0	24.5	60.0
5:00	110.2	110.2	0.0	70.2	-60.0	-24.5	0.0	24.5	60.0
6:00	122.2	122.2	0.0	70.1	-59.9	-24.5	0.0	24.5	59.9
7:00	180.9	180.9	0.0	70.5	-60.6	-24.8	0.0	24.8	60.6
8:00	333.8	333.8	0.0	74.0	-65.7	-26.9	0.0	26.9	65.7
9:00	427.4	427.4	0.0	77.9	-70.9	-29.0	0.0	29.0	70.9
10:00	444.3	444.3	0.0	81.3	-69.2	-28.3	0.0	28.3	69.2
11:00	421.6	421.6	0.0	83.4	-66.0	-27.0	0.0	27.0	66.0
12:00	433.4	433.4	0.0	84.5	-66.6	-27.2	0.0	27.2	66.6
13:00	416.9	416.9	0.0	84.6	-66.6	-27.2	0.0	27.2	66.6
14:00	409.8	285.4	124.4	84.8	57.0	96.8	124.4	152.0	191.9
15:00	245.1	176.5	68.6	85.0	7.3	43.5	68.6	93.6	129.8
16:00	207.2	151.5	55.7	83.5	-7.4	29.9	55.7	81.5	118.8
17:00	209.0	152.7	56.3	81.8	-6.1	30.8	56.3	81.8	118.7
18:00	208.6	152.4	56.2	79.9	-5.1	31.1	56.2	81.3	117.4
19:00	180.5	180.5	0.0	77.4	-60.1	-24.6	0.0	24.6	60.1
20:00	176.8	176.8	0.0	75.1	-60.0	-24.5	0.0	24.5	60.0
21:00	171.0	171.0	0.0	74.3	-60.0	-24.5	0.0	24.5	60.0
22:00	160.1	160.1	0.0	73.3	-60.0	-24.5	0.0	24.5	60.0
23:00	150.4	150.4	0.0	72.6	-60.0	-24.5	0.0	24.5	60.0
0:00	136.7	136.7	0.0	72.1	-60.0	-24.5	0.0	24.5	60.0

	Reference Energy Use (kWh)	Energy Use with DR (kWh)	Change in Energy Use (kWh)	Cooling Degree Hours (Base 70)	Uncertainty Adjusted Impact - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,555.4	5,194.2	361.2	160.7	54.4	235.7	361.2	486.7	668.0

Table 6-7 shows the aggregate on-peak ex ante load impact estimates for each day type by weather year and forecast year. In accordance with the revised resource adequacy hours, the peak period is defined as 1 PM to 6 PM for the typical event day and the April through October monthly peak days and 4 PM to 9 PM for the November through March monthly peak days. As a result of the change in peak period timing, aggregate impacts fluctuate throughout the year. During the 2015 to 2023 time period, 1-in-2 and 1-in-10 aggregate load impacts vary from 0.54 MW to 0.67 MW in November through March and 0.71 MW to 1.06 MW in April through October. For SDG&E BIP customers, usage is higher from 1 PM to 6 PM than it is from 4 PM to 9 PM, as shown in Figures 6-4 and 6-5. This load shape results in a fluctuation in aggregate load impacts as the peak period timing changes throughout the year.

Table 6-7: SDG&E BIP Aggregate On-Peak Load Impacts (MW) for each Day Type by Weather Year and Forecast Year

Weather Year	Day Type	Peak Period	2013	2014	2015-2023
1-in-2	Typical Event Day	1-6 PM	0.80	0.80	0.80
	January Peak	4-9 PM	0.54	0.54	0.54
	February Peak	4-9 PM	0.54	0.54	0.54
	March Peak	4-9 PM	0.58	0.58	0.58
	April Peak	1-6 PM	0.96	0.96	0.96
	May Peak	1-6 PM	1.04	1.04	1.04
	June Peak	1-6 PM	0.97	0.97	0.97
	July Peak	1-6 PM	1.06	1.06	1.06
	August Peak	1-6 PM	0.81	0.81	0.81
	September Peak	1-6 PM	0.90	0.90	0.90
	October Peak	1-6 PM	0.72	0.72	0.72
	November Peak	4-9 PM	0.60	0.60	0.60
	December Peak	4-9 PM	0.59	0.59	0.59
1-in-10	Typical Event Day	1-6 PM	0.79	0.79	0.79
	January Peak	4-9 PM	0.54	0.54	0.54
	February Peak	4-9 PM	0.59	0.59	0.59
	March Peak	4-9 PM	0.67	0.67	0.67
	April Peak	1-6 PM	0.95	0.95	0.95
	May Peak	1-6 PM	1.05	1.05	1.05
	June Peak	1-6 PM	0.99	0.99	0.99
	July Peak	1-6 PM	1.06	1.06	1.06
	August Peak	1-6 PM	0.79	0.79	0.79
	September Peak	1-6 PM	0.87	0.87	0.87
	October Peak	1-6 PM	0.71	0.71	0.71
	November Peak	4-9 PM	0.55	0.55	0.55
	December Peak	4-9 PM	0.54	0.54	0.54

7 Recommendations for All Utilities

The events in 2012 improved the quality of the over/under performance analysis, which in turn, improved the quality of the ex ante estimates. We recommend that all utilities continue to call at least one event each year. When calling a test event, all utilities need to consider the event conditions that they are attempting to simulate. If a BIP test event is meant to simulate a generation supply shortage, we recommend giving at least one day notice, but not the exact timing of the event. If a BIP test event is meant to simulate a transmission or distribution outage, no day-ahead notice should be given.

Appendix A Table of Hourly Values for Figure 3-1

In Figure 3-1, the magnitude of the difference between predicted and actual kW is unclear because the two lines for each utility are close together on the graph. Table A-1 provides the underlying hourly predicted and actual kW values that are reflected in Figure 3-1.

Table A-1: Hourly Predicted and Actual kW Values Reflected in Figure 3-1

Hour	SCE				PG&E				SDG&E			
	Actual kW	Predicted kW	Error	% Error	Actual kW	Predicted kW	Error	% Error	Actual kW	Predicted kW	Error	% Error
1	1,100.6	1,132.6	31.9	2.90%	1,032.7	1,038.4	5.7	0.55%	110.6	106.9	-3.6	-3.28%
2	1,093.7	1,128.2	34.6	3.16%	1,008.4	1,014.0	5.6	0.56%	97.3	95.5	-1.7	-1.78%
3	1,100.4	1,127.4	27.0	2.46%	1,002.4	1,006.4	4.0	0.40%	94.5	92.3	-2.2	-2.30%
4	1,108.1	1,127.2	19.1	1.73%	1,004.6	1,005.7	1.0	0.10%	95.0	92.0	-3.0	-3.13%
5	1,129.0	1,151.7	22.8	2.02%	1,027.7	1,025.7	-1.9	-0.19%	106.5	104.0	-2.5	-2.34%
6	1,177.4	1,192.4	15.0	1.27%	1,085.6	1,082.7	-2.9	-0.27%	116.5	117.8	1.3	1.13%
7	1,204.7	1,222.2	17.5	1.45%	1,151.2	1,145.6	-5.6	-0.49%	183.1	181.0	-2.0	-1.12%
8	1,207.9	1,227.7	19.7	1.63%	1,165.7	1,167.6	1.9	0.16%	323.1	340.6	17.4	5.40%
9	1,210.2	1,209.7	-0.5	-0.04%	1,177.0	1,172.5	-4.4	-0.38%	419.7	433.7	14.1	3.36%
10	1,224.3	1,214.1	-10.1	-0.83%	1,178.2	1,175.0	-3.2	-0.27%	439.8	452.0	12.2	2.78%
11	1,222.6	1,220.0	-2.6	-0.21%	1,177.7	1,172.1	-5.6	-0.48%	428.4	436.6	8.1	1.89%
12	1,207.5	1,210.0	2.4	0.20%	1,167.4	1,163.4	-4.0	-0.34%	429.0	444.3	15.3	3.56%
13	1,176.9	1,184.0	7.1	0.60%	1,131.4	1,139.4	8.0	0.70%	400.3	432.5	32.1	8.03%
14	1,170.2	1,181.4	11.1	0.95%	1,114.9	1,130.2	15.3	1.37%	396.7	424.8	28.2	7.10%
15	1,149.9	1,158.2	8.3	0.72%	1,074.5	1,099.0	24.5	2.28%	242.3	243.1	0.8	0.34%
16	1,122.9	1,133.8	10.8	0.96%	1,029.6	1,057.4	27.7	2.69%	206.2	202.6	-3.6	-1.75%
17	1,099.2	1,109.9	10.7	0.97%	1,010.5	1,040.2	29.7	2.94%	203.5	199.8	-3.7	-1.82%
18	1,081.8	1,092.1	10.4	0.96%	995.9	1,028.2	32.3	3.25%	198.7	196.4	-2.3	-1.15%
19	1,090.1	1,095.2	5.1	0.47%	1,039.2	1,063.7	24.5	2.36%	175.0	175.5	0.5	0.29%
20	1,103.7	1,104.0	0.4	0.03%	1,070.6	1,085.7	15.1	1.41%	174.3	173.5	-0.8	-0.46%
21	1,125.4	1,123.2	-2.2	-0.19%	1,078.3	1,090.3	12.0	1.11%	167.5	169.3	1.7	1.04%
22	1,120.0	1,115.7	-4.3	-0.39%	1,085.0	1,097.3	12.3	1.14%	155.4	158.3	2.9	1.85%
23	1,180.4	1,170.6	-9.9	-0.84%	1,080.8	1,091.2	10.4	0.96%	144.4	147.1	2.8	1.92%
24	1,184.2	1,184.2	-0.1	0.00%	1,068.1	1,075.7	7.7	0.72%	130.6	133.0	2.5	1.88%
Avg. (1-6 PM)	**1,124.8**	**1,135.1**	**10.3**	**0.91%**	**1,045.1**	**1,071.0**	**25.9**	**2%**	**249.5**	**253.4**	**3.9**	**1.55%**