2009 Load Impact Evaluation and Cost Effectiveness Tests of California Statewide Automated Demand Response Programs

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Executive Summary

This report documents various aspects of the load reductions achieved by the Automated Demand Response (Auto-DR) programs at the three California investor-owned electric utilities ("Joint Utilities") for Program Years 2008 and 2009. Auto-DR offers customers an incentive to install equipment that enhances their ability to reduce load during DR program events. PG&E's web site offers the following examples of equipment that qualifies for incentives:

- Wired and wireless controls for lighting, HVAC, motors, pumps, fans, air compressors, process equipment, audio/video equipment, etc.;
- Energy Management software;
- Energy Management Systems, including repairs/upgrades/reprogramming of existing controls;
- Thermostats, plug strips, occupancy sensors and other devices capable of receiving curtailment signals; and
- Appliances and vending machines capable of receiving curtailment signals.

Customers who choose to participate in Auto-DR first undergo an energy audit in which the utility determines strategies and equipment that are appropriate for the customer's facility. If the customer chooses to install the recommended equipment, a load shed test is conducted. The result of this test (measured in kW) serves as the basis for the Auto-DR incentive payment that the customer receives. This is a one-time incentive equal to the lesser of the equipment cost or $300 per tested kW. Auto-DR customers are required to participate in a DR program, from which the customers may receive on-going incentives based on its performance during event hours.

Through the 2009 program year, Auto-DR customers at PG&E and SCE were enrolled in CPP and DBP. At SDG&E, Auto-DR customers were enrolled in CPP and CBP.

The load impacts for the programs were estimated using separate econometric models (*i.e.*, regression equations) for each enrolled Auto-DR customer, based on historical load data for the summer of 2009. The models assume that hourly loads are a function of weather data; time-based variables such as hour, day of week, and month; and program event information.

A cost effectiveness (CE) model was developed to perform the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests for each utility. Because customer costs are assumed to be equal to the utility incentive costs, the two tests return the same benefit-cost ratios. The CE tests were developed using the draft cost effectiveness protocols.[1]

[1] "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols", Rulemaking 07-01-041, January 25, 2007.

Summary of Auto-DR Participants and Event Days

Table ES-1 summarizes the number of service accounts and total kW from the Auto-DR load shed tests (which serve as the basis for Auto-DR incentive payments). The largest program by verified kW is PG&E's DBP, which includes two service accounts with especially large load shed test values (9 MW and 5.2 MW). SCE's enrollments in both CPP and DBP are dominated by two service accounts that together account for the majority of the tested kW. SDG&E's CBP service accounts are all enrolled by one aggregator.

Table ES-1: Summary of Load Impacts by Utility and Demand Response Program

Utility	Program	Number of Service Accounts	Load Shed Test kW
PG&E	CPP	43	4,317
	DBP	20	25,415
SCE	CPP	19	5,869
	DBP	12	6,124
SDG&E	CPP	10	1,697
	CBP	66	3,720

Table ES-2 shows the number of event days by demand response (DR) program. SCE called the most events, with 12 CPP and 15 DBP events spread throughout the summer. PG&E called its 12 CPP events relatively early in the summer compared to the other utilities, and only called one DBP test event. SDG&E called its 8 CPP and 7 CBP (day-of, 4 hour) events relatively late in the season. SDG&E called one CPP event (August 29th) on a Saturday, while the remaining events were on weekdays.

Table ES-2: Number of Events in 2009 by DR Program

Utility	Program	Number of Events
PG&E	CPP	12
	DBP	1
SCE	CPP	12
	DBP	15
SDG&E	CPP	8
	CBP	7

Estimates of Auto-DR Load Impacts

Direct estimates of total ex post load impacts for each utility's Auto-DR participants were developed from the coefficients of individual customer regression equations. These equations were estimated for each customer account using interval load data from the summer months for 2009 using individual data for all customer accounts enrolled in each program.

The regression equations were based on models of hourly loads as functions of a list of variables designed to control for factors that affect consumers' hourly usage levels, such as:

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours (CDH))

- Event indicators—Hourly indicator variables interacted with event indicators, in order to provide estimates of the hourly load impacts during each event.

The method used in this study differs from the method used to measure demand response in the DBP and CBP programs during the 2009 program year, which was a “3-in-10” baseline method. This method calculates the baseline as the average of the three highest loads during the previous ten days that could have been events (*i.e.*, non-holiday weekdays), but were not.

The 3-in-10 baseline method (and the 10-in-10 methods with and without day-of adjustment currently in use) is useful for program purposes because customers understand it (compared to the regression-based method) and it is comparatively easily implemented for calculating settlements. However, the regression-based method is a more powerful tool for calculating baselines, as it more explicitly accounts for weather effects and regular load patterns (*e.g.*, by day of week). Because we use the regression-based load impact estimates, the load impacts used in the CE tests do not match the program-based load impact estimates that may be more familiar to the utilities.

Table ES-3 contains the load impact estimates for each utility and program, including the reference loads (which are estimated by adding the estimated load impacts to the observed event-hour loads), the percentage load impacts, the ratio of the estimated load impacts to the results of the Auto-DR load shed tests (labeled "LI / Tested kW"), the bid levels (for the Demand Bidding Program only), and the coefficient of variation (CV) across the 2009 events. The CV is equal to the standard deviation of the event-specific load impacts divided by the average of the load impacts. It is a measure of the variability of load impacts across events, normalized for the average level of load impacts.

The percentage load impacts were quite different across programs, with PG&E's CPP on the low end at 6.1 percent and PG&E's DBP at the high end with 45.6 percent (though this result was likely affected by the overlap of the DBP event with another DR event for the Base Interruptible Program). Load impacts relative to the load shed test kW were lowest for SDG&E's CBP program, at 16 percent. However, this performance appears to be improving in 2010 and was significantly better in 2008.

Some of the load shed tests imply very high percentage load impacts relative to the reference loads observed in 2009. For example, SDG&E's Auto-CBP customers provided a 605 kW load impact (or 11.4 percent), which was just 16 percent of the load shed test value. Given the reference loads on the 2009 event days, these customers would have needed to achieve a 71 percent load reduction in order to reach the load shed test value. Similar performance levels (over 70 percent load reductions) are required from SCE's Auto-DBP and Auto-CPP customers in order to reach load shed test values.

In terms of the variability of load impacts across events (measured by the coefficient of variation), SDG&E's CBP program had the least variable load impacts while SCE's DBP program had the most variable load impacts. (We cannot calculate a coefficient of variation for PG&E's DBP load impacts because they only called one event.) The CV for

SCE's CPP program is inflated by the variability in the load impacts for one large customer; and the CV for SDG&E's CPP program is inflated by the unusually low load impacts estimated for the last CPP event.

Table ES-3: Summary of Load Impacts by Utility and Demand Response Program

Utility	Program	Load Impact (kW)	Reference Load (kW)	% Load Impact	LI / Tested kW	Bid kW	2009 CV
PG&E	CPP	1,701	27,836	6.1%	42%	n/a	0.26
	DBP	19,066	41,794	45.6%	89%	25,156	n/a
SCE	CPP	2,369	7,765	30.5%	40%	n/a	0.41
	DBP	1,712	7,820	21.9%	28%	4,498	0.52
SDG&E	CPP	1,349	6,998	19.3%	79%	n/a	0.33
	CBP	605	5,299	11.4%	16%	n/a	0.16

In addition to the total load impacts described above, we estimated *incremental* load impacts, which are intended to represent the change in load impacts that occurred because of the adoption of Auto-DR. That is, customers are likely to be able to provide some level of load impacts in the absence of Auto-DR, and the estimation of incremental load impacts attempts to net this amount out of the total load impacts.

This method compares percentage load impacts within narrowly defined industry groups for customers who are and are not Auto-DR enabled. (The comparison group is always selected from customers who participate in the same DR program.) Where possible, we conduct comparisons of load impacts within a 6-digit NAICS code or 4-digit SIC code. Where a comparison at this level of disaggregation is not possible, we compare at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes. In some cases, the sample of service accounts does not contain any reasonable basis of comparison. When this occurs, we use the average percentage load impact for all of the non-Auto-DR customers as the comparison group. The difference in the percentage load impacts is within the industry group is then applied to the reference load for the Auto-DR participants to calculate the incremental load impact.

While we believe this method to be a reasonable approach for estimating incremental load impacts, some potential problems exist. For example, we do not know whether any of the comparison group customers have enabling technology that they purchased without incentives. Where this occurs, we would understate the incremental load impact (because the calculation would not be based on the difference between load impacts for customers with and without automated technology). In addition, there may be differences across service accounts even within narrowly defined industry groups that affect the ability of the customer to respond during DR events. Any such differences that exist may introduce bias in the incremental load impact estimate, though we cannot know the direction of the bias in the absence of additional information regarding the nature of the differences across service accounts.

As expected, the resulting incremental load impacts were lower than the total load impacts. However, for PG&E's DBP program, the incremental load impact was negative (implying that Auto-DR caused a reduction in load response for participants). This counter-intuitive result indicates the difficulty that can exist in finding a reasonable comparison group to which Auto-DR load impacts may be compared.

Cost Effectiveness Models

Separate cost effectiveness (CE) models were developed for each utility. Within each utility's model, information was included from all of the demand response programs on which the utility has Auto-DR customers. The CE model conducts the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests.

Within each program, the CE model separately analyzes three equipment installation years (hereafter referred to as "vintage years"): 2007, 2008, and 2009. For each vintage year, the CE model calculates 10 years of costs and benefits. (*E.g.*, for 2007, costs and benefits are calculated for 2007 through 2016.) In this case, 10 years represents the expected useful life of the equipment.

For each vintage year, the per-event-hour load impacts are derived from the 2009 program year load impact estimates, where the load impacts are divided into vintage years. We assume that the allocated load impact values remain constant across the 10-year analysis window. The 10-year cost and benefit streams for the three vintage years are discounted to a common year (labeled the "base year" in the CE model).

For both the TRC and PAC tests, benefits are calculated as the sum of avoided capacity costs, avoided energy costs, and avoided T&D costs.

For the TRC test, costs are calculated as the sum of administrative costs, Auto-DR capital incentive costs, and customer costs. For the PAC test, costs are calculated as the sum of administrative costs, Auto-DR capital incentive costs, and DR incentives. Because customer costs are assumed to be equal to the DR incentives, the TRC and PAC tests return the same results.

CE tests were run under different sets of assumptions. First, we included load impacts (and therefore benefits) in two ways: as *total* and *incremental* Auto-DR load impacts. The second sensitivity analysis is based on the inclusion of the 70th percentile exceedance factor (*E*). This factor is intended to discount benefits associated with programs that have more variable (*i.e.*, less reliable) load impacts. While this factor is not included in the cost effectiveness draft protocols, it is potentially important for evaluating Auto-DR programs because they may provide more reliable load impacts than non-automated DR customers.

The 70th percentile exceedance factor was taken from a proposed decision regarding resource adequacy, in which the factor was proposed as a means for valuing wind and solar generation.[2] The intermittency of wind and solar resources (*e.g.*, due to varying wind conditions) is conceptually similar to the variability in the load impacts that DR (including Auto-DR) customers provide. In the case of DR customers, the variability may be due to a

[2] Appendix B of the proposed decision by ALJ Gamson, "Decision Adopting Local Procurement Obligations for 2011 and Further Refining the Resource Adequacy Program", Rulemaking 09-10-032.

number of factors, including production schedules, changes in load levels in response to economic conditions, etc.

Our "base" CE tests set *E* to 1, which is consistent with current CE test methods in that benefits are not affected by the uncertainty (or variability across events) in load impacts. A sensitivity analysis incorporates appropriate values of *E* for each utility and program. The factors are based on the uncertainty in the load impact estimates and/or the variability in load impacts across events.

Table ES-4 summarizes the benefit-cost ratios by utility and program for a variety of scenarios. For reference purposes, the Auto-DR incentive payments associated with each program are included in the table.

The results labeled "B/C at Base LI" contain the benefit-cost ratios assuming a "conservative" level of load impacts. Specifically, the results are primarily taken from the 2009 program year. At SCE, two of the largest customers (together accounting for over 70 percent of the load shed test kW) experienced a reduction in their baseline load levels in 2009 because of a combination of changes in behavior induced by the Auto-DR equipment and a response to worsening economic conditions. These factors made it difficult for these customers to perform up to their tested levels.

At SDG&E, the Auto-CBP customers performed at a significantly lower level in 2009 than they did in 2008. Customer education efforts that SDG&E has subsequently pursued appear to have been successful in raising the load impact somewhat thus far in 2010 (based on a preliminary examination of events in July). The "B/C at High LI" column shows the CE test results using the preliminary 2010 load impacts, which results in an increase of the benefit-cost ratio to 0.82.

At PG&E, the Auto-DBP load impacts (and therefore the benefit-cost ratio) depend on the performance of one service account. In both 2008 and 2009, PG&E called only one DBP test event. The service account in question provided load impacts that were approximately 15 MW higher in 2009 than they were in 2008. The results of PG&E's CE test assuming the higher load impact level are shown in the "B/C at High LI" column. As the results show, the behavior of one customer on one event day is the difference between obtaining a benefit-cost ratio of 0.54 or 2.20.

The results shown in the "B/C at Tested kW" were calculated to demonstrate that, had customers performed to their tested kW levels, all of the Auto-DR programs would have been cost effective. This demonstrates that the Auto-DR program concept was not flawed from the start.

Table ES-4: Summary of Benefit-Cost Ratios by Utility and Scenario

Utility	Program	B/C at Base LI	B/C at High LI	B/C at Tested kW	Auto-DR Incentive
PG&E	CPP	1.11	1.11	3.11	$700,495
	DBP	0.44	2.38	2.64	$3,856,096
	Auto-DR	**0.54**	**2.20**	**3.04**	$4,556,591
SCE	CPP	0.54	n/a	1.23	$705,336
	DBP	0.46	n/a	0.99	$1,742,822
	Auto-DR	**0.49**	**n/a**	**1.07**	$2,448,158
SDG&E	CPP	3.75	3.75	4.71	$253,316
	CBP	0.27	0.36	0.87	$1,127,866
	Auto-DR	**0.77**	**0.82**	**1.18**	$1,381,182

Summary and Conclusions

The results of the CE models indicated that, under most assumptions, the Auto-DR programs are not currently cost effective (although PG&E's and SDG&E's Auto-CPP programs do appear to be cost effective by themselves). However, a couple of factors contribute to some uncertainty regarding the validity of this conclusion:

- The load impact estimates, which are the source of program benefits, are often driven by the behavior of very few customers on very few event days. For example, the benefit-cost ratio of PG&E's Auto-DBP program changes from 0.54 to 2.20 simply by using the 2009 load impact estimate in place of the 2008 load impact estimate *for one customer*. Furthermore, PG&E only called one DBP event in both 2008 and 2009, so the cost effectiveness is determined by customer load response in four hours per year.
- Customer baselines may change over time, making it difficult for some customers to perform up the level of their Auto-DR load shed test. These baseline changes could be caused by Auto-DR program (*e.g.*, by using information from an energy management system to better manage usage in all hours, and not only on event days; or by installing energy efficiency equipment funded by the bill savings from participating in demand response), or in response to changes in economic conditions or other "exogenous" factors.

Even considering these concerns, it appears that many Auto-DR customers are providing load impacts during events that are significantly below their load shed test values. Because Auto-DR pays its participants an incentive based on the results of the load shed test, it is important for the tests to reflect the performance that will be provided during DR program events. For example, if the load shed test values were consistently too high relative to the load impacts that customers can deliver during DR program events, it becomes difficult for the Auto-DR program to be cost effective. Therefore, it may be worthwhile for the utilities to review the load shed test methods, perhaps by comparing test conditions to event conditions to determine whether improvements to the load shed impact tests are necessary.

1. Introduction and Purpose of the Study

This report documents various aspects of the load reductions achieved by the Automated Demand Response (Auto-DR) programs at the three California investor-owned electric utilities ("Joint Utilities") for Program Years 2008 and 2009. These aspects include 1) summarizing the load impacts achieved by Auto-DR participants, including the consistency of load impacts across events, 2) providing estimates of incremental load impacts (*e.g.*, relative to load impacts of non-Auto-DR customers), 3) analyzing the cost-effectiveness ("CE") of the Auto-DR programs at each utility using standard CE tests, and 4) reporting on the findings. The reporting will include both a written report and a workshop presentation.

Auto-DR provides commercial customers with incentives to install technology that automates a customer's response to demand response (DR) program events. Auto-DR participants must enroll in a DR program, where the options include: the Demand Bidding Program (DBP), Critical Peak Pricing (CPP), and the Capacity Bidding program (CBP).[3]

The load impacts for the programs were estimated using separate econometric models (*i.e.*, regression equations) for each enrolled Auto-DR customer, based on historical load data for the summer of 2009. The models assume that hourly loads are a function of weather data; time-based variables such as hour, day of week, and month; and program event information.

A cost effectiveness (CE) model was developed to perform the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests for each utility. The CE tests were developed using the draft cost effectiveness protocols.[4] The ability to conduct reliable CE tests is complicated by the fact that the load impact estimates, which directly contribute to the avoided costs that serve as the program benefits, are often influenced by the behavior of one or two customers, and sometimes on only one event day. In addition, SCE's largest customers (in terms of tested kW) may have issues with the baseline level changing over time. If true, this would mean that the CE tests conducted in this study understate program benefits.

After this introductory section, Section 2 describes the Auto-DR program, including the characteristics of the enrolled customer accounts. Section 3 discusses evaluation methodology. Section 4 presents Auto-DR load impact estimates. Section 5 presents the cost effectiveness tests. Section 6 provides a summary and conclusions.

[3] Specifically, SDG&E allows participation on CBP and CPP; while PG&E and SCE allow participation in CPP and DBP.

[4] "Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols", Rulemaking 07-01-041, January 25, 2007.

2. Description of the Automated Demand Response Program

2.1 Auto-DR Program Description

Auto-DR offers customers an incentive to install equipment that enhances their ability to reduce load during DR program events. PG&E's web site offers the following examples of equipment that qualifies for incentives:

- Wired and wireless controls for lighting, HVAC, motors, pumps, fans, air compressors, process equipment, audio/video equipment, etc.;
- Energy Management software;
- Energy Management Systems, including repairs/upgrades/reprogramming of existing controls;
- Thermostats, plug strips, occupancy sensors and other devices capable of receiving curtailment signals; and
- Appliances and vending machines capable of receiving curtailment signals.

Customers who choose to participate in Auto-DR first undergo an energy audit in which the utility determines strategies and equipment that are appropriate for the customer's facility. If the customer chooses to install the recommended equipment, a load shed test is conducted. The result of this test (measured in kW) serves as the basis for the Auto-DR incentive payment that the customer receives. This is a one-time incentive equal to the lesser of the equipment cost or $300 per tested kW. Auto-DR customers are required to participate in a DR program, from which the customers may receive on-going incentives based on its performance during event hours.

Through the 2009 program year, Auto-DR customers at PG&E and SCE were enrolled in CPP and DBP. At SDG&E, Auto-DR customers were enrolled in CPP and CBP.

The next section describes the Auto-DR participants.

2.2 Participant characteristics

Tables 2.1 through 2.6 contain Auto-DR enrollments for each utility and demand response program during the 2009 program year.

Each table shows the participants by industry code (NAICS code for PG&E and SDG&E, SIC code for SCE), including a description of the industry group, the number of enrolled service accounts, and the amount of verified (tested) kW from the load shed tests conducted for Auto-DR.[5]

The largest program by load shed test kW is PG&E's DBP, which includes two service accounts with especially large load shed test values (9 MW and 5.2 MW). PG&E’s programs cover a fairly broad range of industry groups compared to SCE and SDG&E.

[5] For the DBP tables (PG&E and SCE), the number of service accounts includes only the master service account. That is, the service accounts that participate under the master account are excluded from the table.

SCE's enrollments in both CPP and DBP are dominated by two service accounts that together account for the majority of the load shed test kW. This is described in more detail in Section 4.1.4.

SDG&E's CBP service accounts are all enrolled by one aggregator.

Table 2.1: 2009 Auto-DR Enrollment, PG&E CPP

NAICS Code	NAICS Description	Number of Service Accounts	Load Shed Test kW
221310	Water Supply and Irrigation Systems	1	74
311412	Frozen Specialty Food Manufacturing	2	580
311812	Commercial Bakeries	1	100
334419	Other Electronic Component Manufacturing	9	306
442110	Furniture Stores	2	329
452112	Discount Department Stores	3	136
511210	Software Publishers	2	488
531123	Lessors of Nonresidential Buildings	1	44
541710	Research and Development in Biotechnology	4	209
551114	Corporate Offices	2	527
611112	Elementary and Secondary Schools	2	39
611114	Elementary and Secondary Schools	2	18
611513	Apprenticeship Training	1	59
624310	Vocational Rehabilitation Services	1	250
712110	Museums	1	24
921190	Other General Government Support	4	455
922120	Police Protection	1	300
922130	Legal Counsel and Prosecution	1	60
922140	Correctional Institutions	2	250
923130	Administration of Human Resource Programs	1	69
Total		**43**	**4,317**

Table 2.2: 2009 Auto-DR Enrollment, PG&E DBP

NAICS Code	NAICS Description	Number of Service Accounts	Load Shed Test kW
115114	Postharvest Crop Activities (except Cotton Ginning)	1	550
221112	Hydroelectric Power Generation	1	800
325120	Industrial Gas Manufacturing	2	11,430
423930	Recyclable Material Merchant Wholesalers	1	5,175
424410	General Line Grocery Merchant Wholesalers	1	385
442110	Furniture Stores	1	193
452111	Department Stores	1	2,874
452112	Discount Department Stores	1	76
518210	Data Processing, Hosting, and Related Services	1	76
531123	Lessors of Nonresidential Buildings	1	402
551114	Corporate Managing Offices	3	2,202
713940	Fitness and Recreational Sports Centers	1	85
921190	Other General Government Support	4	1,167
Total		**20**	**25,415**

Table 2.3: 2009 Auto-DR Enrollment, SCE CPP

SIC Code	SIC Description	Number of Service Accounts	Load Shed Test kW
1611	Highway and Street Construction	2	353
2834	Pharmaceutical Preparations	1	127
3069	Fabricated Rubber Products	1	899
3691	Storage Batteries	1	3,200
3716	Recreational Vehicle Manufacturers	2	441
5211	Lumber Dealers	1	174
6512	Operators of Non-Residential Buildings	11	675
Total		**19**	**5,869**

Table 2.4: 2009 Auto-DR Enrollment, SCE DBP

SIC Code	SIC Description	Number of Service Accounts	Load Shed Test kW
2834	Pharmaceutical Preparations	1	127
3069	Fabricated Rubber Products	1	899
3691	Storage Batteries	2	3,986
5211	Lumber Dealers	1	174
5712	Furniture Stores	3	693
6512	Operators of Non-Residential Buildings	11	675
Total		**19**	**6,554**

Table 2.5: 2009 Auto-DR Enrollment, SDG&E CPP

NAICS Code	NAICS Description	Number of Service Accounts	Load Shed Test kW
452111	Department Stores	6	1,148
512131	Motion Picture Theaters	1	11
721110	Hotels and Motels	2	277
721120	Casino Hotels	1	261
Total		**10**	**1,697**

Table 2.6: 2009 Auto-DR Enrollment, SDG&E CBP

NAICS Code	NAICS Description	Number of Service Accounts	Load Shed Test kW
441222	Boat Dealers	2	22
451120	Hobby, Toy & Game Stores	16	1,086
452990	All Other General Merchandise Stores	18	980
561439	Other Business Service Centers (including Copy Shops)	12	332
713940	Fitness and Recreational Sports Centers	18	1,300
Total		**66**	**3,720**

In 2010, Auto-DR participation has continued to increase. Table 2.7 shows that PG&E has installed an additional 9.4 MW of estimated load reduction to its Auto-DR portfolio in 2010 (as of August), with another 19.8 MW in progress. This represents the potential for a significant increase in the size of PG&E's Auto-DR program.

Table 2.7: PG&E Auto-DR Activity in 2010

Status	# of Service Accounts	Estimated Load Reduction (MW)
In Progress	80	19.8
Installed	16	9.4
Total	**96**	**29.2**

Table 2.8 provides information on SCE's 2010 Auto-DR program activity as of August 2010. In this table, currently participating customers are shown in the "PAID" and "Measurement & Verification Pending" groups, which together account for 34 service accounts and approximately 19 MW of potential load reduction. The other status categories ("Pending Reservation", "Confirmed Reservation", and "TI in Progress") indicate the potential scale for near-term program expansion. The potential load reduction from these categories is approximately 39 MW from 129 service accounts. (Note that these load reduction values are estimated and not taken from load shed tests.)

Table 2.8: SCE Auto-DR Enrollments and Activity as of August 2010

Reservation Status	Data	Total
Pending Reservation	Sum of Reserved kW	1,338
	# of Service Accounts	10
	Count of Projects	3
Confirmed Reservation	Sum of Reserved kW	32,631
	# of Service Accounts	78
	Count of Projects	29
TI in Progress	Sum of Reserved kW	4,730
	# of Service Accounts	41
	Count of Projects	10
Measure & Verification Pending	Sum of Reserved kW	925
	# of Service Accounts	7
	Count of Projects	2
PAID	Sum of Reserved kW	18,102
	# of Service Accounts	26
	Count of Projects	6
Total Sum of Reserved kW		57,726
Total # of Service Accounts		162
Total Count of Projects		50

Pending Reservation	Customer submitted reservation; under review before confirmation is issued.
Confirmed Reservation	SCE is holding funds for customer; customer installation/construction in progress.
TI in Progress	SCE receives invoice package; scheduled Load Test with customer.
Measurement & Verification Pending	Load test performed (basis of kW for incentive payment).
Paid	Project is closed - check issued by SCE.

2.3 Program events

Table 2.9 lists event days for each program and utility during 2009. SCE called the most events, with 12 CPP and 15 DBP events spread throughout the summer. PG&E called its 12 CPP events relatively early in the summer compared to the other utilities, and only called on DBP test event. SDG&E called its 8 CPP and 7 CBP (day-of, 4 hour) events relatively late in the season. SDG&E called one CPP event (August 29th) on a Saturday, while the remaining events were on weekdays.

Table 2.9: Demand Response Program Events, 2009

		PG&E		SCE		SDG&E	
Date	**Day of Week**	**CPP**	**DBP**	**CPP**	**DBP**	**CPP**	**CBP**
6/4	Thu				1 (test)		
6/18	Thu			1 (test)			
6/29	Mon	1					
6/30	Tue	2					
7/13	Mon	3					
7/14	Tue	4					
7/15	Wed			2	2		
7/16	Thu	5					
7/17	Fri			3	3		
7/20	Mon			4	4		
7/21	Tue	6					1
7/22	Wed			5	5		
7/27	Mon	7		6	6		
7/28	Tue			7	7		
8/10	Mon	8					
8/11	Tue	9					
8/18	Tue	10					
8/20	Thu			8			
8/26	Wed						2
8/27	Thu	11		9	8	1	3
8/28	Fri	12	1 (test)	10	9	2	4
8/29	Sat					3	
8/31	Mon				10	4	
9/1	Tue			11	11		
9/2	Wed			12	12		5
9/3	Thu				13	5	6
9/4	Fri					6	
9/8	Tue				14		
9/22	Tue				15		
9/24	Thu					7	7
9/25	Fri					8	

3. Load Impact Study Methodology

Direct estimates of total ex post load impacts for each utility's Auto-DR participants were developed from the coefficients of individual customer regression equations. These equations were estimated for each customer account using interval load data from the summer months for 2009 using individual data for all customer accounts enrolled in each program.

The method used in this study differs from the method used to measure demand response in the DBP and CBP programs during the 2009 program year, which was a "3-in-10" baseline method. This method calculates the baseline as the average of the three highest loads during the previous ten days that could have been events (*i.e.*, non-holiday weekdays), but were not.

The 3-in-10 baseline method (and the 10-in-10 methods with and without day-of adjustment currently in use) is useful for program purposes because customers understand it (compared to the regression-based method) and it is comparatively easily implemented for calculating settlements. However, the regression-based method is a more powerful tool for calculating baselines, as it more explicitly accounts for weather effects and regular load patterns (*e.g.*, by day of week). Because we use the regression-based load impact estimates, the load impacts used in the CE tests do not match the program-based load impact estimates that may be more familiar to the utilities.

3.1 Primary regression equation specifications

The regression equations were based on models of hourly loads as functions of a list of variables designed to control for factors that affect consumers' hourly usage levels, such as:

- Seasonal and hourly time patterns (*e.g.*, month, day-of-week, and hour, plus various hour/day-type interactions)
- Weather (*e.g.*, cooling degree hours (CDH))
- Event indicators—Hourly indicator variables interacted with event indicators, in order to provide estimates of the hourly load impacts during each event.

The basic model specification is shown below. (There were some relatively minor variations in the specification across utilities and programs.)

$$
\begin{aligned}
Q_t &= a + \sum_{Evt=1}^{E} \sum_{i=1}^{24} (b_{i,Evt}^{DR} \times h_{i,t} \times DR_t) + b^{MornLoad} \times MornLoad_t + \sum_{i=1}^{24} (b_i^{CDH} \times h_{i,t} \times CDH_t) \\
&+ \sum_{i=2}^{24} (b_i^{MON} \times h_{i,t} \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI} \times h_{i,t} \times FRI_t) + \sum_{i=2}^{24} (b_i^{h} \times h_{i,t}) + \sum_{i=2}^{5} (b_i^{DTYPE} \times DTYPE_{i,t}) \\
&+ \sum_{i=6}^{10} (b_i^{MONTH} \times MONTH_{i,t}) + b_t^{Summer} \times Summer_t + \sum_{i=1}^{24} (b_i^{CDH,S} \times h_{i,t} \times Summer_t \times CDH_t) \\
&+ \sum_{i=2}^{24} (b_i^{MON,S} \times h_{i,t} \times Summer_t \times MON_t) + \sum_{i=2}^{24} (b_i^{FRI,S} \times h_{i,t} \times Summer_t \times FRI_t) \\
&+ \sum_{i=2}^{24} (b_i^{h,S} \times h_{i,t} \times Summer_t) + b^{OTH} \times OTH_t + e_t
\end{aligned}
$$

In this equation, Q_t represents the amount of usage in hour t for a customer enrolled in the DR program; the b's are estimated parameters; $h_{i,t}$ is a dummy variable for hour i; DR_t is an indicator variable for the demand response program's event days; CDH_t is cooling degree hours;[6] E is the number of event days that occurred during the program year; $MornLoad_t$ is a variable equal to the average of the day's load in hours 1 through 10; MON_t is a dummy variable for Monday; FRI_t is a dummy variable for Friday; $DTYPE_{i,t}$ is a series of dummy variables for each day of the week; $MONTH_{i,t}$ is a series of dummy variables for

[6] Cooling degree hours (CDH) was defined as MAX[0, Temperature – 50], where Temperature is the hourly temperature in degrees Fahrenheit. Customer-specific CDH values are calculated using data from the most appropriate weather station. Our previous studies used cooling degree days with a 65 degree threshold (CDD65). Our review of the results this year found that using CDH50 in place of CDD65 produced implied event-day reference loads that better reflected observed usage patterns and levels on hot, non-event days.

each month; $Summer_t$ is a variable indicating summer months (defined as mid-June through mid-August)[7], which is interacted with the weather and hourly profile variables; OTH_t is a dummy variable indicating an event hour for any other demand response programs in which the customer is also enrolled[8]; and e_t is the error term. The "morning load" variable was used in lieu of a more formal autoregressive structure in order to adjust the model to account for the level of load on a particular day. Because of the autoregressive nature of the morning load variable, no further correction for serial correlation was performed in these models.

3.2 Customer-level screening of results

Separate models were estimated for each enrolled customer. We screened the customer-level models for the effects of omitted variable bias. That is, while we include a large number of variables to account for systematic variations in customer load levels (*e.g.*, by time of day, or day of week), many other factors may affect a customer's usage in a particular hour. For example, in our previous load impact studies we found that the load shapes for sports arenas in the PG&E area are difficult to predict because the load changes substantially on days on which they apparently host events, but we do not have the information to design variables to account for the occurrence of such events. For these customers, we sometimes observed large positive load impacts and sometimes large negative load changes in the hours following DR event windows. However, these estimated "load impacts" were clearly unrelated to the existence of the DR event, but rather artifacts of whether the arena happened to host an event on the day of the DR event. In these cases, we set the load impacts equal to zero for those accounts. (We determine whether the load impacts are "real" by examining the daily load profiles for event and similar non-event days.)

Our screening resulted in very little modification of the regression results. In PG&E's CPP program, we revised the load impacts for three customers on the July 27th event. In two of the cases, we replaced the regression-based load impacts with load impacts generated as a comparison of the event day to a similarly hot non-event day earlier in the summer. For the third customer, we set the estimated load impact to zero.

There is another source of difference between the load impacts in this report and those reported in our program-wide (*i.e.*, for CPP, DBP, or CBP as a whole, not only for Auto-DR) load impact studies from earlier in 2010. We discovered in this project that some DBP service accounts at both PG&E and SCE were aggregated for program purposes. Because bidding data only exist for the "master" service account, the load impacts for the customer's other service accounts were not counted in our previous load impact studies. (We only count estimated load impacts when a customer has submitted a bid.) The utilities provided us with information on the aggregated customers, which we used to correct the error for this study.

[7] This variable was initially designed to reflect the load changes that occur when schools are out of session. We have found the variables to a useful part of the base specification, as they do not appear to harm load impact estimates even in cases in which the customer does not change its usage level or profile during the summer months.

[8] For DBP, the variable is equal to one if it is an event hour and the customer submitted a bid for that hour.

4. Load Impact Study Findings

In this section, we describe the load impacts obtained from the Auto-DR participants. The results are summarized by utility and program. Two types of load impacts are reported: total and incremental load impacts. Total load impacts are simply equal to the sum of the customer-level load impacts that we directly estimated. Estimating *incremental* load impacts is a more complicated task, which we conducted by developing comparison groups of service accounts in similar industry classifications. The method used is described in more detail in Section 4.2.

4.1 Total Auto-DR Load Impacts

The following sub-sections summarize the total load impact estimates by utility and program. In the final sub-section, we include a summary table that facilitates comparisons across programs.

4.1.1 PG&E Critical Peak Pricing

The Auto-DR load impacts across PG&E's twelve CPP events are shown in Table 4.1. The Auto-DR customers averaged a 1,701 kW load impact across the events. The coefficient of variation (CV) associated with the load impacts (which is equal to the standard deviation divided by the mean) was 0.26.[9] The 70th percentile load impact is 94 percent of the 50th percentile, which indicates relatively little variability in load impacts.

The lowest load impact (933 kW) occurred in July 27, which was also the event date that had the lowest load impacts for the program as a whole (including non-Auto-DR customers). It's not clear why this was the case. For example, the temperatures on that event day were not unusually mild compared to other event days and it did not follow another event day.

The load impacts were not highly concentrated within the Auto-DR customers. The highest average load impact for a service account was 277 kW. Therefore, it does not appear that the variability in load impacts across events was driven by the behavior of a small sub-set of the enrolled customers.

[9] The coefficient of variation (CV) is equal to the standard deviation of the load impacts across events divided by the average load impact across events. CV is a useful as a normalized measure of variability, akin to looking at percentage load impacts in place of kW load impacts.

Table 4.1: Total Auto-DR Participant Load Impacts: PG&E CPP

Date	Load Impact Estimate (kW)	% Load Impact
6/29/2009	1,949	6.9%
6/30/2009	1,110	4.2%
7/13/2009	1,556	5.8%
7/14/2009	1,830	6.1%
7/16/2009	1,109	4.2%
7/21/2009	1,652	6.6%
7/27/2009	933	2.3%
8/10/2009	1,956	6.5%
8/11/2009	1,993	7.3%
8/18/2009	1,947	7.2%
8/27/2009	2,075	7.1%
8/28/2009	2,301	7.3%
Average	1,701	6.0%
Std. Dev.	437	
Coeff. of Variation	0.26	
70th Percentile	1,594	
Tested kW	4,036	

4.1.2 PG&E Demand Bidding Program

In 2009, PG&E only called one event for its Demand Bidding Program from 2 p.m. to 6 p.m. The first two hours of the DBP event overlapped with the event from another program, the Base Interruptible Program (BIP). Some of the DBP customers are also enrolled in BIP, and the BIP event takes precedence over the DBP event. The customers who are dually enrolled in DBP and BIP have much higher load impacts than the customers who are enrolled only in DBP. It appears that the DBP/BIP customers simply carried their high rate of BIP load response into the DBP event hours.

We cannot say with certainty whether the DBP/BIP customers would have responded at the same level if the DBP event had not overlapped with the BIP event. However, we can examine the load impacts from the 2008 test event, which was also four hours in duration, but did not overlap with a BIP event. The load impacts from Auto-DR customers for this event were 5,715 kW, significantly lower than the load response observed in 2009. Because the 2008 DBP event was a stand-alone event, the load impacts estimated for it may be more representative of a typical DBP event response.

Table 4.2 shows the load impacts with and without the customers dually enrolled in BIP. The first row of results includes the BIP customers, and the load impacts are averaged across only the second two hours of the DBP event (to avoid confusion in interpreting the first two hours, which contained a high level of response that is attributed to BIP and not DBP). The second row of results shows the comparatively low level of load impacts obtained from the DBP customers who were not also enrolled in BIP.

One interesting note about the 2009 load impacts is that one customer (consisting of aggregated department stores) responded in the two hours *following* the DBP event. That is, we estimated a small amount of response from 4 to 6 p.m. (averaging 350 kW), but from 6 to 8 p.m., the customer provided an average of 2,610 kW in load response. Because the load reduction occurred after the DBP event concluded, they are not reflected in Table 4.2.

Table 4.2a: Total Auto-DR Participant Load Impacts: PG&E DBP 2009

Date	Load Impact Estimate (kW)	Bid Amount (kW)	% Load Impact*
8/28/2009, with BIP	19,066	25,156	45.6%
8/28/2009, without BIP	2,550	4,033	7.1%
Tested kW	21,314		

Table 4.2b: Total Auto-DR Participant Load Impacts: PG&E DBP 2008

Date	Load Impact Estimate (kW)	Bid Amount (kW)	% Load Impact*
7/9/2008	5,715	12,501	11.7%
70th Percentile	4,793		

* The percentage load impact is calculated using only customers who submitted a bid.

Another customer who is not reflected in the estimated load impacts has a high tested kW value of 5,175 kW. However, this customer is very responsive to price signals on all days and therefore has very low usage levels during the time-of-use (TOU) peak pricing period. Because this, their baseline load is very low until 6 p.m., when they typically increase their usage level. This means that they can only respond to DBP events from 6 p.m. through 8 p.m. (which is the end of the allowed window for DBP events). However, the DBP test events that PG&E called in 2008 and 2009 both ended at 6 p.m. Therefore, we have not observed this customer's DBP event response. In theory, it would be quite simple for them to respond to a DBP event by just delaying their processes an additional two hours beyond their usual daily pattern. While it seems likely that this customer would perform close to its tested kW level, their load response is not included in the cost effectiveness tests because we have not observed it.

4.1.3 SCE Critical Peak Pricing

As shown in Table 4.3, SCE's CPP program averaged 2,369 kW per event during the 2009 program year. For this program, one service account comprises more than half of the total load impact. This customer was not yet Auto-DR enabled for the first two CPP events, provided about half of its average response on July 27th, and did not respond at all on July 28th. Therefore, this customer contributes significantly to the total variation in load impacts. Removing this customer from the calculation of the coefficient of variation across CPP events reduces the value from 0.41 to 0.25.[10]

[10] The average load impact for the program excluding the large customer is 1,225 kW and the standard deviation is 312 kW.

Additional discussion of issues associated with measuring the load impacts of two customers who account for the majority of the program's tested kW is included in the next sub-section (because the customers are also enrolled in DBP).

For the program as a whole, the 70th percentile load impact is nearly 99 percent of the 50th percentile, which reflects the fact that many of the event days had load impacts close to the mean level.

Table 4.3: Total Auto-DR Participant Load Impacts: SCE CPP

Date	Load Impact Estimate (kW)	% Load Impact
6/18/2009	862*	15.8%
7/15/2009	1,061*	18.3%
7/17/2009	2,575	34.3%
7/20/2009	2,539	32.9%
7/22/2009	2,636	32.5%
7/27/2009	2,207	29.6%
7/28/2009	717	9.9%
8/20/2009	2,672	36.3%
8/27/2009	3,146	34.6%
8/28/2009	3,515	38.7%
9/1/2009	2,998	33.9%
9/2/2009	3,505	36.9%
Average	2,369	30.5%
Std. Dev.	981	
Coeff. of Variation	0.41	
70th Percentile	2,340	
Tested kW	5,869	

* Large customer not yet enrolled, averages 1,374 kW by itself.

4.1.4 SCE Demand Bidding Program

Table 4.4 shows the load impacts by event for SCE's Demand Bidding Program. The load impacts are quite variable across events. At first glance, it would appear that a significant contributing factor to this variability is the presence of one customer that accounts for a large share of total load impacts. (This is the same large customer referred to in the previous section – it is enrolled in both CPP and DBP.) This customer was not Auto-DR enabled for the first two DBP events and did not perform for two of the events (July 28 and August 27). Because this customer accounts for approximately two thirds of the total load impact, these absences from the load impacts drive large variations in the overall level of the load impacts.

While the remaining customers have significantly lower total load impacts (averaging 617 kW combined, versus 1,263 kW for the single large customer), they actually provide more variable load impacts than the single large customer, when considered as a proportion of their average load impact. That is, the coefficient of variation of load impacts across events for these customers is 0.59, higher than the CV of 0.52 for the program as a whole.

Table 4.4: Total Auto-DR Participant Load Impacts: SCE DBP

Date	Load Impact Estimate (kW)	Bid Amount (kW)	% Load Impact**
6/4/2009	370*	3,254	6.9%
7/15/2009	1,128*	3,000	19.0%
7/17/2009	2,129	4,150	29.7%
7/20/2009	1,979	4,375	28.2%
7/22/2009	2,349	4,425	28.9%
7/27/2009	1,955	4,800	27.4%
7/28/2009	364	4,580	4.9%
8/27/2009	140	4,075	1.9%
8/28/2009	2,492	4,685	30.5%
8/31/2009	2,303	5,828	23.7%
9/1/2009	2,039	4,254	25.9%
9/2/2009	2,834	3,910	36.5%
9/3/2009	2,822	5,201	25.5%
9/8/2009	1,141	5,283	14.2%
9/22/2009	1,634	5,648	17.9%
Average	1,712	4,498	21.9%
Std. Dev.	887	795	
Coeff. of Variation	0.52	0.18	
70th Percentile	1,387		
Tested kW	6,124		

* Large customer not yet enrolled, averages 1,263 kW by itself.
** The percentage load impact is calculated using only customers who submitted a bid.

The high variability in the load impacts may be surprising given the nature of the Auto-DR program and technology, which one would think would lead to fairly consistent demand response. The DBP program has a couple of features that may contribute to the variability of load impacts: overlap in enrollment with CPP (and CPP events take precedence over DBP events); and fact that customers can change bid amounts (or not bid at all) for DBP events.

We conducted an analysis of load impacts to determine whether these factors explain any of the variability in load impacts across events. The unit of observation for the analysis was a customer event, where the load impact and bid amounts were equal to the average value across the hours in which the customer bid. The dependent variable was the average load impact (in kW). The independent (explanatory) variables were: the bid amount (in kW); the number of hours in which the customer bid for that event; a dummy variable that equals one on overlapping CPP and DBP event days for customers who were dually enrolled in CPP; and fixed customer effects. An ordinary least squares regression model was used to estimate parameters for each of the explanatory variables.

The estimates indicated that none of the included factors had a statistically significant effect on load impacts. That is, the level of load impacts was not affected by changing bid amounts or an overlap between CPP and DBP event days. This is somewhat surprising, and leaves us with the conclusion that the variation in load impacts is due to customer-specific factors (*e.g.*, production schedules) that we do not observe.

An important issue to consider when evaluating SCE's Auto-DR load impacts (for both CPP and DBP) is that a large percentage of the tested load response comes from two service accounts, both of which are enrolled in both DBP and CPP. These two accounts, which we will call Customer A and Customer B, account for 4,099 of the tested kW, or 91 percent of the tested kW in Auto-DBP and 70 percent of the tested kW in Auto-CPP. Therefore, the cost effectiveness of SCE's entire Auto-DR program depends largely on the performance of these two service accounts.

In addition, these two service accounts appear to have used the information and technology acquired through the Technical Assistance and Technology Incentives (TA/TI) and Auto-DR programs to modify their usage pattern on a daily basis, and not only during DR program events.

These changes in behavior present problems when assessing load impacts. That is, the customer's baseline is set at the time the Auto-DR equipment is installed. If Auto-DR leads customers to change their behavior on non-event days, the baseline can be reduced to the point where it is no longer possible to achieve the tested kW load impacts. Other factors can lead to the same effect. For example, the baseline load level will also be reduced when a company uses less in response to an economic downturn.

Figures 4.1 and 4.2 illustrate the average weekday load profile for each customer on summer non-event days in 2008 and 2009, expressed as a ratio of the hour's average usage to the average usage during all hours of non-event weekdays in 2008. (This was done to ensure customer confidentiality.) Customer A appears to have flattened its non-event day load profile in 2009, reducing the overall level of usage in the process. Customer B inverted its load profile in 2009, moving usage out of the peak period on non-event days. However, they also reduced their overall usage level.

The DR programs measure load impacts using methods that only consider usage levels on the previous ten non-event days (on non-holiday weekdays); and the load impact estimates that CA Energy Consulting produces use only data from the current program year. Therefore, neither approach is capable of reflecting the "permanent" (or long-term) load changes that Auto-DR (or TA/TI) may have produced over the course of years.

To the extent that Auto-DR leads customers to permanently reduce load on all days (and not only during events), additional benefits are created that are not included in the cost effectiveness tests performed in this report. In the case of the two SCE customers examined here, it seems plausible that such benefits exist. However, it is not possible for us to quantify these benefits because we cannot distinguish responses to changing economic conditions (which were not caused by Auto-DR) from behavioral changes induced by the Auto-DR program. It is important to keep in mind that the benefits calculated in the cost effectiveness tests below may understate the "true" benefits from Auto-DR because of the factors described above.

Figure 4.1: Average Non-Event Day Weekday Usage in the Summer of 2008 and 2009: Customer A

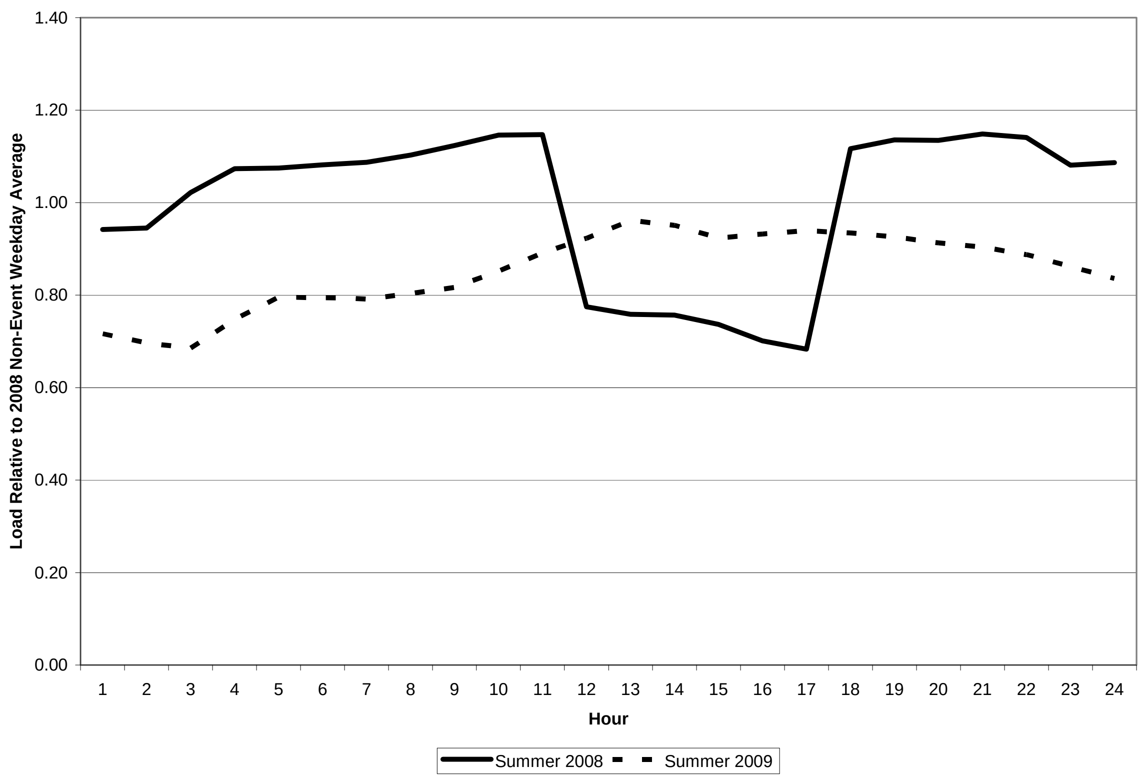
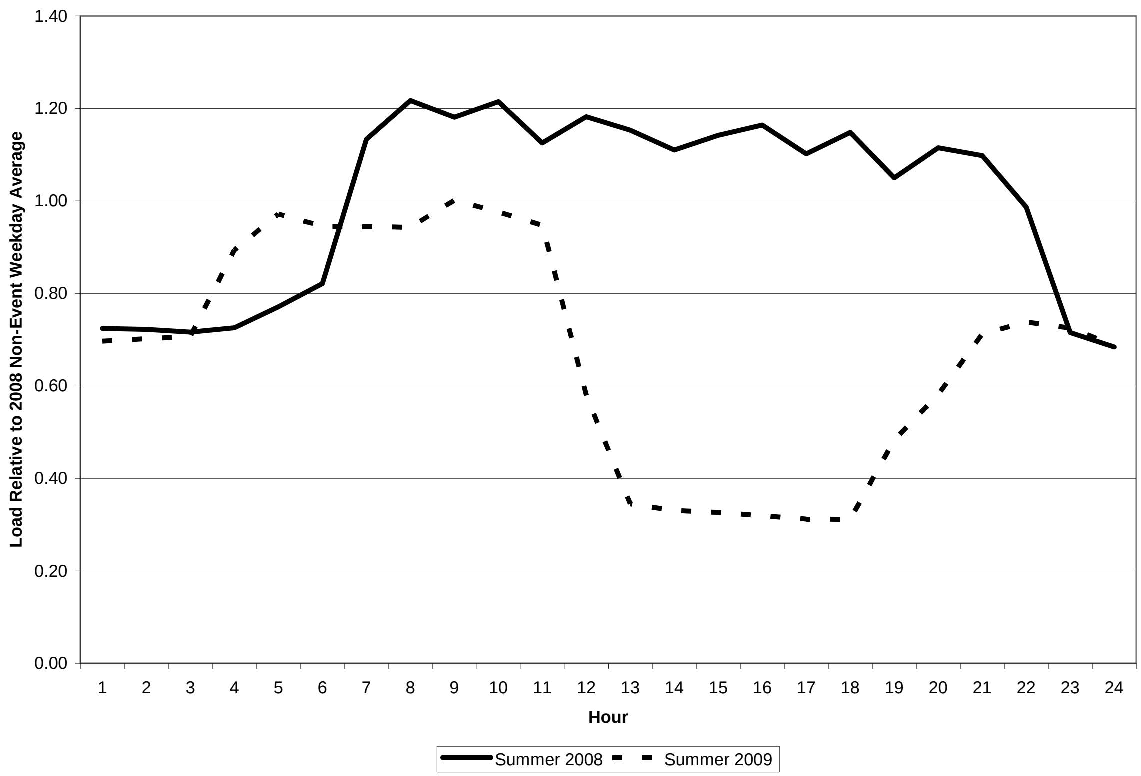


Figure 4.2: Average Non-Event Day Weekday Usage in the Summer of 2008 and 2009: Customer B



4.1.5 SDG&E Critical Peak Pricing

The load impacts for SDG&E's CPP program were quite stable across events, with the exception of the last event on September 25th. Figure 4.3 shows the hourly load impacts by event day. Notice that the September 25th response (shown as a bold blue line) is quite different in nature from the response on the other event days. It appears that the customers respond to the event during the first three hours and then stop responding. An examination of customer-level data also makes it appear as though the event was shortened by four hours on that date. We notified SDG&E of this pattern and asked whether they know of any special circumstances on that date. They told us that the CPP event was not shortened (which is consistent with what we observed for the program as a whole in our prior analysis of 2009 CPP load impacts) and that SDG&E was unaware of any problems with the Auto-DR equipment on that date.

The summary statistics in Table 4.5 include the load impacts for the last event day. Excluding the load impacts from the last event day increases the average load impact to 1,479 kW and reduces the CV to 0.18.[11]

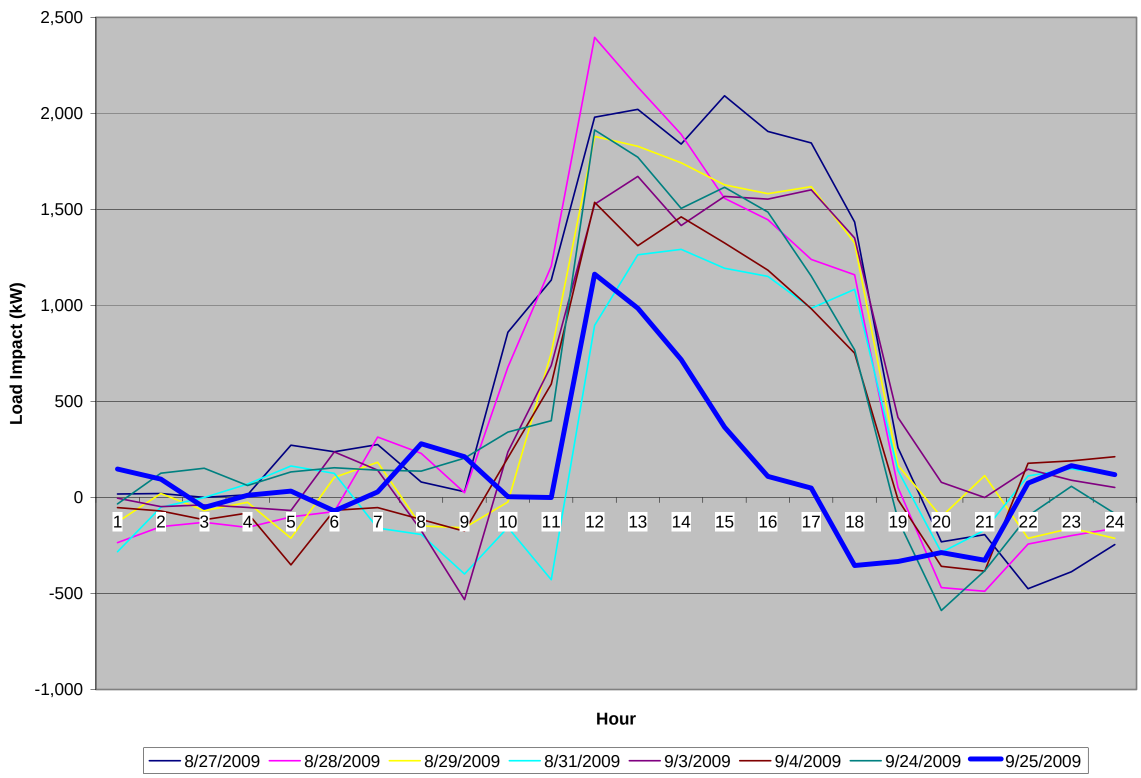
[11] The last event was included when setting the inputs for the cost effectiveness tests.

The vast majority (92 percent) of the load impacts come from five of the ten service accounts on the program. However, the average load impact for these five accounts ranges from 151 kW to 313 kW, so the load impact is spread somewhat evenly across the five customers.

Table 4.5: Total Auto-DR Participant Load Impacts: SDG&E CPP

Date	Load Impact Estimate (kW)	% Load Impact
8/27/2009	1,858	26.7%
8/28/2009	1,670	22.9%
8/29/2009	1,629	21.6%
8/31/2009	1,104	16.7%
9/3/2009	1,451	19.9%
9/4/2009	1,196	17.0%
9/24/2009	1,448	21.6%
9/25/2009	438	6.7%
Average	1,349	19.3%
Std. Dev.	443	
Coeff. of Variation	0.33	
70^{th} Percentile	1,297	
Tested kW	1,697	

Figure 4.3: Hourly Load Impacts by Event Day, SDG&E CPP



4.1.6 SDG&E Capacity Bidding Program

Load impacts for the Auto-DR customers on SDG&E's Capacity Bidding Program were fairly consistent across the seven event days in 2009. However, the level of response was low compared to the experience in the previous year. In the 2008 program year, the same customers had an average load impact of 1,537 kW, more than 2.5 times the load impact observed in 2009. SDG&E has reported to us that this is due in part to some of the customers discontinuing their lighting response during event days. SDG&E explored the issue with these customers and has worked with them to restore some of the demand response. A preliminary analysis of 2010 data (for events on July 14th through 16th, compared to a similar non-event day on August 17th) indicates an average event-hour load reduction of 867 kW. This indicates an increase in load impacts relative to the levels estimated for 2009, but not as high as what we found in 2008.

Table 4.6: Total Auto-DR Participant Load Impacts: SDG&E CBP

Date	Load Impact Estimate (kW)	% Load Impact
7/21/2009	592	11.7%
8/26/2009	437	8.4%
8/27/2009	672	12.5%
8/28/2009	633	11.7%
9/2/2009	586	10.9%
9/3/2009	753	13.4%
9/24/2009	561	11.1%
Average	605	11.4%
Std. Dev.	98	
Coeff. of Variation	0.16	
70th Percentile	587	
Tested kW	3,720	

4.1.7 Summary of total load impacts by program

Table 4.7 summarizes the key results by utility and program. The percentage load impacts were quite different across programs, with PG&E's CPP on the low end at 6.1 percent and PG&E's DBP at the high end with 45.6 percent (though this result was likely affected by the overlap of the DBP event with a BIP event). Load impacts relative to load shed test kW were lowest for SDG&E's CBP program, at 16 percent. However, this performance appears to be improving in 2010 and was significantly better in 2008.

Some of the load shed tests imply very high percentage load impacts relative to the reference loads observed in 2009. For example, SDG&E's Auto-CBP customers provided a 605 kW load impact (or 11.4 percent), which was just 16 percent of the load shed test value. Given the level of the reference loads on the 2009 event days, these customers would have needed to achieve a 71 percent load reduction in order to reach the load shed test value. Similar performance levels (over 70 percent load reductions) are required from SCE's Auto-DBP and Auto-CPP customers in order to reach load shed test values.

In terms of the variability of load impacts across events (measured by the coefficient of variation), SDG&E's CBP program had the least variable load impacts while SCE's DBP program had the most variable load impacts. (We cannot calculate a coefficient of variation for PG&E's DBP load impacts because they only called one event.) Recall that the CV for SCE's CPP program was inflated by the variability in the load impacts for one large customer; and the CV for SDG&E's CPP program was inflated by the unusually low load impacts estimated for the last event.

Table 4.7: Total Auto-DR Participant 2009 Load Impacts by Program and Utility

Utility	Program	Load Impact (kW)	Reference Load (kW)	% Load Impact	Tested kW	LI / Tested kW	Bid kW	2009 CV
PG&E	**CPP**	1,701	27,836	6.1%	4,036	42%	n/a	0.26
	DBP	19,066	41,794	45.6%	21,314	89%	25,156	n/a
SCE	**CPP**	2,369	7,765	30.5%	5,869	40%	n/a	0.41
	DBP	1,712	8,556	20.0%	6,124	28%	4,498	0.52
SDG&E	**CPP**	1,349	6,998	19.3%	1,697	79%	n/a	0.33
	CBP	605	5,299	11.4%	3,720	16%	n/a	0.16

4.2 Incremental Auto-DR Load Impacts

In this section, we develop estimates of the incremental load impacts associated with the Auto-DR customers. There are two interpretations one may use to estimate incremental load impacts. First, for Auto-DR customers who were not previously enrolled in a DR program, it may be reasonable to assume that the incremental load impact is equal to the total load impact. That is, if the customer only participated in the DR program because of their participation in Auto-DR, their entire load impact may reasonably thought of as incremental.

A second interpretation of incremental load impacts is implemented below. This method compares percentage load impacts within narrowly defined industry groups for customers who are and are not Auto-DR enabled. (The comparison group is always selected from customers who participate in the same DR program.) Where possible, we conduct comparisons of load impacts within a 6-digit NAICS code or 4-digit SIC code. Where a comparison at this level of disaggregation is not possible, we compare at a higher level of industry aggregation, such as 2-digit SIC codes or 3-digit NAICS codes. In some cases, the sample of service accounts does not contain any reasonable basis of comparison. When this occurs, we use the average percentage load impact for all of the non-Auto-DR customers as the comparison group.

The difference in the percentage load impacts is within the industry group is then applied to the reference load for the Auto-DR participants to calculate the incremental load impact.

For each utility and incentive program, we present three tables of information (four for DBP). All of the tables show data for customers with and without Auto-DR. The first table contains a description of the industry group, the number of service accounts (SAIDs) and average per customer event-day reference load by industry group. The second table shows load impacts in kW and percentage terms. The third table (fourth for DBP) shows the incremental load impact calculation. For DBP customers, we also present a table with average bid amounts during event hours.

While we believe this method to be a reasonable approach for estimating incremental load impacts, some potential problems exist. For example, we do not know whether any of the comparison group customers have enabling technology that they purchased without incentives. Where this occurs, we would understate the incremental load impact (because the calculation would not be based on the difference between load impacts for customers with and without automated technology). In addition, there may be differences across service accounts even within narrowly defined industry groups that affect the ability of the customer to respond during DR events. Any such differences that exist may introduce bias in the incremental load impact estimate, though we cannot know the direction of the bias in the absence of additional information regarding the nature of the differences across service accounts. Even given these potential shortcomings, we believe that the comparisons made in this section are informative and the most relevant ones to provide given the available data.

4.2.1 PG&E Critical Peak Pricing

Tables 4.8 and 4.9 show the characteristics of the treatment and comparison group of PG&E's Auto-CPP program. The Auto-CPP customers are divided into 16 groups. Notice that the average size (represented by the average reference loads shown in the two rightmost columns) can be quite different between the comparison group and the Auto-CPP participants. Typically, though not always, the Auto-CPP customers have higher usage levels than the comparison group customers.

Table 4.9 shows the load impacts in kW and percentage terms. A positive sign indicates load reductions during event hours. Notice that there are some wrong-signed results (indicating load increases during event hours) and some counter-intuitive differences between the Auto-DR load impacts and those of the comparison group. (*I.e.*, we expect that Auto-DR customers will have a higher percentage load impact than the comparison group customers, but this is not always the case.)

Table 4.10 combines the percentage load impact estimates with the reference loads to calculate the incremental load impacts. In this case, the incremental load impact is 1,452 kW, which is somewhat lower than the total load impact estimate of 1,701 kW. Note that the industry-group level calculations do not necessarily produce positive incremental Auto-DR load impacts. This occurs when the comparison group has a higher percentage load impact than the Auto-DR customers. (For example, see the results for industry group 311412 on the second row of the results.)

Table 4.8: Number of Service Accounts and Average Reference Load: PG&E CPP

NAICS Code	NAICS Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221310	Water Supply and Irrigation Systems	6-digit NAICS	7	1	56	272
311412	Frozen Specialty Food Manufacturing	6-digit NAICS	4	2	321	558
334419	Other Electronic Component Manufacturing	6-digit NAICS	3	9	873	455
442110	Furniture Stores	Average Program	391	2	418	834
452112	Discount Department Stores	2-digit NAICS	30	3	249	216
511210	Software Publishers	6-digit NAICS	3	2	542	1,038
531123	Lessors of Nonresidential Buildings	6-digit NAICS	15	1	449	328
541710	Research and Development in Biotechnology	6-digit NAICS	13	4	371	387
551114	Corporate Offices	6-digit NAICS	19	2	372	2,432
611112	Elementary and Secondary Schools	6-digit NAICS	76	2	204	109
611114	Elementary and Secondary Schools	6-digit NAICS	23	2	91	35
624310	Vocational Rehabilitation Services	2-digit NAICS	8	1	789	1,945
712110	Museums	6-digit NAICS	1	1	434	240
921190	Other General Government Support	6-digit NAICS	4	4	482	727
922120 & 922130	Police Protection, Legal Counsel and Prosecution	4-digit NAICS	1	2	204	1,426
922140	Correctional Institutions	6-digit NAICS	2	2	366	1,493

Table 4.9: Average Load Impacts in Levels and Percentages: PG&E CPP

NAICS Code	NAICS Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221310	Water Supply and Irrigation Systems	6-digit NAICS	-2.8	69.3	-5.0%	25.5%
311412	Frozen Specialty Food Manufacturing	6-digit NAICS	68.5	113.7	21.3%	20.4%
334419	Other Electronic Component Manufacturing	6-digit NAICS	-11.0	5.9	-1.3%	1.3%
442110	Furniture Stores	Average Program	13.3	88.3	3.2%	10.6%
452112	Discount Department Stores	2-digit NAICS	40.3	32.0	16.2%	14.8%
511210	Software Publishers	6-digit NAICS	-9.9	36.6	-1.8%	3.5%
531123	Lessors of Nonresidential Buildings	6-digit NAICS	1.3	27.0	0.3%	8.2%
541710	Research and Development in Biotechnology	6-digit NAICS	-1.5	32.7	-0.4%	8.5%
551114	Corporate Offices	6-digit NAICS	-1.4	139.3	-0.4%	5.7%
611112	Elementary and Secondary Schools	6-digit NAICS	-7.4	0.8	-3.6%	0.7%
611114	Elementary and Secondary Schools	6-digit NAICS	-7.3	1.4	-8.1%	3.9%
624310	Vocational Rehabilitation Services	2-digit NAICS	4.8	41.8	0.6%	2.2%
712110	Museums	6-digit NAICS	3.7	37.3	0.8%	15.5%
921190	Other General Government Support	6-digit NAICS	9.0	45.1	1.9%	6.2%
922120 & 922130	Police Protection, Legal Counsel and Prosecution	4-digit NAICS	-3.7	125.2	-1.8%	8.8%
922140	Correctional Institutions	6-digit NAICS	-2.2	29.3	-0.6%	2.0%

Table 4.10: Incremental Load Impact Calculation: PG&E CPP

NAICS Code	NAICS Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
221310	Water Supply and Irrigation Systems	-5.0%	25.5%	272	83
311412	Frozen Specialty Food Manufacturing	21.3%	20.4%	1,116	-11
334419	Other Electronic Component Manufacturing	-1.3%	1.3%	4,095	105
442110	Furniture Stores	3.2%	10.6%	1,669	124
452112	Discount Department Stores	16.2%	14.8%	649	-9
511210	Software Publishers	-1.8%	3.5%	2,077	111
531123	Lessors of Nonresidential Buildings	0.3%	8.2%	328	26
541710	Research and Development in Biotechnology	-0.4%	8.5%	1,547	137
551114	Corporate Offices	-0.4%	5.7%	4,864	297
611112	Elementary and Secondary Schools	-3.6%	0.7%	218	9
611114	Elementary and Secondary Schools	-8.1%	3.9%	71	8
624310	Vocational Rehabilitation Services	0.6%	2.2%	1,945	30
712110	Museums	0.8%	15.5%	240	35
921190	Other General Government Support	1.9%	6.2%	2,910	126
922120 & 922130	Police Protection, Legal Counsel and Prosecution	-1.8%	8.8%	2,853	303
922140	Correctional Institutions	-0.6%	2.0%	2,986	76
Total					**1,452**

4.2.2 PG&E Demand Bidding Program

PG&E's Auto-DBP customers are divided into 8 groups. The table omits the customers who overlap with BIP (including the largest responder) for two reasons. First, the high level of uncertainty regarding the *level* of load impacts for these customers makes it unlikely that we can develop a reasonable estimate of incremental load impacts. Second, no comparable customers exist for the customer with the largest load impacts.

However, the inability to find comparable customers pervades the Auto-DBP program, as you can see in the "basis of comparison" column. It may therefore be unsurprising that the incremental load impact calculation performed in Table 4.14 produces a negative value (implying that Auto-DR reduced the load impacts of participating customer). This result, which clearly does not seem plausible, is indicative of the difficulties that can arise when attempting to estimate incremental load impacts with limited data.

Table 4.11: Number of Service Accounts and Average Reference Load: PG&E DBP

NAICS Code	NAICS Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221112	Hydroelectric Power Generation	Average Program	34	9	1,477	1,081
424410	General Line Grocery Merchant Wholesalers	Average Program	34	1	1,477	723
442110	Furniture Stores	Average Program	34	1	1,477	847
452111	Department Stores	Average Program	34	25	1,477	116
452112	Discount Department Stores	Average Program	34	1	1,477	442
518210	Data Processing, Hosting, and Related Services	2-digit NAICS	2	1	674	253
551114	Corporate Managing Offices	6-digit NAICS	2	6	3,402	1,999
921190	Other General Government Support	Average Program	34	13	1,477	721

Table 4.12: Average Load Impacts in Levels and Percentages: PG&E DBP

NAICS Code	NAICS Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
221112	Hydroelectric Power Generation	Average Program	3.6	109.3	8.3%	10.1%
424410	General Line Grocery Merchant Wholesalers	Average Program	3.6	195.1	8.3%	27.0%
442110	Furniture Stores	Average Program	3.6	226.8	8.3%	26.8%
452111	Department Stores	Average Program	3.6	7.1	8.3%	6.1%
452112	Discount Department Stores	Average Program	3.6	84.7	8.3%	19.2%
518210	Data Processing, Hosting, and Related Services	2-digit NAICS	8.1	11.3	1.2%	4.5%
551114	Corporate Managing Offices	6-digit NAICS	258.7	34.5	7.6%	1.7%
921190	Other General Government Support	Average Program	3.6	59.9	8.3%	8.3%

Table 4.13: Average Bid: PG&E DBP

NAICS Code	NAICS Description	Basis of Comparison	Average Bid (kW) / SAID	
			No AutoDR	AutoDR
221112	Hydroelectric Power Generation	Average Program	191	22
424410	General Line Grocery Merchant Wholesalers	Average Program	191	378
442110	Furniture Stores	Average Program	191	100
452111	Department Stores	Average Program	191	30
452112	Discount Department Stores	Average Program	191	50
518210	Data Processing, Hosting, and Related Services	2-digit NAICS	50	76
551114	Corporate Managing Offices	6-digit NAICS	125	342
921190	Other General Government Support	Average Program	191	49

Table 4.14: Incremental Load Impact Calculation: PG&E DBP

NAICS Code	NAICS Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
221112	Hydroelectric Power Generation	8.3%	10.1%	9,730	178
424410	General Line Grocery Merchant Wholesalers	8.3%	27.0%	723	135
442110	Furniture Stores	8.3%	26.8%	847	157
452111	Department Stores	8.3%	6.1%	2,889	-62
452112	Discount Department Stores	8.3%	19.2%	442	48
518210	Data Processing, Hosting, and Related Services	1.2%	4.5%	253	8
551114	Corporate Managing Offices	7.6%	1.7%	11,994	-705
921190	Other General Government Support	8.3%	8.3%	9,379	2
Total					**-239**

4.2.3 SCE Critical Peak Pricing

SCE's Auto-CPP customers are spread across six different industry groups. The largest customer is in SIC 3691, or storage batteries. Notice the large difference in average size for this industry group. Since we compare percentage load impacts, this does not necessarily render a comparison of the two groups meaningless, but it does call into question whether the processes that occur at the Auto-CPP service account are at all similar to the process that occur at the comparison group sites. The majority of the service accounts are in SIC 6512, or operators of non-residential buildings.

Table 4.15: Number of Service Accounts and Average Reference Load: SCE CPP

SIC Code	SIC Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
1611	Highway and Street Construction	Average Program	437	2	273	135
2834	Pharmaceutical Preparations	2-digit SIC	14	1	185	343
3069	Fabricated Rubber Products	4-digit SIC	3	1	298	349
3691	Storage Batteries	2-digit SIC	8	1	294	2,788
5211	Lumber Dealers	2-digit SIC	1	1	263	396
6512	Operators of Non-Residential Buildings	4-digit SIC	6	11	113	344

Table 4.16: Average Load Impacts in Levels and Percentages: SCE CPP

SIC Code	SIC Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
1611	Highway and Street Construction	Average Program	51.1	-15.1	18.7%	-11.2%
2834	Pharmaceutical Preparations	2-digit SIC	26.2	64.7	14.2%	18.9%
3069	Fabricated Rubber Products	4-digit SIC	29.6	95.4	9.9%	27.3%
3691	Storage Batteries	2-digit SIC	77.3	1,821.3	26.3%	65.3%
5211	Lumber Dealers	2-digit SIC	33.5	161.7	12.7%	40.9%
6512	Operators of Non-Residential Buildings	4-digit SIC	1.2	51.1	1.0%	14.8%

Table 4.17 shows the incremental load impact estimates. The majority of the incremental load impacts come from the storage batteries comparison, with the second-highest contribution coming from the operators or non-residential buildings. The incremental load impact is 1,446 kW as compared to the total load impact of 2,369 kW.

Table 4.17: Incremental Load Impact Calculation: SCE CPP

SIC Code	SIC Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
1611	Highway and Street Construction	18.7%	-11.2%	269	-81
2834	Pharmaceutical Preparations	14.2%	18.9%	343	16
3069	Fabricated Rubber Products	9.9%	27.3%	349	61
3691	Storage Batteries	26.3%	65.3%	2,091	816
5211	Lumber Dealers	12.7%	40.9%	396	111
6512	Operators of Non-Residential Buildings	1.0%	14.8%	3,788	522
Total					**1,446**

4.2.4 SCE Demand Bidding Program

SCE's Auto-DBP customers are spread across six different industry groups. The storage batteries customer is present in this program as well, but DBP contains a larger pool of customers against which to compare its response. Those sites are not at all demand responsive, however, as seen in Table 4.19. As seen in Table 4.21, the storage batteries customer accounts for 1,405 kW of the 1,614 kW incremental load impact estimate.

Table 4.18: Number of Service Accounts and Average Reference Load: SCE DBP

SIC Code	SIC Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
2834	Pharmaceutical Preparations	4-digit SIC	3	1	1,389	305
3069	Fabricated Rubber Products	2-digit SIC	30	1	896	499
3691	Storage Batteries	2-digit SIC	28	2	3,381	1,405
5211	Lumber Dealers	Average Program	483	1	1,356	363
5712	Furniture Stores	4-digit SIC	1	3	168	831
6512	Operators of Non-Residential Buildings	4-digit SIC	35	11	573	244

Table 4.19: Average Load Impacts in Levels and Percentages: SCE DBP

SIC Code	SIC Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
2834	Pharmaceutical Preparations	4-digit SIC	-2	-52	-0.1%	-17.0%
3069	Fabricated Rubber Products	2-digit SIC	14	232	-1.6%	46.5%
3691	Storage Batteries	2-digit SIC	6	707	0.2%	49.7%
5211	Lumber Dealers	Average Program	110	12	8.1%	3.4%
5712	Furniture Stores	4-digit SIC	-2	64	-1.1%	7.7%
6512	Operators of Non-Residential Buildings	4-digit SIC	77	18	13.4%	7.2%

Table 4.20: Average Bid: SCE DBP

SIC Code	SIC Description	Basis of Comparison	Average Bid (kW) / SAID	
			No AutoDR	AutoDR
2834	Pharmaceutical Preparations	4-digit SIC	140	100
3069	Fabricated Rubber Products	2-digit SIC	240	327
3691	Storage Batteries	2-digit SIC	131	1,476
5211	Lumber Dealers	Average Program	343	119
5712	Furniture Stores	4-digit SIC	60	173
6512	Operators of Non-Residential Buildings	4-digit SIC	186	68

Table 4.21: Incremental Load Impact Calculation: SCE DBP

SIC Code	SIC Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
2834	Pharmaceutical Preparations	-0.1%	-17.0%	305	-51
3069	Fabricated Rubber Products	-1.6%	46.5%	499	224
3691	Storage Batteries	0.2%	49.7%	2,810	1,405
5211	Lumber Dealers	8.1%	3.4%	363	-17
5712	Furniture Stores	-1.1%	7.7%	2,492	219
6512	Operators of Non-Residential Buildings	13.4%	7.2%	2,683	-166
Total					**1,614**

4.2.5 SDG&E Critical Peak Pricing

SDG&E's Auto-CPP customers are spread across four industry groups. In three of the four cases, the average reference load is lower for the comparison group customers.

Table 4.22: Number of Service Accounts and Average Reference Load: SDG&E CPP

NAICS Code	NAICS Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
452111	Department Stores	6-digit NAICS	10	6	461	837
512131	Motion Picture Theaters	6-digit NAICS	17	1	256	511
721110	Hotels and Motels	6-digit NAICS	47	2	274	493
721120	Casino Hotels	6-digit NAICS	2	1	561	546

Table 4.23: Average Load Impacts in Levels and Percentages: SDG&E CPP

NAICS Code	NAICS Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
452111	Department Stores	6-digit NAICS	10.7	214.7	2.4%	34.5%
512131	Motion Picture Theaters	6-digit NAICS	3.8	17.8	1.5%	3.6%
721110	Hotels and Motels	6-digit NAICS	12.8	13.3	4.9%	2.8%
721120	Casino Hotels	6-digit NAICS	136.5	18.3	32.1%	3.5%

As Table 4.24 shows, the incremental load impact for this program is 1,062 kW, but virtually all of this load impact (more actually, because of some wrong-signed results) comes from the department stores. By comparison, the total load impacts for Auto-CPP are 1,349 kW.

Table 4.24: Incremental Load Impact Calculation: SDG&E CPP

NAICS Code	NAICS Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
452111	Department Stores	2.4%	34.5%	5,024	1,171
512131	Motion Picture Theaters	1.5%	3.6%	511	10
721110	Hotels and Motels	4.9%	2.8%	987	-19
721120	Casino Hotels	32.1%	3.5%	478	-100
Total					**1,062**

4.2.6 SDG&E Capacity Bidding Program

SDG&E's Auto-CBP customers are divided into four industry groups. The majority of the incremental load impact comes from one of the groups: hobby, toy and games stores, and all other general merchandise stores. The incremental load impact of 138 kW is quite a bit lower than the total load impact of 605 kW for this program.

Table 4.25: Number of Service Accounts and Average Reference Load: SDG&E CBP

NAICS Code	NAICS Description	Basis of Comparison	Number of SAIDs		Average Reference Load (kW) / SAID	
			No AutoDR	AutoDR	No AutoDR	AutoDR
441222	Boat Dealers	6-digit NAICS, different accounts for same customer	1	2	31	85
451120 & 452990	Hobby, Toy & Game Stores; All Other General Merchandise Stores	2-digit NAICS	38	34	331	84
561439	Other Business Service Centers (including Copy Shops)	6-digit NAICS, different accounts for same customer	3	12	13	33
713940	Fitness and Recreational Sports Centers	6-digit NAICS, different accounts for same customer	10	18	23	103

Table 4.26: Average Load Impacts in Levels and Percentages: SDG&E CBP

NAICS Code	NAICS Description	Basis of Comparison	Average Load Impact (kW) / SAID		Average Percentage LI	
			No AutoDR	AutoDR	No AutoDR	AutoDR
441222	Boat Dealers	6-digit NAICS, different accounts for same customer	0.6	8.9	2.0%	10.5%
451120 & 452990	Hobby, Toy & Game Stores; All Other General Merchandise Stores	2-digit NAICS	32.5	12.2	9.8%	14.4%
561439	Other Business Service Centers (including Copy Shops)	6-digit NAICS, different accounts for same customer	2.1	3.7	15.9%	11.3%
713940	Fitness and Recreational Sports Centers	6-digit NAICS, different accounts for same customer	1.5	7.2	6.4%	6.9%

Table 4.27: Incremental Load Impact Calculation: SDG&E CBP

NAICS Code	NAICS Description	Average Percentage LI		Reference Load (kW)	Incremental LI (kW)
		No AutoDR	AutoDR		
441222	Boat Dealers	2.0%	10.5%	171	15
451120 & 452990	Hobby, Toy & Game Stores; All Other General Merchandise Stores	9.8%	14.4%	2,873	131
561439	Other Business Service Centers (including Copy Shops)	15.9%	11.3%	397	-19
713940	Fitness and Recreational Sports Centers	6.4%	6.9%	1,858	11
Total					**138**

5. Cost Effectiveness Tests

5.1 Cost effectiveness methodology

This section describes the model that CA Energy Consulting has developed to conduct cost effectiveness tests for each utility's Auto-DR program. The remainder of this section describes the methods used in the various components of the cost effectiveness (CE) model.

Description of the Overall CE Model Framework
Separate CE models were developed for each utility. Within each utility's model, information was included from all of the demand response programs on which the utility has Auto-DR customers.[12] The CE model conducts the Total Resource Cost (TRC) and Program Administrator Cost (PAC) tests.

Within each program, the CE model separately analyzes three equipment installation years (hereafter referred to as "vintage years"): 2007, 2008, and 2009. For each vintage year, the CE model calculates 10 years of costs and benefits. (*E.g.*, for 2007, costs and benefits are calculated for 2007 through 2016.) In this case, 10 years represents the expected useful life of the equipment.

For each vintage year, the per-event-hour load impacts are derived from the 2009 program year load impact estimates, where the load impacts are divided into vintage years. (*E.g.*, 1 MW of total 2009 load impacts is allocated to vintage years depending on the installation year, so that 500 kW may come from equipment installed in 2007, 250 kW from equipment installed in 2008, and 250 kW from equipment installed in 2009.) We assume that the allocated load impact values remain constant across the 10-year analysis window.

The 10-year cost and benefit streams for the three vintage years are discounted to a common year (labeled the "base year" in the CE model).

[12] The programs are CPP and DBP for PG&E and SCE; and CBP and CPP for SDG&E.

Avoided Capacity Costs

The following formula is used to calculate avoided capacity costs for a given utility, program, and vintage year:

Avoided capacity costs = *Q* * *C* * (1 + *reserves*) * *loss factor* * *A* * *B* * *E*

In this equation, *Q* is the estimated load impact in kW; *C* is the capacity cost net of gross margins in $/kW-year; *reserves* is the required reserves (15 percent); *loss factor* accounts for line losses, where the factor equals 1 / (1 – line loss percentage); *A* is a factor ranging from 0 to 1 that discounts avoided cost as appropriate to account for the fact that program parameters may not allow it to "cover" all of the hours in which a positive loss of load probability is estimated; *B* is a factor ranging from 0 to 1 that accounts for the loss of value that can occur because of program notice provisions (*e.g.*, day-ahead versus day-of notice); and *E* is the "70^{th} percentile exceedance factor" (ranging from 0 to 1) that can be used to reduce the value of programs that exhibit more variable (or less certain) load impacts. This parameter is derived from the methods that California has developed to value wind capacity.

The *A* and *B* factors are named according to SCE's convention, and are applied in the same manner that SCE has used in its CE tests.[13]

Avoided Energy Costs

The avoided energy costs (for each utility/program/vintage year) are calculated according to the formula shown below.

Avoided energy costs = 1000* *Q* * *MC* * *Hrs* * *Evts* * *loss factor*

In this equation, *Q* is the estimated load impact in kW; *MC* is the average wholesale energy price across the event hours for the year in question (in $/MWh); *Hrs* is the number of hours per event; *Evts* is the number of events; and *loss factor* accounts for line losses. We allow for the energy loss factor to differ from the capacity loss factor, which can differ because average line losses may be lower than line losses during peak hours.

Avoided Transmission and Distribution (T&D) Costs

The following formula is used to calculate avoided capacity costs for a given utility, program, and vintage year:

Avoided T&D costs = *Q* * *TD* * *loss factor* * *A* * *B* * *E* * *R*

In this equation, *Q*, *loss factor*, *A*, *B*, and *E* are the same values as used to calculate avoided capacity costs; *TD* is the avoided T&D cost in $/kW-year; and *R* is a factor ranging from 0

[13] See "Volume I: Amended Testimony in Support of Southern California Edison Company's Amended Application for Approval of Demand Response Programs, Goals, and Budgets for 2009-2011" (U 338-E), September 19, 2008, page 208.

to 1 that accounts for the "right place, right time" criteria for determining when load reductions are expected reduce T&D costs.

Program Costs
Four categories of program costs are entered into the CE model.

1. Auto-DR capital incentive costs for each vintage year (2007 through 2009).
2. Annual Auto-DR administrative program costs.[14]
3. Annual DR program-specific administrative costs. For example, this represents CPP administrative costs that are incrementally incurred by the presence of the Auto-DR customers. These program-related costs could plausibly be zero for all years and DR programs (and, in fact, all utilities set these costs to zero).
4. Annual DR incentive costs by program.

The annual DR incentive costs, which reflect credits for load reductions, are zero for CPP because there are no event-based credits. For DBP and CBP, the incentive costs are calculated from the program parameters and load impacts (*e.g.*, $0.50 per kWh of load impact for DBP customers).

The Auto-DR administrative program costs are allocated to the DR programs. For SCE, the costs are allocated using the share of service accounts. For PG&E and SDG&E, the costs are allocated using the share of Auto-DR technology incentive payments.

Cost Effectiveness Tests
For both the TRC and PAC tests, benefits are calculated as the sum of avoided capacity costs, avoided energy costs, and avoided T&D costs.

For the TRC test, costs are calculated as the sum of administrative costs, Auto-DR capital incentive costs, and customer costs. For the PAC test, costs are calculated as the sum of administrative costs, Auto-DR capital incentive costs, and DR incentives. Because customer costs are assumed to be equal to the DR incentives, the TRC and PAC tests return the same results.

CE tests were run under different sets of assumptions. First, we included load impacts (and therefore benefits) in two ways: as *total* and *incremental* Auto-DR load impacts. The second sensitivity analysis is based on the inclusion of the 70th percentile exceedance factor (*E*). This factor is intended to discount benefits associated with programs that have more variable (*i.e.*, less reliable) load impacts. While this factor is not included in the cost effectiveness draft protocols, it is potentially important for evaluating Auto-DR programs because they may provide more reliable load impacts than non-automated DR customers.

The 70th percentile exceedance factor was taken from a proposed decision regarding resource adequacy, in which the factor was proposed as a means for valuing wind and solar

[14] The program administrative costs for years beyond 2009 should only be associated with costs incurred from managing the 2007 to 2009 vintage customers. As long as new customers are enrolled in Auto-DR beyond 2009, these values will be less than the total Auto-DR administrative cost for 2010 through 2018.

generation.[15] The intermittency of wind and solar resources (*e.g.*, due to varying wind conditions) is conceptually similar to the variability in the load impacts that DR (including Auto-DR) customers provide. In the case of DR customers, the variability may be due to a number of factors, including production schedules, changes in load levels in response to economic conditions, etc.

Our "base" CE tests set *E* to 1, which is consistent with current CE test methods in that benefits are not affected by the uncertainty (or variability across events) in load impacts. A sensitivity analysis incorporates appropriate values of *E* for each utility and program. The factors are based on the uncertainty in the load impact estimates and/or the variability in load impacts across events.[16]

5.2 Cost effectiveness test results

Tables 5.1 through 5.3 summarize the key inputs to the CE models by utility and program. Some of the inputs, such as annual avoided capacity costs and avoided energy costs, are confidential for at least one of the utilities and are therefore not summarized in the report.

Table 5.2 shows the utility-wide CE model parameters. Only the required reserve margin is the same across utilities. SCE does not differentiate line losses for capacity vs. energy, while the other utilities do.

Table 5.1: CE Model Parameter Values by Utility

Parameter	PG&E	SCE	SDG&E
Discount Rate	7.6%	10.0%	8.4%
Inflation Rate	2.0%	Avg. 1.7%	3.0%
Capacity Line Losses	12.24%	8.40%	9.34%
Energy Line Losses	9.17%	8.40%	8.10%
Reserve Margin	15%	15%	15%

Table 5.2 shows program-specific inputs, including assumptions regarding the number of events and event hours per year (which is assumed to be constant across years); the *A, B, E,* and *R* factors described in Section 5.1; and the Auto-DR technology incentive payments across 2007 through 2009.

[15] Appendix B of the proposed decision by ALJ Gamson, "Decision Adopting Local Procurement Obligations for 2011 and Further Refining the Resource Adequacy Program", Rulemaking 09-10-032.
[16] PG&E called only one DBP event day in each of 2008 and 2009. For this program, we use the uncertainty in the estimated load impacts to create the 70th percentile exceedance factor. For all other programs, we use the variability in the estimated load impacts across event days.

Table 5.2: DR Program Parameter Values by Utility

Parameter	PG&E DBP	PG&E CPP	SCE DBP	SCE CPP	SDG&E CBP	SDG&E CPP
Hours per event	8	4	8	4	4	7
Events per year	1	10	15	12	9	9
A factor	85.9%	72.7%	79.0%	53.0%	73.0%	86.0%
B factor	100%	100%	99%	95%	90%	90%
E factor	83.9%	93.7%	81.0%	98.8%	97.0%	96.1%
R factor	0%	0%	0%	0%	79.2%	57.9%
Auto-DR Incentive Payments '07-'09	$3,856,096	$700,495	$1,742,822	$705,336	$1,127,866	$253,316

A adjusts avoided costs for DR program availability; *B* adjusts for DR program notice time; *E* adjusts for DR load response variability; and *R* adjusts for T&D "right time, right place" criteria.

Table 5.3 shows the load impact assumptions used for each program. Both the total and incremental load impact values are shown. Because of the counter-intuitive result, we set the incremental load impact for PG&E's DBP program to 0 kW. In the table, the total load impact for PG&E's DBP program assumes that the largest customer provides load response at its 2008 level (which was not affected by overlap with a BIP event), while the remaining customers are assumed to provide load response at their 2009 level. Using the 2009 level for the largest customer increases the total load impact for the 2007 vintage year from 2.6 MW to 18.4 MW. We will present the CE test results at both load levels.

Table 5.3: DR Program Load Impacts by Utility (MW per hour)

Year	PG&E DBP	PG&E CPP	SCE DBP	SCE CPP	SDG&E CBP	SDG&E CPP
Total Load Impact						
2007	2.623	0.952	0.000	0.162	0.564	0.000
2008	0.666	0.749	0.491	0.160	0.046	0.000
2009	0.000	0.000	1.461	2.277	0.000	1.349
Total	**3.289**	**1.701**	**1.952**	**2.598**	**0.610**	**1.349**
Incremental Load Impact						
2007	0.000	0.927	0.000	0.111	0.112	0.000
2008	0.000	0.525	0.392	0.077	0.015	0.000
2009	0.000	0.000	1.222	1.257	0.011	1.062
Total	**0.000**	**1.452**	**1.614**	**1.445**	**0.138**	**1.062**

5.2.1 CE Tests Using Total Load Impacts

In this section, we present the results of the cost effectiveness tests using total load impacts (as opposed to incremental load impacts). Results are also shown under some different load impact scenarios (for PG&E's DBP program and SDG&E's CBP program), and with and without an adjustment to avoided costs for the variability of the load impacts (accomplished by setting the *E* factor described above to a value that is less than 100 percent).

Recall that the TRC and PAC tests return the same results, because the customer costs in the TRC test are assumed to be equal to the DR and Auto-DR incentive costs in the PAC test. Therefore, we present only the TRC test results (which simply amounts to labeling one of the cost categories as "customer costs" instead if "incentive payments".

PG&E
Table 5.4 shows the CE test for PG&E's Auto-DR program using the low Auto-DBP load level. Auto-CPP is cost effective, with a benefit-cost ratio of 1.11. Auto-DBP is not cost effective in this case, with a ratio of 0.44. The Auto-DR program as a whole is not cost effective in this scenario, with a benefit-cost ratio of 0.54.

Table 5.4: Auto-DR Total Resource Cost Test, *PG&E*
Total Load Impacts, No Accounting for LI Variability

Benefits	**DBP**	**CPP**	**Total**
Avoided Capacity	$4,199,591	$1,843,396	$6,042,987
Avoided Energy	$27,926	$64,480	$92,405
Avoided T&D	$0	$0	$0
Total Benefits	$4,227,517	$1,907,876	$6,135,393
Costs			
Administrative Costs	$4,882,895	$887,023	$5,769,918
Customer Costs	$4,817,275	$828,852	$5,646,127
Total Costs	$9,700,170	$1,715,875	$11,416,044
Benefit to Cost Ratio	0.44	1.11	**0.54**

Table 5.5 runs the same scenario for PG&E, but this time assuming that the load impacts for one Auto-DBP customer are equal to its high 2009 response rather than its low 2008 response. Notice that the program as a whole becomes very cost effective in this scenario, with a benefit-cost ratio of 2.20. A comparison of Tables 5.4 and 5.5 show how sensitive these CE tests can be. In this case, the performance of the entire program is determined by the performance of one customer on one event day.

Table 5.5: Auto-DR Total Resource Cost Test, *PG&E*
Using 2009 DBP Response

Benefits	**DBP**	**CPP**	**Total**
Avoided Capacity	$24,346,843	$1,843,396	$26,190,239
Avoided Energy	$164,316	$64,480	$228,796
Avoided T&D	$0	$0	$0
Total Benefits	$24,511,159	$1,907,876	$26,419,036
Costs			
Administrative Costs	$4,882,895	$887,023	$5,769,918
Customer Costs	$5,396,751	$828,852	$6,225,603
Total Costs	$10,279,646	$1,715,875	$11,995,521
Benefit to Cost Ratio	2.38	1.11	**2.20**

SCE

Table 5.6 shows the CE test for SCE's Auto-DR program. According to the results, Auto-CPP appears to be more cost effective than Auto-DBP, but the program as a whole is not cost effective, with a benefit-cost ratio of 0.49. However, recall that SCE's load impact estimates are greatly influenced by the behavior of two service accounts that are enrolled in both CPP and DBP. Both of these accounts appear to have reduced load on all days (not just event days) since becoming Auto-DR enabled. It is not possible for us to distinguish the extent to which these reductions were due to the information acquired through Auto-DR technology or a worsening economy. However, both factors have contributed to an inability of these customers to meet their tested kW demand response levels.

Table 5.6: Auto-DR Total Resource Cost Test, *SCE*
Total Load Impacts, No Accounting for LI Variability

Benefits	**DBP**	**CPP**	**Total**
Avoided Capacity	$1,768,353	$1,508,089	$3,276,442
Avoided Energy	$138,224	$73,494	$211,718
Avoided T&D	$0	$0	$0
Total Benefits	$1,906,577	$1,581,583	$3,488,160
Costs			
Administrative Costs	$1,324,826	$2,097,640	$3,422,466
Customer Costs	$2,832,765	$814,941	$3,647,705
Total Costs	$4,157,590	$2,912,581	$7,070,171
Benefit to Cost Ratio	0.46	0.54	**0.49**

Table 5.7 shows what the CE test results would be for SCE if all of its customers responded at their tested kW levels. The benefit-cost ratio of 1.07 indicates that the Auto-DR program would have been cost effective had customers performed up to tested levels. This indicates that the Auto-DR program has a sustainable design provided that the load response tests (upon which the Auto-DR incentive payments are based) are correct and customers perform to that level.

Table 5.7: Auto-DR Total Resource Cost Test, *SCE*
Using Load Shed Test kW Load Impacts

Benefits	**DBP**	**CPP**	**Total**
Avoided Capacity	$5,611,047	$3,418,857	$9,029,904
Avoided Energy	$435,288	$166,189	$601,477
Avoided T&D	$0	$0	$0
Total Benefits	$6,046,335	$3,585,046	$9,631,381
Costs			
Administrative Costs	$1,324,826	$2,097,640	$3,422,466
Customer Costs	$4,779,485	$814,941	$5,594,425
Total Costs	$6,104,310	$2,912,581	$9,016,891
Benefit to Cost Ratio	0.99	1.23	**1.07**

SDG&E
Table 5.8 shows the Auto-DR cost effectiveness test for SDG&E. Its CPP program is very cost effective, but the CBP program is not, with a benefit-cost ratio of 0.27. The overall benefit-cost ratio is 0.77, indicating that the Auto-DR program is not cost effective in this scenario.

Table 5.8: Auto-DR Total Resource Cost Test, *SDG&E*
Total Load Impacts, No Accounting for LI Variability

Benefits	**CBP**	**CPP**	**Total**
Avoided Capacity	$550,812	$1,301,549	$1,852,362
Avoided Energy	$26,622	$94,274	$120,896
Avoided T&D	$137,076	$236,772	$373,848
Total Benefits	$714,511	$1,632,595	$2,347,106
Costs			
Administrative Costs	$717,346	$161,111	$878,457
Customer Costs	$1,896,054	$274,594	$2,170,648
Total Costs	$2,613,399	$435,705	$3,049,105
Benefit to Cost Ratio	0.27	3.75	**0.77**

As we did for SCE, we conducted the CE test for SDG&E under the assumption that the customers performed to their tested kW levels. The results in Table 5.9 show that this would make the Auto-DR program cost effective, with a benefit-cost ratio of 1.18. As with the SCE program, this indicates that Auto-DR was designed to be cost effective, but problems with load impact tests and/or customer performance during events have prevented the program from being cost effective.

Table 5.9: Auto-DR Total Resource Cost Test, *SDG&E*
Using Load Shed Test kW Load Impacts

Benefits	**CBP**	**CPP**	**Total**
Avoided Capacity	$3,359,134	$1,637,309	$4,996,443
Avoided Energy	$162,367	$118,594	$280,961
Avoided T&D	$835,961	$297,852	$1,133,813
Total Benefits	$4,357,463	$2,053,754	$6,411,217
Costs			
Administrative Costs	$717,346	$161,111	$878,457
Customer Costs	$4,294,577	$274,594	$4,569,171
Total Costs	$5,011,923	$435,705	$5,447,628
Benefit to Cost Ratio	0.87	4.71	**1.18**

5.2.2 CE Tests Accounting for the Variability of Load Impacts

We next re-ran the CE models for each utility setting the *E* factors to appropriate values, given the variability we observed in the load impacts across events. The *E* factor is set by taking the ratio of the 30th percentile load impact across 2009 event days to the average load impact across event days. The exception is the *E* factor for PG&E's DBP program, which was set using the standard error of the estimated load impacts because there was only one event.

Table 5.10 compares benefit-cost ratios when $E = 1$ vs. *E* being set to account for the variability of the load impacts across events (denoted "E < 1" in the table). As expected, the benefit-cost ratio is lower when *E* is set at a value less than 1. This reflects the "penalty" imposed upon the program's benefits for having load impacts that are not 100 percent present during every event. Note that CE tests used for DR programs do not currently incorporate this factor. In theory, if Auto-DR produces more reliable load impacts, the penalty assessed on Auto-DR CE tests would be less than the penalty assessed on DR programs as a whole (which would have more variable load impacts). This would make Auto-DR seem relatively more cost effective (even as its own CE test produces a worse result by including the *E* factor).

The reduction in the benefit-cost ratio is smallest for SDG&E's program. This indicates that the SDG&E's load impacts are the least variable across the utility programs.

Table 5.10: Benefit-Cost Ratios Accounting for Load Impact Variability

	PG&E	SCE	SDG&E
Benefit-cost ratio if $E = 1$	0.54	0.49	0.77
Benefit-cost ratio if $E < 1$	0.47	0.44	0.74

5.2.3 CE Tests Using Incremental Load Impacts

We conducted separate cost effectiveness tests using the incremental load impacts in place of the total load impacts. These CE models assume an *E* factor equal to 1. The incremental load impacts used in the models are shown in Table 5.3 above. Table 5.11 summarizes the benefit-cost ratios for each utility. As expected, the benefit-cost ratio is lower using incremental load impacts vs. total load impacts. The reduction is particularly large for PG&E, which shows a reduction from 0.54 to 0.14.

However, when interpreting the results in Table 5.11, one should recall the difficulties in determining incremental load impacts. Given data limitations, we are not confident that they accurately reflect the "true" incremental load impacts from participating in Auto-DR.

Table 5.11: Benefit-Cost Ratios Using Total vs. Incremental Load Impacts

	PG&E	SCE	SDG&E
Total Load Impacts	0.54	0.49	0.77
Incremental Load Impacts	0.14	0.36	0.54

5.3 Factor not included in the cost effectiveness tests

In principle, Auto-DR customers should be able to provide load impacts on shorter notice than many other customers because the installed technology allows for an automated response to an event. This may allow Auto-DR customers to participate in ancillary services markets by selling spinning reserves. The current CE model does not account for this feature of Auto-DR.

In order to include the reserves value of Auto-DR in the CE test, the following changes to the cost effectiveness model would need to be implemented.

- Avoided capacity costs should not include the value of reserves;
- A factor should be added that accounts for the difference (if any) between the average hourly Auto-DR load impact and the amount of response that can be provided with the required amount of notice (*e.g.*, 10 minutes); and
- The annual value of the ancillary services should be added to the model.

Once these changes are made, the ancillary services value could be calculated in much the same manner as the other avoided costs. If the data show that Auto-DR does increase the ability of customers to sell into the ancillary services market, the CE test results would improve relative to evaluations of non-Auto-DR programs.

6. Summary and Conclusions

This study summarizes our analysis of load impacts and cost effectiveness tests for the Automated Demand Response (Auto-DR) programs at PG&E, SCE, and SDG&E. These programs delivered a total of approximately 28 MW of demand response per event hour in 2009.[17]

Load impacts were estimated in two ways: the *total* and the *incremental* load impact across Auto-DR customers. Total load impacts are simply equal to the total of the estimated load impacts across Auto-DR customers. Incremental load impacts were estimated by comparing percentage load impacts of Auto-DR customers to the percentage load impacts for customers in the same industry group (which was defined as narrowly as possible given the DR program participants).

As part of this study, we developed a cost effectiveness (CE) model that was applied to each utility's Auto-DR program. While the structure of the CE model was the same for all utilities, utility-specific input values (*e.g.*, discount rates, avoided capacity costs, and line losses) were used. The CE models assumed a 10-year life span for the Auto-DR program and examined the cost effectiveness of equipment installed from 2007 through 2009.

[17] This figure includes the 21 MW of demand response from the customers who were dually enrolled in DBP and BIP at PG&E. Because the sole 2009 DBP event overlapped with a BIP event (which includes large penalties for failing to reduce load during events), the DBP load impacts for these customers may not be representative of the performance they would provide during a DBP-only event. The load impact for PG&E's DBP test event in 2008 (which did not overlap with a BIP event) was 5.7 MW.

In some scenarios, the CE model included for one feature not seen in other CE tests conducted in California: the variability in program load impacts. This factor is intended to reflect the fact that programs with more reliable load response should have a higher value than programs with less reliable load response (all else equal).

The results of the CE models indicated that, under most assumptions, the Auto-DR programs are not currently cost effective (although PG&E's and SDG&E's Auto-CPP programs do appear to be cost effective by themselves). However, a couple of factors contribute to some uncertainty regarding the validity of this conclusion:

- The load impact estimates, which are the source of program benefits, are often driven by the behavior of very few customers on very few event days. For example, the benefit-cost ratio of PG&E's Auto-DBP program changes from 0.54 to 2.20 simply by using the 2009 load impact estimate in place of the 2008 load impact estimate *for one customer*. Furthermore, PG&E only called one DBP event in both 2008 and 2009, so the cost effectiveness is determined by customer load response in four hours per year.
- Customer baselines may change over time, making it difficult for some customers to perform up the level of their Auto-DR load shed test. These baseline changes could be caused by Auto-DR program (*e.g.*, by using information from an energy management system to better manage usage in all hours, and not only on event days; or by installing energy efficiency equipment funded by the bill savings from participating in demand response), or in response to changes in economic conditions or other "exogenous" factors.

Even considering these concerns, it appears that many Auto-DR customers are providing load impacts during events that are significantly below their load shed test values. Because Auto-DR pays its participants an incentive based on the results of the load shed test, it is important for the tests to reflect the performance that will be provided during DR program events. For example, if the load shed test values were consistently too high relative to the load impacts that customers can deliver during DR program events, it becomes difficult for the Auto-DR program to be cost effective. Therefore, it may be worthwhile for the utilities to review the load shed test methods, perhaps by comparing test conditions to event conditions to determine whether improvements to the load shed impact tests are necessary.