DOCKETED

Docket Number:	15-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	207031
Document Title:	Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report
Description:	N/A
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	12/15/2015 3:13:01 PM
Docketed Date:	12/15/2015

CHRISTENSEN
ASSOCIATES
ENERGY CONSULTING

Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report

Daniel G. Hansen
Steven D. Braithwait
David Armstrong

November 15, 2015

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299

Voice 608.231.2266 Fax 608.231.2108

Table of Contents

1. INTRODUCTION AND PURPOSE OF THE STUDY 2

1.1 Background 2
1.2 Alternative scenarios 2

2. STUDY METHODOLOGY 3

2.1 Methodology 3
2.2 Data and TOU rates 4

3. REVIEW OF RECENT RELEVANT TOU STUDIES 5

3.1 Indicators of TOU demand response 6
3.2 TOU demand response findings in recent studies 8
3.3 Going beyond summer peak demand reductions 11
3.4 Applicability of previous findings to current study 12

4. RESIDENTIAL TOU LOAD IMPACTS 14

4.1 Adjusted overall SPP elasticities of substitution 14
4.2 Simulated TOU load impacts 15
4.3 TOU load impacts with target marketing 24

5. SMALL AND MEDIUM COMMERCIAL AND INDUSTRIAL TOU LOAD IMPACTS 30

6. LARGE COMMERCIAL AND INDUSTRIAL TOU LOAD IMPACTS 34

6.1 Estimates of embedded TOU load impacts using SDG&E data 34
6.2 Simulations of embedded TOU load impacts for PG&E, SCE, and SDG&E 36

7. COMMERCIAL AND INDUSTRIAL CPP LOAD IMPACTS 42

8. SUMMARY AND CONCLUSIONS 51

REFERENCES 52

APPENDIX 53

1. INTRODUCTION AND PURPOSE OF THE STUDY

This report documents a high-level study of the potential load impacts from offering new time-of-use (TOU) rates for residential and non-residential customers in California. The statewide study has been requested by the Energy Division of the California Public Utilities Commission. It considers a range of scenarios regarding the design and market participation of the new TOU rates at Pacific Gas and Electric Company ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas and Electric (SDG&E). Also included are alternative scenarios regarding retention rates for non-residential default critical-peak pricing (CPP) after expiration of customers' bill protection period. The report provides simulated load impacts for 2016 through 2025, where results are based on the following:

1) class-level reference load data provided by the IOU's and a consultant for the California Energy Commission (CEC);
2) TOU rate designs;
3) assumptions regarding customer price responsiveness derived from recent relevant research; and
4) different trajectories of customer participation over time.

1.1 Background

PG&E and SCE have been transitioning small and medium business (SMB) and agricultural customers to default TOU energy rates since 2012. Large business customers were transitioned in 2002 and 2003 in conjunction with installation of real-time energy meters (RTEM). SDG&E transitioned its medium and large business customers to TOU rates prior to 2000 and will start to default its small business and agricultural customers to CPP rates with the option to opt-out to a TOU rate in late 2015. Residential customers have the option of enrolling in peak time rebate ("PTR") programs (at SCE and SDG&E) or Peak Day Pricing ("PDP"), a version of critical peak pricing (at PG&E), and Decision D-15-07-001 requires the utilities to file a residential rate design window (RDW) application no later than January 1, 2018 proposing a default TOU rate for residential customers.

This study simulates the potential percentage and aggregate load impacts at each of the utilities, and statewide, under alternative scenarios of TOU rate design (*e.g.*, different price structures and the peak period occurring later in the day) and opt-in participation rates.

1.2 Alternative scenarios

The alternative scenarios that are included in the study are the following:

- Scenario 1 reflects existing TOU rates and peak period definitions, differing from the Utilities' base cases only in that opt-in residential TOU participation rates are assumed to ramp up to 10 percent by 2025.
- Scenario 2 reflects the Utilities' proposed TOU rates (in R.12-06-013) and proposed changes in TOU peak periods, with the same assumption that opt-in residential TOU participation rates ramp up to 10 percent by 2025.
- Scenario 3 is the same as Scenario 2, except that opt-in residential TOU participation rates are assumed to ramp up to 30 percent by 2025.

The scenarios also differ according to non-residential participation rates in critical peak pricing (CPP) rates. The participation rates vary across utilities according to their experience. The guidelines provided by the CEC included the following participation rates as an example: Scenarios 1 and 2 also include an assumption that 25 percent of small and medium non-residential customers will remain on default CPP rates after their bill protection period ends; and Scenario 3 also includes an assumption that default CPP retention rates are 75 percent after bill protection ends.

The study is organized as follows: Section 2 describes our methodology for the residential portion of the study; Section 3 presents a review of previous residential TOU studies; Section 4 presents the residential simulation results; Section 5 contains a description of the effects on small and medium C&I customer TOU response; Section 6 contains a description of the effects on large C&I customer TOU response; Section 7 presents simulation results for non-residential CPP customers; and Section 8 provides a summary and conclusions.

2. STUDY METHODOLOGY

This section describes the methodology, data, and assumptions used to simulate residential TOU load impacts in this study.

2.1 Methodology

Simulating the load impacts of TOU rates requires three basic sets of information, plus an analytical tool, or model. The three sets of information are:

- Hourly load data for a base period for relevant groups of customers;
- TOU rate designs and participation rates; and
- Assumptions on how participating consumers respond to TOU rates.

Once that information is in hand, we need an analytical tool for manipulating the load data and applying the customer response information to relevant TOU time periods. The first two sets of data are described below. The assumptions on TOU demand response are described in Section 3, following a brief review of the findings from recent studies of residential TOU rates in California and elsewhere.

The analytical tool implements a version of the familiar constant elasticity of substitution (CES) demand model, as described in Section 3. In each case, the TOU rate in question is compared to a corresponding flat rate that is constructed for purposes of this study. Each flat rate is assumed to include the same monthly (or daily) customer charge as the corresponding TOU rate and is constructed to be revenue neutral in each year to the TOU rate and reference load profile. Note that the revenue neutrality is enforced at the annual level. Because the TOU rates are seasonal, the overall summer price level is typically higher on the TOU rate than the flat rate, leading to small reductions in the overall usage level during that season. The opposite occurs in the winter season, during which the TOU price level is lower than the annual flat rate. All rates (TOU and flat) are designed without tiers. The CES model is separately applied to each day of the year, using the applicable rates, pricing periods, and reference loads for the day.

2.2 Data and TOU rates

Customer load data

We received one year of hourly load data for the average residential customer at each of the three utilities, from the CEC consultant that is pursuing a related study. The loads are based on Dynamic Load Profile (DLP) data for 2012, and are adjusted in future years by assumptions regarding growth in the number of customers served and the share of customers with rooftop solar systems.

TOU rates

The Scenario 1 rates reflect existing TOU time periods and rates, though the rates have been adjusted to remove the pricing tiers.[1] The TOU rates proposed by the Utilities for Scenarios 2 and 3 for this study are generally characterized by peak, part-peak, and off-peak prices (PG&E proposes only peak and off-peak periods), though with some differences in how the different pricing periods are labeled. Each utility proposes to move the peak period to later in the evening than is the case in the current rates. Different rates are designed for CARE and non-CARE customers. Table 2.1 summarizes the rate designs. For PG&E and SDG&E, the ratios of peak to off-peak prices in Scenarios 2 and 3 for non-CARE customers are approximately 1.5, while the SCE rates have a ratio of about 3.2. In each case, the customer charge is $10 per month for non-CARE customers and $5 per month for CARE customers.[2]

[1] SCE has had its proposed rates accepted, which has the implication that its rates are same for Scenarios 1 and 2.
[2] The customer charges have no effect on the analysis because we assume that the flat rate (against which the TOU rate is compared for load response purposes) has the same customer charge as the TOU rate.

Table 2.1: TOU rate designs by scenario

Season	Pricing Period	Scenario 1 Non-CARE	Scenario 1 CARE	Scenario 2 & 3 Non-CARE	Scenario 2 & 3 CARE
PG&E					
Summer	Off-peak	$ 0.181	$ 0.100	$ 0.207	$ 0.141
	Partial-peak	$ 0.258	$ 0.163		
	Peak	$ 0.373	$ 0.259	$ 0.310	$ 0.212
Winter	Off-peak	$ 0.176	$ 0.099	$ 0.156	$ 0.107
	Peak/Partial-peak	$ 0.192	$ 0.113	$ 0.175	$ 0.120
SCE					
Summer	Super Off-peak	$ 0.113	$ 0.073	$ 0.113	$ 0.073
	Off-peak	$ 0.198	$ 0.142	$ 0.198	$ 0.142
	Peak	$ 0.366	$ 0.263	$ 0.366	$ 0.263
Winter	Super Off-peak	$ 0.113	$ 0.073	$ 0.113	$ 0.073
	Off-peak	$ 0.159	$ 0.114	$ 0.159	$ 0.114
	Peak	$ 0.265	$ 0.190	$ 0.265	$ 0.190
SDG&E					
Summer	Off-peak	$ 0.210	$ 0.119	$ 0.173	$ 0.096
	Semi-peak	$ 0.252	$ 0.153	$ 0.229	$ 0.141
	Peak	$ 0.311	$ 0.200	$ 0.266	$ 0.170
Winter	Off-peak	$ 0.211	$ 0.126	$ 0.176	$ 0.105
	Semi-peak	$ 0.232	$ 0.143	$ 0.194	$ 0.119
	Peak	$ 0.247	$ 0.155	$ 0.211	$ 0.133

3. REVIEW OF RECENT RELEVANT TOU STUDIES

Arguably the most important assumption underlying this study involves the selection of appropriate estimates of how customers will respond under TOU rates (*e.g.*, how much will they reduce peak demand, or shift usage from peak to off-peak periods). The question of the degree to which customers will respond to time-varying pricing such as TOU has been the subject of considerable research since as far back as the 1970s. The past decade or so has seen relatively greater interest in more dynamic forms of electricity pricing, such as CPP, although TOU rates are also sometimes studied alone, or in conjunction with the more dynamic forms.

To identify the most appropriate indicator of demand response to TOU prices, we reviewed some of the most recent studies that may provide insights on, or be most relevant to TOU pricing in California. These include the following:

- A recent evaluation of residential TOU pricing at PG&E
- The evaluation of Sacramento Municipal Utility District's SmartPricing pilot
- An evaluation of default TOU pricing in Ontario, Canada
- An evaluation of Salt River Project's (SRP) TOU peak rates, with 7-hour and 3-hour peaks
- The California Statewide Pricing Pilot
- An evaluation of a pricing pilot in Connecticut
- An evaluation of a TOU pricing experiment at PECO

We also relate findings from the above studies to other recent evaluations of TOU load impacts.

A number of factors have the potential to affect the comparability of TOU load impact estimates across utilities and programs, including:

1. Whether customers opted into or were defaulted onto the rate. It could be that volunteers will have a different load profile (a lower share of peak-period usage) or be more responsive to TOU prices compared to customers who were defaulted onto a TOU rate.
2. The length of the peak pricing period. Shorter peak periods may correspond to higher demand response estimates because it is easier to modify energy usage during the shorter time period.
3. Climate conditions and the associated air conditioning (AC) penetration rates. Areas with persistently hotter weather are likely to have a higher share of customers with central AC. The central AC is an energy-intensive end use that may provide greater opportunities for demand response.
4. Relative TOU prices. Economic models assume that customer response to TOU rates is more pronounced when there is a greater difference between peak and off-peak prices. Our methods account for this feature by using elasticities that are constant across price levels and ratios.
5. The presence of enabling technology. Some programs (usually CPP or PTR rather than TOU) include automated demand response technology such as programmable controllable thermostats, or information devices that are intended to increase customer awareness of their energy use.

As we will show in our literature review below, there is no one study that provides a reliable estimate of how large numbers of residential customers at PG&E, SCE, and SDG&E would respond to TOU rates. As such, the simulation results should be used with some caution due to the considerable uncertainty about customer responsiveness.

3.1 Indicators of TOU demand response

Before turning to the findings from the different studies, it is useful to discuss which indicators, or metrics are most useful for characterizing customer demand response to TOU pricing. The most straightforward metric is the reduction in peak demand, typically shown in percentage terms (*i.e.*, the change in demand during the peak period, divided by the average value during that period for a reference non-TOU load). This is the metric that is most commonly reported in studies of the impacts of TOU rates.

Presenting the peak reduction in percentage terms is also one way to normalize for differences in customer size. For example, a customer in the Arizona desert with a peak demand of 5 kW due to central air conditioning might reduce load by 0.5 kW during a TOU peak period, while a customer in the Bay Area with a peak demand of 1 kW might reduce load by only 0.1 kW. Translating the results in *levels* of demand from one location to another would require a number of assumed factors. However, in the simple example above, both reduce peak demand by 10 percent. Of course it is possible that percentage peak reductions also vary from one type of customer, or location, to another, which is discussed below. However, *percentage* peak reductions are likely more similar than *levels* of peak reductions across such different conditions.

Percentage peak load reductions may be estimated in several possible ways, typically depending on the type of data used in the analysis. First, it may be calculated directly, as, for example, the difference between demand during the TOU peak-period hours of the average summer weekday for a *pre-treatment* and *post-treatment* period, or between the peak demands of a *control group* and of the *treatment group*. Second, they may be estimated as coefficients in a regression equation that includes data for either of the above types (*e.g*., pre- and post-treatment, or treatment and control group), or both (*e.g*., a difference-in-differences estimator). Finally, they may be simulated from the parameters of a formal customer demand model, such as those described below.

A more complicated indicator of demand response, which is estimated in some TOU studies is an *elasticity of substitution* (ES). The ES is a relative measure of demand response, indicating the degree of substitution between usage in two pricing periods (*e.g.*, the on-peak and off-peak periods), in response to a change in the ratio of on-peak to off-peak prices. Technically, it is formed as the negative of the ratio of the percentage change in the ratio of peak to off-peak usage, divided by the percentage change in the ratio of peak to off-peak prices, or:

$$ES = - \%Chg\ (Q_{Pk} / Q_{OffPk}) / \%Chg\ (P_{Pk} / P_{OffPk}),$$

where Q_t represents usage in a given time period (*e.g*., average kW in the peak period), P_t represents price in a given time period, and the *Pk* and *OffPk* subscripts represent peak and off-peak periods respectively. By convention, the ES is a positive number, typically taking on a value between zero and one.[3] The ES may in principle be calculated directly from observed data of the type discussed above, where the percentage changes are calculated from differences between pre- and post-treatment periods, or between treatment and control group customers. However, it is more often estimated as a parameter (or a function of several parameters) in a formal model of customer demand for electricity, such as the constant elasticity of substitution (CES)[4], the nested CES[5], or the Addilog demand model.[6]

[3] In the TOU application, the denominator takes on a positive value (*e.g.*, 100%), since the TOU peak to off-peak price ratio is greater than it is under a non-TOU case, and the numerator takes on a negative value, as consumers reduce peak usage relative to off-peak usage (*e.g.*, - 10%) in response to the price increase. The negative sign converts the resulting negative value to a positive (*e.g.*, 0.10). Note that some studies define the ES without the initial negative sign, with the result that the reported ES vales take on negative signs.
[4] The CES model has been used in the California Statewide Pricing Pilot and a number of other studies.
[5] The NCES model has been used in analyses of real-time pricing (RTP), as it adds a degree of flexibility in measuring customers' substitution between both usage in different hours on a given day, and average usage on days with different average prices.
[6] The Addilog demand model was used in the evaluation of TOU pricing in Ontario.

There is a useful relationship between the two metrics of ES and percentage peak load reduction, particularly under certain simplifying assumptions, that may help readers understand the link between the two concepts. In addition, we use this relationship to derive implied ES values from reported percentage peak reductions in the studies reviewed below, for which ES values were not estimated or are not provided.

To demonstrate this relationship, first note that since prices typically do not vary by time period in the non-TOU case, the denominator in the ES equation above reduces to the percentage ratio of the TOU peak and off-peak prices. Second, if it is assumed that off-peak usage will change by only a small amount, or none at all, then the numerator in the equation reduces to the percentage change in peak usage (or the percentage peak reduction) between the non-TOU and TOU cases. As a result, we can solve the simplified version of the above equation for the percentage change in peak usage as a function of the TOU peak to off-peak price ratio and the ES, or:

$$\%Chg\ (Q_{Pk}^{TOU} / Q_{Pk}^{non\text{-}TOU}) = -\ ES * \%\ (P_{Pk} / P_{Opk}).$$

So, for example, for a peak to off-peak price ratio of 2:1 and an ES of 0.10, the implied percentage change (reduction) in peak demand is (- 0.10 x 100%), or –10%. Alternatively, if the percentage peak demand reductions are known, but ES values are not reported, then the same relationship may be used to calculate implied ES values. We have used this approach in constructing comparative summaries of the TOU studies reported below.[7]

3.2 TOU demand response findings in recent studies

Table 3.1 summarizes the demand response findings from several recent evaluations of TOU rates, including both pilot experiments and full roll-out plans. The second column indicates how customers were enrolled in the rate, primarily indicating whether they were defaulted onto the TOU rate or chose to enroll (opt-in). In general, we exclude rate plans that had an enabling technology component to facilitate customer response, because that is not a feature of the rates being simulated in this study. An exception to this exclusion is the SMUD experiment, because two of the interesting options only included offers of in-home displays (IHD) combined with TOU pricing. The third column indicates the hours of the summer TOU peak period. There is some variability, with the SMUD rates and one of the SRP rates extending to 7:00 or 8:00 p.m.

[7] The model used in our analysis is more complex than the equation shown here, because it considers partial-peak periods, as well as peak and off-peak, and also accounts for changes in overall energy use. A full description of the CES model applied here can be found in Appendix L of "2013 Evaluation of PG&E's Mandatory TOU Rates for Small and Medium Non-residential Customers" by Bode and Cook, April 2014.

Table 3.1: Features of Recent TOU Load Impact Studies

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Utility (Year of Study)	Enrollment	Peak Hrs (HE)	Pk / Off-pk Prices	Peak Reduction (%)	Implied ES	Daily Elast. or % Reduced
PG&E TOU (2015)	Opt-in (E-6)	13-18	2.0	15%	0.22	Not est.
Statewide Pricing Pilot (2005)**	Opt-in	15-19	2.0	5%	0.07	-0.044
SMUD SmartPricing (2015)***	Opt-in, IHD offer	17-19	2.0	12%	0.17	0.90%
	Opt-in	17-19	2.0	9%	0.14	1.10%
	Default, IHD offer	17-19	2.0	6%	0.08	1.30%
SRP (2012)	Opt-in	14-20	3.4	9%	0.07	Not est.
		16-18 (from base)	5.2	20%	0.12	Not est.
		16-18 (from TOU)	5.2	20%	0.12	Not est.
Ontario (2015)*	Default	12-17	1.5	3%	0.07	None found
PECO (2015)*	Opt-in	15-18	1.7	6%	0.11	Not est.
Connecticut (2014)	Opt-in	13-18	2.0	3%	0.04	-0.45 (not sig.)^

* TOU prices applied to generation services only. Price ratio includes distribution charges in peak & off-peak.
** Results for CPP-F Normal Weekday, All Summer
***The off-peak rate was characterized by an inclining block; these ratios are calculated relative to an average of the initial and tail block prices.
^Authors assume zero in impact scenarios

The fourth column indicates the ratio of peak to off-peak prices. Most are modest, with ratios of 2 to 1 or less. The SRP rates are an exception, with ratios as high as 5 to 1 for their 3-hour peak (referred to as EZ-3) options. The fifth column shows estimated percentage reductions in peak period usage, as reported in the studies.

The sixth column shows values for elasticities of substitution that are calculated from the percentage summer peak reductions and price ratios, as described above.[8] These ES values, which are reasonably consistent with each other and those reported in previous studies, are also useful in the current study for simulating impacts other than overall summer peak reductions, such as peak reductions for non-summer periods, partial-peak reductions, and demand reductions for CARE customers, as described below.

The seventh and final column shows the daily elasticity or percentage load change across all hours. The daily elasticity is included in our simulations to allow the overall level of customer usage to change as their average price level changes (*i.e.*, total daily usage decreases when the

[8] An exception is SPP, which reported both ES and percentage peak load reductions, both of which are reported in the table.

average daily price index increases). Notice that some studies provided an estimate of the overall change in energy use in lieu of a daily elasticity, while other studies did not estimate the effect of TOU pricing on the overall usage level.

Features of the individual studies

Not surprisingly, the largest peak demand reductions (20%) are associated with SRP's EZ-3 options, which have the highest price ratios and narrowest peak period among the studies in the table.[9] The only other rate with results close to that magnitude of estimated peak load reduction is PG&E's E-6 rate, for which program-year 2014 evaluation results are reported. That average summer-month load reduction of 15 percent appears to be somewhat anomalously high among these studies, as well as other previous TOU evaluations. This result is discussed in more detail below.

The SMUD experiment is one of the most comprehensive and carefully designed randomized control trials (RCT) of time-based pricing that has been conducted in the industry to date. The experiment examined alternative rates (TOU and CPP), alternative enrollment methods (opt-in and default), and the effect of enabling technology (IHD offers). The findings reported in the table illustrate the effects of some of these features on TOU demand response (the table does not show results for CPP since this study focuses only on TOU rates). For example, customers assigned to TOU by default produced the smallest load response, at 6 percent. Load response for the opt-in groups was somewhat larger for those with no IHD (9 percent), and larger still for those who received the IHD offer (12 percent).

The Ontario case is of interest because it is one of the few full-scale default TOU rates, and it is current. Demand response in that case is relatively small, at 2 to 3 percent, likely due to both the default element and the relatively low peak to off-peak price ratio.[10] The Connecticut pilot in the last row focused largely on CPP and enabling technology, but also included a TOU rate. The estimated demand reductions for that experiment were relatively small.

The second to last row shows findings from an evaluation of a recent TOU pricing experiment at PECO in Pennsylvania. Approximately 4 percent of the customers offered the rate enrolled during a five-month recruitment effort. Peak load reductions for the four-hour peak period averaged 6 percent during the four primary summer months. Similarly to the Ontario case, the TOU prices applied only to the generation component of customers' bills (the rate was offered by a retail service provider in conjunction with PECO). The peak to off-peak price ratio of the

---

[9] The second and third rows showing SRP results represent two different groups of customers who selected the EZ-3 rate. One group (from base) previously faced the standard non-TOU rate, while the other (from TOU) was previously enrolled in the seven-hour standard TOU rate. SRP found that the latter group, having previously reduced peak load under the TOU rate, reduced usage further, by the same percentage amount as those customers who were previously on the non-TOU rate.

[10] As noted, the TOU prices applied only to the generation services portion of customers' bills. The ratio of the peak to off-peak generation prices was approximately 1.8. However, after accounting for the non-TOU distribution rate, the ratio falls to 1.5, the value shown in the table. Using the higher price ratio of TOU generation prices produces an ES of 0.05.

TOU generation rates was approximately 2.3, while the ratio falls to 1.7 after accounting for the non-TOU distribution charges.

The California SPP results are included, despite being somewhat dated, because of their direct relevance to the current California study, and the fact that the study quantified differences in demand response across the widely varying climate zones in California. Because of concerns about the small sample sizes used in the analysis of TOU rates in the pilot, we have instead used results from the CPP-F portion of the pilot, focusing on normal (non-CPP) weekdays, in which a TOU rate applied. This study served as the primary source of information on TOU demand response, as discussed in Section 3.4 below.

Results for a number of other earlier TOU studies are reported by Faruqui and Sergici (2010). While that paper focused largely on CPP results, it also reports percentage load reductions for some TOU programs, concluding that the average reduction in peak demand was 4 percent for programs without enabling technology, with a confidence interval ranging from 3 to 6 percent. More recent presentations by Ahmad Faruqui show TOU peak reductions of zero to 8 percent for peak to off-peak price ratios of 2 or less, and of 2 to 12 percent for price ratios of around 3.

3.3 Going beyond summer peak demand reductions

In addition to estimates of overall summer peak demand reductions under TOU rates, certain elements of this current study require further detail. These include:

- Peak demand reductions in non-summer months;
- Changes in demand outside of the peak period (*e.g.*, load shifting from peak to off-peak periods);
- Changes in overall energy consumption; and
- Estimates of differential price response among low-income, or CARE customers.

Considerably less information is available from existing studies on these topics compared to the overall results, which tend to focus on summer periods. However, some studies provide indications of relative magnitudes of load reductions at this further detail. These may be summarized as follows:

- Regarding load reductions in *non-summer months*, the Ontario evaluation found peak load reductions of approximately half those in summer months (*e.g.*, 1 percent compared to 3 percent, and an ES of 0.05 compared to 0.11). Similarly, the PG&E evaluation found winter peak load impacts of approximately 6 percent, compared to 15 percent in the summer, or less than half. Winter peak reductions in SPP were also considerably smaller than those in summer. These differences are likely due in part to generally smaller peak to off-peak price ratios and the lack of air conditioning loads that are present in summer. The PECO study also found peak demand reductions in shoulder months around the four summer months that averaged about half those during the summer.
- Regarding load changes *outside the peak* period, the SMUD evaluation found no evidence of load shifting from peak to off-peak periods (there was no partial-peak

period). The Ontario study found reductions in the mid-peak period that were smaller than those in the peak period, as well as some off-peak usage increases. Similar results were found in winter, but less so than in summer. The PG&E evaluation found smaller load reductions in the partial-peak hours prior to the peak (11 percent) and following the peak (6 percent) than during the peak hours (15 percent). In addition, that study found usage *increases* in off-peak hours averaging 4 percent. The SPP found small (2 percent) off-peak usage increases.

- Regarding estimated changes in *overall consumption*, the PG&E study found overall average usage reductions of about 4 percent over the summer months. The SMUD study found indications of small (1 percent) overall reductions in usage by month, but most estimates were not statistically significant. Ontario found no evidence of overall usage reductions. SPP found small seasonal reductions, which are discussed further below.
- Regarding estimated peak load reductions for *CARE, or other low-income categories* of customers, SMUD found similar TOU percentage load reductions for Energy Assistance customers compared to the average customer, although load reductions under CPP were considerably smaller than for the average customer. An Institute for Electric Efficiency (IEE) report on the effect of dynamic pricing on low-income customers reported a range across five studies of estimates of the relationship between load reductions for low-income customers and the average (or for the average non-low-income) customer. The estimates for low-income customers ranged from 50 to 100 percent of those for the average customer. The PECO study reported a somewhat larger peak load reduction for the summer month of July for customers classified as "low-income" based on survey responses compared to the overall average (7.3 percent, compared to 5.7 percent), though these customers accounted for less than 4 percent of the residential participants. It is not clear how that classification compares to the CARE or Energy Assistance qualifications used in California.

  Of particular relevance to California, the evaluation of PG&E's SmartRate for program-year 2009 found load reductions for CARE customers that were 50 percent of those for the average customer (which includes CARE and non-CARE customers), and one-third of non-CARE customers. Also, the SPP found that CPP and TOU load reductions for CARE customers were considerably smaller than those for the average customer.

3.4 Applicability of previous findings to current study

The studies summarized in Table 3.1 and discussed above vary considerably in terms of type of enrollment (opt-in or default), peak period definitions, and prices. They also differ in terms of typical weather conditions and air conditioner saturations, which are typically not discussed in the individual studies. Few provide a close match to the conditions that characterize the scenarios in the current study. The East-coast studies obviously apply to different climate and retail market conditions than those in California. The SMUD study is one of the best experiments to date, but most of the pricing options differ from what is being simulated in this study (*e.g.*, two of the TOU plans offered IHDs, and one was designed as a default rate). The most relevant option in that study appears to be "opt-in without IHD", which produced peak load reductions of 9 percent, implying an ES of 0.14.

SRPs base TOU rate is also relevant to the current study, in that it has been offered for a number of years, has a wide peak window that extends into the early evening, has a price ratio only somewhat larger than the rates planned in California, and had opt-in enrollment amounting to 24 percent of residential customers as of 2009. However, the much hotter climate in Arizona relative to California reduces its direct relevance to this study. The PECO study is comparable in the sense of indicating potential enrollment rates in opt-in TOU. It also produced a similar average peak reduction (6 percent compared to 4.7 percent), though at a somewhat lower overall price ratio (1.7 compared to 2.0). However, offering the rate through a competitive retail provider, including switching from the PECO default service, makes the setting somewhat different from that in California.

The most relevant studies are arguably the evaluation of PG&E's E-6 TOU rate for program-year 2014, and the SPP. However, some of the E-6 characteristics make it less than representative for a simulation of relatively high rates of participation over time for all three utilities. Current enrollment represents a very small percentage of PG&E's total residential base[11], and given the lack of active marketing, enrollment likely involves considerable self-selection of customers with relatively low peak-period usage, such as the 80 percent of enrollment that is net metering customers with rooftop solar.[12] The relatively large estimated load impacts in all pricing periods may represent the effects of unobservable characteristics associated with the relatively few E-6 participants, despite attempts to control for such factors through selection of matched control groups.

All of these considerations point to the SPP as the most directly relevant source of TOU demand response information for this study. As described above, we have selected results for "normal weekdays" under the CPP-F option as the most relevant source of elasticity of substitution values for use in this study. In Section 4, we describe how we adjusted estimates by the four climate zones in the SPP study to represent conditions at each of the three utilities.

The SPP provides us with base ES values that vary by season and climate zone. In addition, the SPP provides estimates of the seasonal daily elasticity, which defines how TOU customers change their overall load level in response to changes in the average price level across all hours. We apply these SPP-based values to the non-CARE customers, after an appropriate adjustment described in Section 4.1. For the CARE customers, we set the elasticity at half of the equivalent non-CARE elasticity.[13] For partial-peak periods, we use the base ES values, but apply them to the partial-peak price ratios.

---

[11] The Program Year 2014 load impact evaluation of E-6 customers (which excluded NEM customers) included only 7,926 customers, or approximately 0.2 percent of PG&E's residential customer population.

[12] Net Energy Metering (NEM) customers were removed from the E-6 load impact evaluation due to a lack of eligible control-group customers. That is, NEM customers are required to be on E-6, so there are not non-TOU NEM customers (at least in any significant number) against which to compare NEM customers on E-6.

[13] One element of the SPP found very little response by CARE customers on CPP event days, but did not report findings for normal weekdays. Other studies have reported load reductions or elasticity of substitution values for CARE-type customers that vary from a fraction of those for non-CARE customers, to values that did not differ. These guided our assumption that CARE customers were half as responsive as non-CARE.

4. RESIDENTIAL TOU LOAD IMPACTS

This section summarizes results from applying the adjusted SPP elasticities to the load data and rate designs in the various scenarios. We also include an alternative scenario that assumes that utilities target market the TOU rates to customers in hotter climate zones, where the estimated elasticities of substitution (and hence TOU demand response) are higher.

4.1 Adjusted overall SPP elasticities of substitution

The SPP estimated elasticities of substitution and daily price elasticities for the entire pilot program, as well as separately by four climate zones. For the most part, the estimates by climate zone did not differ greatly from the state-level estimates. However, the summer ES values did differ somewhat by climate zone. Because the Utilities have different shares of loads in the four climate zones, we derived utility-specific summer ES values.[14] For example, because PG&E has a higher share than SCE of customers in a mild climate zone, its summer ES value is lower. Table 4.1 summarizes the elasticity values used for each utility. The values listed as applying to "All" customer groups were directly derived from the SPP. We created non-CARE and CARE elasticity values that assume CARE customers are half of responsive as non-CARE customers and that the load-weighted average of the CARE and non-CARE elasticities matches the SPP-derived values.

Table 4.1: Elasticity Values used in the Residential TOU Study

Utility	Customer Group	Summer		Winter	
		Substitution	Daily	Substitution	Daily
PG&E	All	0.059	0.040	0.025	0.020
	Non-CARE	0.068	0.046	0.029	0.023
	CARE	0.034	0.023	0.014	0.012
SCE	All	0.078	0.040	0.025	0.020
	Non-CARE	0.091	0.046	0.029	0.023
	CARE	0.045	0.023	0.015	0.012
SDG&E	All	0.070	0.040	0.025	0.020
	Non-CARE	0.076	0.044	0.027	0.022
	CARE	0.038	0.022	0.014	0.011

[14] We approximated each utility's share of customers by climate zone using sampling plan data contained in Appendix 3 of the SPP final report. This provided, for each utility, the number of customers by weather station and an indication of the climate zones to which the weather station applies. Where more than one climate zone is associated with a weather station (which was common), we applied an equal share of customers to each climate zone. We used the utility-level share of customers by climate zone to calculate a weighted average ES from the zone-specific estimates contained in the SPP.

4.2 Simulated TOU load impacts

Table 4.2a presents results of the TOU load impact simulations, where the results represent the average outcome across non-holiday weekdays.[15] The first two columns indicate season and pricing period. The results are presented in three sets of columns. The first two show TOU demand response in percentage terms, for non-CARE and CARE customers respectively. These percentages apply to TOU participants only. The class-level percentage load changes (including participants and non-participants) are much smaller and vary by year as the assumed enrollment rate increases. The final set shows implied aggregate load changes for the final year of analysis (2025) after applying the percentage changes to the number of participating customers, according to the relevant assumed participation rate at the end of the period. The three columns in each set report results for each of the three scenarios. In all columns, negative signs indicate load *reductions*. The bold values within the groups of rows for each utility indicate results for the summer peak period. Table 4.2b contains the energy impacts associated with the rightmost three columns of Table 4.2a.

Using the PG&E results for illustration, the percentage peak reductions for the summer peak period for non-CARE customers are 3.7 percent in Scenario 1, and 3.0 percent in Scenarios 2 and 3, for which the peak prices are somewhat lower than in the first scenario. Results for CARE customers have a similar pattern, but are smaller in magnitude. The final set of columns indicate aggregate reductions in peak demand of about 16.0 MW in Scenario 1, 16.2 MW in Scenario 2 (10 percent participation in 2025), and 48.7 MW in Scenario 3 (30 percent participation in 2025).

[15] Demand response was simulated for weekends and holidays as well, but those results are omitted from the table.

Table 4.2a: Residential TOU load impacts – *Percentage and Aggregate (MW) Changes*

Season	Pricing Period	Non-CARE			CARE			Total		
		Percentage Impact			Percentage Impact			Aggregate Impact (MW) - 2025		
		Scen. 1	Scen. 2	Scen. 3	Scen. 1	Scen. 2	Scen. 3	Scen. 1	Scen. 2	Scen. 3
	PG&E									
Summer	Off-peak	1.1%	-0.3%	-0.3%	0.8%	-0.1%	-0.1%	3.1	-0.9	-2.6
	Partial-peak	-1.3%	n/a	n/a	-0.8%	n/a	n/a	-4.8	n/a	n/a
	Peak	**-3.7%**	**-3.0%**	**-3.0%**	**-2.4%**	**-1.5%**	**-1.5%**	**-16.0**	**-16.2**	**-48.7**
	Summer total	-0.6%	-0.9%	-0.9%	-0.3%	-0.4%	-0.4%	-3.3	-4.1	-12.2
Winter	Off-peak	0.4%	0.4%	0.4%	0.3%	0.2%	0.2%	1.3	1.1	3.3
	Peak/Partial-peak	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.6	0.3	1.0
	Winter total	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%	1.2	0.9	2.8
	SCE									
Summer	Super Off-peak	4.3%	4.3%	4.3%	2.5%	2.5%	2.5%	13.0	13.0	38.9
	Off-peak	-0.9%	-0.9%	-0.9%	-0.6%	-0.6%	-0.6%	-3.6	-3.6	-10.9
	Peak	**-6.3%**	**-6.3%**	**-6.3%**	**-3.4%**	**-3.4%**	**-3.4%**	**-32.3**	**-32.3**	**-96.8**
	Summer total	-0.1%	-0.1%	-0.1%	0.0%	0.0%	0.0%	-3.9	-3.9	-11.6
Winter	Super Off-peak	1.2%	1.2%	1.2%	0.7%	0.7%	0.7%	3.1	3.1	9.4
	Off-peak	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.4	0.4	1.3
	Peak	-1.3%	-1.3%	-1.3%	-0.7%	-0.7%	-0.7%	-4.5	-4.5	-13.5
	Winter total	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.3	0.3	1.0
	SDG&E									
Summer	Off-peak	1.0%	1.7%	1.7%	0.7%	1.2%	1.2%	0.8	1.3	3.9
	Semi-peak	-0.4%	-0.5%	-0.5%	-0.2%	-0.3%	-0.3%	-0.4	-0.4	-1.1
	Peak	**-2.0%**	**-1.6%**	**-1.6%**	**-1.2%**	**-1.0%**	**-1.0%**	**-1.7**	**-1.7**	**-5.2**
	Summer total	-0.4%	-0.2%	-0.2%	-0.2%	-0.1%	-0.1%	-0.4	-0.3	-1.0
Winter	Off-peak	0.2%	0.4%	0.4%	0.1%	0.3%	0.3%	0.2	0.3	1.0
	Semi-peak	0.0%	0.2%	0.2%	0.0%	0.1%	0.1%	0.0	0.1	0.4
	Peak	-0.2%	-0.1%	-0.1%	-0.1%	-0.1%	-0.1%	-0.2	-0.1	-0.2
	Winter total	0.1%	0.2%	0.2%	0.0%	0.1%	0.1%	0.0	0.1	0.4

Table 4.2b: Total 2025 Energy Changes (MWh) by Utility, Scenario, and Pricing Period

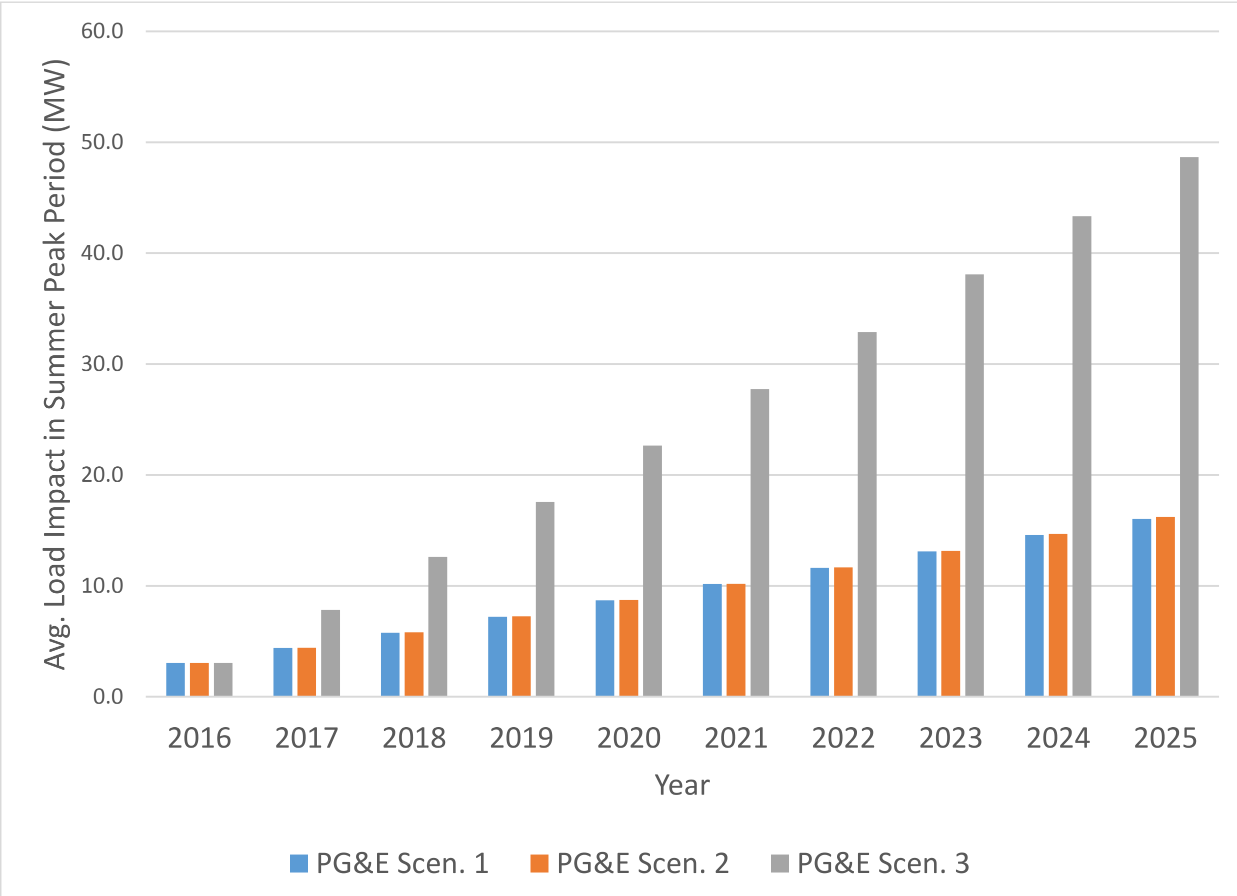
Season	Pricing Period	Scen. 1	Scen. 2	Scen. 3
PG&E				
Summer	Off-peak	5,234	-1,383	-4,150
	Partial-peak	-6,238	n/a	n/a
	Peak	**-12,418**	**-6,812**	**-20,435**
	Summer total	-13,422	-8,195	-24,585
Winter	Off-peak	3,300	3,477	10,432
	Peak/Partial-peak	226	287	860
	Winter total	3,526	3,764	11,291
SCE				
Summer	Super Off-peak	10,896	10,896	32,687
	Off-peak	-2,437	-2,437	-7,310
	Peak	**-16,259**	**-16,259**	**-48,777**
	Summer total	-7,800	-7,800	-23,400
Winter	Super Off-peak	5,281	5,281	15,842
	Off-peak	574	574	1,722
	Peak	-4,522	-4,522	-13,566
	Winter total	1,333	1,333	3,999
SDG&E				
Summer	Off-peak	825	1,003	3,009
	Semi-peak	-421	-519	-1,558
	Peak	**-1,577**	**-1,565**	**-4,694**
	Summer total	-1,173	-1,081	-3,243
Winter	Off-peak	189	237	710
	Semi-peak	-11	226	678
	Peak	-78	-39	-116
	Winter total	101	424	1,272

Recall that the reference loads in the simulation varied across years, with the load shape changing due to increasing adoption of residential solar installations. Given those changes, it is interesting to note that the simulated percentage load impacts are essentially constant across the years of the study. That is, the changes in the residential load profiles are not large enough to affect the simulated percentage load impacts. Therefore, the only material change across years in each Utility/scenario combination is the TOU participation rate. We assume that TOU participation begins at 2 percent in 2016 and increases linearly to its maximum value (10 percent in Scenarios 1 and 2, and 30 percent in Scenario 3) by 2025.

Average Summer Peak-period Load Impacts

Figures 4.1 through 4.3 illustrate the average summer peak-period load impact by utility, expressed in megawatts. The growth across years represents a combination of exogenous load changes (due to changing numbers of customers or increasing PV adoption) and increasing participation in the TOU rates. Again, the percentage load impacts that underlie these figures do not change (or change very little) across years within each Utility/scenario combination.[16]

Figure 4.1: Average Load Impact during Summer Peak Period (MW), *PG&E*



[16] The reference loads consist of 8,760 hours of data. We can provide a load impact for each of these hours, but the percentage load impacts shown in Table 4.2 represent the most detailed level at which the results vary (for non-holiday weekdays).

Figure 4.2: Average Load Impact during Summer Peak Period (MW), *SCE*

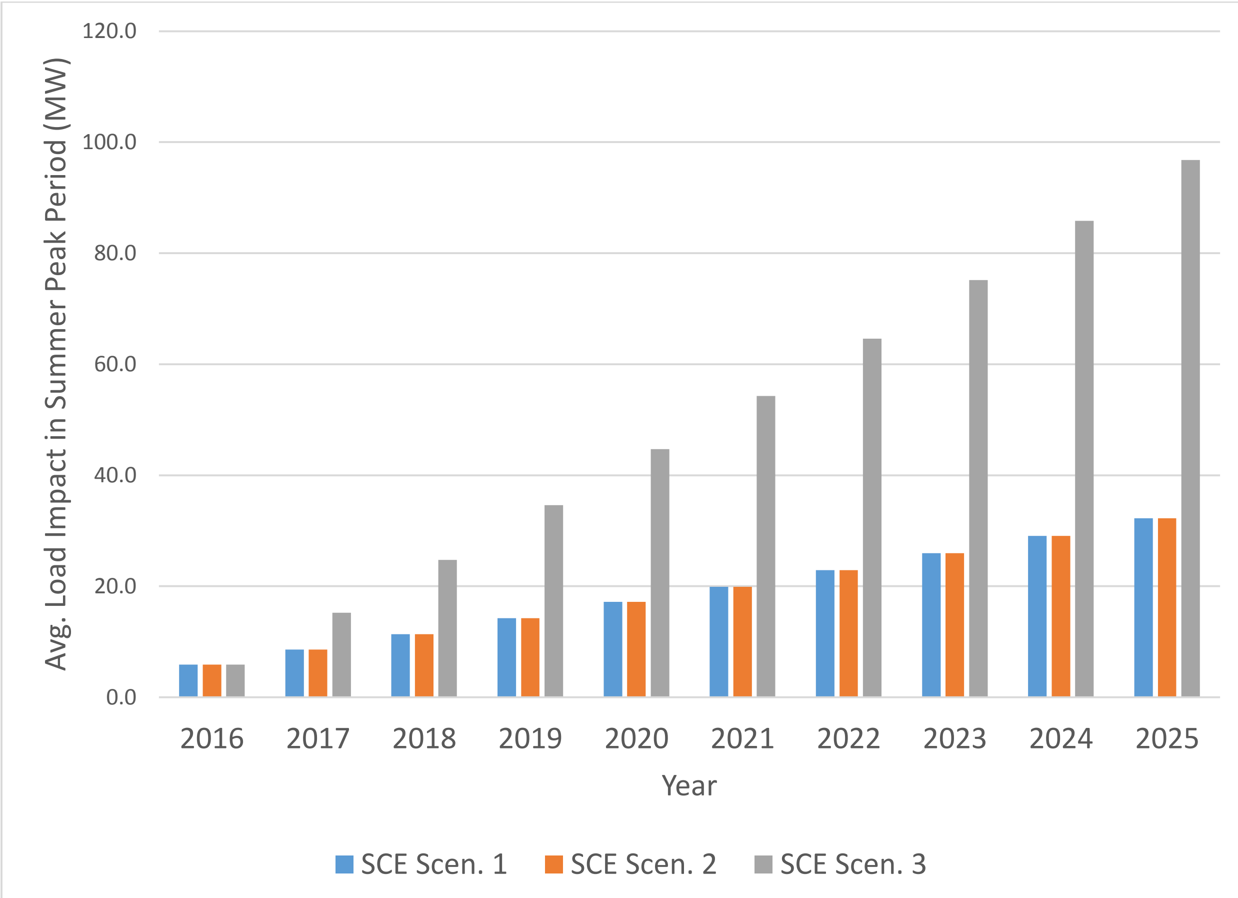
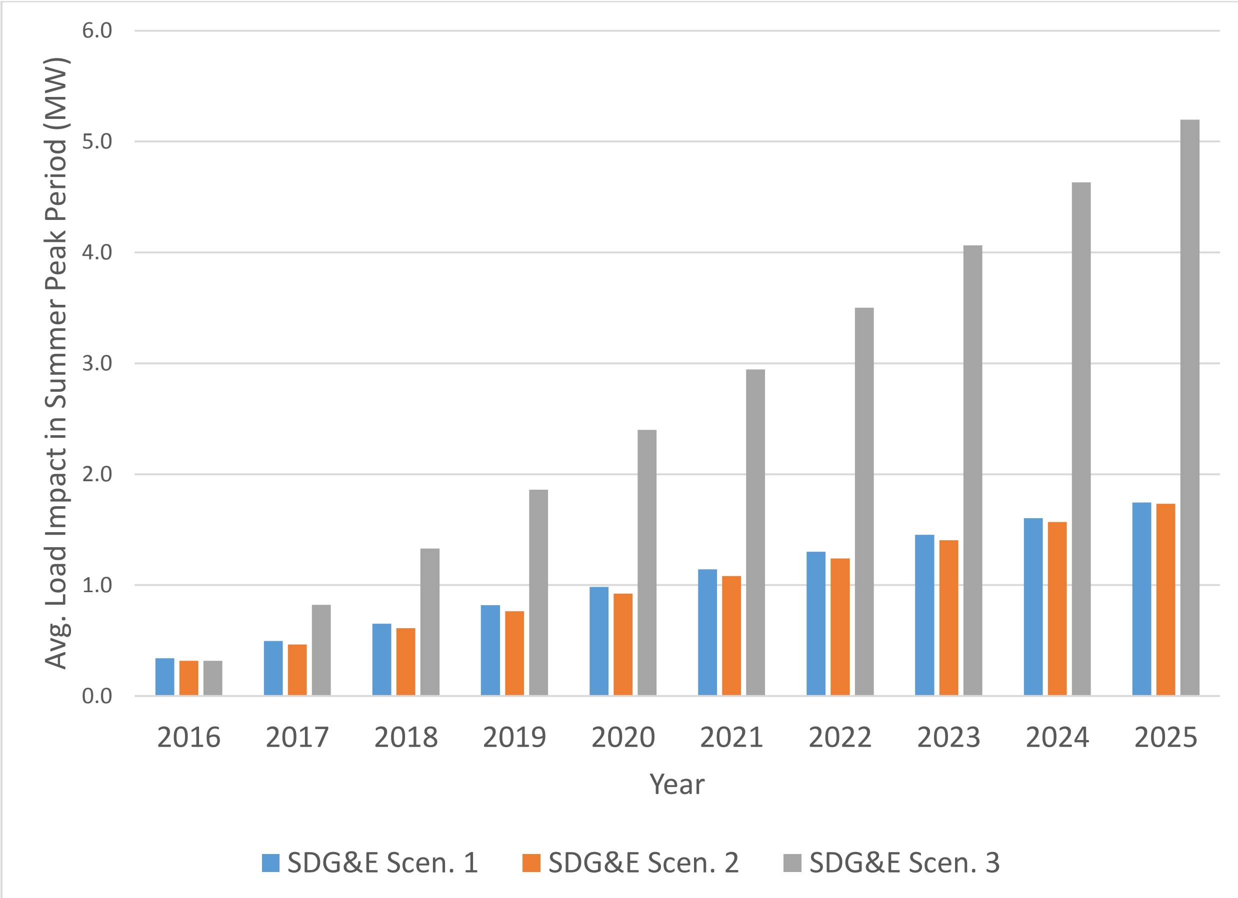


Figure 4.3: Average Load Impact during Summer Peak Period (MW), *SDG&E*



Average Annual Residential Peak Demand Reduction

Another potential outcome of interest is the effect of TOU pricing on annual residential peak demand.[17] Figures 4.4 through 4.6 show the simulated reduction in peak demand for each utility, year, and scenario. For the most part the patterns are consistent with the summer peak demand figures (Figures 4.1 through 4.3), but the MW load reductions are higher, reflecting the higher load levels during the peak demand hour. The exception is the SDG&E Scenario 1 load reduction, which is low relative to the result for Scenario 2. This is because the peak hour falls in the hour after the on-peak period ends in the Scenario 1 TOU rate, so the TOU load impact is relatively low in that hour. In Scenario 2, the peak hour falls in the on-peak period.[18] The data contained in the figures is shown in Table 4.3.[19]

[17] The peak hour is specific to each utility's residential profile (*i.e.*, it is the profile-specific non-coincident peak). Here are the hours by utility: PG&E: August 13th, hour-ending 19; SCE: August 13th, hour-ending 18; SDG&E: September 14th, hour-ending 19.

[18] The Scenario 1 load impact for the hour before the peak (which is in the on-peak TOU pricing period) is 3.4 MW in 2025 (compared to 0.6 MW in the peak hour for Scenario 1 and 2.8 MW during the peak hour for Scenario 2).

[19] The Appendix includes a version of this table that shows peak-hour reductions for the coincident peak across the three utilities.

Figure 4.4: Peak-hour Load Impact (MW), *PG&E*

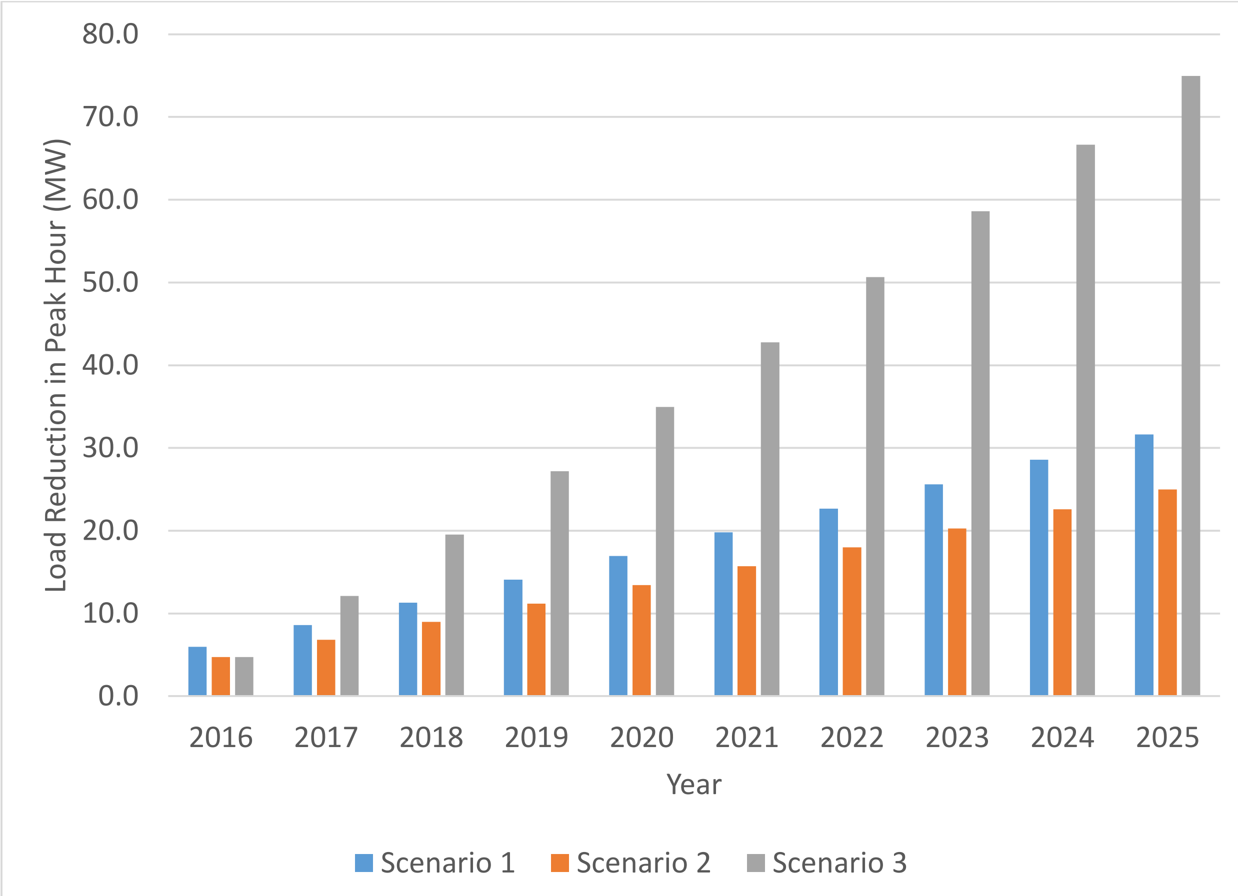


Figure 4.5: Peak-hour Load Impact (MW), *SCE*

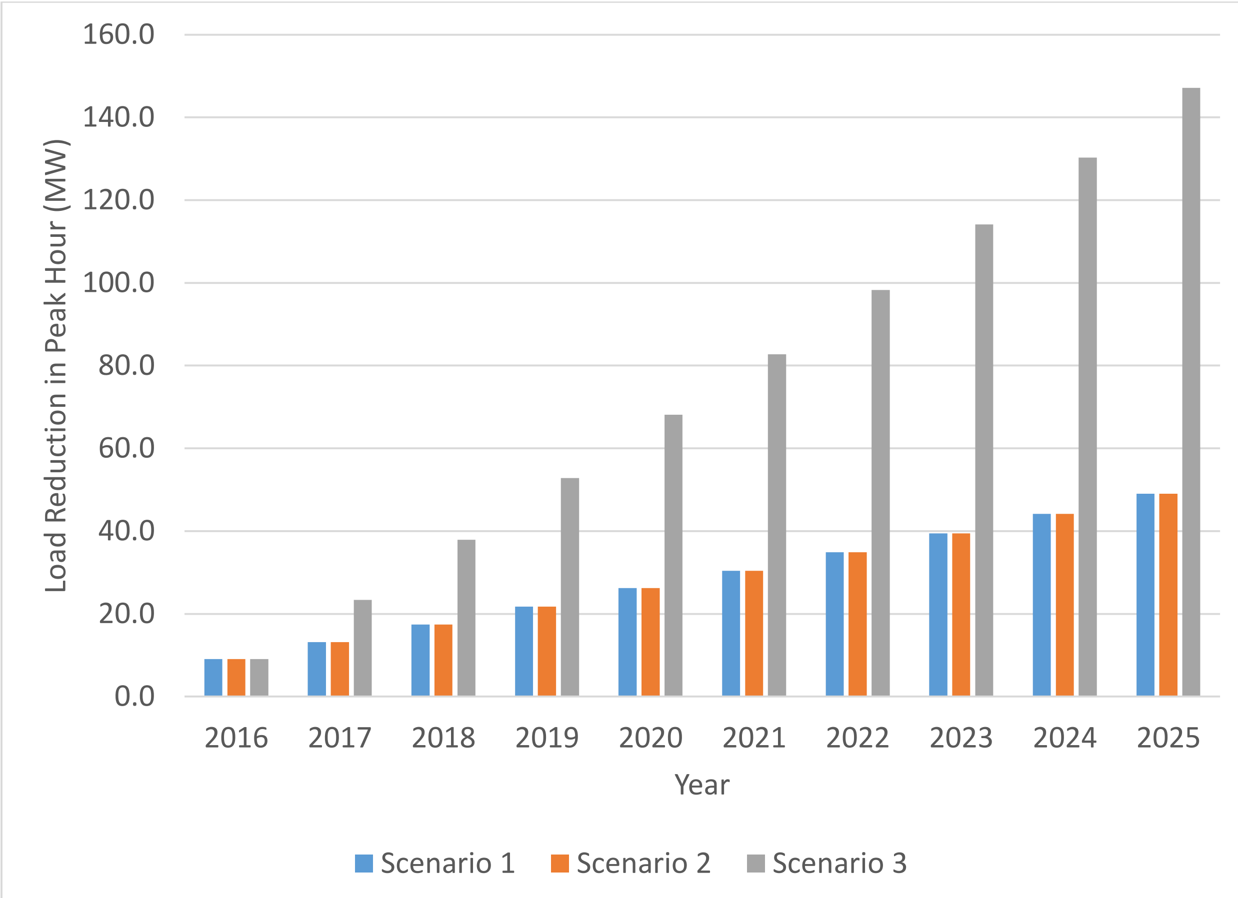


Figure 4.6: Peak-hour Load Impact (MW), *SDG&E*

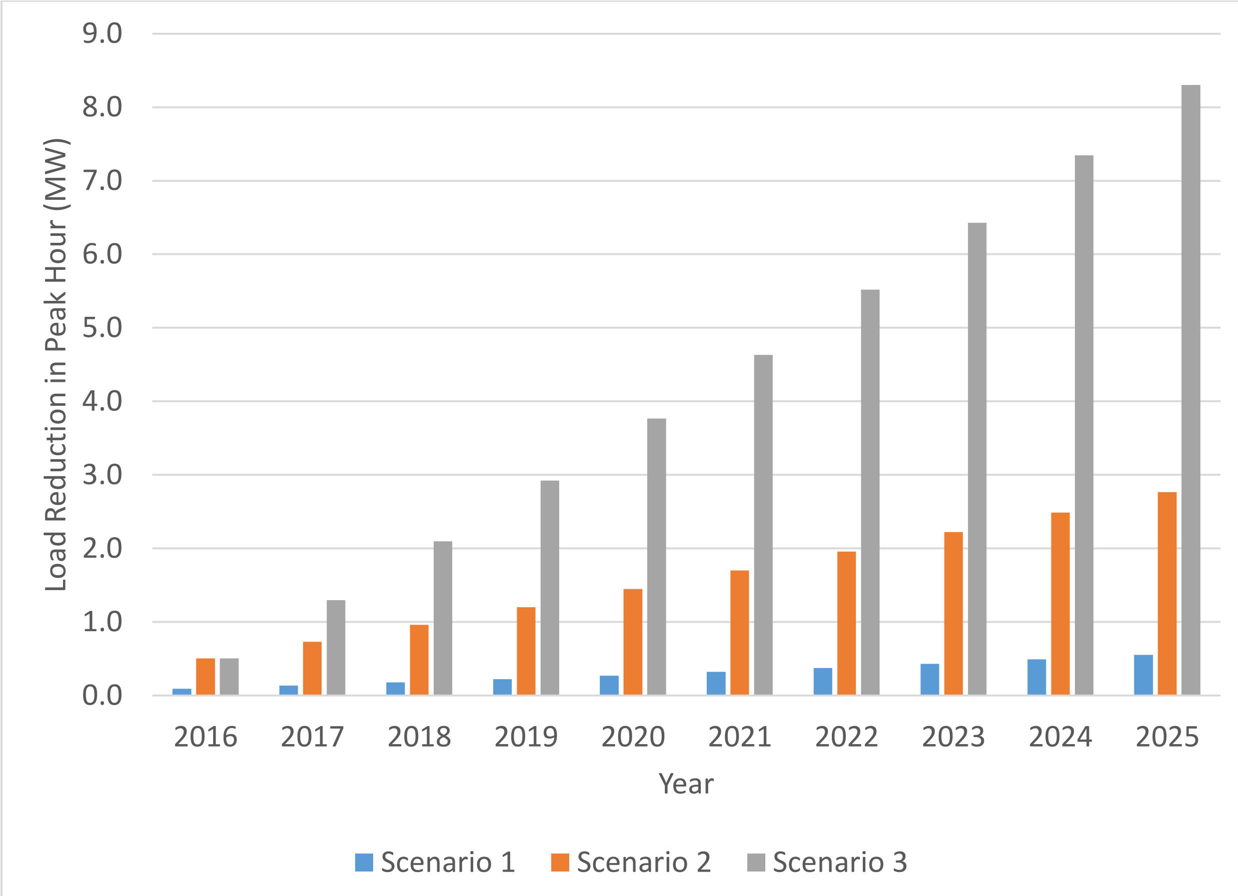


Table 4.3: Residential Peak-hour Load Changes by Utility, Scenario, and Year

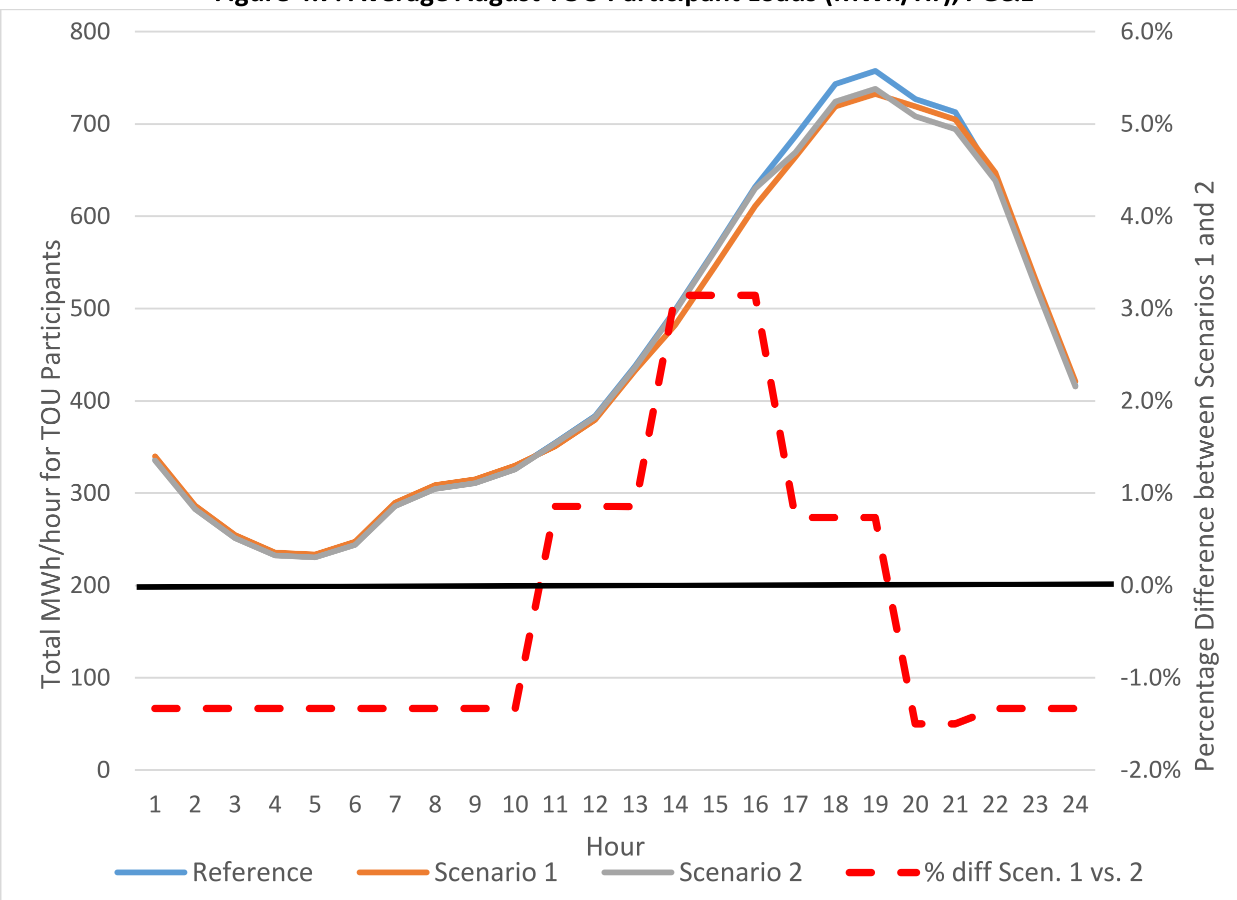
Year	PG&E			SCE			SDG&E		
	Scen 1	Scen 2	Scen 3	Scen 1	Scen 2	Scen 3	Scen 1	Scen 2	Scen 3
2016	5.9	4.7	4.7	9.1	9.1	9.1	0.1	0.5	0.5
2017	8.6	6.8	12.1	13.2	13.2	23.3	0.1	0.7	1.3
2018	11.3	9.0	19.5	17.4	17.4	37.9	0.2	1.0	2.1
2019	14.1	11.2	27.2	21.8	21.8	52.8	0.2	1.2	2.9
2020	16.9	13.4	34.9	26.2	26.2	68.1	0.3	1.4	3.8
2021	19.8	15.7	42.8	30.4	30.4	82.7	0.3	1.7	4.6
2022	22.7	18.0	50.6	34.9	34.9	98.3	0.4	2.0	5.5
2023	25.6	20.3	58.6	39.5	39.5	114.2	0.4	2.2	6.4
2024	28.6	22.6	66.7	44.1	44.1	130.3	0.5	2.5	7.3
2025	31.6	25.0	75.0	49.0	49.0	147.1	0.6	2.8	8.3

Change in Residential Load Profile
Figure 4.7 shows an example of how customers' hourly load profile is affected by the change in the TOU period definitions and price levels. This figure shows average August weekday usage for PG&E TOU participant loads in the Reference case, Scenario 1, and Scenario 2. The dashed red line indicates the percentage difference between the Scenario 1 and 2 loads.

The changes in the load profile from Scenario 1 to 2 reflect the differences in the rates and pricing periods. Off-peak prices are lower in Scenario 1, leading to the reduction in Scenario 2 loads during those hours. The hours that were peak hours in the Scenario 1 TOU rate but are no longer peak hours in Scenario 2 (1 p.m. to 4 p.m.) experience usage *increases* in Scenario 2. Loads changes very little during the hours that are in the peak period for both TOU rates (4 p.m. to 7 p.m.). Finally, customer usage *decreases* in Scenario 2 for the new peak hours from 7 p.m. to 9 p.m. The magnitude of the changes across Scenarios is relatively small, ranging from 0.7 to 3.1 percent (in absolute value).

Note that this figure only includes TOU participant loads. The percentage effects on the total residential load are much smaller, as 90 percent of the residential customers in the scenario considered are not on the TOU rate.

Figure 4.7: Average August TOU Participant Loads (MWh/Hr), *PG&E*



4.3 TOU load impacts with target marketing

The Energy Division requested that we examine a scenario in which the Utilities target market the TOU rates in the hotter climate zones that contain (on average) more responsive customers. Because the SPP estimates upon which we have based our primary (base) analysis are differentiated by climate zones, we can explore the effect of TOU target marketing through a relatively minor adjustment to our methods. Specifically, we simulate a somewhat extreme example of target marketing in which all opt-in TOU customers come from the hottest (and most demand responsive) climate zones.

The SPP divided customers into four climate zones. Zones 1 and 2 are largely coastal areas with milder weather, while zones 3 and 4 are mostly inland areas with hotter weather. Separate elasticity values were estimated for each climate zone. The summer elasticity of substitution estimates were notably higher in zones 3 and 4 relative to zones 1 and 2, but the other elasticities (daily elasticities and winter elasticities of substitution) did not display much variation across the climate zones.

Table 4.4 shows the SPP summer ES values by climate zone in the second column. The three columns to the right contain approximate shares of population by climate zone for each Utility. Notice that only about a quarter of PG&E's customers live in the hotter climate zones, which raises questions about the plausibility of the 30 percent enrollment assumption (in Scenario 3) under target marketing. Even for SDG&E, obtaining a 30 percent participation rate from only the hottest climate zones would require approximately 78 percent of the eligible customers to enroll in the TOU rate (78 percent = 30 percent / 38.6 percent).

The second-to-bottom row of Table 4.4 shows the weighted average ES value across only Zones 3 and 4, which are the basis of our target marketing scenario. The bottom-row ES values are used in the base analysis described in Section 4.2. Based on a comparison across these two rows, we expect PG&E to have the largest simulated increase in load impacts due to target marketing. This is because SCE and SDG&E already had a higher percentage of customers in the hotter climate zones in the base analysis, so there's relatively less to be gained from target marketing in those service territories.

Table 4.4: SPP Summer Elasticities of Substitution and Utility Population Shares by SPP Climate Zone

Zone	SPP Summer ES Estimates	Share of Population by Zone		
		PG&E	SCE	SDG&E
1	0.034	34.7%	0.0%	0.0%
2	0.055	39.4%	42.8%	61.4%
3	0.093	13.0%	47.6%	38.6%
4	0.105	13.0%	9.7%	0.0%
% of Pop. in 3 & 4		**25.9%**	**57.2%**	**38.6%**
Weighted Avg. ES for zones 3 & 4		**0.099**	**0.095**	**0.093**
Weighted Avg. ES for all zones		**0.059**	**0.078**	**0.070**

Table 4.5 summarizes all of the elasticities used in the target marketing scenario. Only the summer ES values are changed relative to Table 4.1, but this table illustrates the CARE and non-CARE ES values that correspond to the higher overall ES values.[20]

Table 4.5: Elasticity Values used in the Residential TOU Study, Assuming Target Marketing

Utility	Customer Group	Summer		Winter	
		Substitution	Daily	Substitution	Daily
PG&E	All	0.099	0.040	0.025	0.020
	Non-CARE	0.114	0.046	0.029	0.023
	CARE	0.057	0.023	0.014	0.012
SCE	All	0.095	0.040	0.025	0.020
	Non-CARE	0.110	0.046	0.029	0.023
	CARE	0.055	0.023	0.015	0.012
SDG&E	All	0.093	0.040	0.025	0.020
	Non-CARE	0.102	0.044	0.027	0.022
	CARE	0.051	0.022	0.014	0.011

Figures 4.8 through 4.10 illustrate the average summer peak-period load impact by utility (in MW) using the elasticity values contained in Table 4.5. These can be compared to Figures 4.1 through 4.3, which use the base case elasticity values in Table 4.1.[21]

[20] Note that we have applied the same share of CARE customers to the target marketing scenario as we did in our base analysis. However, PG&E has a higher share of CARE customers in its hotter climate zones. Specifically, approximately 25 percent of its residential customers are CARE customers across its entire service territory, but approximately 36 percent of the customers in PG&E's hottest climate zones are CARE customers. This difference in CARE customer shares by climate zone may be properly reflected in the SPP estimates, but we cannot be sure because the SPP does not report the share of CARE customers by climate zone (and our interpretation of the report is that the SPP sample was not selected to be representative of CARE customer shares by climate zone).

[21] Note that both the base analysis and this target marketing variant are based on dynamic load profiles that represent all residential customers. Opt-in TOU rates, particularly when target marketed, are likely to lead to load profiles that differ from the class average.

Figure 4.8: Average Load Impact during Summer Peak Period (MW), *PG&E w/ Target Marketing*

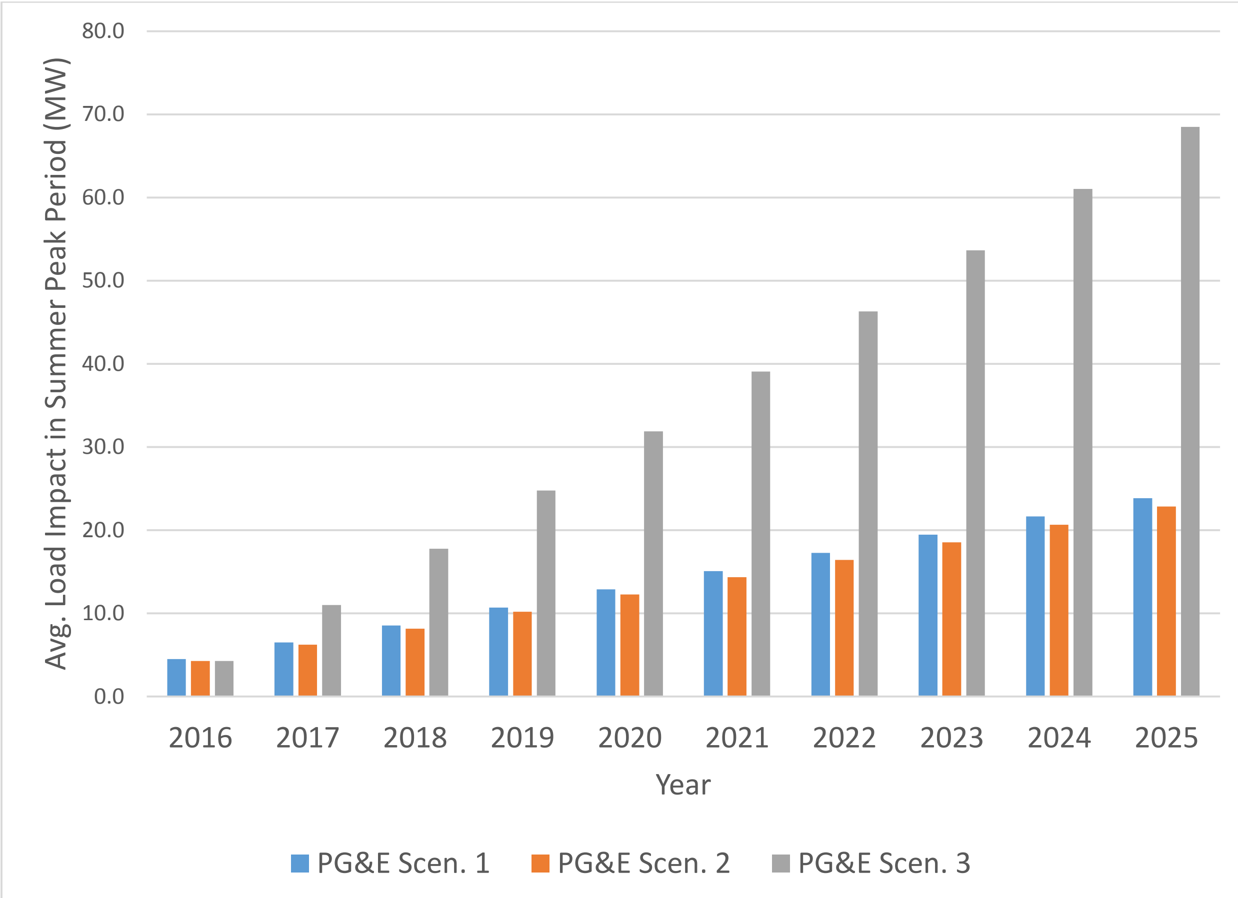


Figure 4.9: Average Load Impact during Summer Peak Period (MW), *SCE w/ Target Marketing*

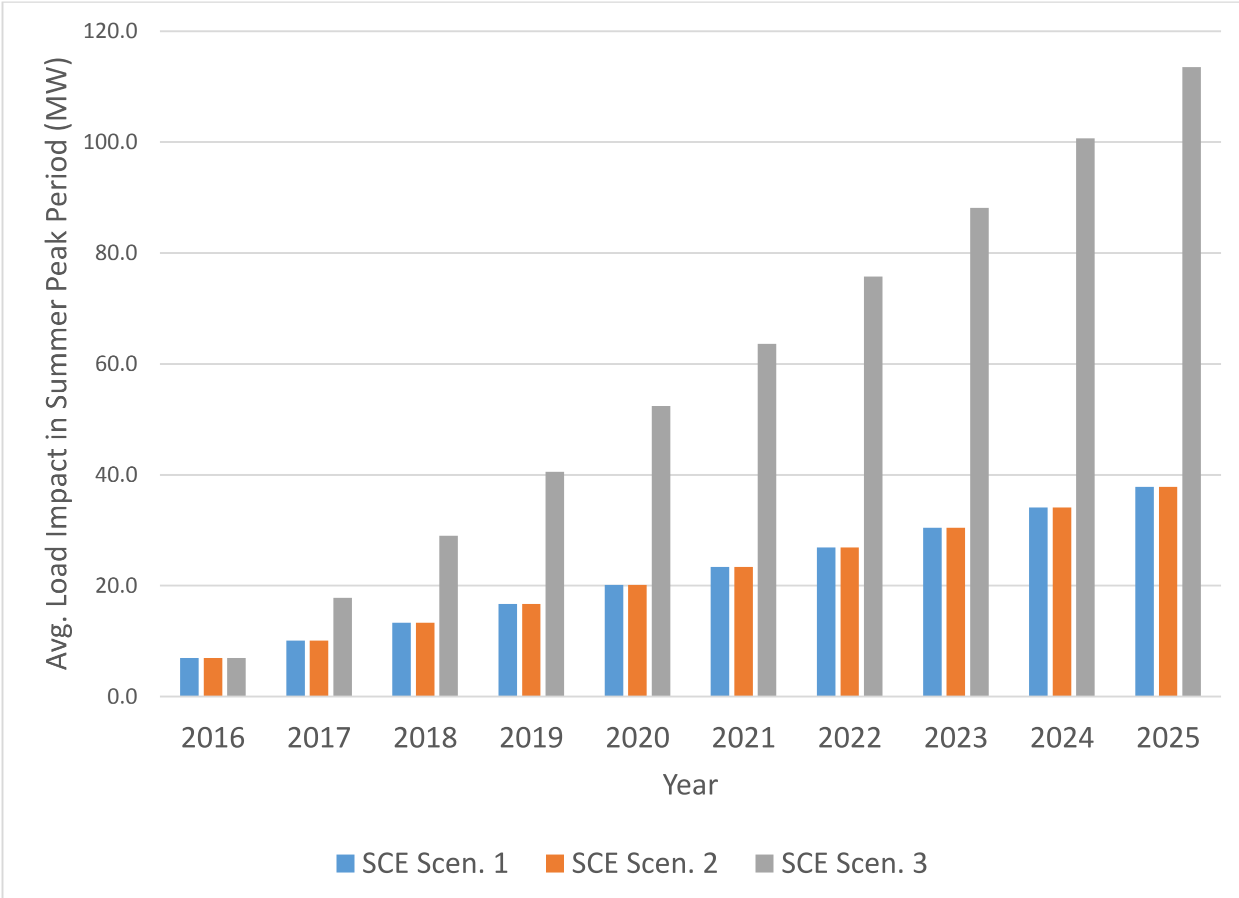
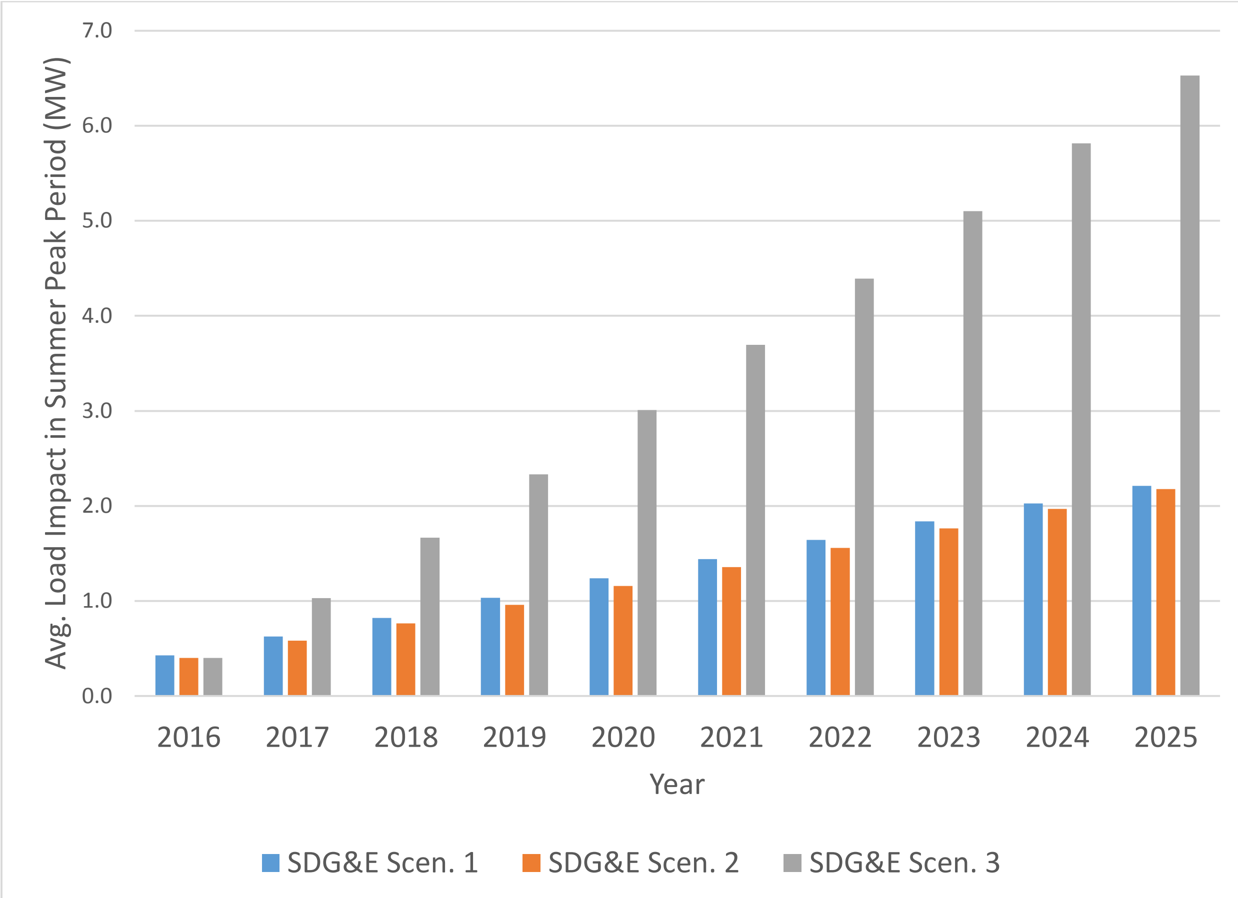


Figure 4.10: Average Load Impact during Summer Peak Period (MW), *SDG&E w/ Target Marketing*



The percentage difference between the base case and target marketing load impacts is nearly the same across years (within Utility and scenario). The approximate percentage increases in load impacts due to target marketing are as follows:

1. PG&E: 48 percent in scenario 1, 41 percent in scenarios 2 and 3;
2. SCE: 17 percent in all scenarios; and
3. SDG&E: 26 percent in scenario 1, 25 percent in scenarios 2 and 3.

Note that the target marketing scenarios constructed here are likely to overstate the benefits of target marketing because we assume the utilities are able focus *all* TOU enrollment in the climate zones that are expected to have the highest TOU demand response. In reality, it is likely that some customers who are in milder climate zones will opt into the TOU rates and that there may be limits on the share of opt-in TOU customers in the hotter climate zones. However, we are still simulating load impacts within the confines of the SPP estimates, which are lower than the estimates from some other studies (*e.g.*, the SMUD study that estimated an ES of 0.14[22]).

[22] It is worth pointing out that the peak period in the referenced SMUD study was only three hours long while our simulated peak periods are five to seven hours in duration. It should be easier for customers to shift usage out of shorter peak periods, which would tend to increase the estimated ES. We are also not able to control for potential

5. SMALL AND MEDIUM COMMERCIAL AND INDUSTRIAL TOU LOAD IMPACTS

The Utilities are in the process of transitioning small (under 20kW) and medium (20 to 200kW) commercial and industrial customers to TOU rates. One goal of the present study is to simulate the changes in load impacts that may occur under an alternative definition of TOU pricing periods (and the associated rates).

To date, three studies have been conducted of the estimated load impacts from these customers: two studies of PG&E customers who were transitioned to TOU rates prior to program years 2013 and 2014 (respectively; and a study of SCE customers who were transitioned to TOU rates prior to program year 2014.

The findings from these studies indicate that customers have not responded in a manner consistent with economic price theory (*i.e.*, reducing usage in newly higher-price peak hours). Rather, customers appear to respond by conserving in roughly equal percentages across the pricing periods, perhaps reflecting increased energy awareness due to participation in the transition process.

Because of this research finding, we do not conduct a separate analysis of the change in load impacts for small and medium C&I customers under the proposed TOU pricing periods. We believe the current evidence does not provide any evidence that customers will change their behavior as the TOU rates and pricing periods are changed (in Scenarios 2 and 3). We therefore refer readers to the ex-ante load impact studies from the most recent load impact studies as the most relevant source of TOU load impacts in all scenarios.[23,24]

The remainder of this section provides a comparison of the three studies listed above for SCE's and PG&E's non-residential customers, and why the results imply that modifying the TOU rates will have no effect.

Because PG&E first transitioned its SMB customers to TOU rates a year earlier than SCE, two studies have been conducted for its non-residential TOU rates versus one for SCE's non-residential TOU rates.[25] Note that the two PG&E studies defined the customer groups somewhat differently. In the PY2013 study, the study was divided by rate (A1 and A10), whereas the PY2014 study divided customers into size groups (under 20kW and 20 to 200 kW).

---

differences between the central AC saturation rate in SMUD's service territory and the hotter climate zones in PG&E's, SCE's, and SDG&E's service territories.

[23] "2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: Ex-post and Ex-ante Report", Hansen and Patton, April 2015.

[24] "2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: Ex-post and Ex-ante Report", Hansen and Patton, April 2015.

[25] Differences in results across studies are not likely to be due to differences in methodology, since all three studies used essentially the same methods.

For simplicity, this memo focuses on the load impacts on summer weekdays. Specifically, we describe the effect of TOU rates on the peak to off-peak usage ratio for each rate class. Customer response to TOU price signals should (in theory) be reflected by a reduction in the peak to off-peak usage ratio as customers shift usage away from the costlier time period toward the less costly time period.

Table 5.1 compares the results across three studies (one for SCE, two for PG&E) for the small C&I customers. The first row shows the peak to off-peak price ratio.[26] Notice that SCE implemented a much larger difference between peak and off-peak prices than PG&E, which we would expect to lead to larger changes in the peak to off-peak usage ratio. However, the estimates are not consistent with our expectations, in that they indicate that SCE's high TOU price ratio didn't affect the TOU usage ratio at all (*i.e.*, it was 2.28 before and after the implementation of TOU rates). In contrast, the PY2013 study of PG&E's A1 customers showed a reduction in the TOU usage ratio despite the comparatively flat TOU prices. This result was not replicated in PY2014 when the analysis focused on PG&E's under 20kW customers (some of which were A1 customers and some of which were A10 customers), where we found no change in the TOU usage ratio. The bottom row of the table shows the average kWh per customer during summer peak hours, which just provided a means of comparing customer sizes across utilities and studies.

Table 5.1: Comparison of Summer TOU Load Impacts, Small C&I Customers

Variable	SCE GS-1 (2014)	PG&E A1 (2013)	PG&E Under 20kW (2014)
P/O Price	2.93	1.16	1.17
P/O kWh, pre-TOU	2.28	2.23	2.02
P/O kWh, TOU	2.28	2.19	2.02
Avg. summer peak kWh	1.96	2.96	2.28

Table 5.2 provides the same comparison for medium-sized C&I customers. Once again, SCE had a significantly larger difference between peak and off-peak TOU prices, but the estimated effect of TOU pricing on the usage ratio is nearly the same in all three studies (*i.e.*, very little change).[27]

[26] SCE calls peak hours "on peak" in its TOU tariffs.

[27] The PY2014 estimates for PG&E's 20 to 200kW customers were sensitive to the methodology used to match TOU customers to control customers. A reasonable alternative method led to estimated TOU load *increases* in all pricing periods, versus the estimated TOU load decreases upon which Table 5.2 is based. In either case, there was little estimated effect of TOU pricing on the peak to off-peak usage ratio.

Table 5.2: Comparison of Summer TOU Load Impacts, Medium C&I Customers

Variable	SCE GS-2 (2014)	PG&E A10 (2013)	PG&E 20 to 200 kW(2014)
P/O Price	2.13	1.20	1.22
P/O kWh, pre-TOU	2.07	1.93	2.06
P/O kWh, TOU	2.07	1.94	2.07
Avg. summer peak kWh	29.19	29.67	16.16

Table 5.3 shows the estimated load impacts from PG&E's and SCE's PY2014 studies of its small and medium C&I customers that had been transitioned to TOU rates in the prior year. The highlighting indicates the pricing period definitions for each group of customers. These estimates show that peak-period load impacts were not generally higher (in percentage terms) than the load impacts in other pricing periods. Furthermore, the small C&I load impacts are not very different for SCE and PG&E despite the fact that the SCE's TOU rate had a much higher peak to off-peak price ratio.

Table 5.3: Hourly TOU Load Impact Estimates by Utility and Customer Group

Hour	SCE Small C&I	SCE Medium C&I	PG&E Small C&I	PG&E Medium C&I
1	-2.70%	-0.50%	-2.00%	-2.70%
2	-2.90%	-0.80%	-2.20%	-2.40%
3	-2.60%	-0.90%	-1.60%	-2.90%
4	-3.70%	-1.00%	-1.80%	-2.80%
5	-3.00%	0.00%	-0.90%	-2.70%
6	-3.50%	-0.40%	-1.30%	-2.50%
7	-0.60%	-0.50%	-3.30%	-3.10%
8	-2.60%	-0.50%	-2.70%	-2.40%
9	-2.60%	0.10%	-3.00%	-2.10%
10	-2.60%	0.00%	-2.90%	-2.00%
11	-2.40%	-0.20%	-2.70%	-2.10%
12	-2.60%	-0.60%	-2.60%	-2.10%
13	-2.70%	-0.30%	-2.60%	-2.20%
14	-3.10%	-0.40%	-2.20%	-2.30%
15	-2.80%	-0.40%	-2.00%	-2.20%
16	-2.50%	-0.40%	-1.90%	-2.40%
17	-2.60%	-0.30%	-1.80%	-2.60%
18	-2.20%	-0.30%	-2.00%	-2.50%
19	-2.10%	-0.10%	-2.20%	-2.30%
20	-3.10%	-0.20%	-2.40%	-2.50%
21	-3.90%	-0.50%	-2.80%	-2.90%
22	-3.80%	-0.60%	-2.20%	-2.20%
23	-3.60%	-1.00%	-2.20%	-2.30%
24	-2.80%	-1.40%	-2.10%	-2.80%
Peak	**-2.60%**	**-0.40%**	**-2.10%**	**-2.40%**
Part Peak	**-3.00%**	**-0.40%**	**-2.50%**	**-2.30%**
Off Peak	**-2.70%**	**-0.70%**	**-2.10%**	**-2.60%**

Some comments and observations:

- The estimates consistently reflected load reductions in all pricing periods following the implementation of TOU pricing.
- The estimates typically do not find large (or any) changes in the ratio of usage in peak to off-peak hours.
- SCE implemented TOU rates that had much larger differences between peak and off-peak prices than PG&E, but the estimated changes in loads do not reflect changes in customer behavior that are consistent with this notable difference in the price signals across utilities (*i.e.*, shifting usage away from more costly hours toward less costly hours, with larger shifts expected as the relative price differences across periods increases).
- In our opinion, the estimated TOU load impacts look more like all-hours conservation that may have been induced by an increase in overall energy awareness from the transition to TOU rates.

6. LARGE COMMERCIAL AND INDUSTRIAL TOU LOAD IMPACTS

In this section, we address the change in TOU load impacts for C&I customers as the TOU peak period definition changes (in Scenarios 2 and 3). In general, these customers have been on TOU rates for many years, so their TOU demand response is “embedded” in the Utility’s load profile. However, one might expect the load profile for these customers to change after their rate structure is modified.

Because these customers have been on TOU rates for many years, it is difficult to estimate their load impacts in response to TOU rates. That is, we can’t conduct a before vs. after analysis (“before” happened too long ago to be practical or useful) nor can we conduct a treatment vs. control-group analysis because all of the comparable customers are required to be on a TOU rate.

In response to these difficulties, we conducted two types of analyses. In the first, we attempted to estimate TOU demand response for SDG&E C&I customers by comparing summer and winter usage patterns. That is, we focused on the months surrounding the TOU pricing season changes (April, May, October, and November) in an attempt to estimate differences in seasonal load profiles that one could attribute to TOU demand response.

In the second analysis, we simulated the change in embedded TOU demand response under the proposed TOU pricing periods using assumed elasticity values. This method provides an approximation of TOU demand response in the absence of the ability to estimate it. Each of these methods is described in detail below.

6.1 Estimates of embedded TOU load impacts using SDG&E data

In this analysis, we used hourly load data provided by SDG&E in an attempt to estimate TOU demand response to seasonal changes in TOU prices and pricing periods. For example, because the summer on-peak period is longer (and somewhat higher priced) than the winter on-peak period, one might expect that the change from winter to summer TOU prices would result in a change in customer load profiles as they shift usage out of the longer summer on-peak period and into less costly TOU pricing periods.

SDG&E provided aggregate hourly load data by rate and customer type (commercial versus industrial) to allow us to test this hypothesis. In order to focus on the months with the most similar weather and operating conditions, we limited the analysis to the months before and after the TOU seasonal pricing change: April, May, October, and November. The data include those months from October 2013 through May 2015.

The customer groups included in the study are:

1. Commercial AL-TOU customers
2. Commercial AL-TOU customers on CPP
3. Commercial AY-TOU customers
4. Commercial AY-TOU customers on CPP
5. Industrial AL-TOU customers

6. Industrial AL-TOU customers on CPP

We restricted our analysis to non-holiday weekdays and focused our attention on one time period: 11 a.m. to 5 p.m. These hours are in the on-peak period during the summer months, but in the semi-peak period during winter months, thus creating a large price difference across seasons for those hours. We would expect the ratio of usage during this time period to the other periods of the day to be lower in summer than winter, controlling for temperatures and year and day-of-week effects (*i.e.*, allowing each year and day of week to have its own average usage level).

Rather than directly estimating an elasticity of substitution, we first estimated whether the usage ratio described above (11 a.m. to 5 p.m. average usage divided by the average usage during the rest of the day, on non-holiday weekdays) is statistically significantly different in summer months than in winter months, controlling for the temperature ratio for those same periods and year and day-of-week effects. We estimated a separate model for each of the six customer groups listed above.

$$kWhRat_{t,g} = a + b_{TempRat} \times TempRat_t + b_{Summer} \times Summer_t + b_{2014} \times D2014_t$$
$$+ b_{2015} \times D2015_t + \sum_{i=2}^{5} b_{DayTypei} \times DayType_{i,t} + e_t$$

Table 6.1 describes the variables in the equation.

Table 6.1: Variables included in Embedded TOU Regression Model

Variable or Parameter Name	Definition
$kWhRat_{t,g}$	The ratio of average usage from 11 a.m. to 5 p.m. to other all hours of the day on day *t* for customer group *g*
a	The constant term
b parameters	Estimated coefficients
$TempRat_t$	The ratio of average temperature from 11 a.m. to 5 p.m. to all other hours of the day on day *t*
$Summer_t$	Indicator for whether the day *t* is in the summer TOU pricing period
$D2014_t$	Indicator for whether day *t* is in 2014
$D2015_t$	Indicator for whether day *t* is in 2015
$DayType_{i,t}$	Indicator for whether day *t* is day type *i* (1 = Monday, … 5 = Friday)[28]
e_t	The error term

Our estimates did not find a statistically significant difference in the summer usage ratio relative to the winter usage ratio (that is b_{Summer} was not statistically significantly different from

[28] Monday is the excluded day type in the equation. The data set only includes non-holiday weekdays.

zero).[29] That is, we do not find evidence of customer TOU demand response across seasons. Given the limitations of our study, we would not conclude that these customers are unaffected by TOU rates, rather that the extent of the TOU demand response is likely to be modest and therefore difficult to detect using the available data.

6.2 Simulations of embedded TOU load impacts for PG&E, SCE, and SDG&E

In this section, we describe the results of simulations of the change in C&I customer load profiles in response to the proposed changes in TOU pricing periods. We conduct the simulations in two steps:

1. Simulate the change in the load profile as customers change from current TOU rates to an equivalent flat rate; and
2. Simulate the change in the load profile as customers change from the constructed flat rate to the proposed TOU rates.

The difference between the TOU load profile constructed in the second step and the observed TOU load profile (which is the starting point of the first step) represents the simulated change in TOU load impacts due to changing the TOU pricing period definition.

To conduct the simulations, we apply the same three-period CES model used to simulate residential TOU load impacts. Setting the TOU rates is complicated by the presence of demand charges. Where applicable, we convert demand charges to "effective energy charges" (EECs) by dividing the monthly demand charge by the number of hours to which it applies (*e.g.*, for a demand charge that applies only to on-peak hours, we divide the $/kW rate by the number of peak hours in the month). The EECs by pricing period are added to the corresponding energy rates to form the total TOU rates.

For PG&E and SCE, TOU rates are based on current tariffs and we assumed that TOU rates remain the same under the proposed TOU pricing periods. For SDG&E, we obtained "present" and "proposed" TOU rates from SDG&E's RDW filing.[30]

The ES values were based on a study of PG&E's embedded TOU response conducted for PY2011[31], which were subsequently adapted for use in the PY2013[32] and PY2014[33] embedded TOU load impact studies. Appendix K of the PY2013 study shows the estimated ES values by

[29] We also estimated a model using the *level* of usage during 11 a.m. to 5 p.m. as the dependent variable, with the average temperature during those hours as an explanatory variable. These results also found no statistically significant difference in usage during the summer months.
[30] Specifically, we used AL-TOU Secondary rates contained in Revised Attachments A and B of Cynthia Fang's revised direct testimony dated February 24, 2014.
[31] "2011 Ex Ante Load Impacts for PG&E's Non-residential TOU Rates", George, Bode, Holmberg, and Malaspina, June 2012.
[32] "2013 Evaluation of PG&E's Mandatory TOU Rates for Small and Medium Non-residential Customers", Bode and Cook, April 2014.
[33] "2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers", Hansen and Patton, April 2015, CALMAC ID PGE0354.

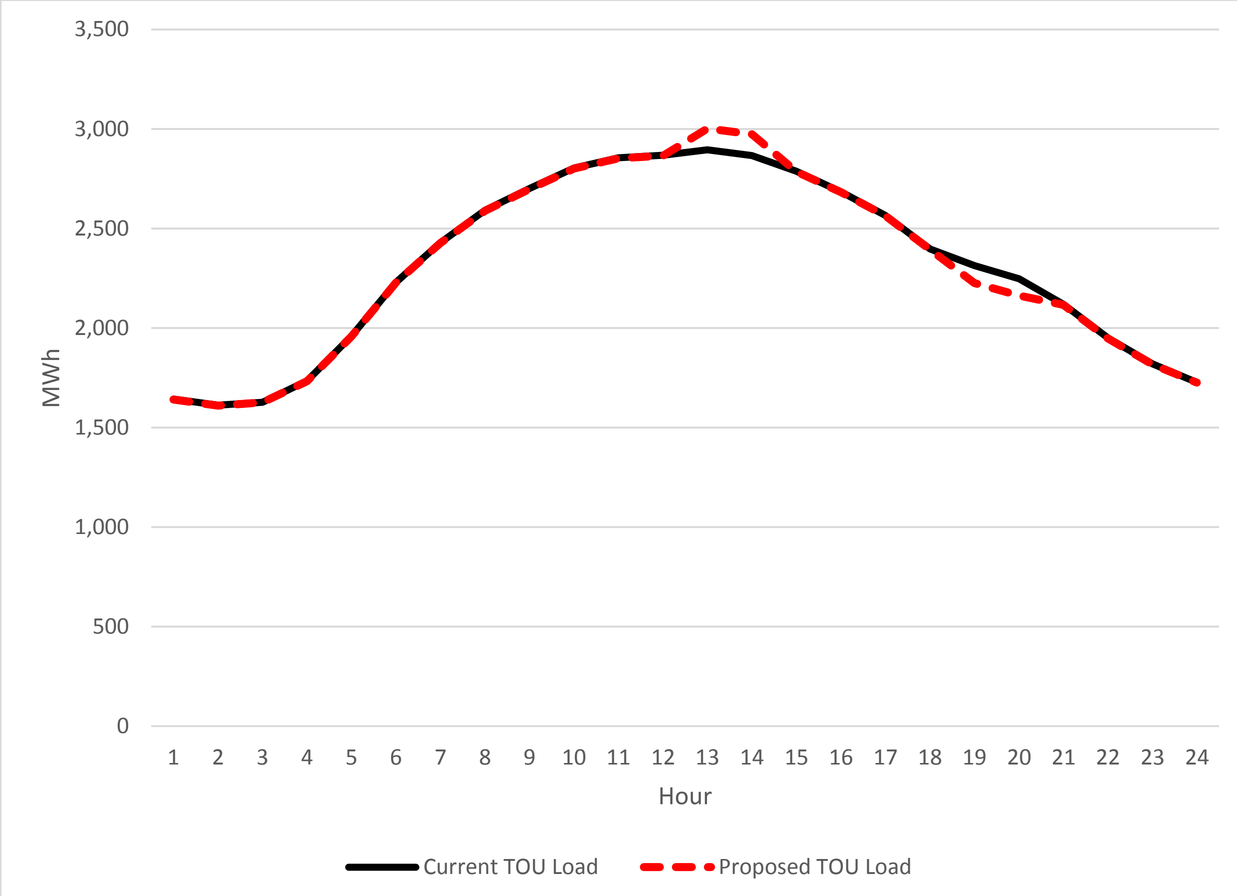
PG&E rate from the PY2011 study and explains why they applied one-third of these estimated values in the PY2013 study (which is because data limitations prevented them from adequately controlling for self-selection bias). The resulting ES values are 0.033 for E19 customers and 0.08 for A6 customers.

In this study, the PG&E demand response is directly derived from the PY2014 *ex-ante* forecast. That is, we use (and modify) that forecast rather than conducting a new simulation with distinct ES assumptions. For SCE and SDG&E, we conduct a CES simulation of TOU load impacts assuming an ES of 0.04. This assumption places more weight on the larger customer ES (for E19 customers) of 0.033. However, as the simulation results below show, even this relatively low ES produces simulated TOU load impacts that are fairly large.

SCE Simulation Results
For SCE, we obtained hourly load data for TOU-GS-3 and TOU-8-SEC customers from October 2013 through September 2014.[34] The proposed summer TOU pricing periods shift the on-peak period two hours later in the day. As a result, hours-ending 13 and 14 go from on-peak hours in the current definition to mid-peak hours under the proposed TOU period definition. Similarly, hours-ending 19 and 20 go from mid-peak hours under the current definition to on-peak hours under the proposed definition. Figure 6.1 shows the simulated change in the load profile that results from our simulation.

[34] DR program event days for which SCE estimated a load reduction greater than 100 MW were excluded from the analysis.

Figure 6.1: Summer Weekday Load Profiles under Current and Proposed TOU Definitions, *SCE*



As one might expect, the change in the TOU pricing periods results in customers using more in HE 13 and 14 (which are no longer on-peak hours) and using less in HE 19 and 20 (which have become on-peak hours). The average load increase in hours-ending 13 and 14 is 108 MW, or 3.7 percent of the current TOU load. The average load decrease in hours-ending 19 and 20 is 86 MW, or 3.8 percent of the current TOU load. The load in the remaining hours is essentially unchanged (0.1 percent lower under proposed TOU rates).

Note that even the modest assumed elasticity of 0.04 results in a simulated TOU load profile that does not appear reasonable to our eye. That is, we do not expect the “bulge” in the middle of the day (where the red dashed line exceeds the solid black line) to result from adopting the proposed TOU pricing periods. While we believe this simulation result is a valid outcome of the model-based process we have implemented, real-world behavior will likely result in a somewhat different outcome. We regard the 3.7 to 3.8 percent load impacts as upper bounds on the change in the C&I embedded TOU load profile.

PG&E Simulation Results

For PG&E, our process is somewhat simplified due to our ability to leverage existing studies. That is, PG&E’s annual load impact studies of non-residential TOU rates have included forecasts of embedded TOU load impacts.[35] We use the reference loads and load impacts from the most recent study as the basis for our analysis. Applying what we learned from our SCE analysis, we adjust the timing of the load impacts across hours to match the proposed changes in the pricing periods.[36] That is, the most significant changes in the TOU pricing periods are that hours-ending 13 through 16 go from peak hours under the current definition to off-peak hours under the proposed TOU periods; and that hours-ending 19 through 21 go from part-peak hours under current definition of periods to peak hours under the proposed TOU periods.

In the existing study, embedded TOU load impacts are 2.9 percent during peak hours on the 2015 August peak day (assuming utility-specific 1-on-2 peak weather conditions). By shifting this 2.9 percent load impact to the new peak period and applying the smaller off-peak and part-peak percentage load changes to other hours of the day, we obtain the simulated load profile shown in Figure 6.2.

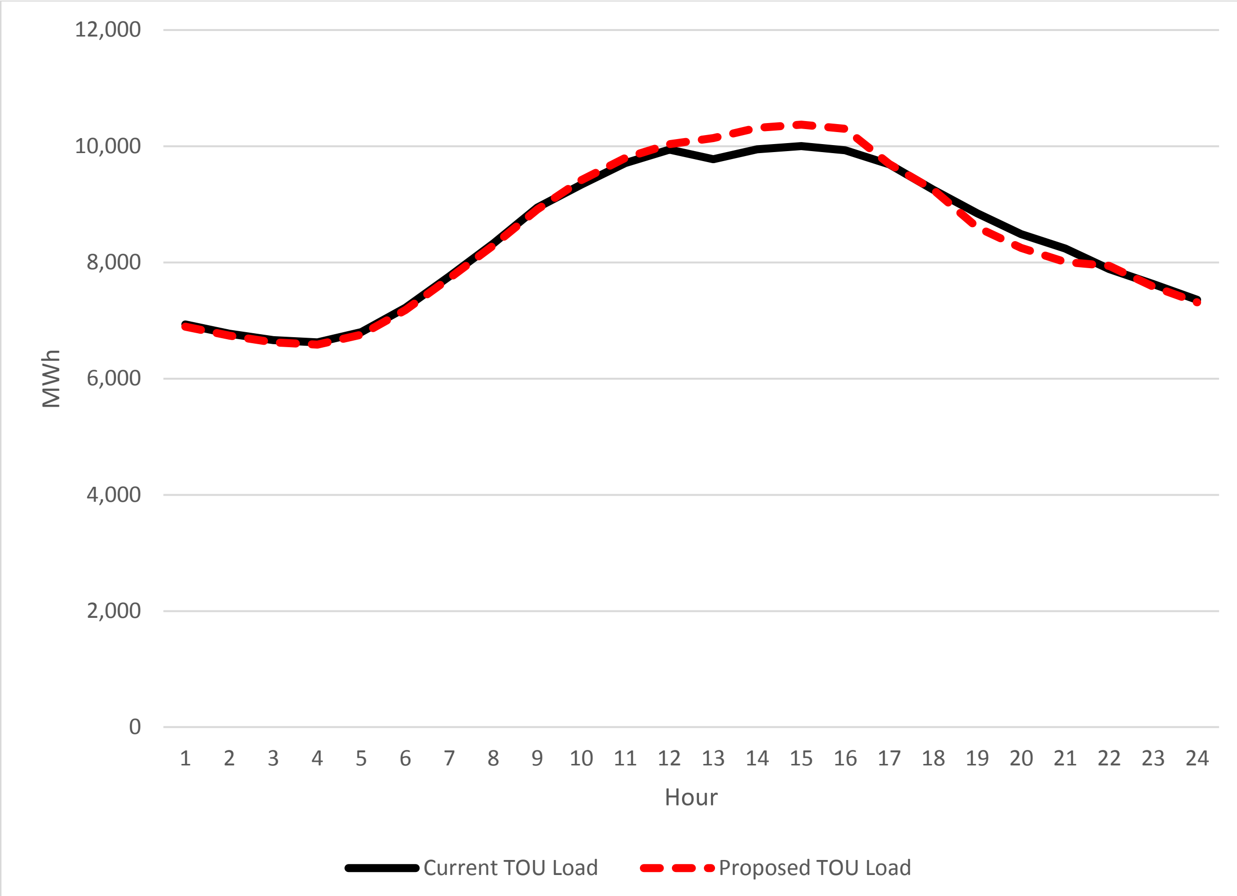
In Figure 6.2, the solid black line represents the embedded TOU load from the PY2014 load impact study (under current TOU pricing periods). The dashed red line shows the simulated embedded TOU load impacts for the proposed pricing periods. As with the SCE study, we see an increase in loads during earlier hours that are peak hours under the existing TOU periods, but off-peak hours under the proposed TOU periods. The increase during these hours averages 368 MW, or 3.7 percent of the current TOU load. Similarly, we see a decrease in loads during later hours that are part-peak hours under the existing TOU periods, but peak hours under the proposed TOU periods. The decrease during these hours averages 237 MW, or 2.8 percent of the current TOU load.[37] The percentage changes in the other hours of the day are relatively small, ranging from -0.6 to +0.9 percent.

[35] "2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers", Hansen and Patton, April 2015, CALMAC ID PGE0354. We use the table generator labeled Appendix E.

[36] This is far simpler than reconstructing the original study and directly simulating the proposed TOU rates. The original study is a combination of several analyses, which were themselves complicated by changes in the assumed weather scenarios applied in the *ex-ante* forecast. Please see the study for details.

[37] The percentage decrease during HE 19 to 21 is smaller than the percentage increase during HE 13 to 16 because the price change is relatively smaller during HE 19 to 21, which are part-peak hours under the current TOU periods.

Figure 6.2: Summer Weekday Load Profiles under Current and Proposed TOU Definitions, *PG&E*



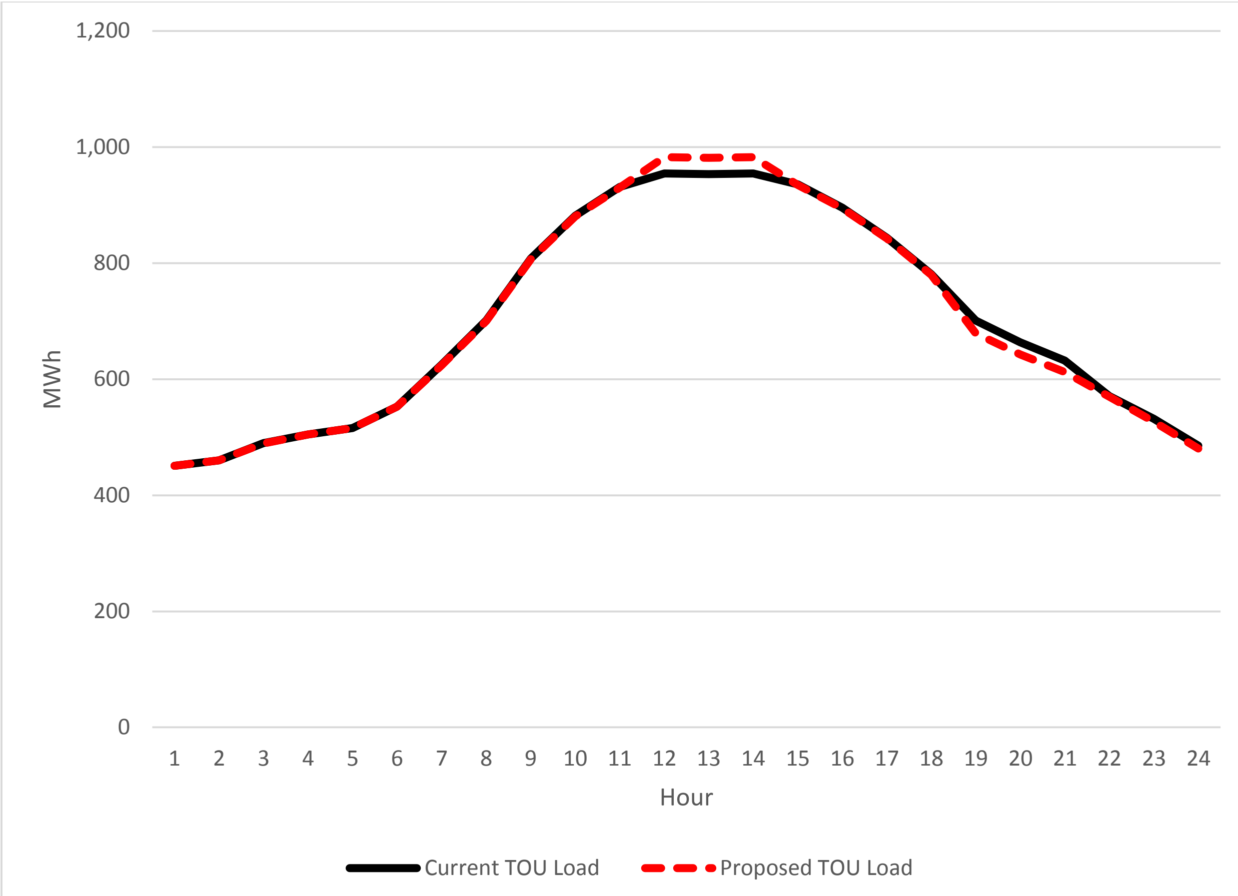
SDG&E Simulation Results

For SDG&E, we used the same October 2013 through September 2014 time period we used for SCE.[38] As described in Section 6.1, SDG&E provided hourly load data for a number of AL-TOU and AY-TOU customer groups. We aggregated these customer groups into a single profile for purposes of the simulation. As with the SCE analysis, we assumed a modest ES of 0.04.

The most significant change under the proposed summer TOU pricing periods is that the on-peak period is shifted three hours later in the day. As a result, hours-ending 12 through 14 go from on-peak hours in the current definition to semi-peak hours under the proposed definition. Similarly, hours-ending 19 through 21 go from semi-peak hours under the current definition to on-peak hours under the proposed definition. Figure 6.3 shows the simulated change in the load profile that results from our simulation.

[38] DR program event days were excluded from the analysis.

Figure 6.3: Summer Weekday Load Profiles under Current and Proposed TOU Definitions, *SDG&E*



As one might expect, the change in the TOU pricing periods results in customers using more in HE 12 through 14 (which are no longer on-peak hours) and using less in HE 19 through 21 (which have become on-peak hours). The average load increase in hours-ending 12 through 14 is 28 MW, or 3.0 percent of the current TOU load. The average load decrease in hours-ending 19 through 21 is 21 MW, or 3.1 percent of the current TOU load. The only other hours with notable percentage load changes are hours-ending 23 and 24, which change from off-peak to semi-peak hours. Our simulations show a 1 percent load reduction during those two hours.

Summary

The simulation results presented in this section consistently show a shift in TOU load impacts from earlier in the day to later in the day. The added TOU load impacts that are obtained in the evening hours (*e.g.*, hours-ending 19 through 21 for SDG&E) are offset by reduced TOU load impacts earlier in the day (*e.g.*, hours-ending 12 through 13 for SDG&E).

The CES model used to conduct the simulations produced results (based on assumptions about customer price-driven behavior) that appear to exaggerate some of the load impacts. Specifically, the load increases that occur in the middle of the day may not be likely to occur (or persist) in exactly that way (we might expect some smoothing of the load changes). The 3 to 4 percent simulated load changes that occur in the re-classified on-peak hours may prove to be large compared to real-world experience.

7. COMMERCIAL AND INDUSTRIAL CPP LOAD IMPACTS

The proposed scenarios include two elements that affect load impacts from non-residential critical peak pricing (CPP) programs:[39]

- The change in the definition of the TOU peak period, which we assume coincides with the event-day critical pricing period; and
- Low and high assumed levels of participation for defaulted customers.

The most recent CPP load impact study[40] contains a complete *ex-ante* forecast of load impacts for each utility. We have based our scenario analyses on this study, using per-customer reference loads and load impacts by size group (under 20kW, 20 to 200kW, and over 200kW) for each peak month day of the years 2016 through 2025. Results for the different enrollment scenarios were obtained by scaling the per-customer reference loads and load impacts by the appropriate forecast enrollment value (as detailed below).

Load impacts for the proposed peak-period definition were simulated by shifting the *ex-ante* percentage load impacts for the current event window to coincide with the forecast event window. We don't know of any information that would allow us to estimate the CPP load impacts for the later event window, so we assume that the percentage load impacts carry forward. The *level* of the load impacts will change with the (presumably lower) load levels during the later event window. The mapping of percentage load impacts was carried out as follows.

For small C&I customers (under 20kW):

- For PG&E and SCE, load impacts were assumed to be 2 percent during event hours and zero elsewhere;[41]
- For SDG&E, we assumed no load impacts from these customers, which is consistent with their findings and assumptions to date.

For medium C&I customers (20 to 200kW):

- For PG&E and SCE, load impacts were assumed to be 1.5 percent during event hours and zero elsewhere;
- For SDG&E, the load impact percentage is based on a 2.5 percent "base" value that is adjusted downward due to customer awareness assumptions. This results in load impacts of roughly 2.2 percent in later years.

---

[39] CPP is marketed as Peak Day Pricing (PDP) at PG&E and Summer Advantage Incentive (SAI) at SCE.

[40] "2014 Load Impact Evaluation of California's Statewide Non-residential Critical Peak Pricing Program", George, Schellenberg, and Blundell, April 2015. CALMAC ID SDG0287.

[41] Note that PG&E's preliminary estimates during PY2015 indicates very little, if any, CPP demand response from its small and medium C&I customers. Therefore, the assumptions in this study may prove to be too high.

The justification for these percentages is contained in this excerpt from the PY2014 CPP load impact study.[42]

> For small and medium customers, we lack robust empirical data about how they respond to default CPP. Around 170,000 SMB [small and medium business] customers were defaulted onto CPP in November 2014 at PG&E, but those customers have yet to experience any CPP events. SCE and SDG&E small and medium customers have yet to be defaulted onto CPP. Therefore, default CPP ex post impact estimates are not available. The percent load reductions from the EEP [Early Enrollment Pilot] customers at PG&E provide information on how small and medium customers respond to CPP on an opt-in basis. Previous studies of residential customers have shown that customers who enroll on an opt-in basis tend to be more engaged and deliver significantly larger percent reductions than those who enroll on a default basis.[43] Nexant therefore used the EPP CPP percent reductions as an upper bound for the expected response of defaulted small and medium customers, and adjusted the overall percent reduction downward. For SCE and PG&E, this yielded percent reductions of 2.0% and 1.5%, for small and medium customers respectively, to be applied to SMB customers to be defaulted onto CPP in the future. For SDG&E, the initial percent reduction for medium customers was 2.5%, to which an awareness factor was then applied. The awareness factor increased from 0.7 in 2016 to 0.9 in 2018 onwards, which led to percent impacts of 1.75% in 2016 and 2.25% in 2018 onwards.

For large C&I customers (over 200kW), the following table shows how hourly load impacts were mapped from the current event window into the proposed event window. Load impacts are assumed to be zero percent in the hours preceding those contained in the table. For example, for PG&E, the current CPP event period is defined as hours-ending 15 through 18 and the proposed CPP event period is defined as hours-ending 17 through 21. The percentage load impact assigned to hour-ending of the proposed event period is taken from hour-ending 15 of the *ex-ante* forecast filed on April 1, 2015.

[42] *Ibid*., p. 27.

[43] Interim report on Sacramento Municipal Utility District's Smart Pricing Options pilot: https://www.smartgrid.gov/sites/default/files/MASTER_SMUD%20CBS%20Interim%20Evaluation_Final_SUBMITTED%20TO%20TAG%2020131023.pdf

Table 7.1: Mapping of Percentage Load Impacts for Large C&I Customers

Hour with proposed event-hour definition	Hour in April 1, 2015 *ex-ante* forecast		
	PG&E	SCE	SDG&E
14		14	11
15		15	12
16	14	16	13
17	15	17	14
18	16	18	15
19	16	18	16
20	17	18	17
21	18	19	18
22	19	20	19
23	20	21	20
24	21	22	21

Enrollment Assumptions
Large C&I enrollments are assumed to be somewhat stable and thus not subject to the alternative scenario assumptions. However, the default process for small and medium C&I customers is in the early stages. PG&E has started defaulting these customers to CPP, SDG&E will do so in 2016, and SCE will follow in 2017. The scenario analysis is based on the share of customers that opt-out of CPP over time.

For PG&E, the enrollment assumptions are:

- In the current *ex-ante* forecast, 33% opt out after default and 20% opt out after bill protection expires;
- In the high enrollment scenario for this study (Scenarios 1 and 2), 15% opt out after default and 10% opt out after bill protection expires; and
- In the low enrollment scenario for this study (Scenario 3), 60% opt out after default and 40% opt out after bill protection expires.

For SCE, the enrollment assumptions are:

- In the low enrollment scenario for this study (Scenario 3), which matches the *ex-ante* forecast, 50% opt out prior to CPP enrollment and 60% opt out after bill protection expires; and
- In the high enrollment scenario for this study (Scenarios 1 and 2), 25% opt out after default and no customers opt out after bill protection expires.

For SDG&E, the enrollment assumptions are described in Table 7.2. The High enrollment scenario corresponds to the value used in the *ex-ante* forecast filed on April 1, 2015.

Table 7.2: SDG&E Medium C&I CPP Enrollment Assumptions

Time Period	Scenarios 1 and 2 (Low)	Scenario 3 (High)
3/2016 to 7/2016	33%	82%
8/2016 to 2/2017	30%	76%
3/2017 to 7/2017	28%	69%
8/2017 to 2/2018	27%	66%
3/2018 +	25%	62%

Event Hours

The CPP event hours are assumed to be the following:

- PG&E: Scenario 1 = 2 to 6 p.m.; Scenarios 2 and 3 = 4 to 9 p.m.
- SCE: Scenario 1 = 2 to 6 p.m.; Scenarios 2 and 3 = 2 to 8 p.m.
- SDG&E: Scenario 1 = 11 a.m. to 6 p.m.; Scenarios 2 and 3 = 2 p.m. to 9 p.m.

Results

Figures 7.1 through 7.3 show the average event-hour load impacts by Utility, scenario, and year. In each case, the load impacts represent a 1-in-2 utility August peak day. CPP enrollments are included as well – note that Scenarios 1 and 2 assume the same enrollment levels but different CPP event hours.

The results for all three Utilities show that load impacts are lower in Scenario 2 than Scenario 1. That is, despite the fact that the enrollment and event-hour percentage load impacts are held constant, the shift to a later event window reduced the load impacts because overall load levels were lower during that time.

Note that SDG&E's CPP load impacts are largely from the large C&I customers, the enrollment for which remains constant across scenarios. The load impacts for the medium C&I customers vary with enrollments, but are small in comparison to the large C&I load impacts.

Figure 7.1: PG&E CPP Load Impacts and Enrollments by Scenario and Year

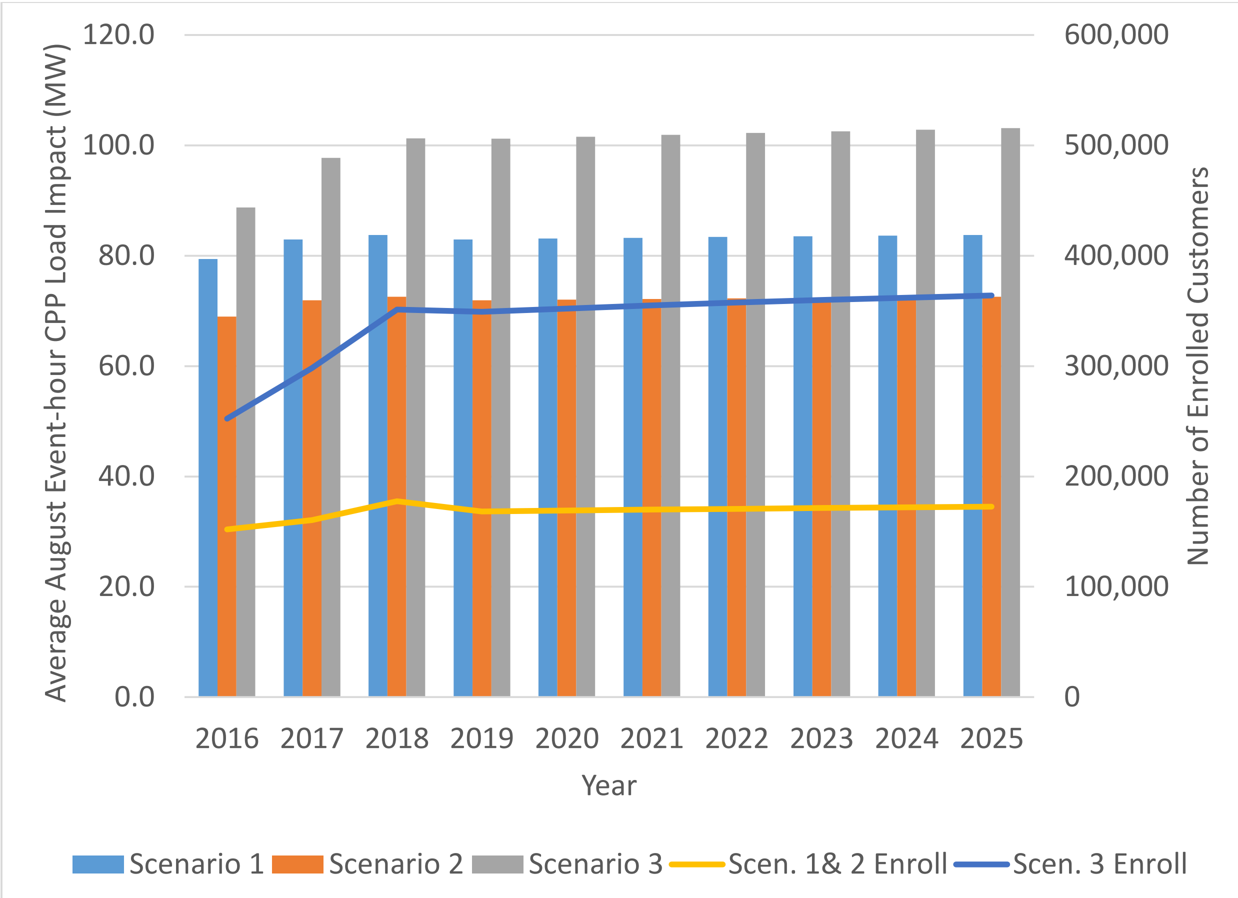


Figure 7.2: SCE CPP Load Impacts and Enrollments by Scenario and Year

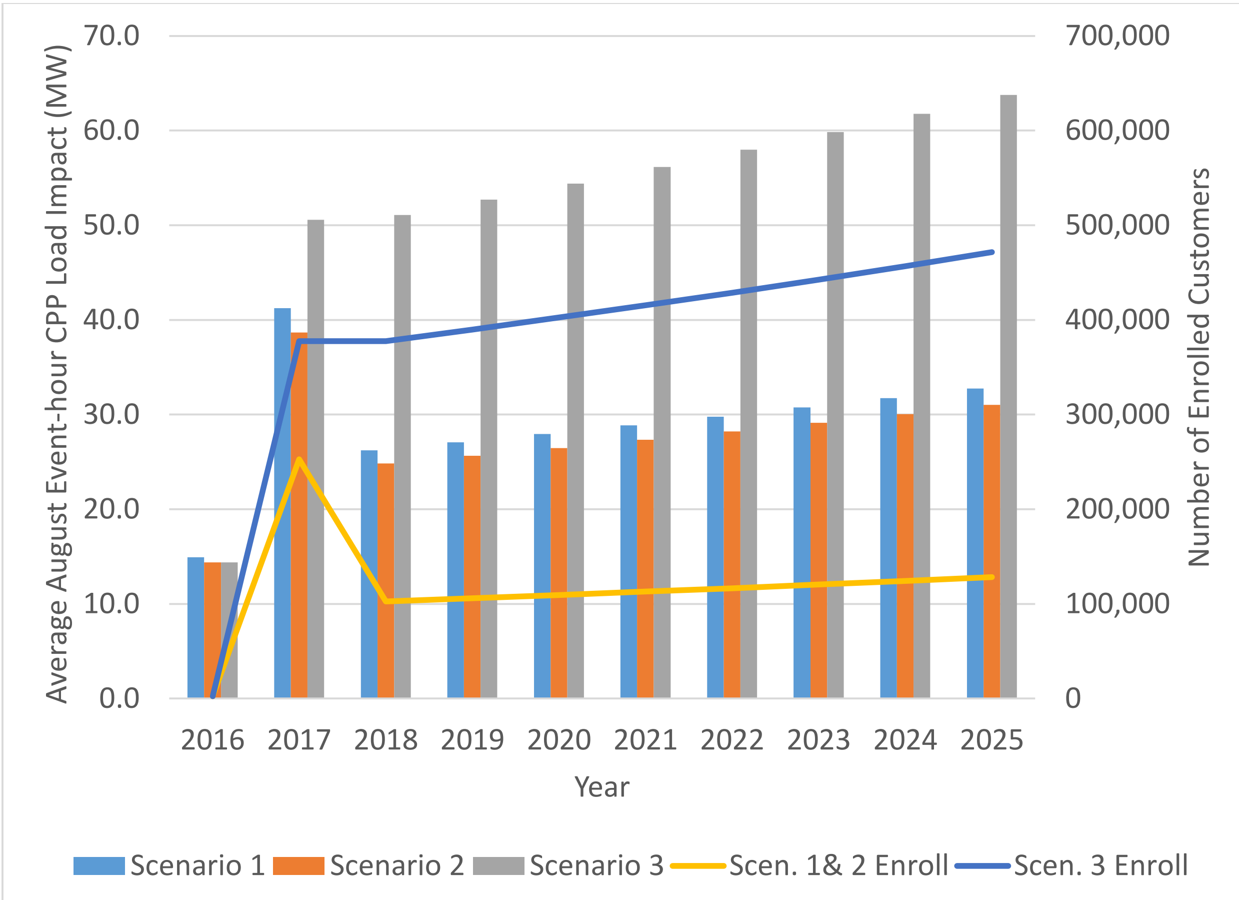
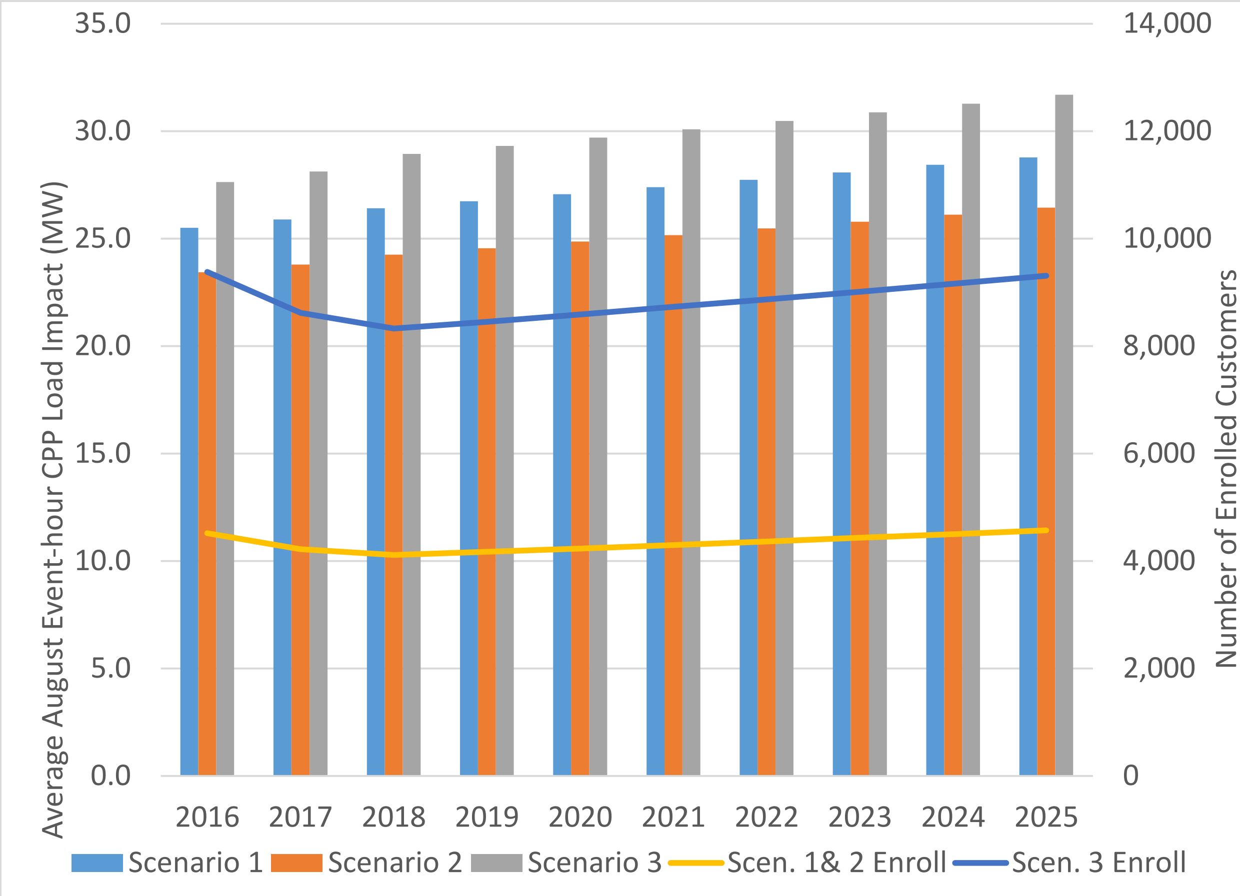


Figure 7.3: SDG&E CPP Load Impacts and Enrollments by Scenario and Year



Figures 7.4 through 7.6 present the CPP load impacts and enrollments excluding the large C&I (over 200kW) customers. This may facilitate the interpretation of changes in small and medium C&I enrollments on CPP load impacts, as those enrollments vary considerably more than large C&I enrollments during the study period.

Figure 7.4: PG&E CPP Load Impacts and Enrollments, Excluding Large C&I

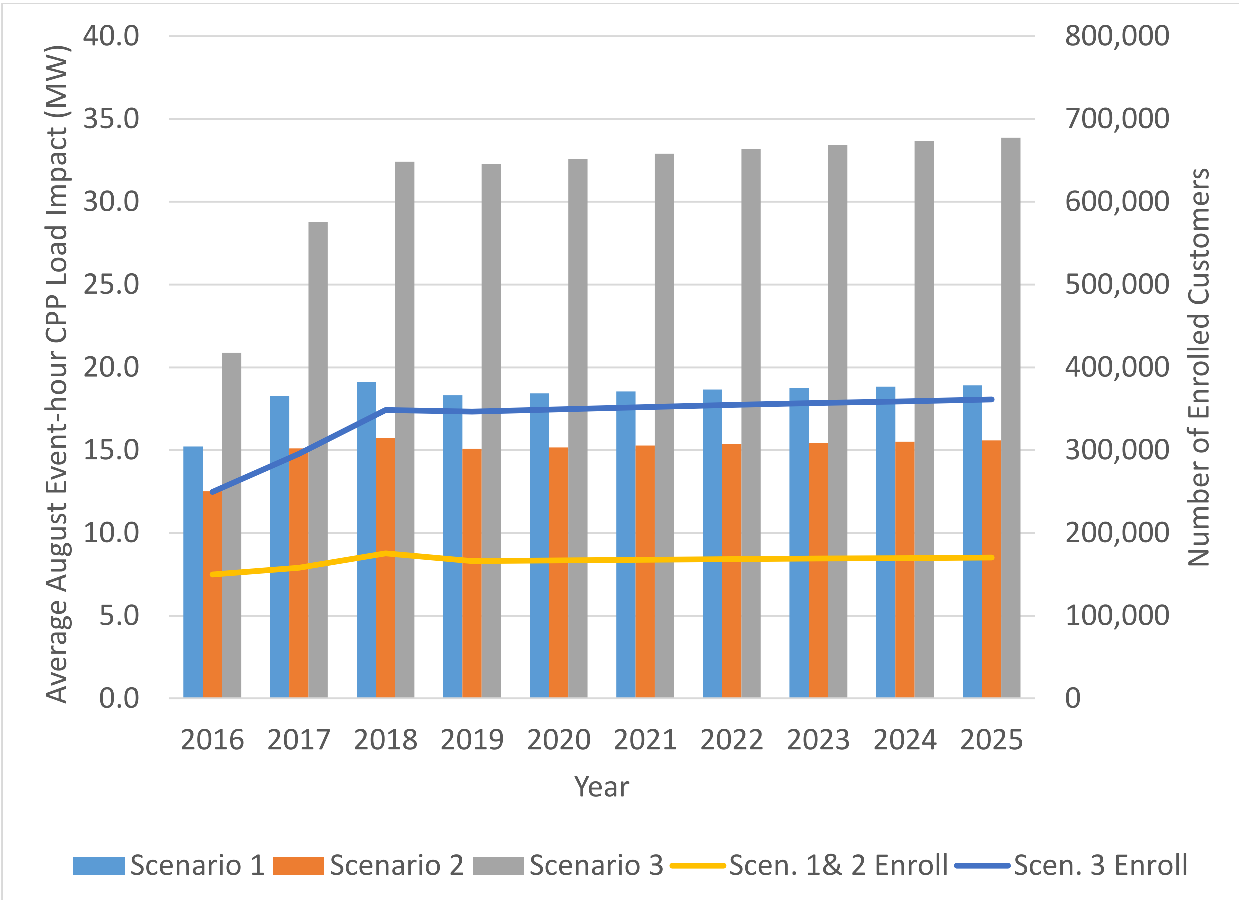


Figure 7.5: SCE CPP Load Impacts and Enrollments, Excluding Large C&I

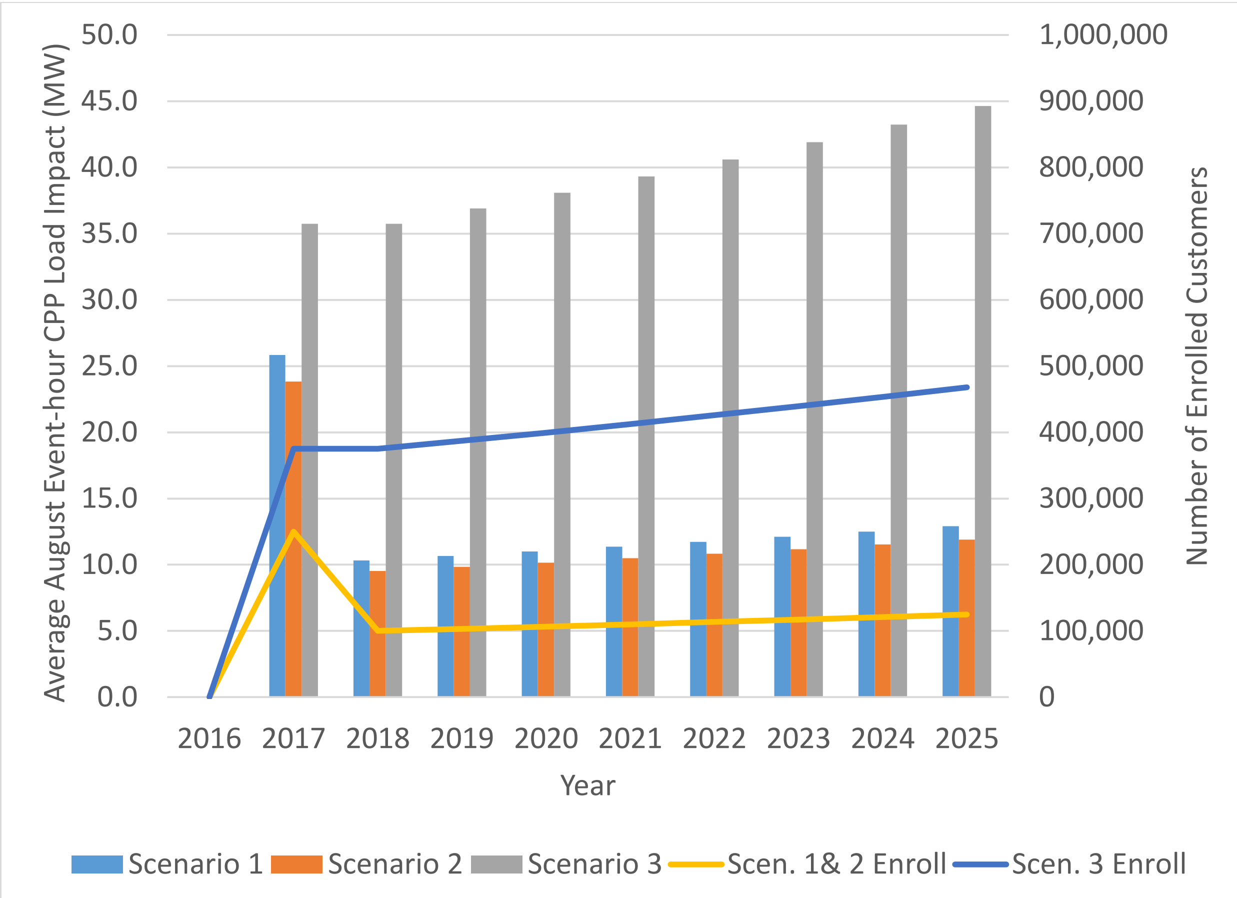
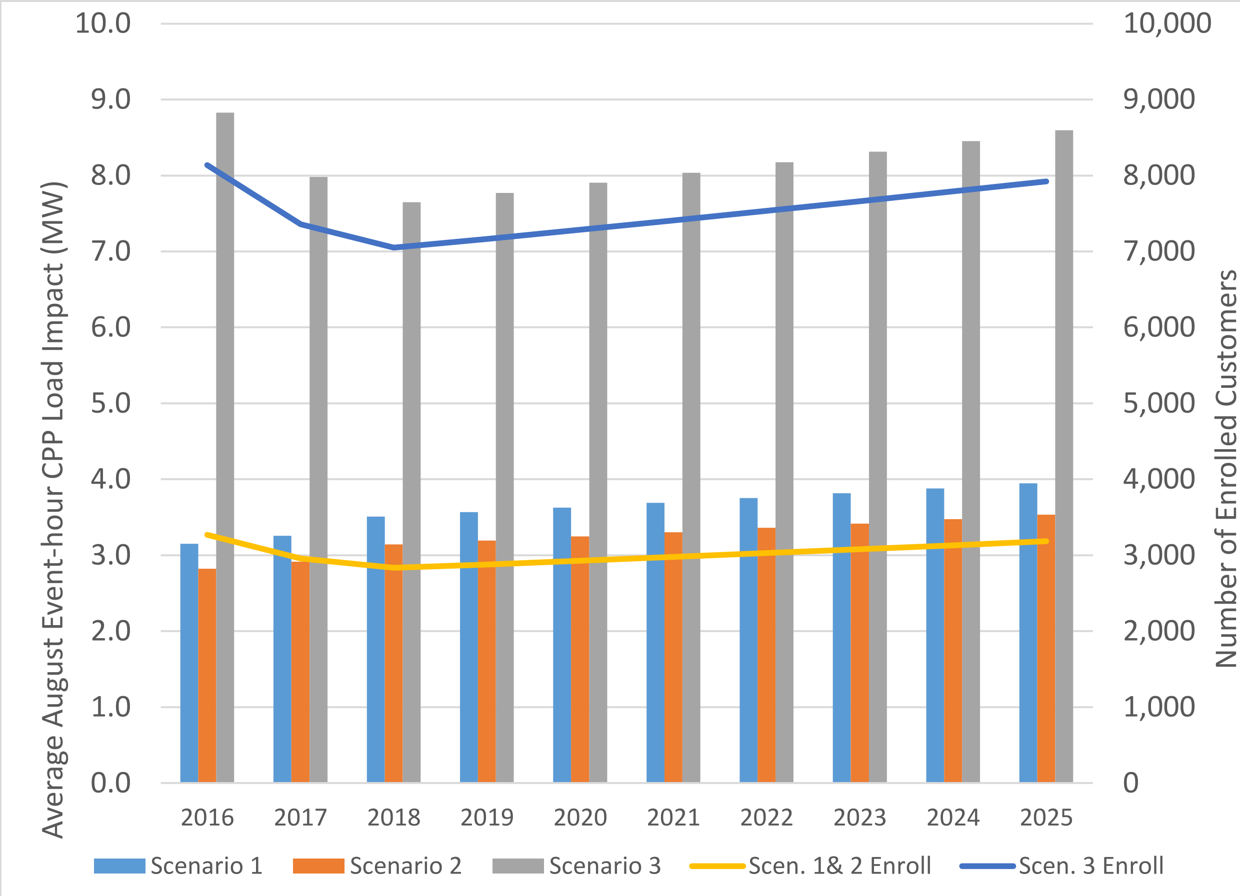


Figure 7.6: SDG&E CPP Load Impacts and Enrollments, Excluding Large C&I



8. SUMMARY AND CONCLUSIONS

This study contains a high-level examination of the potential effects of changes in TOU rate design on customer load impacts for California's the three investor-owned electric utilities. The analysis includes three scenarios that vary according to the TOU rates being offered and the assumed level of customer participation in the TOU rates, which are assumed to be offered as voluntary (opt-in) rates. The study also includes a simulation of changes in commercial and industrial CPP load impacts under high and low enrollment scenarios and a later event window.

The findings generally indicate small reductions in the amount of load impacts (TOU and CPP) under the prices and later peak periods (and CPP event window) assumed in Scenarios 2 and 3 compared to Scenario 1 (current rates). The results in Scenarios 2 and 3 also indicate that the *total* amount of TOU and CPP demand response is quite sensitive to assumed customer participation rates.

REFERENCES

Faruqui, Ahmad and Sanem Sergici, "Household response to dynamic pricing of electricity: a survey of 15 experiments," *Journal of Regulatory Economics* (2010), 38:193-225.

Faruqui, Ahmad, Sanem Sergici, and Jennifer Palmer, "The Impact of Dynamic Pricing on Low Income Customers," IEE Whitepaper, September 2010.

"Impact Evaluation of the California Statewide Pricing Pilot," Final Report, Charles River Associates, March 16, 2005.[44]

Kirkeide, Loren, "Effects of Three-Hour On-Peak Time of Use Plan on Residential Demand During Hot Phoenix Summers," *The Electricity Journal*, May 2012, Vol. 25, Issue 4.

[44] Key authors of the report were Ahmad Faruqui (now at The Brattle Group) and Stephen George (now at Nexant).

APPENDIX

Table A.1 shows the coincident peak-hour load reductions by utility, scenario, and year, where the coincident peak hour was hour-ending 19 on August 13th. This hour was set to be the hour with the maximum load after summing the residential profiles across utilities. Note that this may not be the same as the coincident peak for the *entire* utility loads (*i.e.*, including C&I loads, etc.). The table below shows the peak load changes for the residential coincident peak. Note that for PG&E, the residential coincident peak hour is the same as the non-coincident peak hour, so the results in Table A.1 match those in Table 4.3.

Table A.1: Residential Coincident Peak-hour Load Changes by Utility, Scenario, and Year

Year	PG&E			SCE			SDG&E		
	Scen 1	Scen 2	Scen 3	Scen 1	Scen 2	Scen 3	Scen 1	Scen 2	Scen 3
2016	5.9	4.7	4.7	9.0	9.0	9.0	0.1	0.5	0.5
2017	8.6	6.8	12.1	13.0	13.0	23.0	0.1	0.7	1.2
2018	11.3	9.0	19.5	17.2	17.2	37.4	0.2	0.9	1.9
2019	14.1	11.2	27.2	21.5	21.5	52.1	0.2	1.1	2.7
2020	16.9	13.4	34.9	25.8	25.8	67.2	0.3	1.3	3.4
2021	19.8	15.7	42.8	30.0	30.0	81.7	0.3	1.5	4.2
2022	22.7	18.0	50.6	34.5	34.5	97.2	0.4	1.8	5.0
2023	25.6	20.3	58.6	39.1	39.1	113.0	0.4	2.0	5.9
2024	28.6	22.6	66.7	43.8	43.8	129.2	0.5	2.3	6.7
2025	31.6	25.0	75.0	48.7	48.7	146.2	0.5	2.5	7.6