Default Critical Peak Pricing for Non-residential Customers: Do Demand Reductions Persist? Are the Reductions Reliable?

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ABSTRACT

California remains the only state to have implemented default Critical Peak Pricing (CPP) for customers with peak demand over 200 kW. Altogether, more than 6,000 C&I customers with almost 1,500 MW of peak load are enrolled in CPP in California; and nearly 70% of them have experienced multiple CPP events for three or more years. The analysis present addresses two key policy questions regarding default dynamic rates like CPP: do price-induced demand reductions persist, decrease, or grow over time; and do customers produce reliable and predictable demand reductions from one event to the next?

Demand reduction patterns for customers that have experienced every default CPP event from 2010 to 2012 at three different California utilities were analyzed. Changes in the customer mix as a potential reason for variation in demand reductions were eliminated by restricting the analyses to customers enrolled on CPP during all historical events. The demand reduction for each historical event is estimated using difference-in-differences. This approach relies on both a matched control group and non-event data to account for exogenous factors. Then, historical event estimates were used to explore trends and variability in behavior-based demand response patterns. In particular, persistence of response across years, variability in response from event to event and the effects of weather conditions and day of week on demand response were analyzed.

Introduction

California is the first and so far the only state to have implemented CPP on a default basis. Customers on CPP rates experience higher prices for consumption of electricity on critical hours (usually afternoon peak hours on 12 or fewer days a year) in exchange for reductions in non-peak energy charges, demand charges, or both. These higher charges reflect the cost of building additional peaking power plants to meet high demand levels. By limiting energy usage during CPP event days, participants can both reduce their electricity bill and help limit the need to build additional peaking power plants.

SDG&E implemented default CPP in 2008 and PG&E and SCE implemented it prior to summer of 2010. Each utility defaulted all accounts with peak demands over 200 kW that were not already enrolled on DR programs. While customers can opt out of CPP, default enrollment leads to higher enrollment rates and, in theory, can be less costly than recruiting customers into a rate. In addition, California utilities will begin to default nearly one million medium and small business accounts onto CPP in 2014 and 2016.

This paper explores the key policy questions of whether CPP-induced demand reductions persist, decrease or grow over time and whether customers produce reliable and predictable demand reductions from one event to the next. System planners need to know if CPP demand reductions will persist across years and system operators need to understand the variability and predictability of demand reductions associated with demand response programs such as CPP.

The remainder of this paper is structured as follows. The paper begins with a description of the CPP rates implemented by each of the three utilities. While conceptually similar, there are key differences between them. Next is a summary of the results from three years of historical impact evaluations and the limitations of using them to determine whether demand reductions persist over time and for assessing volatility in response. This is followed by a discussion of the methodology used to assess persistence of demand reduction, which eliminates differences that arise due to changes in the customer mix and/or in evaluation methods. The results are presented next. The paper concludes with a presentation of key findings and a discussion on the implication and limitations of the results.

CPP Rates and Default Process

While many of the details and mechanics of CPP tariffs vary across the utilities, the overall structure and goals of the default CPP program for medium and large C&I customers remains similar across the three IOUs. Most importantly, with the exception of a few changes, such as in 2011 when SDG&E transitioned from only being able to call events on summer non-holiday weekdays, to any day of the year, CPP has been implemented at each utility in a consistent manner since 2010. A persistence analysis of California's statewide CPP program, with its total of 76 events called since 2010, is now possible and of interest. Such an analysis would assess the reliability of load impacts due to CPP and whether they vary over day type, month, temperature or time since program inception. Important similarities across all three utilities include:

- The default tariff for large and medium commercial and industrial customers is a dynamic pricing tariff;
- Default rates include a high price during peak periods on a limited number of critical event days and TOU rates on non-event days;
- The opt-out tariff for all non-residential default customers is a time varying rate – in other words, there is no longer a flat rate option for default CPP customers once the default schedule is implemented;
- The critical peak price represents the cost of capacity required to meet peak energy needs plus the marginal cost of energy – in essence, all capacity value should be allocated to peak period hours on critical event days; and
- First-year bill protection was offered to customers defaulted onto dynamic rates, in addition to bill comparisons that demonstrated how their bill would be calculated under both CPP and the opt-out TOU rate.
- The CPP rate is also available to other non-residential customers on an optional basis.

Key differences between the CPP rates at the three utilities include:

- The rate design window schedule for each IOU caused the CPP rates to be implemented at different times. SDG&E was the first to default customers onto a CPP tariff, on May 1, 2008. SCE began defaulting customers onto CPP in October 2009, 18 months later than SDG&E, and PG&E began defaulting customers in May 2010.
- SDG&E defaulted customers whose maximum demand exceeded 20 kW for the prior 12 consecutive months. PG&E defaulted customers with maximum demand that exceeded 200 kW for 3 consecutive months in the prior year. In addition, PG&E transitioned approximately 110 small customers that had voluntarily enrolled on SmartRate, a pure CPP tariff, to the new CPP/TOU tariff. SCE required only that a customer's monthly maximum demand exceed 200 kW.
- At SDG&E, customers are locked into the CPP rate for a full year if they do not opt out prior to going on the default rate, while customers can opt out at anytime at PG&E and SCE.

However, at these utilities, customers must forgo bill protection if they leave the CPP rate during the first year when bill protection is in effect.

- SCE and PG&E share the same event hours, 2 PM to 6 PM, although a small number of customers in PG&E's service territory have elected a 12 PM to 6 PM event window with reduced credits and CPP charges. SCE and PG&E also share the same TOU peak period hours, 12 PM to 6 PM, Monday through Friday. For SDG&E, both the CPP event period hours and TOU peak period hours are from 11 AM to 6 PM.
- PG&E and SDG&E can call CPP events throughout the calendar year and on any day of the week, while SCE only calls events on non-holiday summer weekdays. PG&E and SCE are committed to a minimum of 9 and a maximum of 15 events each year. SDG&E is committed to a maximum of 18 events with no minimum.
- PG&E attempts to notify customers via phone, email, pager or text by 2 PM on the day before an event, while SCE and SDG&E attempts to notify customers by 3 PM the day before.
- PG&E and SDG&E offer customers the ability to hedge part or all of their demand against higher CPP prices – a feature known as a Capacity Reservation – while SCE has not yet implemented this feature.

The critical peak price at the California IOUs is typically an adder, in effect during CPP hours. The CPP credits take the form of reduced demand charges ($/kW), reduced consumption charges ($/kWh), or both. The on-peak demand credits vary substantially across the utilities. SDG&E and PG&E also have small energy credits for non-event periods, but SCE does not.

SDG&E offers a CR option to all CPP customers and PG&E offers it to CPP customers whose underlying TOU rate is E-19 or E-20.[1] SCE does not currently offer the CR option. Capacity reservation is a type of insurance contract in which a customer pays a fee (charged per kW) to set a level of demand below which it will be charged the non-CPP, TOU price during event periods. Above the set level, a customer will pay the normal CPP price during an event. Customers choosing this option will pay the capacity reservation fee whether or not events are called and whether or not they actually reach their specified level of demand during an event. The default CR level for SDG&E customers is 50% of a customer's average of their monthly maximum demands during the previous summer. PG&E also sets the default level to 50% of the same metric, but the capacity reservation structure is different. For PG&E, E-19 and E-20 customers pay capacity reservation charges according to the peak (during summer) and part-peak (during winter) demand charges that they normally pay during the hours of a CPP event.

Table 1 provides examples of the default CPP rates at each utility. There are a number of different CPP rates at each utility, which vary with customer demand and service voltage. All CPP rates also change over time due to periodic rate changes. Table 1 demonstrates that the rate components, credits and charges vary significantly across the utilities. Seasonal definitions also differ across the IOUs: PG&E defines summer as the period from May through October while SDG&E defines summer as May through September and SCE defines summer as June through September.

[1] A-10 customers are not eligible for CR, but they are offered other risk-shifting options: the every-other-event option and the six-hour event period option.

Table 1. Example Total Default CPP Rates at PG&E, SCE and SDG&E[2]

Season	TOU/CPP Component	Type of Charge/Credit	Period	PG&E E-19 $	SCE TOU-GS-3 $	SDG&E AL-TOU $
Summer	TOU Component	Energy Charges (per kWh)	On-peak	0.13	0.12	0.14
			Semi-peak	0.10	0.09	0.12
			Off-peak	0.07	0.07	0.10
		Demand Charges (per kW)	On-peak	14.70	12.96	12.86
			Semi-peak	3.43	3.08	NA
			Maximum	11.85	13.30	13.57
	CPP Component	Energy Charges and Credits (per kWh)	CPP Event Adder	1.20	1.36	1.06
			On-peak	0.00	NA	(0.01)
			Semi-peak	0.00	NA	(0.06)
			Off-peak	NA	NA	(0.01)
		Demand Credits (per kW)	On-peak	(6.35)	(11.62)	(5.21)
			Semi-peak	(1.37)	NA	NA
		Capacity Reservation Charge (per kW per month)	Summer	13.05	NA	6.42
Winter	TOU Component	Energy Charges (per kWh)	On-peak	NA	NA	0.13
			Semi-peak	0.09	0.07	0.13
			Off-peak	0.07	0.05	0.11
		Demand Charges (per kW)	On-peak	NA	–	4.92
			Semi-peak	0.21	–	NA
			Maximum	11.85	13.30	13.57
	CPP Component	Energy Charges and Credits (per kWh)	CPP Event Adder	1.20	NA	1.06
			On-peak	NA	NA	(0.01)
			Semi-peak	NA	NA	(0.01)
			Off-peak	NA	NA	(0.01)
		Demand Credits (per kW)	On-peak	NA	NA	(0.17)
			Semi-peak	NA	NA	NA
		Capacity Reservation Charge (per kW per month)	Winter	1.12	NA	6.42

[2] Table 1 does not include all CPP rates at each utility and the rates shown are presented for illustrative purposes only. Rates may vary over the course of the program year and by customer demand and service voltage. The rates shown are for customers at the secondary service voltage level. E-19 is mandatory for PG&E customers who fail to meet the requirements of E-20, but have monthly maximum billing demand above 499 kW and is voluntary for PG&E customers with maximum billing demand greater than 200 kW and less than 500 kW; TOU-GS-3 is mandatory for SCE customers with maximum demand greater than 200 kW and less than 500 kW; and AL-TOU applies to all SDG&E customers whose monthly maximum demand equals, exceeds, or is expected to equal or exceed 20 kW. This example PG&E E-19 rate was effective March 1, 2012; the SCE TOU-GS-3 rate was effective January 1, 2012; the SDG&E AL-TOU demand charges were effective March 1, 2012 and the energy charges were effective January 1, 2012; the SDG&E EECC AL-TOU and EECC-CPP-D commodity rates were effective January 1, 2012.

2010–2012 CPP Enrollment and Ex Post Load Impacts

The statewide CPP program has been evaluated on an annual basis to estimate the demand response load impact of the CPP price signal (George et al. 2011; George, Bode & Holmberg 2012; Bode, Churchwell & George 2013). These historic ex post load impacts necessarily reflect the enrollment mix, weather, dispatch strategy and program rules in effect at the time of each event.

However, in order to appropriately assess persistence of CPP load impacts across the three California IOUs, a comparison of 2010, 2011 and 2012 historic load impacts is not enough. The CPP participant mix and event day conditions have changed in the course of the three years. Between 2010 and 2011, the SCE CPP enrollment declined from approximately 4,000 customers to 2,400, while also adding 400 new enrollments. PG&E's enrollments, on the surface, did not change much in 2011 compared to 2010, however there were 200 opt outs during that period and 300 new enrollments. As a result, there was an increase in the share of participants in the agricultural and water transport sectors and a decrease in retail and office sectors. Multi-year persistence analysis must account for these changes in participant mix and in event day conditions.

Table 2 illustrates some of the ways that the CPP program has changed since 2010. While more than 15,000 medium and large C&I utility customers were eligible for default CPP during the years it was introduced at the three IOUs, a large proportion of these default-eligible customers migrated to TOU rates prior to defaulting to CPP or during the first year of CPP. By the end of the first summer on CPP, roughly 40%, 50% and 55% of default-eligible customers at PG&E, SCE and SDG&E, respectively, remained on the CPP rate. The remaining customers migrated to the optionally available TOU rate. Since then, statewide CPP enrollment has generally decreased across the three years that all three utilities have had default CPP in effect. One reason for the reduction in participants is that a number of customers exited CPP after they tested the rate during the initial year when bill protection was in place.

The aggregate electric load of all customers enrolled on CPP has also dropped from 2010 to 2012. SCE's aggregate enrolled load has significantly decreased since 2010, PG&E less so. SDG&E's enrolled load has also decreased but has been more consistent than the other two IOUs.

Importantly, while the number of enrolled customers and megawatts of enrolled load have decreased, the demand reduction capability of CPP has not. SDG&E's historic percent load impacts have, on average, remained fairly consistent since 2010; and PG&E and SCE's programs show much stronger results in 2011 and 2012 than in 2010. Specifically, PG&E's aggregate impacts, for the average event day, started in 2010 at 18.8 MW, followed by 23.0 MW in 2011 and 30.2 MW in 2012. SCE's average aggregate load impacts were 30.7, 35.0 and 32.9 MW in 2010, 2011 and 2012, respectively. SDG&E's average aggregate weekday load impacts were 18.8 MW in 2010, 18.6 MW in 2011 and 18.1 MW in 2012. The program has succeeded in delivering fairly consistent, and in some cases increasing, aggregate megawatts of demand response since 2010, but with fewer customers and less load. These load impacts have continued to be delivered necessarily because the percentage of load shed or shifted load by participants has increased.

While a review of the historic performance of the CPP program is helpful for motivating an inquiry into the persistence of CPP load impacts, these historic program benchmarks don't provide sufficient information for assessing the persistence of CPP load impacts. Not only do weather conditions and customer mix vary from year to year, but evaluation methods do as well. Analyzing load impacts with a consistent method across all three years is crucial for addressing this threat to the internal validity of the results of the analysis.

Table 2. CPP Enrollment, Enrolled Load and Load Impact at PG&E, SCE and SDG&E

	PG&E			SCE			SDG&E		
	2010	**2011**	**2012**	**2010**	**2011**	**2012**	**2010**	**2011**	**2012**
Customers	1,669	1,750	1,627	4,091	3,006	2,470	1,368	1,293	1,117
Enrolled Load (MW)	592.3	473.4	437.3	1078.1	615.4	554.3	356.6	358.8	300.5
Demand Reduction (MW)	18.8	23.0	30.2	30.7	35.0	32.9	18.8	18.6	18.1
Avg. Percent Load Impact	3.9%	5.9%	6.9%	2.8%	5.7%	5.9%	5.3%	5.2%	6.0%

Persistence Analysis Methodology

Whether default CPP load impacts grow, decrease or remain constant has important implications for long term resource planning and policy. So does the weather sensitivity of demand reductions. A program that provides larger demand reductions when temperatures are hotter and resources are in short supply is more valuable than one that provides constant or decreasing demand reductions as temperatures increase. Persistence analysis is, by necessity, a multi-year analysis. Taking a broader perspective allows for better assessment of overall performance and volatility in demand reductions. It also can help determine whether factors such as weather or duration of enrollment affect performance. Too few data points weaken the ability to produce reliable estimates and to draw inferences about factors that affect performance.

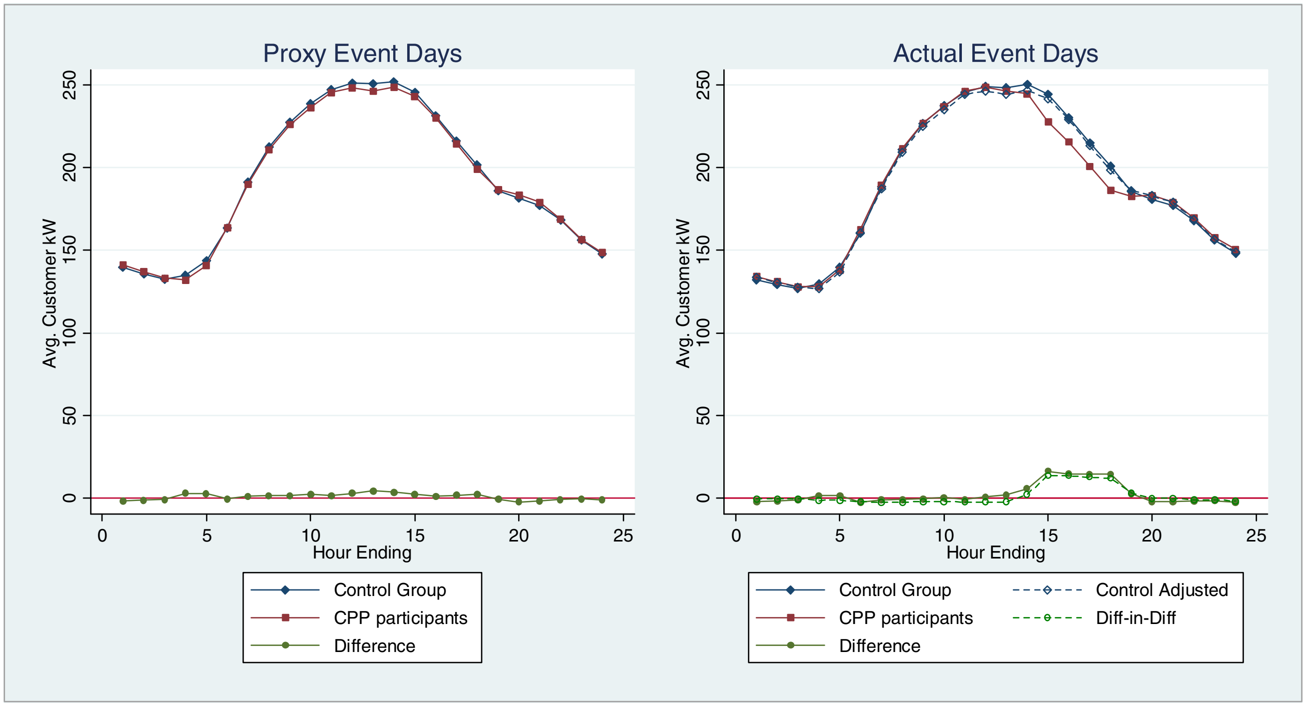
The primary feature of persistence analysis is a multiyear investigation of CPP load impacts. With at least three years of coinciding program history at all three utilities, an analysis of load impacts across the years 2010, 2011 and 2012 is now possible. However, an important aspect of the history of CPP in California is that not all current CPP participants were participating in 2011 or 2010; conversely, many customers who were enrolled in 2010 or 2011 were not enrolled in 2012. The first step of the analysis was to restrict the analysis population to those CPP customers who in fact have three years of history on CPP. The number of customers in this population are anticipated to be notably smaller than the 2012 CPP participant population: not only have new participants joined the program and some participants opted off, normal customer churn for medium and large C&I utility customers in California is approximately 10% per annum. Compounded over three years, an initial hypothetical medium and large C&I customer population of 1,000 customers should shrink to approximately 730 customers by the third year. This persistence population for the CPP program years 2010 through 2012 is 1,180, 1,759 and 869 customers at PG&E, SCE and SDG&E, respectively. It should be noted that these counts of customers in the persistence population represent 67% of the 2012 CPP population at PG&E and SDG&E and 72% of the SCE 2012 CPP population. This important fact is discussed later in this paper.

Load impacts across multiple years of CPP program history were estimated for each IOU using difference-in-differences, a method that makes use of both an external control group and non-event day data. The difference-in-differences approach can produce more accurate results for individual CPP days versus an approach that only uses participants' data from event-like days. This is because the control group provides information about how program participants would have used electricity if they were not exposed to CPP event notification and prices. More specifically, this approach can be particularly advantageous when CPP events are called on nearly all hot days, which is often the case for some utilities.

Figure 1 illustrates the estimation process conceptually. The left side of the figure shows hourly loads for CPP participants and control customers during event-like days that have similar exogenous conditions, such as weather, as those that occur on event days. The loads of the two customer groups closely mirror each other on event-like days, indicating that the control group load allows us to estimate CPP participant's hourly electricity consumption patterns in the absence of CPP event day prices. The right side of Figure 1 shows the hourly loads for CPP participants and the control group on event days.

As expected, the loads for the two groups diverge during event hours. Since the only known difference between the two groups is the fact that CPP customers face higher prices and control customers do not, the difference in observed loads can be attributed to the higher CPP prices on event days.

Figure 1. Example of Difference-in-differences Calculation



The difference-in-differences calculation refines the impact estimates by netting out the small differences between the two groups observed during the event-like days (when CPP prices were not in effect for either group). This is also illustrated on the right side of Figure 1. Overall, the adjustment is small, primarily because CPP participant and control group electricity use patterns are nearly identical during event-like days. However, such differences can be larger if results are disaggregated to specific customer segments because sample sizes are smaller and because loads are often concentrated among a few large customers. Load impacts were not disaggregated by customer segments for this persistence analysis.

This approach makes full use of non-event and event day data available for CPP and control group customers. It takes into account whether peak load patterns changed for CPP customers and whether load patterns changed for customers who did not experience CPP prices. It also accounts for differences between CPP participants and the control group observed during non-event days.

Control Group Selection

Propensity score matching was used to select valid control groups for the CPP persistence population at each utility, for each customer segment. This method is a standard approach for identifying statistical look-alikes from a pool of control group candidates to explicitly address self-selection onto CPP tariffs based on observable differences between CPP participants and non-participants.[3] The control group was selected from customers who were present over the entire

[3] For a discussion of the use of propensity score matching to identify control groups, see Imbens, Guido W. and Woolridge, Jeffrey M. "Recent Developments in the Econometrics of Program Evaluation." *Journal of Economic Literature* 47.1 (2009): 5-86.

persistence study period and who were also not on CPP during that period. It included customers who were defaulted onto CPP and opted out as well as customers enrolled in demand response aggregator contracts or on the Baseline Interruptible Program.[4]

With propensity score matching, customer characteristics are weighted based on the degree to which they predict program participation and are used to produce a propensity score. For each CPP customer, the control group candidate with the closest propensity score was selected.[5] CPP participants are matched within industry groups; that is, matched control customers were required to be in the same industry group as CPP participants. Weather conditions (cooling degree days from June through September) were also factored into the match, in addition to consumption levels during hot non-event days and the share of their power consumption that occurred during the peak period. Some control group customers were selected more than once – that is, if customer A was the best match for both customer B and customer C, they were selected twice.

Table 3 compares the CPP persistence treatment group to its matched control group across a number of characteristics for each utility. The differences observed in these characteristics, are small and demonstrate that control and participant customers are very similar in terms of weather conditions, industry mix and hourly demand patterns during hot days (prior to any adjustments or modeling). However, Table 3 illustrates that matches were most difficult to make on the basis of industry. These differences in customer mix between the persistence control group, the persistence treatment group and the current CPP population were serious enough in the case of PG&E to present an issue of external validity: for this reason, the persistence population dataset for PG&E was restricted to the years 2011 and 2012 only. It was not possible to construct a suitable control group for those customers at PG&E who had participated in CPP for three years since 2010.

[4] Participants in the latter two programs were included because they were not dispatched at the same time as CPP rates in 2012 and are typically dispatched once or twice per year, mainly for testing.

[5] Matches were restricted to a tight range: if customers within a very similar propensity score (<0.02 difference) could not be found, those CPP customers went unmatched. For each utility, over 90% of CPP participants and load was matched.

Table 3. Characteristics Comparison of Treatment vs. Control CPP Persistence Customers

Category	Variable	PG&E				SCE				SDG&E			
		CPP n = 1,180	Control n = 943	t	p>t	CPP n = 1,759	Control n = 1,633	t	p>t	CPP n = 869	Control n = 585	t	p>t
Consumption Patterns on Event-like Days	Hour-ending 1 AM	182.8	182.8	0	1.00	135.7	130.4	0.67	0.51	158.4	157.2	0.1	0.92
	Hour-ending 2 AM	177.7	177.9	-0.01	0.99	131.7	126.1	0.7	0.48	154.5	153.1	0.11	0.91
	Hour-ending 3 AM	173.9	173.0	0.06	0.95	127.8	122.8	0.63	0.53	152.2	150.1	0.17	0.86
	Hour-ending 4 AM	173.7	172.1	0.1	0.92	126.6	123.4	0.42	0.68	152.4	151.2	0.1	0.92
	Hour-ending 5 AM	181.0	178.9	0.13	0.89	134.4	131.8	0.33	0.74	157.5	156.1	0.12	0.91
	Hour-ending 6 AM	198.0	197.3	0.05	0.96	154.0	152.4	0.2	0.84	174.3	166.5	0.63	0.53
	Hour-ending 7 AM	224.4	224.3	0.01	0.99	178.9	177.8	0.14	0.89	195.9	190.0	0.46	0.65
	Hour-ending 8 AM	248.9	251.3	-0.15	0.88	199.6	199.9	-0.03	0.98	218.4	215.7	0.2	0.84
	Hour-ending 9 AM	270.3	272.6	-0.13	0.90	215.7	217.5	-0.22	0.82	239.5	236.1	0.24	0.81
	Hour-ending 10 AM	286.2	289.3	-0.18	0.86	226.7	228.9	-0.27	0.79	255.9	251.5	0.3	0.77
	Hour-ending 11 AM	299.0	302.0	-0.17	0.87	236.7	237.7	-0.12	0.91	265.5	261.6	0.26	0.80
	Hour-ending 12 PM	303.5	309.8	-0.35	0.73	239.2	242.9	-0.4	0.69	271.8	267.1	0.31	0.76
	Hour-ending 1 PM	305.5	311.5	-0.32	0.75	237.1	242.8	-0.61	0.54	273.9	268.0	0.37	0.71
	Hour-ending 2 PM	310.9	318.1	-0.39	0.70	239.9	244.0	-0.42	0.67	274.3	267.9	0.4	0.69
	Hour-ending 3 PM	308.3	314.8	-0.35	0.73	235.0	239.3	-0.45	0.65	270.5	264.8	0.36	0.72
	Hour-ending 4 PM	297.3	303.5	-0.33	0.74	222.2	224.9	-0.28	0.78	259.8	253.5	0.41	0.68
	Hour-ending 5 PM	282.1	287.1	-0.27	0.79	205.9	207.8	-0.21	0.84	246.6	240.7	0.38	0.70
	Hour-ending 6 PM	263.5	267.8	-0.24	0.81	190.8	192.9	-0.23	0.82	231.0	226.3	0.31	0.76
	Hour-ending 7 PM	242.0	244.0	-0.11	0.91	180.9	178.8	0.24	0.81	211.0	202.3	0.61	0.54
	Hour-ending 8 PM	231.3	232.1	-0.05	0.96	177.6	173.8	0.43	0.67	202.0	194.0	0.58	0.56
	Hour-ending 9 PM	222.7	225.9	-0.19	0.85	174.2	168.8	0.6	0.55	196.5	189.5	0.51	0.61
	Hour-ending 10 PM	214.2	217.3	-0.18	0.86	163.7	159.5	0.48	0.63	187.4	181.2	0.46	0.65
	Hour-ending 11 PM	203.7	207.4	-0.22	0.82	150.6	148.7	0.23	0.82	177.5	174.1	0.26	0.80
	Hour-ending 12 AM	194.5	197.6	-0.19	0.85	143.6	139.9	0.45	0.66	169.0	166.1	0.23	0.82
	Peak kWh on hot days	1151.2	1173.2	-0.3	0.77	854.0	864.9	-0.29	0.77	1828.0	1788.2	0.37	0.72
	2010 peak kWh on hot days	1163.0	1197.4	-0.44	0.66	834.7	850.9	-0.44	0.66	1792.9	1722.5	0.64	0.52
	2011 peak kWh on hot days	1170.0	1177.9	-0.11	0.92	857.7	858.7	-0.03	0.98	1907.3	1892.6	0.13	0.90
	2012 peak kWh on hot days	1117.3	1146.0	-0.4	0.69	867.3	882.1	-0.39	0.70	1811.0	1774.4	0.33	0.74
	% of cons. during peak hours	0.2	0.2	-0.95	0.34	0.2	0.2	-0.47	0.64	0.4	0.4	-0.32	0.75
Weather	June-September total CDD	3238.8	3385.6	-1.09	0.27	3879.0	3835.4	0.71	0.48	4829.8	4786.8	1.38	0.17
Industry Mix	Ag, mining & construction	0.0	0.0	-1.35	0.18	0.0	0.0	3.32	0.001*	0.0	0.0	-1.14	0.26
	Manufacturing	0.2	0.2	0	1.00	0.3	0.3	0.04	0.97	0.1	0.1	0	1.00
	Wholesale & transport	0.1	0.1	1.93	0.054*	0.2	0.2	0.58	0.56	0.1	0.1	0	1.00
	Retail	0.0	0.1	-1.76	0.079*	0.1	0.1	-1.96	0.05*	0.0	0.0	0.66	0.51
	Offices, hotels, finance, services	0.3	0.3	0.94	0.35	0.2	0.2	-0.36	0.72	0.4	0.4	0	1.00
	Schools	0.2	0.2	-0.4	0.69	0.2	0.2	0	1.00	0.3	0.3	0	1.00
	Institutional/government	0.1	0.1	-1.09	0.28	0.1	0.1	-0.4	0.69	0.1	0.1	0	1.00
	Other or unknown	0.0	0.0	-1.42	0.16	0.0	0.0	1	0.32	0.0	0.0	0	1.00

Persistence of CPP Load Impacts

Load impacts of the CPP persistence population, as calculated by the difference-in-differences method, control for the changing customer mix that has occurred during the course of the CPP program in 2010 through 2012 in addition to being internally consistent with regards to a single methodology applied across all analysis years. With a carefully matched control group and a persistence population of customers who have participated in three full years of CPP, estimates of load impacts will not face these particular threats to internal validity. Other important factors that can influence how and whether CPP load impacts have persisted over time are duration of enrollment on the CPP program and temperature. Figures 2 and 3 below present scatter plots of the persistence population load impacts against both temperature and event day, where event day is an overall count of CPP events across the three IOUs in 2010 through 2012.

Figure 2. 2010-2012 Percent Load Impacts of CPP Persistence Population vs. Event Number, by Utility

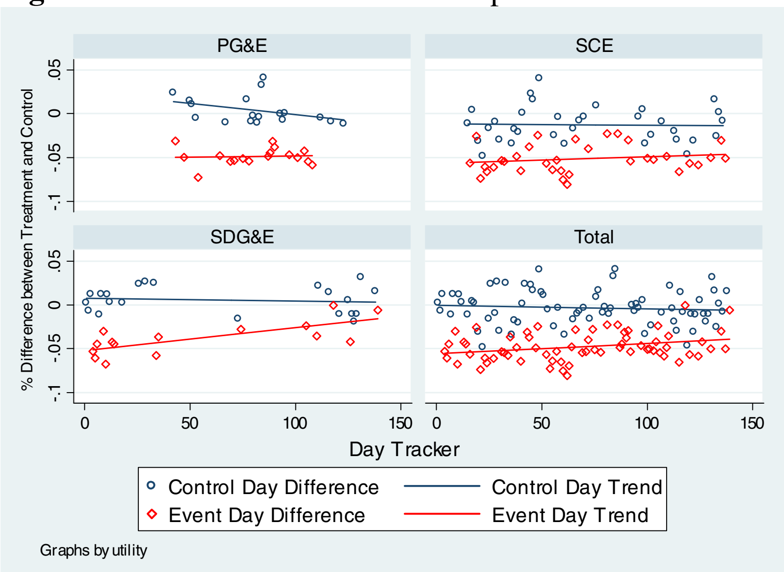
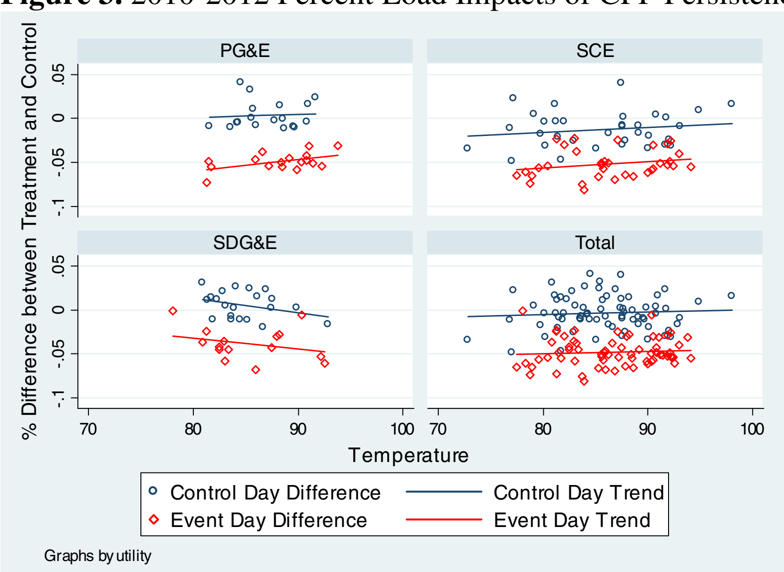


Figure 3. 2010-2012 Percent Load Impacts of CPP Persistence Population vs. Temperature, by Utility



This analysis of the persistence of CPP load impacts across the years 2010, 2011 and 2012 (in PG&E's case, 2011 and 2012 only, as explained earlier) hinges on testing two key hypotheses: that weather conditions experienced by each utility can affect load impacts and that load impacts can be affected by length of time enrolled on the program. Figures 2 and 3 illustrate how these questions were addressed.

The blue data points and trend lines in Figure 2 indicate how well the control group and treatment group match on event-like days; the control group's electric consumption differs during event hours only modestly from that of the treatment group across the event-like days. Further, across time, these small differences between the control and treatment groups do not change significantly. A decreasing trend here is visible for PG&E, indicating a possible relationship between the quality of the control group match and time; however, when tested for statistical significance, none was found. The insignificance of this trend is owed largely to the greater dispersion of control group and treatment group differences – a consequence of the fact that the control group for PG&E was the most difficult to create, which led to the shorter analysis horizon for PG&E. This wider dispersion coupled with fewer event-like days to evaluate are the likely key contributors to this trend's insignificance.

The red data points and trend line in Figure 2 illustrate the assessment of whether or not CPP load impacts change over time. Figure 2 shows that at PG&E and SCE, load impacts for those customers who have participated in CPP for three years have not changed much with respect to duration of enrollment. SDG&E's data tells a different story however. The time trend seen in Figure 5 is statistically significant: the difference in peak electric usage of the treatment and control groups at SDG&E have fallen over time for this persistence population. Notably, there are only 15 data points to include in this analysis, but the relatively small variance in load impacts over time leads to the significant results.

The difference-in-differences load impacts for these event days are represented by the distances between the red and blue trend lines. Figure 2 indicates these difference-in-differences becoming smaller over time for both PG&E and SDG&E.

Figure 3 presents a look at the load impacts from the persistence population relative to temperature. The temperature response trend for the difference in peak electric usage between the treatment and control group for each utility looks very similar for both event-like days and non-event days. At PG&E and SCE, there is a slight trend of decreasing load differences with higher temperatures. However, these differences are not significantly different, and we do not see a significant change in the difference-in-differences as temperatures change. The difference in treatment and control usage at SDG&E shows a trend in the opposite direction – increasing differences with higher temperatures. However, this result, too, is statistically insignificant. With respect to temperature, the few datapoints vary too much to support the claim that temperatures impact CPP demand response. Another important fact to note is that most SDG&E events are on the coolest side of the temperature scale. There are few event days at high temperatures; in fact, there are also very few event-like days at those temperatures – these data points appear to be exerting a great deal of leverage on the temperature trend. The question then arises whether these results should be given much weight.

In both Figures 2 and 3, the "Total" graphs showing data combined for all three utilities are included for convenience and illustration only. Cross-utility comparisons are difficult to make in general; furthermore, in this setting, each utility has differing numbers of customers on CPP for each event day and at each temperature. A more accurate look across all utilities would need to weight load impacts for these differences in customer distribution within the covariates.

Key Findings and Limitations of Persistence Analyses

Key findings and limitations of this study are:

- Statewide, despite substantial decreases in enrolled customers and program loads, aggregate load impacts from default CPP program have historically risen over time.
- An analysis of persistence of impacts over multiple years requires narrowing the analysis to the same set of CPP participants and control group customers that were present throughout the time period. It also requires applying the same evaluation method. This helps eliminate changes in the customer mix and differences in methodology as potential explanations for differences in impacts across years.
- SCE has the most multi-year customers and has called the most CPP event days since 2010, providing the most data with which to conduct this analysis. This largest dataset shows no evidence of load impacts over time or over weather conditions during the 2010 through 2012 period.
- While there currently isn't a large set of data available to analyze for the PG&E and SDG&E default CPP program, there is still an opportunity to revisit the research question in future years. As default CPP becomes a reality for small commercial customers in the future, the opportunity exists for these new programs to begin early on to create more measurement and evaluation data by calling many events, using a randomized control design to employ many large testing groups and to call many events for subsets of these groups. With many events called each year over the course of a few years, it may be possible to draw stronger conclusions about the persistence across years and also within seasons.
- The load impacts for the CPP persistence population (those customers with continuous enrollment on CPP over a certain period of time) represent only a subset of those customers that are currently enrolled on the program. For example, currently many of the agricultural customers enrolled on CPP have short enrollment histories. These customers are among the most responsive of CPP participants, but are excluded from the persistence analysis by dint of their lack of enrollment history.
- Historic statewide default CPP program load impacts are not large, generally ranging from 3 to 7%. However, default CPP was implemented in California after many years of mandatory TOU rates for the default population. Additionally, half of the medium and large C&I customers at PG&E and SCE were never subject to the default because they were already enrolled in a demand response program; these customers are likely to be the most price responsive among medium & large C&I population. CPP is often only called under extreme weather and system conditions, making for a small sample size of event days and event-like days. When testing for relationships between default CPP load impacts and factors such as weather and duration of enrollment, these small sample sizes contribute to noise around already small effects, making conclusive findings elusive.
- It is tempting to consider pooling all default California CPP participants into one single persistence study group. At a minimum, these results would have to be weighted, for example, to account for the different distributions of participants by temperature across the utilities. However, it's not clear that a pooled analysis is a valid approach for this program. System conditions, weather conditions and CPP program operations vary by utility – CPP is never used as a coincident statewide demand response resource.

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