COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. TO AMEND ITS DEMAND SIDE MANAGEMENT PROGRAMS	)))	CASE No. 2019-00277

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF THE KENTUCKY PUBLIC SERVICE COMMISSION STAFF

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits the following responses to data requests of the Kentucky Public Service Commission Staff in the above-styled matter.

Respectfully submitted,

DANIEL CAMERON
ATTORNEY GENERAL

JUSTIN M. MCNEIL
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Certificate of Service and Filing

Counsel certifies that the foregoing is a true and accurate copy of the same document being filed in paper medium with the Commission within two business days; that the electronic filing has been transmitted to the Commission on January 10, 2020; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding. Counsel further certifies that the responses set forth herein are true and accurate to the best of his knowledge, information, and belief formed after a reasonable inquiry.

This 10th day of January, 2020.

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Assistant Attorney General

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 1
Page 1 of 2

Refer to the Direct Testimony of Paul J. Alvarez (Alvarez Testimony), page 7, lines 8-18.

a. Confirm that it is Mr. Alvarez's opinion that low-income customers are impacted more than the average customer during high-priced times.
b. State whether Mr. Alvarez believes that low-income customers exhibit a lower price elasticity than the average customer.
c. State whether Mr. Alvarez believes that the price elasticity is different between peak-time rebate and time-of-use programs and, if so, provide any supporting documentation.
d. State whether Mr. Alvarez believes that low-income customers can benefit from peak-time rebate programs.
e. Provide all studies supporting the level of price elasticity of low income customers as compared to other customers

RESPONSE:

a. Mr. Alvarez confirms that a low-income customer will find it more difficult to accommodate the bill increases which may accompany pricing structures with a critical peak pricing component than the average customer will.
b. Mr. Alvarez confirms that a low-income customer is likely to exhibit a lower price elasticity than the average customer. Mr. Alvarez notes that this is not due to a lack of interest in saving money, which is generally higher among low-income customers than average customers, but due to lower incidence of large modifiable loads in low-income households relative to average households (such as central air conditioning or electric clothes dryers).
c. Mr. Alvarez believes that, all else being equal, the price elasticity exhibited by a participating population for peak-time rebate is greater than that of traditional time-of-use, but less than that of a time-of-use rate with critical peak price (CPP) features. (See attached research, *Faruqui Research Review SSRN-id2020587.pdf*, pages 4 and 5 ["Attachment 1"].) However, Mr. Alvarez notes that these impacts do not take into account participation rates. As time-of-use rate participation (with or without a CPP feature) is voluntary at almost all utilities,

participation is generally in single-digit percentages. As peak-time rebate as envisioned by Mr.
Alvarez is default, available to all customers, participation in any one critical peak event is higher than in TOU with CPP, more than offsetting any price elasticity improvement time-of-use with CPP offers.

d. Mr. Alvarez agrees that many low-income customers can benefit from peak-time rebate programs.
e. See attached research, *CA Statewide_Opt-in_TOU_Evaluation-Final_Report,pdf*, page 6 ["Attachment 2"].

Submitted to the EDI Quarterly

The Discovery of Price Responsiveness – A Survey of Experiments involving Dynamic Pricing of Electricity

Ahmad Faruqui and Jenny Palmer[1]

Abstract

This paper surveys the results from 126 pricing experiments with dynamic pricing and time-of-use pricing of electricity. These experiments have been carried out across three continents at various times during the past decade. Data from 74 of these experiments are sufficiently complete to allow us to identify the relationship between the strength of the peak to off-peak price ratio and the associated reduction in peak demand or demand response. An "arc of price responsiveness" emerges from our analysis, showing that the amount of demand response rises with the price ratio but at a decreasing rate. We also find that about half of the variation in demand response can be explained by variations in the price ratio. This is a remarkable result, since the experiments vary in many other respects – climate, time period, the length of the peak period, the history of pricing innovation in each area, and the manner in which the dynamic pricing designs were marketed to customers. We also find that enabling technologies such as in-home displays, energy orbs and programmable and communicating thermostats boost the amount of demand response. The results of the paper support the case for widespread rollout of dynamic pricing and time-of-use pricing.

Introduction

Electric utilities, which run a capital-intensive business, could lower their costs of doing business by improving their load factor. Other capital intensive industries, such as airlines, hotels, car rental agencies, sporting arenas, movie theaters routinely practice a technique known as dynamic pricing to improve load factor. In dynamic pricing, prices vary to reflect the changing balance of demand and supply through the day, through the week and through the seasons of the year.

Congestion pricing, a simpler form of dynamic pricing, is used to regulate the flow of cars into central cities. Parking spaces in most central cities are priced on a time-of-day basis and in some cities such as San Francisco the prices are varying dynamically. In California, special lanes on freeways are priced dynamically and the Bay Bridge charges toll on a time-of-use basis.

But it has been difficult for electric utilities to follow these examples. There has always been doubt that electric users can change their usage patterns. To assuage these doubts, in the late 1970s and early 1980s, a dozen electricity pricing experiments were carried out with time-of-use rates in the United

[1] The authors are economists with The Brattle Group, based in San Francisco. They are grateful to fellow economist Sanem Sergici of Brattle for reading an early draft of this paper. Comments can be directed to ahmad.faruqui@brattle.com.

States.[2] They showed that customers do respond to such rates by lowering peak usage and/or shifting it to less expensive off-peak periods. But smart meters that would charge on a time-of-day basis were expensive in those days and little progress occurred in the ensuring years. Even now, less than one percent of the more than 125 million electric customers in the United States are charged on a time-of-use basis.

However, the California energy crisis of 2000-01 reinvigorated interested in dynamic pricing, not only in that state but globally. Over the past decade, two dozen dynamic pricing studies featuring over one hundred dynamic time-of-use and dynamic pricing designs were carried out across North America, in the European Union and in Australia and New Zealand.[3]

These experiments have yielded a rich body of empirical evidence. We have compiled this into a database, *D-Rex*, which stands for *D*ynamic *R*ate *ex*periments. This contains the following data from each pilot: details of the specific rate designs tested in the pilot, whether or not enabling technologies were offered to customers in addition to the time-varying rates, and the amount of peak reduction that was realized with each price-technology combination. The *D-Rex* results provide an important perspective on the potential magnitude of impacts with different dynamic rate approaches and should inform the public debate about the merits of smart meters and smart pricing. Across the 129 dynamic pricing tests, peak reductions range from near zero values to near 60 percent values. However, it would be misleading to conclude that there is no consistency in customer response.[4]

We focus on nine of the best designed, more recent experiments to examine the impact of the peak to-off peak price ratio on the magnitude of the reduction in peak demand, or demand response. Because the amount of demand response varies with the presence or absence of enabling technology, such as a smart thermostat, an energy orb or an in-home display, we separate those pricing tests without and with enabling technology. We find a statistically significant relationship between the price ratio and the amount of peak reduction, and quantify this relationship with a logarithmic model. This relationship is termed the Arc of Price Responsiveness. We find that for a given price ratio, experiments with enabling technologies tend to produce larger peak reductions, and display a more price-responsive Arc.

Sidebar: The Dynamic Rates

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[2] For an early summary, see Ahmad Faruqui and J. Robert Malko, "The Residential Demand for Electricity by Time-Of-Use: A Survey of Twelve Experiments with Peak Load Pricing," *Energy*, Volume 8, Issue 10, October 1983. For more recent surveys, see Ahmad Faruqui and Jenny Palmer, "Dynamic Pricing and its Discontents," *Regulation*, Fall 2011 and Ahmad Faruqui and Sanem Sergici, "Household Response to Dynamic Pricing of Electricity – A Survey of 15 Experiments," *Journal of Regulatory Economics*, October 2010. Faruqui and Palmer also discuss the more common myths that surround legislative and regulatory conversations about dynamic pricing.

[3] Most dynamic pricing studies have included multiple tests. For example, a pilot could test a TOU rate and a CPP rate and it could test each rate with and without enabling technology. Thus, this pilot would include a total of four pricing tests.

[4] See, for example, the concluding remarks in an otherwise excellent paper by Paul Joskow, "Creating a smarter U.S. electrical grid," *Journal of Economic Perspectives*, Winter 2012.

Time-of-Use (TOU). A TOU rate could either be a time-of-day rate, in which the day is divided into time periods with varying rates, or a seasonal rate into which the year is divided into multiple seasons and different rates provided for different seasons. In a time-of-day rate, a peak period might be defined as the period from 12 pm to 6 pm on weekdays, with the remaining hours being off-peak. The price would be higher during the peak period and lower during the off-peak, mirroring the variation in marginal costs by pricing period.

Critical Peak Price (CPP). On a CPP rate, customers pay higher peak period prices during the few days a year when wholesale prices are the highest (typically the top 10 to 15 days of the year which account for 10 to 20 percent of system peak load). This higher peak price reflects both energy and capacity costs and, as a result of being spread over relatively few hours of the year, can be in excess of $1 per kWh. In return, the customers pay a discounted off-peak price that more accurately reflects lower off-peak energy supply costs for the duration of the season (or year). Customers are typically notified of an upcoming "critical peak event" one day in advance but if enabling technology is provided, these rates can also be activated on a day-of basis.

Peak Time Rebate (PTR). If a CPP tariff cannot be rolled out because of political or regulatory constraints, some parties have suggested the deployment of peak-time rebate. Instead of charging a higher rate during critical events, participants are paid for load reductions (estimated relative to a forecast of what the customer otherwise would have consumed). If customers do not wish to participate, they simply buy through at the existing rate. There is no rate discount during non-event hours. Thus far, PTR has been offered through pilots, but default (opt-out) deployments have been approved for residential customers in California, the District of Columbia and Maryland.

Real Time Pricing (RTP). Participants in RTP programs pay for energy at a rate that is linked to the hourly market price for electricity. Depending on their size, participants are typically made aware of the hourly prices on either a day-ahead or hour-ahead basis. Typically, only the largest customers —above one megawatt of load — face hour-ahead prices. These programs post prices that most accurately reflect the cost of producing electricity during each hour of the day, and thus provide the best price signals to customers, giving them the incentive to reduce consumption at the most expensive times.

The Dynamic Pricing Studies

The *D-Rex* Database contains the results of 129 dynamic pricing tests from 24 pricing studies. [5] As shown in Figure 1, these results range from close to zero to up to 58 percent. Part of the variation in impacts comes simply from the fact that different rate types are being tested. Filtering by rate in Figure 2, some trends begin to emerge. We observe that the Critical Peak Pricing (CPP) rate tends to have higher impacts than Time-of-Use (TOU) rates, likely because the CPP rates have higher peak to off-peak price ratios. We can also filter by the presence of enabling technology, as in Figure 3, and observe that for the same rates, the impacts with enabling technologies tends to be higher.

[5] 23 of the 24 studies are pricing pilots. The other study is PG&E's full scale rollout of TOU and SmartRate.

Figure 1. Impacts from Residential Dynamic Pricing Tests, Sorted from Lowest to Highest

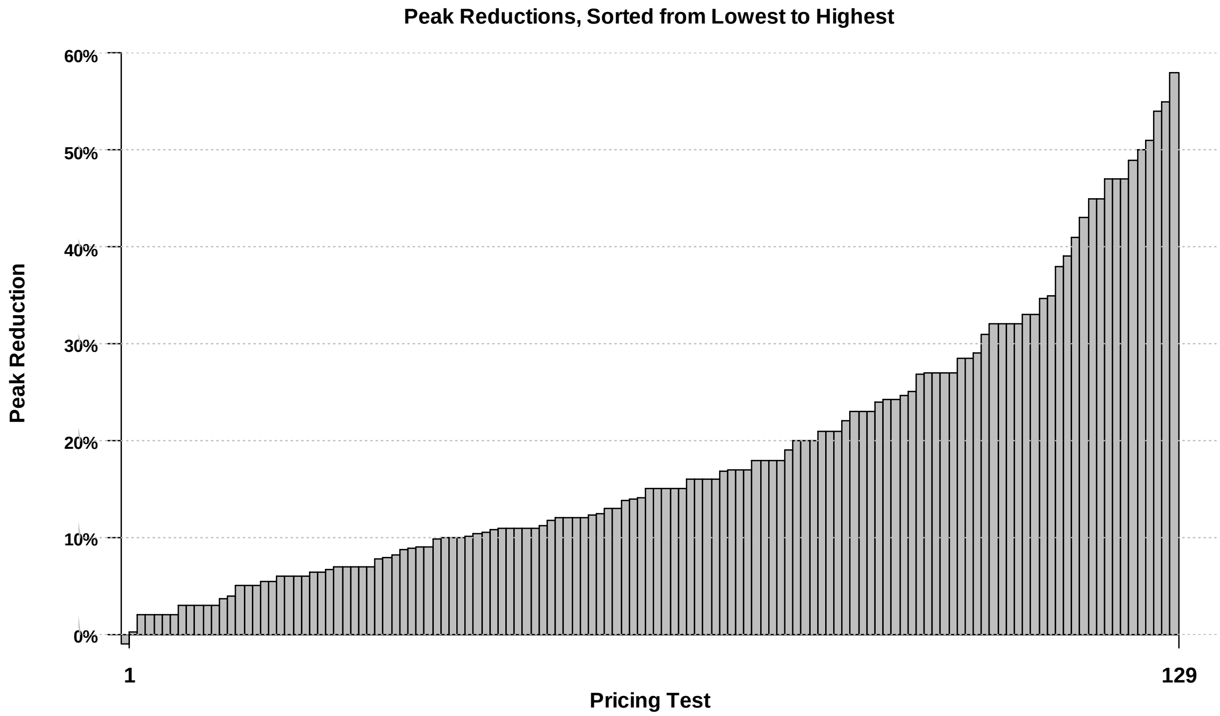
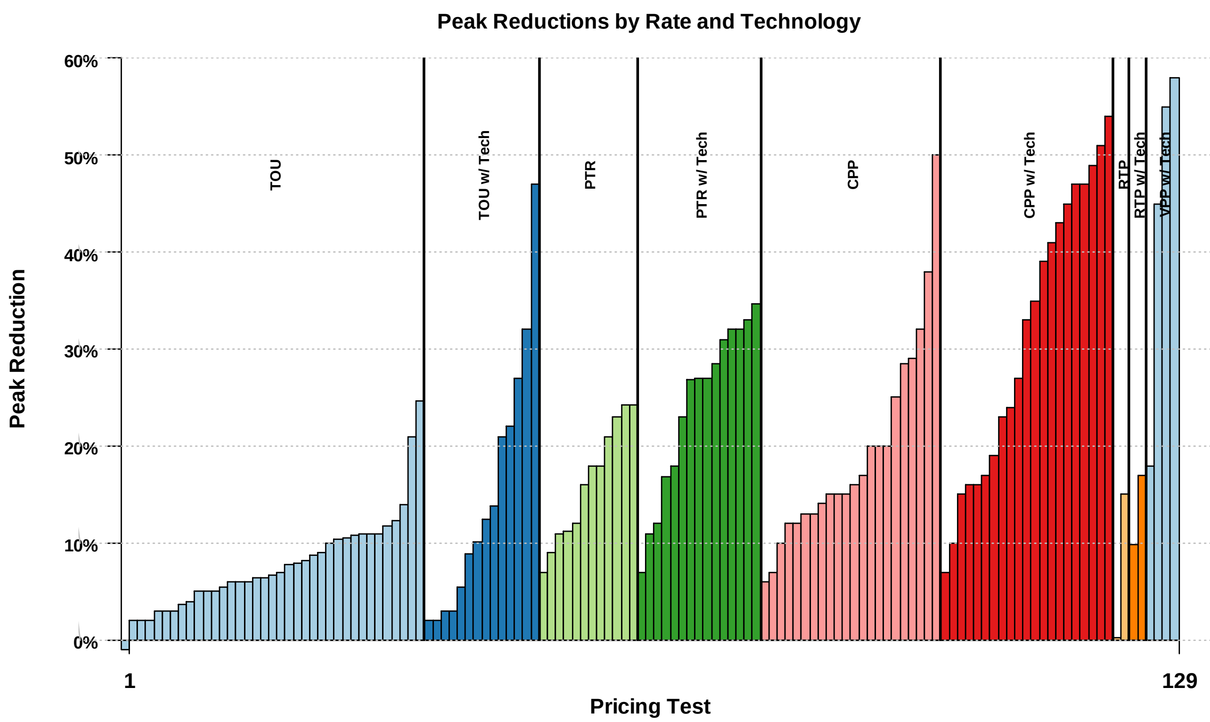


Figure 2. Impacts from Pricing Tests, by Rate Type

Figure 3. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies



Even with the rate and technology filters, there remains significant unexplained variation. In order to understand the cause of this variation, we first limit the sample to only the best-designed studies which have reported the relevant data. We selected studies in which samples are representative of the population and the results are statistically valid. Moreover, we selected studies in which participants were selected randomly, as opposed to volunteers responding to a mass mailing. The nine best-designed pilots, shown in Table 1, include 42 price-only tests and 32 pricing tests with prices *cum* enabling technology.[6] In these 74 tests, the peak reductions range from 0% to just under 50%. The remainder of this paper focuses on explaining the variation in these results.

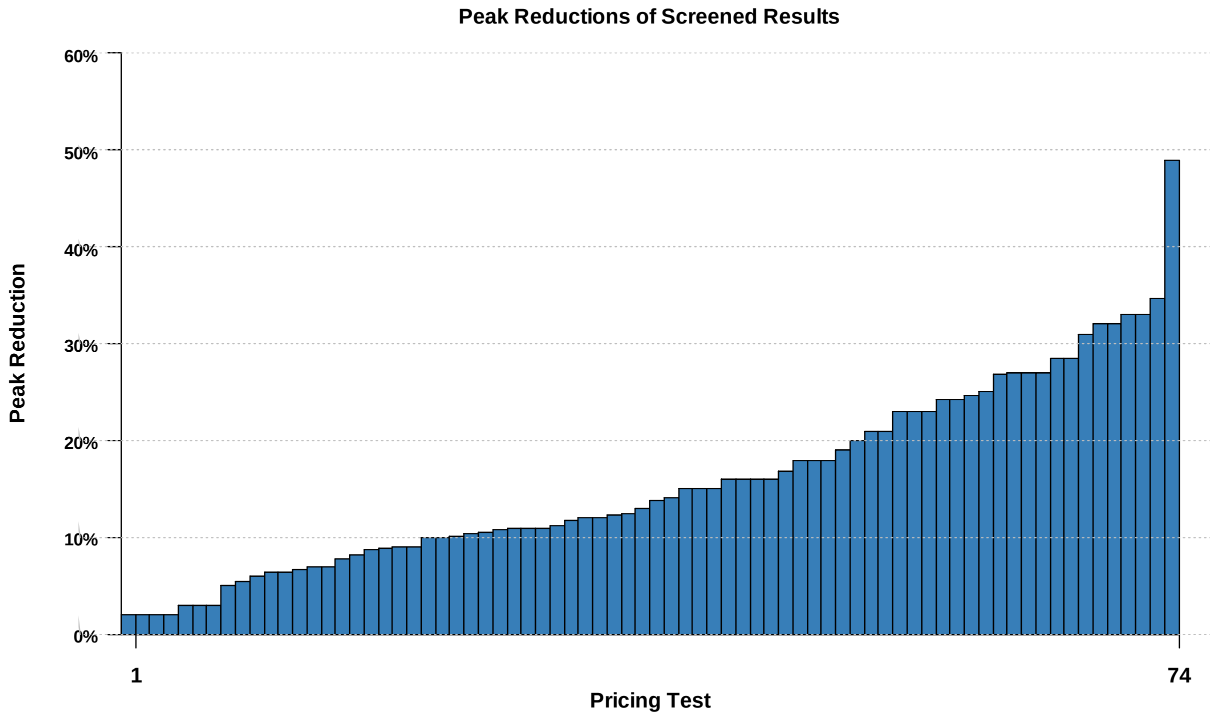
[6] OG&E was not included in these screened results because only the draft results are available thus far. When these results are finalized, they will be included in this analysis.

Table 1. Features of the Nine Dynamic Pilots

Utility	Location	Year	Rates	Enabling Technologies	Number of Tests
Baltimore Gas & Electric	Maryland	2008, 2009, 2010	CPP, PTR	CPP w/ Tech, PTR w/ Tech	17
Connecticut Light & Power	Connecticut	2009	TOU, CPP, PTR	TOU w/ Tech, CPP w/ Tech, PTR w/ Tech	18
Consumers Energy	Michigan	2010	CPP, PTR	CPP w/ Tech	3
Pacific Gas & Electric (Full scale rollout)	California	2009, 2010	TOU, CPP	Not tested	4
Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison (Statewide Pricing Pilot)	California	2003, 2004	TOU, CPP	CPP w/ Tech	4
Pepco DC	District of Columbia	2008, 2009	CPP, PTR, RTP[2]	CPP w/ Tech, PTR w/ Tech, RTP w/ Tech	4
Salt River Project	Arizona	2008, 2009	TOU	Not tested	2
Utilities in Ireland[2]	Ireland	2010	TOU	TOU w/ Tech	16
Utilities in Ontario	Ontario, Canada	2006	TOU, CPP, PTR	Not tested	6
				Total	**74**

1. Run by the Commission for Energy Regulation (CER)
2. The two RTP pricing tests are excluded from this analysis because they do not have a clear peak to off-peak price ratio.

Figure 4. Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies

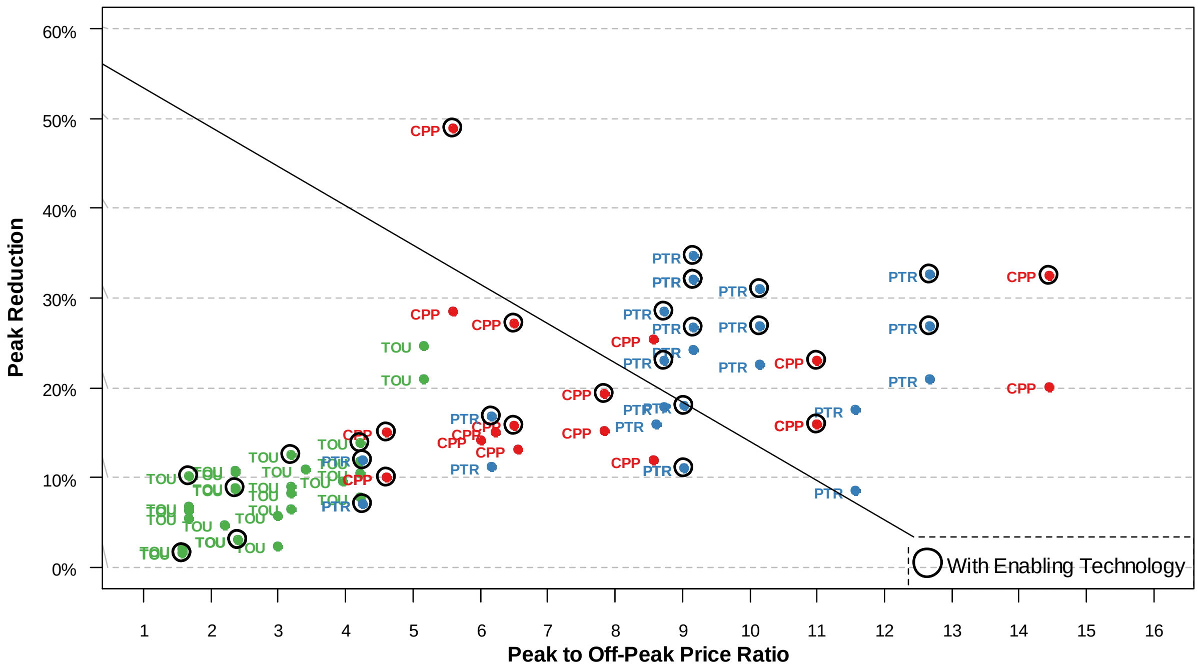


Methodology

The nine best-designed studies in *D-Rex* include 42 price-only test results and 32 price-cum-enabling technology test results for a total of 74 observations. For each result, we plot the all-in peak to off-peak price ratio against the corresponding peak reduction. As expected, the CPP and PTR rates tend to have higher peak to off-peak ratios than the TOU rates, with some overlap, and those rates with higher price ratios tend to yield greater peak reductions. [7] It also appears that that the enabling technology impacts may be greater than those with price only.

[7] For the PTR rate, the effective critical peak price is calculated by adding the peak time rebate to the rate that the customer pays during that time period.

Figure 5. Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Rate Type and Presence of Enabling Technologies



The plot suggests that peak impacts increase with the price ratio but at a decreasing rate. The logarithmic model would model rapid increases in peak reduction in the lower price ratios, followed by slower growth.[8]

Logarithmic Model

$$y = a + b * \ln(price\ ratio)$$

where $y = peak\ reduction\ percent$

Results

When we fit the logarithmic model to the full dataset (n = 74), it yields a coefficient of 0.106 with a standard error of 0.012, significant at the 0.001 level. In other words, as the price ratio increases, the peak reduction is also expected to increase. The peak-to-off-peak price ratio successfully explains 49 percent of the variation in demand response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction could be close to 30 percent.

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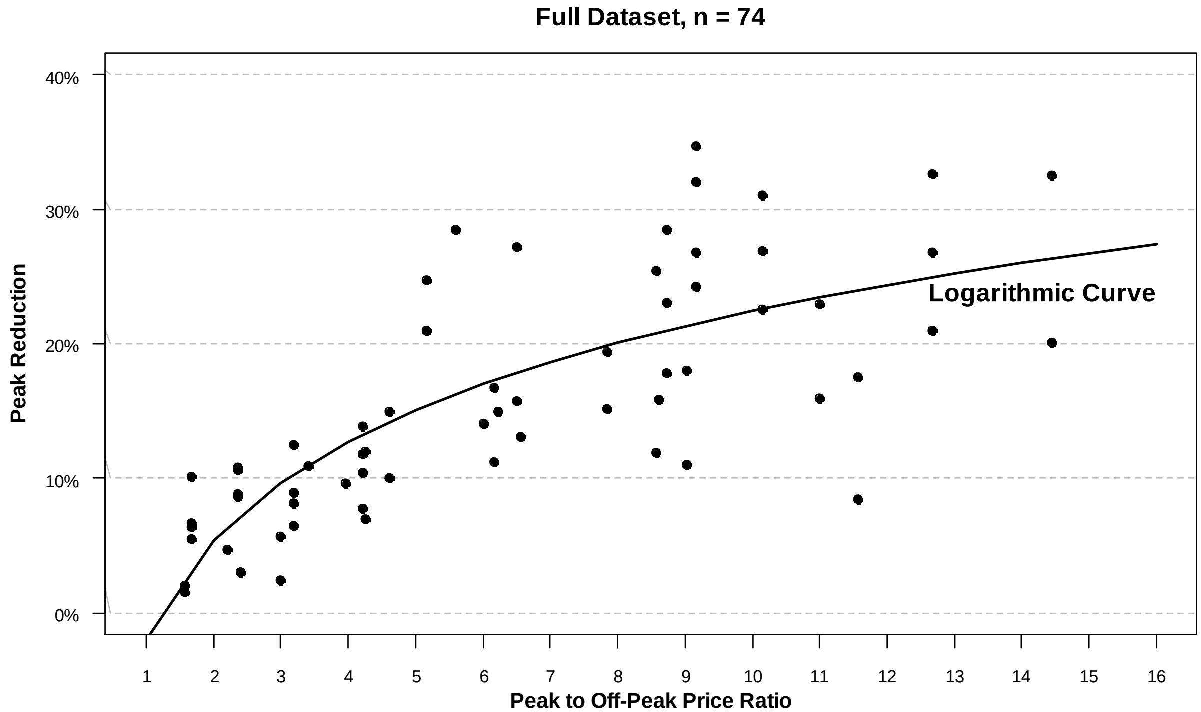
[8] We also considered a logistic growth model that features slow growth at lower price ratios followed by moderate growth, followed by an upper bound peak reduction. The results were not significantly different with this functional form.

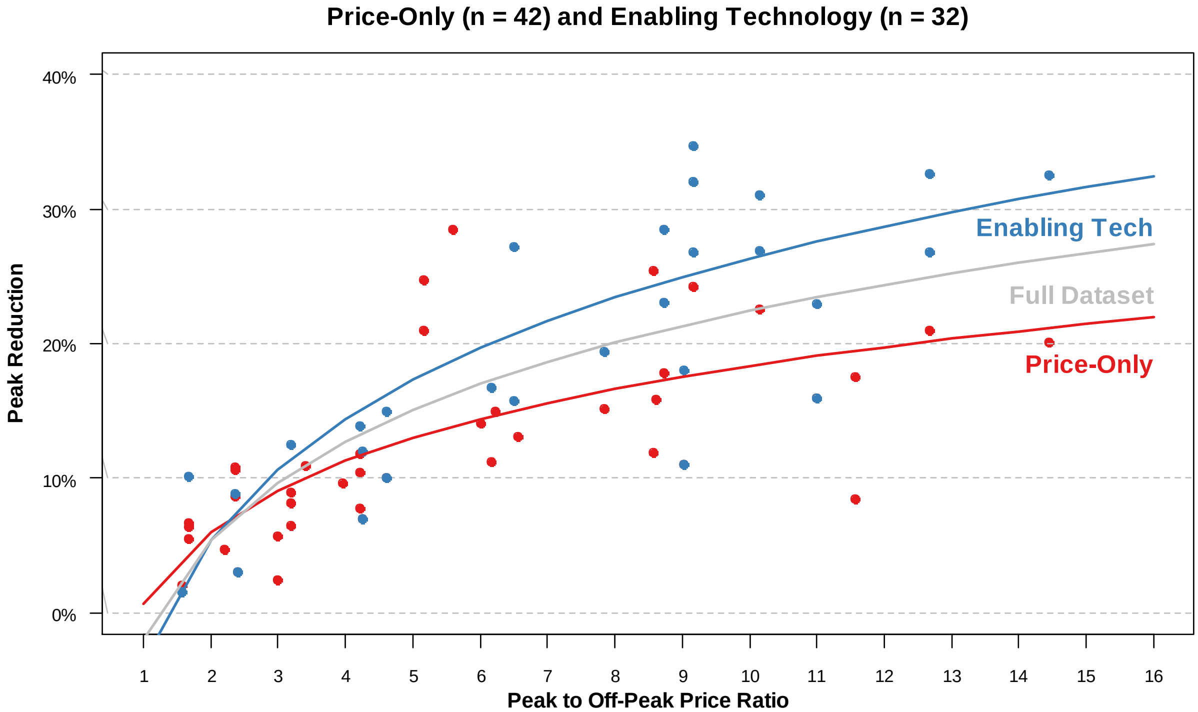
Figure 6. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curve



We can narrow down the model to focus on the price-only observations separately from the enabling technology observations. With this data, the model yields a coefficient of 0.077 with a standard error of 0.012, again significant at the 0.001 level. The coefficient is slightly lower here than in the full dataset, suggesting that the impacts increase more slowly in the absence of enabling technology. In this case, the adjusted R-squared value is 48 percent, meaning the ratio again explains almost half of the variation in response. The logarithmic curve suggests that if the peak to off-peak price ratio were to get as high as 16, the peak reduction would be slightly over 20 percent.

With the enabling technology tests, we find that the curve has a steeper slope than the result with price-only tests. The coefficient of the enabling technology curve is 0.130 which has a standard error of .02. The regression successfully explains 53 percent of the variation in demand response. With a peak to off-peak ratio of 16, the peak reduction is expected to be over 30 percent.

Figure 7. Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curves, Segregated by Presence of Enabling Technologies



The full regression results for the three different data specifications are shown in Table 2 below. In each case, the coefficient on the natural log of the price ratio is positive and significant at the 0.001 level.

Table 2. Regression Results

Coefficient	**Full Dataset**		**Price-Only**		**Enabling Technology**	
Ln(Price Ratio)	0.10611	***	0.07682	***	.13029	***
	(0.01254)		(0.01220)		(0.02164)	
Intercept	-0.01985		0.00654		-0.03668	
	(0.02234)		(0.02071)		(0.04080)	
Adjusted R-Squared	0.4916		0.4852		0.532	
F-Statistic	71.59		39.65		36.24	
Observations	74		42		32	

Standard errors are shown in parentheses below the estimates
*** = 0.001 significance
** = 0.01 significance
* = 0.05 significance

Conclusion

In our view, the results presented in this paper provide strong support for the deployment of dynamic pricing. They conclusively show that customers are responsive to changes in the price of electricity. In other words, they lower demand when prices are higher. Moreover, the results suggest that the presence of enabling technology allows customers to increase their peak reduction even further. These results may be used to quantify the potential peak reductions that may be expected when new dynamic rates are rolled out and to monetize these benefits using estimates of the avoided capacity of capacity and energy.[9]

Sources

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[9] On the monetization of benefits arising from smart meters and dynamic pricing in the context of the EU, see Ahmad Faruqui, Dan Harris, and Ryan Hledik, "Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU's smart grid investment," *Energy Policy*, 2010.

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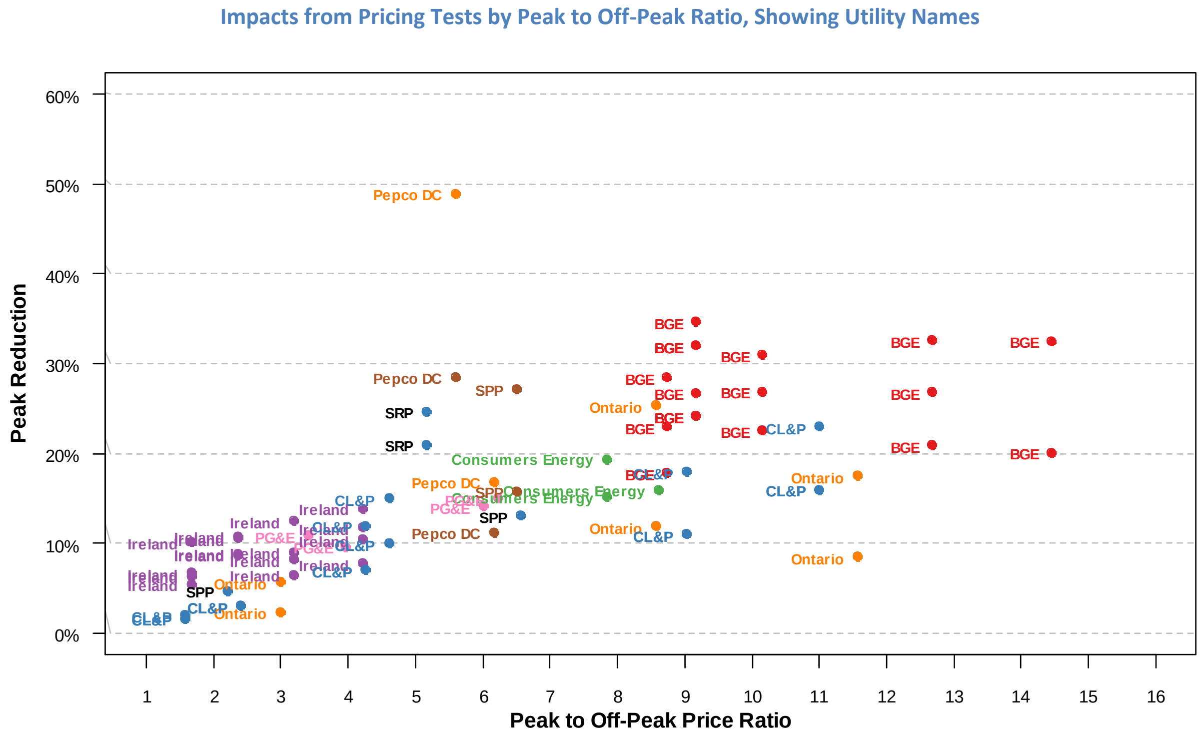
Biography of Authors

Ahmad Faruqui is a principal with The Brattle Group. He has been analyzing time-varying experiments since the beginning of his career in 1979 and his early work is cited in the third edition of Professor Bonbright's canon on public utility ratemaking. The author of four books and more than a hundred papers on energy policy, he holds a doctoral degree in economics from the University of California at Davis and bachelor's and master's degrees from the University of Karachi.

Jennifer Palmer is a research analyst at The Brattle Group. Since joining The Brattle Group in 2009, she has worked with a wide range of utilities on dynamic pricing and advanced metering projects. For several utilities, she has developed dynamic tariffs, simulated the impacts of these rates on customer consumption patterns, and estimated the resulting system-level benefits. She has a bachelor's degree in economics with a certificate in environmental studies from Princeton University.

Appendix


Impacts from Pricing Tests by Peak to Off-Peak Ratio, Showing Utility Names
Peak Reduction
Peak to Off-Peak Price Ratio
60%
50%
40%
30%
20%
10%
0%
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
Pepco DC
BGE
SPP
SRP
Ontario
CL&P
Consumers Energy
Ireland
PG&E

Final Report

Nexant
Reimagine tomorrow.

California Statewide Opt-in Time-of-Use Pricing Pilot

Final Report

March 30, 2018

Prepared for
The TOU Working Group,
under contract to:
Southern California Edison Company

Prepared by
Nexant, Inc. and
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1 Executive Summary

This document constitutes the final evaluation report for California's statewide, residential opt-in time-of-use (TOU) pricing pilots implemented by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E). These pilots were implemented in response to California Public Utilities Commission (CPUC) Decision 15-07-001. A key objective of the pilots was to develop insights that would help guide the IOUs' applications filed in January 2018 proposing the implementation of default TOU pricing for the majority of residential electricity customers and the CPUC's policy decisions regarding default pricing.[1]

Findings from the first summer—June through October 2016—are documented in the "Statewide Opt-in TOU Evaluation First Interim Report"[2] dated April 11, 2017 (hereafter referred to as the First Interim Report). This report contains detailed background information on the pilot, describes the pilot design and the evaluation methodology used for analysis, discusses each IOUs pilot implementation and treatments, and presents load impacts, bill impacts, and survey findings covering the 2016 summer period. The Second Interim Report[3] contains estimated load impacts, bill impacts, and survey findings from the winter period (October through May for PG&E and SCE, and November through April for SDG&E) and first full year of the pilot. This Final Report contains a brief summary of findings documented in more detail in the prior two reports, but focuses primarily on load impacts from the second summer period in 2017 as well as the persistence of load impacts across the two summers for the subset of customers that were enrolled for the full duration of the pilot.

The summer 2017 results provide load impacts for the entire summer rate period of June through September for PG&E and SCE, and May through October for SDG&E. This was the first analysis of a full summer season, as customer enrollment in the Pilot didn't complete until July 2016. Due to the differences in months between the first and second summer evaluations, along with changes in the participant population over time and weather differences, the results from the second summer should not be compared directly with the first summer. The persistence analysis was designed to facilitate this comparison by limiting the evaluation to months common between the two summers, and only including the subset of customers who were enrolled for the full duration of the pilot. These restrictions help control for as many differences between the two summers as possible, with the exception of the weather. The remaining differences in impacts between the summers in the persistence analysis are attributable to customers' responses to the pilot rates, and any differences in the weather. Findings from Nexant's high-level review of the relationship between weather and impact persistence is included in Section 1.2 below.

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[1] The pilots could not be implemented using default enrollment due to legal restrictions on defaulting customers onto TOU rates prior to January 2018. Default TOU rate pilots are currently underway and initial results will become available near the end of 2018 and additional results will be available in spring 2019.

[2] The First Interim Report can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453144
Additional related documents on the CPUC website can be found here: http://www.cpuc.ca.gov/General.aspx?id=12154

[3] The Second Interim Report is contained in two volumes, one authored by Nexant covering the load and bill impact analysis and the second, authored by Research Into Action covering the second survey.
The Nexant report can be found at the following link: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455573
The RIA report can be found at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455572

Collectively, the pilots implemented across the three IOUs tested nine different TOU rate options. For eight of the nine options, more than 50,000 households were enrolled and assigned to one of the TOU rates or retained in the study on the standard tiered rate to act as a control group for those who were placed on the new tariffs. The ninth rate option was a complex, dynamic rate that SDG&E tested on a very small group of customers. Recruitment for this rate led to enrollment of roughly 65 customers. Due to the low enrollment number, it is not possible to estimate load or bill impacts for customers on the ninth rate. Consequently, this rate is not covered in the evaluation.

1.1 Pilot Design and Evaluation

Evaluation of the opt-in pilots focused on a number of important research objectives, including:

- Determining the change in electricity use in different time periods for different customer segments and climate regions from each rate treatment and in response to the technology and information treatments that were also included in the pilot as described in the First Interim Report;
- Estimating the distribution of bill impacts associated with each rate option both before and after enrolling on the TOU rates;
- Assessing the extent to which the TOU rates cause unreasonable hardship among selected customer segments such as seniors and economically vulnerable customers in hot climate areas;
- Determining satisfaction with and perceptions about, understanding of and reported changes in behavior associated with different treatment options.

Although recruitment for the pilots was done on an opt-in basis, not opt out, customers were not recruited onto a specific rate. Instead, the pilots were implemented through what came to be called a "pay-to-play" (PTP) recruitment strategy. Under this approach, prospective participants were offered an economic incentive for agreeing to be in the pilot and were then randomly assigned to one of three[4] rate options or to the control condition after agreeing to participate. Since a key motivation for enrolling on the study was likely to be the PTP incentive rather than the attractiveness of any particular rate feature, this approach eliminates any differential selection bias that might have otherwise occurred if customers were recruited onto each rate separately. It also adheres strictly to the design standard of a randomized control trial (RCT), which is the gold standard of experimental design. The PTP recruitment design may also result in enrollment of a mix of customers more similar to those who would be enrolled under default conditions for reasons discussed in detail in Section 2.1 of the First Interim Report.

Load and bill impacts were estimated for CARE/FERA[5] and non-CARE/FERA customer segments in each of three climate regions (hot, moderate, and cool) in each IOU service territory. In the hot climate region in the PG&E and SCE service territories, senior households (e.g., households with at least one resident who is 65 years or older) and households with incomes below 100% of Federal Poverty Guidelines (FPG) were oversampled for one rate option in order to assess whether TOU rates might cause undue hardship for these segments.

[4] For SDG&E, participants were assigned to one of two rate options or the control group.

[5] California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) customers receive significant electricity price subsidies. Participation in these programs is tied to income and household size.

Load impacts for each rate and technology treatment were estimated by comparing loads for customers randomly assigned to each TOU tariff (e.g., treatment customers) with loads for customers randomly assigned to the otherwise applicable tariff (OAT) (e.g., control customers). The difference in loads between treatment and control customers in each rate period before customers are placed on the TOU rate (e.g., the pretreatment period) is subtracted from the difference after customers are placed on the rate (e.g., the treatment period) to ensure that there is no bias in the estimated impact due to random chance. This is referred to as a "difference-in-differences" (DiD) analysis. When applied to data collected through an RCT design, DiD analysis produces the most accurate load impact estimates possible through experimental research.

Bill impacts[6] were estimated in a similar manner to load impacts in that a DiD analysis was conducted in order to control for exogenous factors that might impact bills between the pre- and post-treatment periods. Bill impacts were estimated as the difference between bills using pre- or post-treatment loads based on the TOU tariff compared with the OAT. Average bill impacts are reported as well as changes in the percent of customers who experience bill impacts above a certain threshold.

Assessing the extent to which TOU rates cause unreasonable hardship among selected customer segments such as seniors and economically vulnerable customers in hot climate regions is done primarily through survey questions designed to measure hardship. Two surveys were conducted, one following the first summer period and another at the end of the first year on the pilot rates.[7] Both surveys were sent to the entire treatment and control population using a mixed mode, email, mail and phone (EMP) methodology. Responses between treatment and control customers were compared to determine if TOU rates significantly increase the percent of customers that report hardship conditions. Satisfaction with, perceptions about, understanding of, and reported changes in behavior associated with different rates and other treatment options were also determined through surveys. Response rates varied somewhat across customer segments and treatment cells but were quite high (e.g., ranging from 66% to 92%) in all segments. As such, any differential response bias across segments and treatments is believed to be insignificant. The survey was designed, managed and analyzed by Research Into Action (RIA).

1.2 Load Impacts

Table 1.2-1 presents the average weekday peak period load reductions for each rate and season for each IOU.[8] Key findings for load impacts are summarized following the table.

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[6] Bill impacts were estimated following the first summer and after completion of the first year of the pilot. Impacts were not estimated again after the second summer. For convenience, key findings from the first two interim reports are included in this report.

[7] Key findings from the two surveys are included in this report but no additional surveys were conducted after the end of the first year. Very detailed survey results are contained in the First and Second Interim Reports.

[8] The values in the table represent the average reduction for each peak period for each rate for the active participants during that season. They do not represent average reductions for a common set of hours or a common set of customers. As such, variation in average load reductions across rates may be due to a differences in the peak-to-off-peak price ratios as well as differences in the length and timing of the peak period. Variation in average load reductions across seasons may be due to changing customer populations, differences in weather conditions, and perhaps other exogenous factors.

Table 1.2-1: Weekday Peak Period Load Reductions*

Utility	Metric	Rate 1			Rate 2			Rate 3		
		Summer 2016	Winter 2016/2017	Summer 2017	Summer 2016	Winter 2016/2017	Summer 2017	Summer 2016	Winter 2016/2017	Summer 2017
PG&E	Peak Period Hours	4 PM - 9 PM			6 PM - 9 PM			4 PM - 9 PM		
	% Impact	5.8%	3.6%	5.3%	6.1%	3.6%	3.8%	5.5%	3.5%	5.6%
	Absolute Impact (kW)	0.06 kW	0.03 kW	0.06 kW	0.06 kW	0.03 kW	0.04 kW	0.06 kW	0.03 kW	0.06 kW
SCE	Peak Period Hours	2 PM - 8 PM			5 PM - 8 PM			4 PM - 9 PM		
	% Impact	4.4%	1.4%	3.6%	4.2%	2.0%	4.1%	2.7%	3.2%	4.0%
	Absolute Impact (kW)	0.06 kW	0.01 kW	0.04 kW	0.06 kW	0.02 kW	0.06 kW	0.03 kW	0.03 kW	0.05 kW
SDG&E	Peak Period Hours	4 PM - 9 PM			4 PM - 9 PM			N/A		
	% Impact	5.4%	2.3%	4.6%	4.6%	1.7%	4.1%			
	Absolute Impact (kW)	0.04 kW	0.02 kW	0.03 kW	0.04 kW	0.01 kW	0.03 kW			

* All impacts presented here are statistically significant

- **Customers can and will respond to TOU price signals during evening hours.** All eight tariffs included in the pilots had a substantial portion of the peak period covering key evening hours. Indeed, the common hours across all eight tariffs are from 6 PM to 8 PM. Some tariffs had peak periods extending until 9 PM and some had shoulder periods extending until midnight. Statistically significant load reductions were found for all rates tested for each IOU service territory for each season. Table 1.2-1 summarizes the percentage and absolute peak-period load reductions for each rate and service territory by season. For the first summer of the pilot, the lowest load impact occurred for SCE's Rate 3, showing an average reduction of 2.7% and 0.03 kW, and the highest occurred for PG&E's Rate 2, which had an average percentage reduction of 6.1% and 0.06 kW. In winter months, the lowest load impact occurred for SCE's Rate 1, showing an average reduction of 1.4% and 0.01 kW, and the highest and the highest occurred for PG&E's Rate 1 and Rate 2, which had average percentage reductions of 3.6% and 0.03 kW. In the second summer, the lowest impacts were 3.6% or 0.04 kW for SCE's Rate 1 and the highest were 5.6% or 0.06 kW for PG&E's Rate 3. On average across all rates, the average peak period reduction for the two summers was 4.6%. With TOU price signals (Tier 2 peak to off-peak price ratios) ranging from around 1.3 to 2.0, the load reductions are not just statistically significant, but could meaningfully reduce the need for peaking capacity, especially if similar impacts could be obtained through default enrollment for all residential customers.

- **Persistence in load impacts between the first and second summer varied by utility.** At PG&E, summer load reductions either declined or remained the same between the first and second summer of the pilot. Most customer segments at SCE showed comparable summer load reductions from the first summer to the second. At SDG&E, percent[9] load reductions in the first and second summer were nearly identical. Weather does not appear to have been a significant driver of persistence. Upon examination of the correlation between weather and impact persistence, no drop-off or increase in persistence appeared to be associated with weather.

- **Customers can and will respond to TOU price signals on weekends.** An important policy question given shifting load patterns at some utilities is the magnitude of peak-period load reductions on weekends. Not all pilot rates had peak-period prices in effect on weekends but for those that did, peak-period reductions and the pattern of load reductions across rate periods on weekends were generally similar to weekday impacts.

- **Peak period reductions in winter were significantly less than in summer.** The average peak-period reduction in winter across all eight rates was 2.7%, with a range from 1.4% for Rate 2 in SCE's service territory to 3.6% for Rates 1 and 2 in PG&E's service territory.

- **Most TOU rates produced overall reductions in electricity use.** Also of interest is whether TOU rates lead to overall reductions, increases, or no change in electricity use. At the service territory level, the average reduction in daily electricity use in summer 2016 across all eight rates equaled 1.9%, with a range from 0.4% for Rate 2 at PG&E to 3.4% for Rate 2 at SDG&E. In summer 2017, the average across all rates was 1.4% with a range from 0.1% to 2.2%. Reductions in the winter were smaller, averaging 0.7% across all rates. There was significant variation in estimated

[9] Percent load reductions rather than kW were evaluated for the persistence analysis to allow for comparison of impacts relative to the available load. For example: if the second summer were cooler than the first, the kW impacts may be lower due to less cooling load, but customers may still be responding similarly between summers given the available load to curtail. The percent impacts help to normalize for any level differences in usage between the summers.

impacts across rates, climate regions and customer segments (CARE/FERA or non-CARE/FERA) but the majority of rate/season/climate region/segment combinations showed small but statistically significant reductions in daily electricity use.

- **Summer peak-period load impacts varied across climate regions and service territories.** In both summers, the absolute impacts at both PG&E and SDG&E were largest in the hot climate region, second largest in the moderate region and smallest in the cool region for all rates. The pattern was similar for percentage impacts although not all differences across regions were statistically significant. At SCE, the pattern was different. In general, the differences across regions were smaller than at PG&E or SDG&E and in some cases, the largest load reduction was found in the cool climate region and the smallest in the hot region. It is noteworthy that SCE's hot region has many more hot days than PG&E's hot region and SCE's moderate region is much hotter than PG&E or SDG&E's moderate regions. These differences, combined with the fact that some of SCE's rates had long shoulder periods during which prices were higher than in the off-peak period may have made it difficult for customers in hot regions to reduce energy use and still stay reasonably comfortable.

- **CARE/FERA customers had lower average percent and absolute peak period load reductions in summer compared with non-CARE/FERA customers.** This pattern was typically (although not universally) true at PG&E and SDG&E for all rates and climate regions. Once again, SCE had a different result for some rates and climate regions. In selected cases, CARE/FERA customers even had larger load reductions than non-CARE/FERA customers in SCE's service territory. The SCE results notwithstanding, the smaller load reductions by CARE/FERA customers in most service territory/climate region combinations compared with non-CARE/FERA customers, could be due to greater difficulty by CARE/FERA customers in reducing or shifting loads. For example, lower income households may lack quality insulation or may have undersized air conditioning equipment, resulting in a greater burden for them to reduce cooling energy use compared to a household with higher quality insulation or adequately sized air conditioning units. Low income customers may also work two jobs, or longer hours, limiting their flexibility to shift loads such as laundry or cooking. It may also be that low income households have lower saturations of end uses such as dishwashers and clothes driers, that can easily be shifted from peak to off-peak periods.

- **Load impacts for households with incomes below 100% of FPG in hot climate regions differed between PG&E and SCE.** This segment did not show statistically significant peak-period load reductions in PG&E's service territory until the second summer of the pilot. However, in SCE's hot climate region, these very low income households had load reductions similar to or slightly larger than the general population in the hot climate region in all three seasons.

- **Senior households in the hot climate region had load impacts very similar to those of the general population.** This was true for both PG&E and SCE in summer 2016 and in winter period. In the second summer, seniors households in SCE's hot climate region actually had greater impacts than the general population in the hot climate region (5.6% vs. 2.9%).

- **Smart thermostats appear to increase load reductions when automated through vendor support.** SCE recruited customers who already owned smart thermostats into the study and randomly assigned them to rate and treatment groups. In the first summer, absolute load impacts for smart thermostat owners were similar to those for the general population even though they had larger usage overall and, therefore, might be expected to have larger load reductions. In winter, smart thermostat owners reduced peak period usage by approximately 4.9% in the SCE service territory, which was significantly higher compared to the non-CARE/FERA population weighted load reductions of 1.8%. In the second summer, the smart thermostat provider implemented specialized thermostat programming optimized for TOU rates, and load reductions increased significantly relative to the first summer. Load impacts in the first summer (July, August, and September) were 3.1%; in the same months during the second summer, impacts increased to 8.1% for the common set of customers enrolled in both summers.

- **The incremental impact of Weekly Usage Alert emails at SDG&E is mixed.** SDG&E tested whether delivery of weekly summaries of usage and bills to TOU customers would produce greater load reductions compared with households on TOU rates that did not receive this information. There was no statistically significant impact for WAEs in summer 2016. However, during the winter months, WAE recipients in SDG&E's moderate climate region had small but statistically significant increases in load reductions equal to approximately 0.01 kW, whereas customers in the cool climate region had impacts decline by approximately 0.01 kW. In summer 2017, customers in the moderate climate region who received the WAEs had statistically significant incremental impacts equal to 0.02 kW.

- **Acceptance rates for PG&E's smart phone app were very low.** PG&E offered a smart phone app that provides a variety of information to those who download it that might help them to manage their energy use. The number of customers who successfully downloaded and accessed the app was quite low and there were not enough users to determine whether the app had an impact on load reductions. App users were surveyed and those who responded reported liking the app.

- **Higher incentives for smart thermostats produced higher acceptance rates.** SDG&E offered rebates for smart thermostats to customers on TOU rates through the Whenergy program**.** Roughly 14,000 rebated offers were made, with roughly 30% of the offers being made through direct mail and the remainder through email. About half of the offers involved a $100 rebate and the other half a $200 rebate. 349 applications (2.4%) were received, and of those, 246[10] were deemed eligible and ultimately accepted. The eligible acceptance rate for the $100 rebate was 1.3% and for the $200 rebate, it was 2.1%.

1.3 Bill Impacts

Average monthly bill impacts were estimated for summer, winter and the year as a whole. Key findings include the following:

- **At PG&E and SCE, average summer monthly bills were higher for all TOU rates than they would have been on the OAT for all customer segments and all climate regions.** Average monthly bill increases over three summer months ranged from a low of roughly $5 to as much as $40**.** Absolute summer bill impacts were typically largest in the hot climate region, second largest in the moderate region and smallest in the cool region.

[10] Load impacts were not estimated for the customers who received the rebates due the sample size being too small to yield statistically significant impacts.

- **Average monthly winter bills were lower for all TOU rates than they would have been on the OAT for nearly all customer segments and all climate regions at PG&E and SCE.** The exception was CARE/FERA customers on Rate 3 in SCE's cool climate region, which saw a very small ($1/month) bill increase in winter. Average monthly bill reductions over the winter months ranged from a low of roughly $1 to as much as $12.

- **Bill impacts at SDG&E were quite different from those at PG&E and SCE**, with very small structural impacts in both summer and winter months. At SDG&E, some customer segments were able to more than offset small structural bill increases with load shifting or conservation behavior and, thus, had slightly lower bills even during the summer period than they would have had on the OAT. Customers faced winter bill impacts that were generally less than 1% in either direction, at the territory level and at the CARE/FERA and non-CARE/FERA level.

- **Total annual bill impacts were very small at all three utilities, with average monthly impacts ranging between 0% (no change) and savings of up to 2%.** The 12-month bill impact varied significantly by climate region and CARE/FERA status. At SCE, CARE/FERA customers faced greater bill increases than non-CARE/FERA customers in most cases (on a percentage basis).

The stark contrast between the relatively large bill increases for TOU customers during the summer months at PG&E and SCE relative to SDG&E is noteworthy. This large difference did not stem from SDG&E having significantly more modest peak-to-off-peak price differentials or smaller differentials between peak prices and the OAT price relative to the other two utilities. Indeed, SDG&E's price differentials were larger than for several of the pilot rates at PG&E and SCE. Rather, the much more modest bill impacts at SDG&E had to do with the fact that both SDG&E's OAT and TOU rates are seasonally price differentiated, with higher prices in the summer than in the winter. SCE and PG&E's OATs are not seasonally differentiated, but their TOU rates are. As a result, the summer bill differentials between their TOU and OAT rates were much greater than SDG&E's.

Although most customers saw very modest bill decreases on an annual basis, the seasonal volatility at PG&E and SCE is concerning, although it should be noted that, especially in hot climate regions, there is significant seasonal variation in bills even under the OAT due to seasonal variation in usage and the tiered rate structure. It is important to keep in mind that bill volatility across seasons can be managed through tools designed specifically to address bill volatility, such as balanced payment plans, which allow customers to pay the same bill each month based on historical usage and current rates (with periodic true-ups). The extent to which this option might mute TOU price signals is subject to debate and will be examined in the default pilots that are currently in the field at each IOU.

A final point to keep in mind is that all customers who will be defaulted onto TOU rates in 2019 will receive bill protection for the first full year on the new tariff. As such, while summer bills may be higher than under the OAT, customers who stay for a full year will not pay a higher bill than they would under the OAT.

1.4 Customer Attrition

Customer attrition is driven by three very different factors. One is customers who move, referred to as customer churn. Another is customers who become ineligible as a result of factors such as installing solar, going onto medical baseline, or switching to service from a Community Choice Aggregator (CCA).

The final factor is customers who consciously opt out of the rate because they are unhappy being on a TOU rate. Importantly, opt-out rates in these pilots were likely influenced, perhaps significantly so, by the incentives that were paid to customers over the first year of the pilot. Customers received a portion of their enrollment incentive upon enrollment, a portion when the first survey was completed in fall 2016 and the final portion after the second survey was completed in late spring 2017. As such, absolute opt-out rates may not be an accurate guide to what would occur in the absence of the incentive payments. Relative opt-out rates across tariffs, however, may provide useful insight regarding the relative preferences of customers for various rate options.

Key findings concerning customer attrition include the following:

- **Cumulative opt-out rates between enrollment and the end of September 2017 were quite low for nearly all rates and customer segments.** Opt-out rates varied across tariffs, service territories, climate regions and customers segments. At the granular customer segment level, the cumulative percent of treatment customers who dropped off the rate was between 1% and 10% at PG&E, and at SCE it was between 0.5% and 14%. For SDG&E, customer segment level opt-out rates were between 1% and 3.9%. Territory wide at PG&E and SCE, there are small differences in the cumulative percent of opt outs between tariffs at each utility. Cumulative opt-out rates territory wide are greatest for PG&E's Rate 2 and SCE's Rate 3 (about 7% and 6%, respectively). At SDG&E, the greatest cumulative opt-out rate, about 3.5%, is for customers in the hot climate region on Rate 2.
- **The number of customers dropping off the TOU rates was highest in the hot region,** second in the moderate region and lowest in the cool climate region for all tariffs.
- **Opt-out rates were slightly lower for CARE/FERA customers in PG&E and SDGE's service territory compared with non-CARE/FERA customers.** In SCE's territory, the differences between CARE/FERA and non-CARE/FERA were small. Opt-out rates leveled off over the course of the winter but ramped up again during the second summer, especially at PG&E.
- **Overall attrition ranged from as low as 12% to as high as 39%** with the highest being for CARE/FERA customers in SCE's hot climate region on Rate 3. Attrition was generally about 10 percentage points higher at SCE than at PG&E, with roughly two thirds of the overall attrition driven by customer churn or CCA activity. Attrition has also been high in PG&E's moderate and cool climate regions for some segments due primarily to customers switching to CCAs, which are quite active in PG&E's service territory.

1.5 Survey Findings

Key findings from the surveys that were administered include the following:

- **Economic hardship was not materially increased by TOU rates for most segments of interest in hot climate regions.** Economic hardship was assessed through survey questions that were used to develop an economic hardship index. Comparisons in index values were made between treatment and control customers in PG&E and SCE's hot climate regions for CARE/FERA customers, senior households, households with incomes below 100% of FPG and households with incomes between 100% and 200% of FPG.[11] In spite of large increases in bills relative to the

[11] The First and Second Interim Reports contain similar comparisons for other climate regions and segments although these segments were not required to be investigated as part of the regulatory decisions guiding implementation of the TOU pilots.

OAT, there were no statistically significant differences in the economic index for any customer segment at PG&E in the first summer period. At SCE, Rate 3 CARE/FERA customers and Rate 2 customers with incomes between 100% and 200% of FPG had higher economic index scores when compared with control group customers. In the second survey, covering winter and spring, none of the segments of interest at SCE showed any statistically significant difference between treatment and control customers. PG&E Rate 3 customers in the hot climate region had a higher economic index score than control customers. For context, the size of the difference in the economic index scores in the above cases is equivalent to the difference in the value of the index from using one additional non-income based method to pay bills or from having difficulty paying one additional bill over the relevant time period (e.g., summer or winter/spring).

- **Health hardship was not materially increased by TOU rates for most segments of interest in hot climate regions.** The surveys also asked customers with air-conditioning equipment and a disability whether members of their household had sought medical attention due to excessive heat in summer, and the second survey asked space-heating customers with a disabled household member whether they sought attention for excessive cold in winter. No difference in the health metric was found for PG&E customers in the summer or winter periods. At SCE, about 10% more Rate 1 and Rate 3 CARE/FERA customers reported seeking medical attention due to excessive heat in the summer and about 6% of Rate 1 and 2 CARE/FERA eligible customers reported seeking medical attention due to excessive cold in the winter compared with control customers. In addition, the second survey included an index to measure overall health hardship, and no differences in average health hardship scores were found at PG&E or SCE.

- **TOU rates do not appear to materially increase or decrease customer satisfaction ratings for the rate or the utility.** Satisfaction with the rate and the IOU were measured on an 11-point scale in both the first and second survey and average ratings were compared between treatment and control customers. Following the first summer at PG&E and SCE, when bills were higher for nearly all customers relative to the OAT, satisfaction ratings with the TOU rate and with the utility were typically slightly lower for TOU rate customers than for control customers and these differences were sometimes statistically significant. However, all differences were less than 1 point on an 11-point scale. In the second survey, following the winter season when bills were much lower, satisfaction ratings for both the IOU and the rate were significantly higher for many of PG&E's and SCE's rate segments, and SDG&E's Rate 2 segments, compared to the first survey results, indicating a significant improvement in satisfaction. Average ratings were slightly lower, however, for many Control group segments compared to first survey results.

- **More customers on TOU rates received bills that were higher than expected in summer.** A large percent of both treatment and control customers reported that their summer bills were higher than expected, but this perception was greater for more customers on TOU rates for most rates, customer segments, and climate regions. The second survey showed that a significantly smaller percent of most customers on TOU rates received bills during the previous six months that were higher than expected compared to the summer months, especially in the hot and moderate regions. This is an important finding that should influence not only the timing of enrollment for customers on TOU rates (e.g., enrolling customers during winter or spring, not in summer or early-fall) but also the content of ME&O materials, which should be designed to prepare customers for higher than expected bills in summer while reminding them about lower bills at other times of the year.

- **CARE/FERA customers had much lower understanding of the timing of the peak period than non-CARE/FERA customers.** Both surveys showed a significant disparity in understanding of the timing of the peak period between CARE/FERA and non-CARE/FERA customers. For some rates and climate regions, between 30% and 40% of CARE/FERA customers could not identify a single hour that fell during the peak-period rate window on the first survey. This disparity could partly be due to the fact that more CARE/FERA customers have English as a second language, but there may be other explanations. In the second survey, a significant improvement in the understanding of peak hours was found for most of PG&E’s customers, SCE’s Rate 3 customers, and SDG&E’s Rate 1 customers, but understanding significantly declined for SCE’s Rate 1 and 2 customers and SDG&E’s Rate 2 CARE/FERA customers.

- **Many customers may not accurately understand bill protection.** In the second surveys, customers were asked if they knew when bill protection ends and about half to two-thirds of customers reported knowing this. At SCE and SDG&E, customers were also given a brief explanation of bill protection and asked if they understood what it means (e.g., yes/no). Over 86% reported they did understand. PG&E customers, however, were provided the same brief explanation but were asked to choose what bill protection means among four possible choices. Between 28% and 59% selected the correct meaning while 25% to 51% chose the wrong answer. Customers may overwhelmingly understand bill protection generally, but many do not understand the specifics when presented with other possible meanings (e.g. several customers think they will receive a bill credit each month during the first year instead of receiving one credit after the first year).

- **For all three utilities, customers on TOU rates were more likely to take time-specific actions than customers on the OAT.** For example, while a similar proportion of customers from control and treatment groups indicated they turned off their lights to conserve energy, a larger proportion of treatment customers indicated they shifted doing laundry and running the dishwasher during peak hours. Differences in the number of actions taken between treatment and control customers were found in both the first and second surveys.

2 Introduction

In Decision 15-07-001, the California Public Utilities Commission (CPUC or the Commission) ordered California's three investor owned utilities (IOUs) to conduct certain "pilot" programs and studies of residential Time-of-Use (TOU) electric rate designs (TOU Pilots and Studies) beginning the summer of 2016, and to file applications no later than January 1, 2018 proposing default TOU rates for the majority of residential electric customers. The IOUs were also directed to form a working group (TOU Working Group) to address issues regarding the TOU pilots and to hire one or more qualified independent consultants to assist with the design and implementation of the TOU Pilots and Studies. Nexant, Inc. was engaged as the independent consultant.

Collectively, the pilots implemented across the three IOUs are testing nine different TOU rate options. For eight of the nine options, more than 50,000 households were enrolled and assigned to one of the TOU rates or retained in the study on the standard tiered rate to act as a control group for those who were placed on the new tariffs. The ninth rate option is a complex, dynamic rate that SDG&E is testing on a very small group of customers. Recruitment for this rate led to enrollment of roughly 65 customers. A key objective of the pilots was to develop insights that would help guide the IOUs' applications filed in January 2018 proposing the implementation of default TOU pricing for the majority of residential electricity customers and the CPUC's policy decisions regarding default pricing.[12]

Findings from the first summer—June through October 2016—are documented in the "Statewide Opt-in TOU Evaluation First Interim Report"[13] dated April 11, 2017 (hereafter referred to as the First Interim Report). This report contains detailed background information on the pilot, describes the pilot design and the evaluation methodology used for analysis, discusses each IOUs pilot implementation and treatments, and presents load impacts, bill impacts, and survey findings covering the 2016 summer period. The Second Interim Report[14] contains estimated load impacts, bill impacts, and survey findings from the winter period and first full year of the pilot. This Final Report contains a brief summary of findings documented in more detail in the prior two reports but focuses primarily on load impacts from the second summer period in 2017 as well as the persistence of load impacts across the two summers for the subset of customers that were enrolled for the full duration of the pilot.

A brief summary of the pilot design and evaluation approach is contained in the Executive Summary (Section 1.2). The remainder of this report is organized as follows. Sections 3, 4, and 5 summarize the load impact results along with a synthesis section for PG&E, SCE, and SDG&E, respectively. Each section starts with a discussion of customer opt-out rates and attrition over the course of the entire pilot. Following the attrition section, load impacts by rate period are presented for each rate option and relevant customer segment for the second summer. The next subsection discusses impact persistence between the first and second summers for a common set of customers that were enrolled over the

[12] The pilots could not be implemented using default enrollment due to legal restrictions on defaulting customers onto TOU rates prior to January 2018. Default TOU rate pilots are currently underway and initial results will become available near the end of 2018 and additional results will be available in spring 2019.

[13] The First Interim Report can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453144 Additional related documents on the CPUC website can be found here: http://www.cpuc.ca.gov/General.aspx?id=12154

[14] The Second Interim Report can be found here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455573

entire course of the pilot. The final subsections of Sections 3 through 5 provide a high level summary and synthesis of the impact and survey results for each IOU.

Section 6 provides a comparison of results across the utilities as well as overall conclusions that can (or cannot) be drawn from the entire body of research. While the pilots were designed jointly and are meant to be complementary, they were not designed specifically to allow cross-utility comparisons in most instances. For example, it is not appropriate to compare Rate 1 from SCE's pilot to Rate 2 from PG&E's pilot and conclude that one rate produced greater load impacts than the other due to differences in rate structure because differences in other factors, such as climate, customer demographics, customer satisfaction, perceptions about the utility, economic conditions and perhaps others may partially or fully explain any observed differences in the load impacts between the two rate options. Nevertheless, cross-utility comparisons are likely to be made by reviewers and some comparisons are more valid than others. As such, we provide a brief comparison of some key findings across utilities in this final section.

Appendix A to this report contains a list of Microsoft Excel files that have been filed as electronic tables in conjunction with the primary report. These electronic tables allow readers to access the underlying data that created the figures and tables in the report, and to determine actual values for data points within the figures.

A summary of key findings from the first and second customer surveys are available in the second volume of this report "California Statewide Opt-In Time-Of-Use Pricing Pilot: 2016 & 2017 Customer Survey Results Summary & Comparisons", written by Research Into Action. This volume also includes two additional series of analyses and results. First, statistical comparisons of the differences between results for the questions that were included in both surveys were made to measure change over time. Second, cross-tabulations of key metrics based on two respondent characteristics, customer language preference (English vs. non-English) and customers' level of understanding of their on-peak hours (high vs. low understanding), were conducted to determine if results varied significantly by these characteristics.

The First Interim Report contained detailed background information on the pilot, a detailed methodology section, and detailed descriptions of each IOUs pilot implementation and treatments. Readers interested in this background information are encouraged to review the first report, as this information is not repeated here. Interested readers may also wish to review the TOU Pilot Design Report,[15] which contains a detailed discussion of research issues and explanations for the design decisions that were made by the TOU Working Group. The IOU advice letters[16] and the CPUC resolutions may also contain information of interest.[17]

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[15] George, S., Sullivan, M., Potter, J., & Savage, A. (2015). Time-of-Use Pricing Opt-in Pilot Plan. *Nexant, Inc.*

[16] SCE: Advice Letter 3335-E; PG&E: Advice Letter 4764-E; and SDG&E: Advice Letter 2835-E.

[17] SCE: Resolution E-4761; PG&E: Resolution E-4762; and SDG&E: Resolution E-4769.

3 PG&E Evaluation

This report section summarizes the attrition and load impacts for the second summer of PG&E's pilot. It also includes a discussion of load impact persistence throughout the entire pilot. Load and bill impacts from the first summer season can be found in the First Interim Report and similar results for the winter season may be found in the Second Interim Report.

3.1 Summary of Pilot Treatments

Figure 3.1-1 through Figure 3.1-3 summarize the three tariffs that were tested in the PG&E service territory. All three tariffs have peak periods that include the prime evening hours from 6 PM to 9 PM. The rates have changed since the launch of the pilot, and the figures represent the tariffs that were in effect in March 2017 and do not reflect the baseline credit of 8.8 ¢/kWh. Appendix B shows the prices that were in effect in each rate period for each tariff, including the OAT. Two sets of prices are shown in the appendix, one covering the period from pilot start through February 2017, and the other beginning on March 1, 2017. While several minor rate changes occurred over the course of the pilot, the rate adjustment that occurred on March 1, 2017 was more significant and, as such, was factored into the estimation of bill impacts in the Second Interim Report.

Rate 1 is a simple, two-period rate with a weekday peak period from 4 PM to 9 PM all year long and off-peak prices in effect on all other weekday hours and all hours on weekends. The tier-2 (price without baseline credit), peak-to-off-peak price ratio[18] in the summer is roughly 1.3 to 1 and is very modest in the winter (non-summer months).

Rate 2 is slightly more complex than Rate 1 as it adds a summer "Partial-Peak" period covering the two hours immediately preceding and the one hour immediately following the three-hour peak period that runs from 6:00 PM to 9:00 PM on weekdays and weekends. In order to offset the additional complexity incurred with a third TOU period, PG&E kept the same prices in effect on both weekdays and weekends.

Rate 3 is more complex than Rates 1 and 2. It includes TOU pricing in the spring (from March until May) that differs from pricing in the winter in order to allow for lower prices during low-cost hours from 10:00 AM until 4:00 PM to be charged in a "Super-Off-Peak" period. The "Super-Off-Peak" period coincides with the period CAISO identifies as being at high risk for excess supply in the future. Rate 3 has the same design as Rate 1 for the summer and winter seasons, with peak times from 4:00 PM to 9:00 PM and all other hours being off-peak. In the spring, the peak hours are also the same as Rate 1, but the remaining hours are divided into off-peak and super-off-peak periods.

[18] The peak-to-off-peak price ratio is equal to the peak price divided by the off-peak price.

Figure 3.1-1: PG&E Pilot Rate 1 (March 2017)[19]

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off-Peak (30.7¢)																Peak (41.0¢)							
	Winter	Off-Peak (26.1¢)																Peak (28.0¢)							
	Spring	Off-Peak (26.1¢)																Peak (28.0¢)							
Weekend	Summer	Off-Peak (30.7¢)																							
	Winter	Off-Peak (26.1¢)																							
	Spring	Off-Peak (26.1¢)																							

Figure 3.1-2: PG&E Pilot Rate 2 (March 2017)

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off Peak (28.6¢)																Partial Peak	Peak (43.5¢)						
	Winter	Off Peak (26.0¢)																	Peak (28.6¢)						
	Spring	Off Peak (26.0¢)																	Peak (28.6¢)						
Weekend	Summer	Off Peak (28.6¢)																Partial Peak	Peak (43.5¢)						
	Winter	Off Peak (26.0¢)																	Peak (28.6¢)						
	Spring	Off Peak (26.0¢)																	Peak (28.6¢)						

Figure 3.1-3: PG&E Pilot Rate 3 (March 2017)

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off-Peak (27.8¢)																Peak (55.6¢)							
	Winter	Off-Peak (26.1¢)																Peak (28.0¢)							
	Spring	Off Peak (25.8¢)										Super Off-Peak (17.4¢)						Peak (34.7¢)							
Weekend	Summer	Off-Peak (27.8¢)																							
	Winter	Off-Peak (26.1¢)																							
	Spring	Off Peak (25.8¢)										Super Off-Peak (17.4¢)													

Figure 3.1-4 presents the seasons for each rate. For all three rates, the summer season covers the months of June through September. The winter season is October through May for Rates 1 and 2, and October through February for Rate 3. The spring period for Rate 3 is March through May.

Figure 3.1-4 Seasons by Rate

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Rate 1	Winter					Summer				Winter		
Rate 2	Winter					Summer				Winter		
Rate 3	Winter		Spring			Summer				Winter		

The following section contains a discussion of customer attrition over the entire pilot. Section 3.3 presents the load impact estimates for the summer 2017 period for each rate and Section 3.4 summarizes the persistence of load impacts over the course of the pilot.

[19] See Appendix B for comparison of tariffs.

3.2 Customer Attrition

Figure 3.2-1 through Figure 3.2-3 show the cumulative opt-out rates over time for each test cell and climate region. As discussed in the prior reports, there is an important distinction between opt-out rates and overall attrition. Opt out refers to customers actively deciding to transfer off a pilot rate whereas attrition refers to customers that leave the study for any reason, including becoming ineligible due to closing their account (customer churn), taking service from a Community Choice Aggregator (CCA), becoming a net metered solar customer, and others. Opt-out rates are much lower than attrition rates. It should also be noted that pilot customers had a financial incentive tied to staying on the pilot rates through completion of the second survey near the end of the first year of enrollment. As such, the overall opt-out rate may be biased downward compared to a situation where no incentive was offered, at least until after the first year. Since all rates had the same financial incentive to stay enrolled for a year, the relative opt-out rates across tariffs may be a valid indicator of the relative customer satisfaction with and preference for each rate.

Overall, opt-out rates are low and steady over the course of the first 12-month period and the differences between customer segments are small. However, the opt-out rates ramp up during the second summer of the pilot, which is especially noticeable in the hot climate region for Rate 2 and Rate 3 for non-CARE customers. This could be explained by the final incentive payments going out after the second survey, but it could also be due to the expectation of higher bills in the summer months. Opt out rates are greatest in the hot climate region, followed by the moderate region and then the cool region. In general, non-CARE/FERA customers opted out at a higher rate than CARE/FERA customers. Customers began to receive the final incentive payment and bill protection was ending during July and August when the increase in non-CARE/FERA opt-outs was observed. Non-CARE customers likely experienced higher bills under TOU during the summer, and non-CARE/FERA customer bills may have been significantly higher than bills for CARE/FERA customers, creating a greater financial motivation to opt-out from the rate.

Figure 3.2-1: Cumulative PG&E Opt Outs by Month – Hot Climate Region

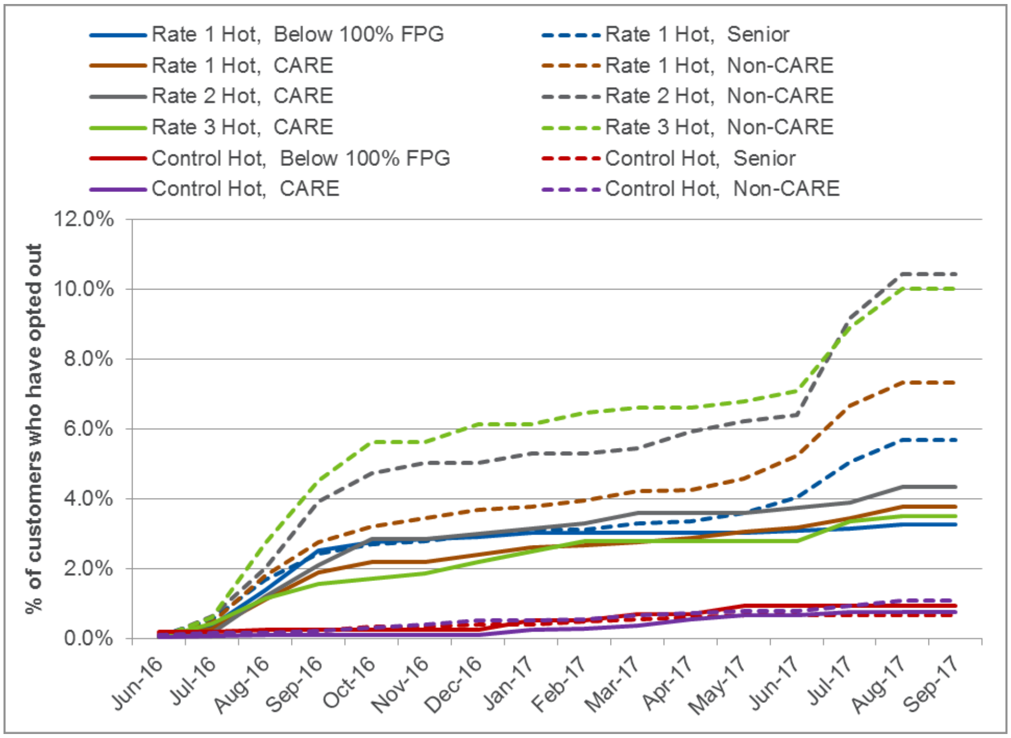


Figure 3.2-2: Cumulative PG&E Opt Outs by Month – Moderate Climate Region

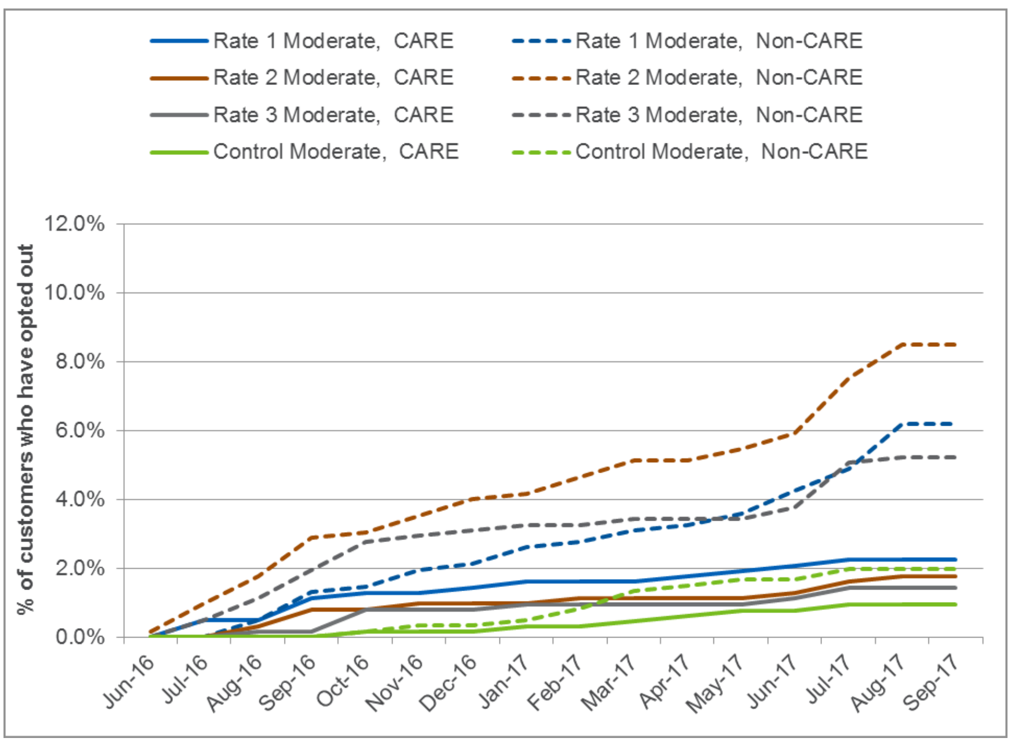


Figure 3.2-3: Cumulative PG&E Opt Outs by Month – Cool Climate Region

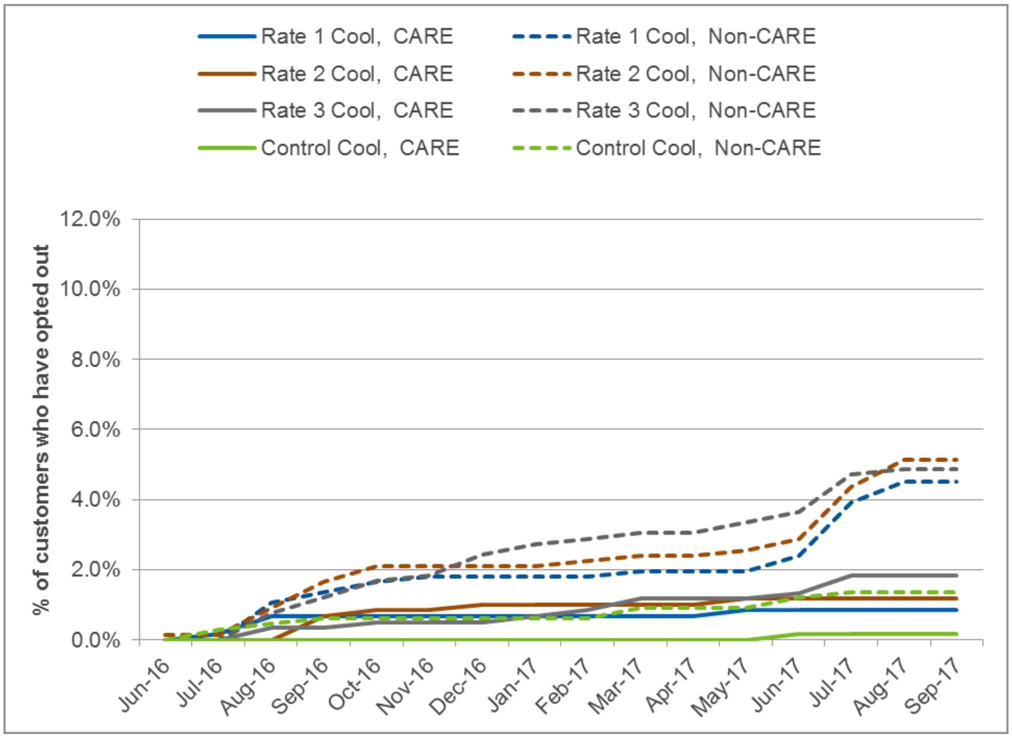


Figure 3.2-4 shows the cumulative percent of customers that opted out of each tariff for the CARE/FERA and non-CARE/FERA segments and for the total population across PG&E's service territory as a whole. As seen, the cumulative percent of customers opting out was quite low for all rates and segments. The lowest cumulative percent opt out was for CARE/FERA customers on Rate 3 and the highest was for non-CARE/FERA customers on Rate 2. For the service territory as a whole, Rate 2 saw the most opt outs. Customers on Rate 1 had the lowest opt-out rate.

Figure 3.2-4: Cumulative Opt Outs by Rate and Customer Segment for the PG&E Service Territory

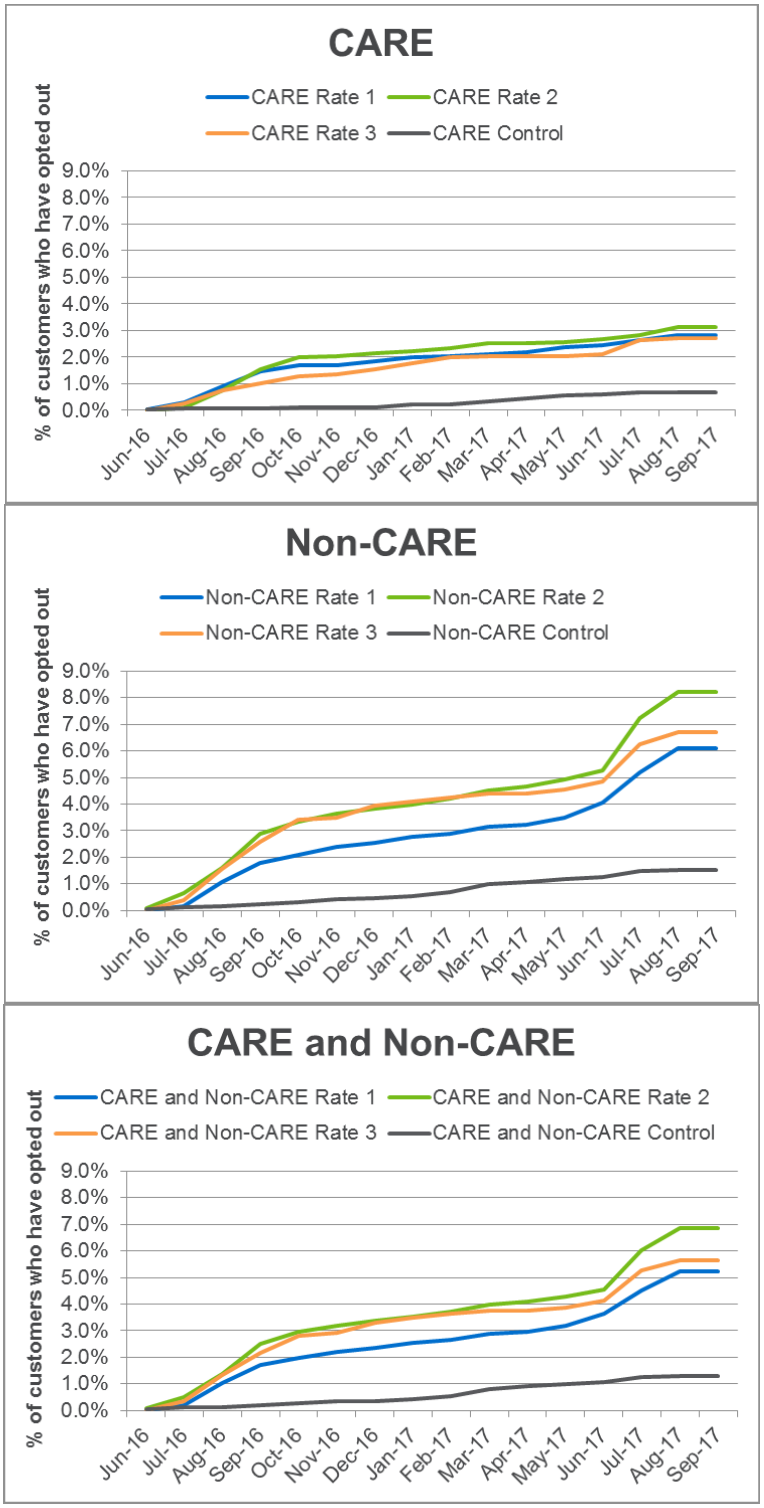


Figure 3.2-5 through Figure 3.2-7 show the overall attrition rate over time for each climate region, customer segment, and TOU rate. As seen in Figure 3.2-5, the attrition rate is quite constant over time in the hot region, with the final attrition rate ranging from a low of roughly 12% for senior households in the control group to a high of over 25% for control households with incomes below 100% of FPG in the hot climate region. The attrition graphs in the moderate and cool climate regions have a very different shape over time, with a significant increase in attrition starting in August in the moderate region and in September in the cool region. These higher rates coincide with more active transitions of customers to CCAs during those periods, especially among non-CARE/FERA customers in the cool climate region. The higher attrition rates are also in line with the end of the first year of the pilot.

Figure 3.2-5: Cumulative PG&E Attrition by Month – Hot Climate Region

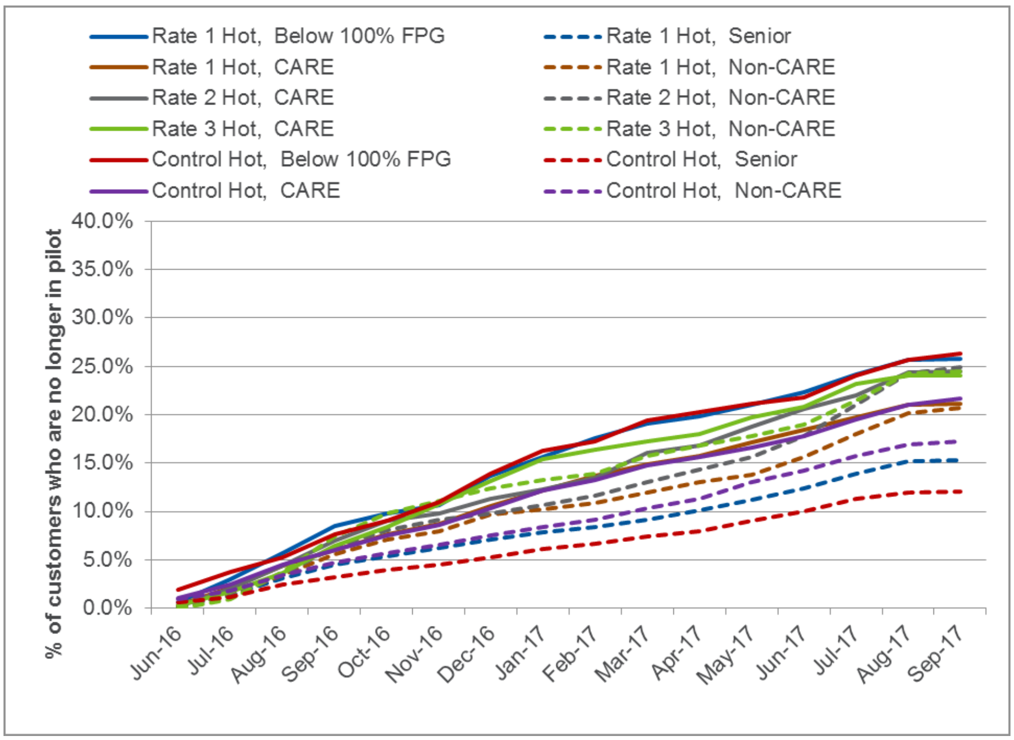
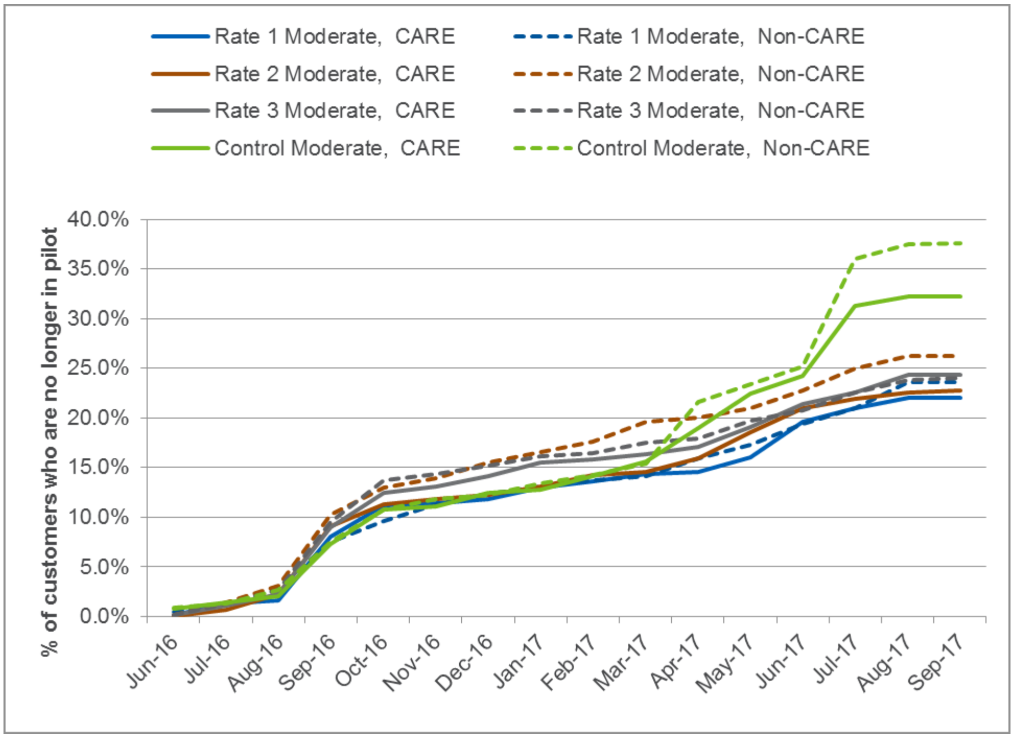
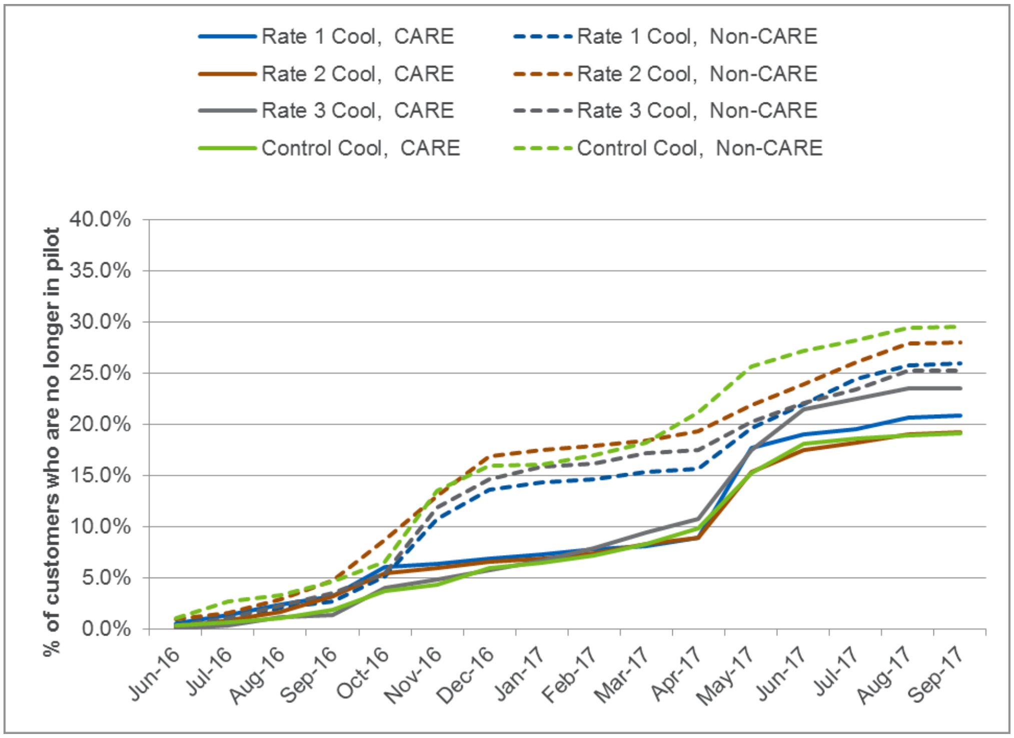


Figure 3.2-6: Cumulative PG&E Attrition by Month – Moderate Climate Region[20]



[20] There is a slight spike in ineligibilities in the Moderate climate region due to customers' transition onto the Redwood Coast Energy Authority and Sonoma Clean Power CCAs.

Figure 3.2-7: Cumulative PG&E Attrition by Month – Cool Climate Region



3.3 Load Impacts

This section summarizes the load impact estimates for the three rate treatments tested by PG&E for summer 2017. A comparison of load impacts across the two summer periods for a common group of participants is discussed in Section 3.4. The CPUC resolution approving PG&E's pilot requires that load impacts be estimated for the peak and off-peak periods and for daily energy use for the following rates, customer segments, and climate regions:

- Seniors, CARE/FERA customers, non-CARE/FERA customers and households with incomes below 100% of FPG in PG&E's hot climate region for Rate 1;
- For all three rates for all customers in PG&E's service territory as a whole and for all customers in PG&E's hot and moderate climate regions; and
- For CARE/FERA and non-CARE/FERA customers on each rate across PG&E's service territory as a whole.

In addition to these required segments, Nexant estimated load impacts for CARE/FERA and non-CARE/FERA customers for each rate for each climate region. Load impacts are reported for each rate period for the average weekday, average weekend and average monthly peak day for the summer months of June through September in 2017. The impacts presented here represent the second summer of the pilot. Impacts are reported for each rate, climate zone and customer segment summarized above. Underlying the values presented in the report are electronic tables that contain estimates for each hour of the day for each day type, segment and climate zone and for each month separately. These values are contained in Excel spreadsheets that are available upon request through the CPUC.

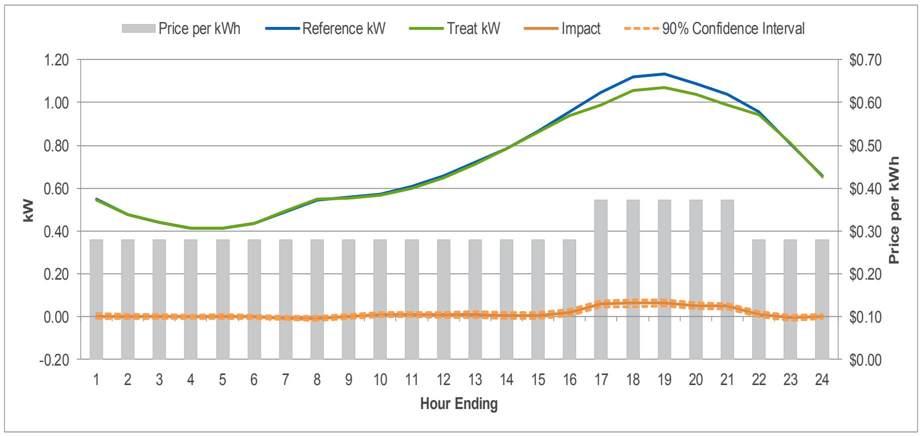
Figure 3.3-1 shows an example of the content of these electronic tables for PG&E Rate 1 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different customer segments, climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time period (individual months or the average of each season).

The remainder of this section is organized by rate treatment – that is, load impacts are presented for each relevant customer segment and climate region for each of the three rates. Following the summary for each rate, load impacts are compared across rates. This comparison is made only for the hours within each peak period that are common across all three rates (6 PM to 9 PM). Because the rates differ with respect to the length and timing of peak and off-peak periods, differences in load impacts across rates for any particular rate period may be due not only to differences in prices within the rate period but also due to differences in the length or timing of the rate periods.

Figure 3.3-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (PG&E Rate 1, Average Summer 2017 Weekday, All Customers)

Segment	All
Rate	Rate 1
Month	Summer 2017
Day Type	Average Weekday
Treated Customers	5,416

Period	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval	
Peak	1.09	1.03	0.06	5.3%	0.05	0.06
Partial Peak	N/A	N/A	N/A	N/A	N/A	N/A
Off Peak	0.63	0.62	0.00	0.5%	0.00	0.01
Super Off Peak	N/A	N/A	N/A	N/A	N/A	N/A
Daily kWh	17.33	16.98	0.35	2.0%	0.29	0.40



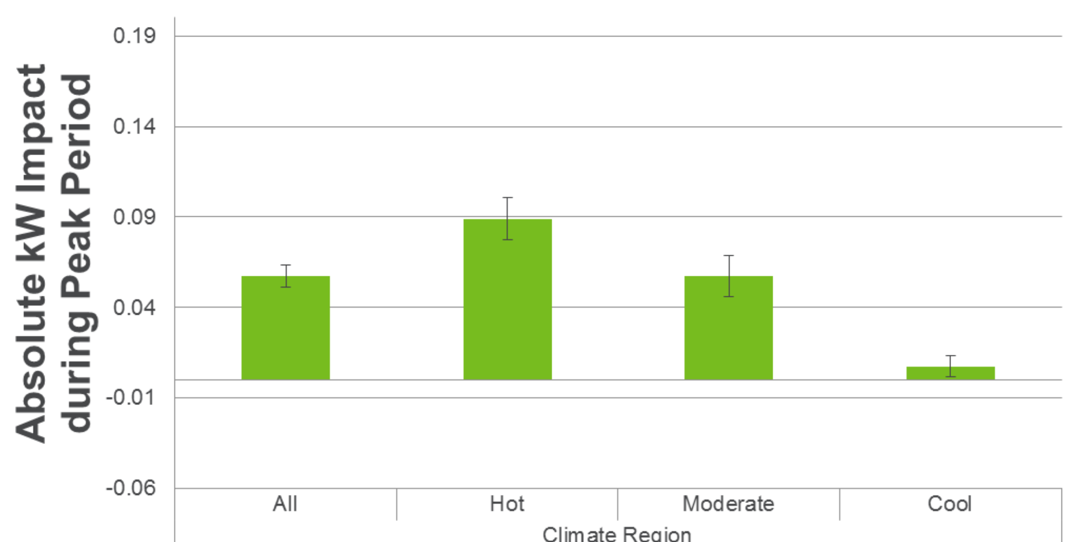
Hour Ending	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval		Price	Period
1	0.55	0.54	0.00	0.5%	-0.01	0.01	$0.28	Off Peak
2	0.48	0.48	0.00	0.3%	-0.01	0.01	$0.28	Off Peak
3	0.44	0.44	0.00	0.1%	-0.01	0.01	$0.28	Off Peak
4	0.41	0.41	0.00	0.0%	-0.01	0.01	$0.28	Off Peak
5	0.41	0.41	0.00	0.2%	-0.01	0.01	$0.28	Off Peak
6	0.43	0.44	0.00	-0.2%	-0.01	0.01	$0.28	Off Peak
7	0.49	0.50	-0.01	-1.3%	-0.01	0.00	$0.28	Off Peak
8	0.54	0.55	-0.01	-1.3%	-0.02	0.00	$0.28	Off Peak
9	0.56	0.55	0.00	0.3%	-0.01	0.01	$0.28	Off Peak
10	0.57	0.57	0.01	1.4%	0.00	0.02	$0.28	Off Peak
11	0.61	0.60	0.01	1.5%	0.00	0.02	$0.28	Off Peak
12	0.66	0.65	0.01	1.4%	0.00	0.02	$0.28	Off Peak
13	0.72	0.71	0.01	1.2%	0.00	0.02	$0.28	Off Peak
14	0.79	0.78	0.00	0.5%	-0.01	0.02	$0.28	Off Peak
15	0.86	0.86	0.01	0.6%	-0.01	0.02	$0.28	Off Peak
16	0.96	0.94	0.02	1.9%	0.00	0.03	$0.28	Off Peak
17	1.05	0.99	0.06	5.6%	0.04	0.07	$0.37	Peak
18	1.12	1.06	0.06	5.6%	0.05	0.08	$0.37	Peak
19	1.14	1.07	0.06	5.7%	0.05	0.08	$0.37	Peak
20	1.09	1.04	0.05	4.7%	0.04	0.06	$0.37	Peak
21	1.04	0.99	0.05	4.8%	0.04	0.06	$0.37	Peak
22	0.96	0.94	0.01	1.2%	0.00	0.02	$0.28	Off Peak
23	0.81	0.81	-0.01	-0.7%	-0.02	0.01	$0.28	Off Peak
24	0.66	0.65	0.00	0.2%	-0.01	0.01	$0.28	Off Peak
Daily kWh	17.33	16.98	0.35	2.0%	0.29	0.40	N/A	N/A

3.3.1 Rate 1

PG&E's Rate 1 is a two-period rate with a peak-period from 4 PM to 9 PM on weekdays. In summer, for electricity usage above the baseline quantity, prices equal roughly 41.0 ¢/kWh[21] in the peak period and 30.7¢/kWh in the off-peak period. All usage on weekends is priced at the off-peak price. For usage below the baseline quantity, a credit of 8.8 ¢/kWh is applied.

Figure 3.3-2 shows the absolute peak period load reduction for Rate 1 for PG&E's service territory as a whole and for each climate region. The lines bisecting the top of each bar in the figure show the 90% confidence band for each estimate. If the confidence band includes 0, it means that the estimated load impact is not statistically different from 0 at the 90% level of confidence. If the confidence bands for two bars do not overlap, it means that the observed difference in the load impacts is statistically significant. If they do overlap, it does not necessarily mean that the difference is not statistically significant.[22] In these cases, t-tests were calculated to determine whether the difference is statically significant.[23]

Figure 3.3-2: Average Load Impacts for Peak Period for PG&E Rate 1[24]
(Positive values represent load reductions)



	All	Hot	Moderate	Cool
Percent Impact	5.3%	5.4%	6.5%	1.6%
kW Impact	0.06	0.09	0.06	0.01

As seen in the figure, all of the average peak-period load impacts for the service territory as a whole and for each climate region are statistically significant at the 90% level of confidence. On average, pilot

[21] Prices reflect the rates that went into effect on March 1, 2017. The original prices are included in Appendix B.

[22] For further discussion of this topic, see https://www.cscu.cornell.edu/news/statnews/stnews73.pdf

[23] The test was applied at the 90% confidence level which means that a t-value exceeding 1.65 indicates statistical significance

[24] PG&E Rate 1 summer impacts represent June through September 2017.

participants across PG&E's service territory reduced peak-period electricity use by 5.3% or 0.06 kW,[25] across the five-hour peak period from 4 PM to 9 PM. The average peak-period load reductions range from a high of 6.5% and 0.06 kW in the moderate climate region to a low of 1.6% and 0.01 kW in the cool climate region. In the hot climate region, load reductions equal 5.4% or 0.09 kW. The variation in absolute impacts across climate regions is greater than the variation in percent impacts due in large part to variation in electricity usage (e.g., the reference load) across regions. The differences in load impacts are statistically significant across the three climate regions.

Table 3.3-1 shows the average percent and absolute load impacts for each rate period for weekdays and weekends and for the average monthly system peak day for the PG&E service territory as a whole and for the participant population in each climate region. The percent reduction equals the load impact in absolute terms (kW) divided by the reference load. Shaded cells in the table contain load impact estimates that are not statistically significant at the 90% confidence level. The percentage and absolute values in the first row of Table 3.3-1, which represent the load impacts in the peak period on the average weekday, equal the values shown in Figure 3.3-2, discussed above.

The reference loads shown in Table 3.3-1 are based on a control group and represent estimates of what customers on the TOU rate would have used if they had not responded to the price signals contained in the TOU tariff.[26] As seen in the table, average hourly usage during the peak period on weekdays is roughly 1.09 kW for the service territory as a whole, and around 0.72 kW over the 24 hour average weekday. In the hot climate region, average usage in the peak period is more than 50% larger, at 1.66 kW. Average usage in the moderate region is 0.88 kW and in the cool region, at 0.48 kW, it is roughly one-third what it is in the hot region.

As seen in Table 3.3-1, nearly all load impacts are statistically significant for each rate period and day type. The average load reduction during the peak period is similar in percentage terms on the average weekday and the monthly system peak day but the absolute impact is statistically significantly larger on the monthly system peak day due to the higher reference loads. All rates show an overall conservation effect between 2.0% and 2.6% for the service territory as a whole and for the hot and moderate climate regions on the average weekday and a reduction of 3.7% for the monthly system peak day in the moderate climate region. In the moderate climate regions, daily loads increased by roughly 2.0%.

[25] The kW value represents the average kWh/hour across the five our peak period. It is not an instantaneous measure of peak demand during the period. The value can be multiplied by the number of hours in the peak period to determine the total reduction in energy use (kWh) that occurred over the period.

[26] See Section 3.1 in the First Interim Report for more detail.

Table 3.3-1: Rate 1 Load Impacts by Rate Period[27] and Day Type*
(Positive values represent load reductions, negative values represent load increases)

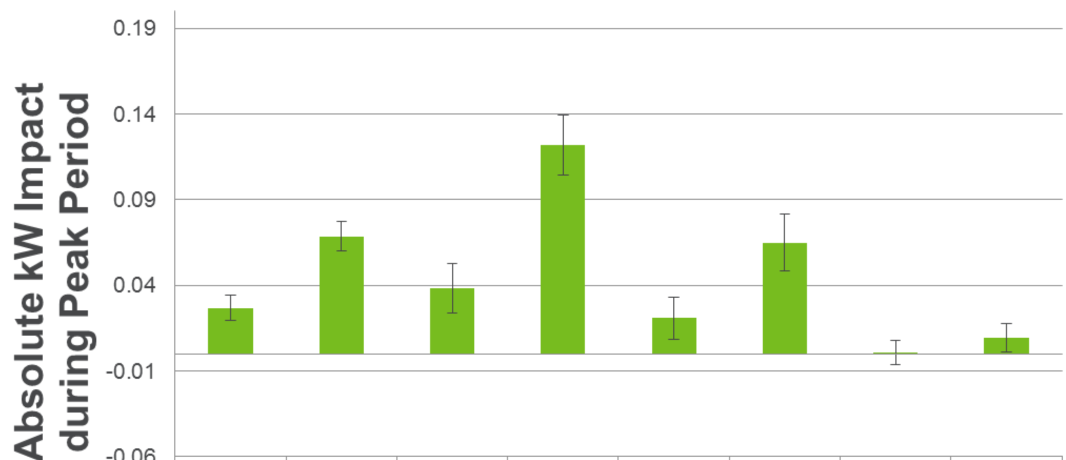
Rate 1															
Day Type	Period	Hours	All			Hot			Moderate			Cool			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.09	0.06	5.3%	1.66	0.09	5.4%	0.88	0.06	6.5%	0.48	0.01	1.6%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.63	0.00	0.5%	0.88	0.01	1.3%	0.54	0.00	0.8%	0.35	-0.01	-3.1%
	Day	**All Hours**	**0.72**	**0.01**	**2.0%**	**1.04**	**0.03**	**2.6%**	**0.61**	**0.02**	**2.5%**	**0.38**	**-0.01**	**-1.9%**
Average Weekend	Off Peak	All Hours	0.79	0.01	1.7%	1.14	0.02	1.8%	0.69	0.02	3.1%	0.40	-0.01	-1.9%
	Day	**All Hours**	**0.79**	**0.01**	**1.7%**	**1.14**	**0.02**	**1.8%**	**0.69**	**0.02**	**3.1%**	**0.40**	**-0.01**	**-1.9%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.61	0.09	5.8%	2.48	0.14	5.6%	1.44	0.10	7.2%	0.50	0.00	0.6%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	0.00	0.2%	1.26	0.00	0.0%	0.73	0.01	1.9%	0.36	-0.01	-3.7%
	Day	**All Hours**	**1.01**	**0.02**	**2.1%**	**1.51**	**0.03**	**1.9%**	**0.88**	**0.03**	**3.7%**	**0.39**	**-0.01**	**-2.5%**

* A shaded cell indicates estimate is not statistically significant

[27] Statistically significant small daily load increases or decreases may be a treatment effect, or it is also possible they are attributable to random differences between the treatment group and the control group. The increased number of hours at the daily level compared to the hourly level may increase the statistical power of the analysis, resulting in statistically significant impacts at the daily level when the impacts at the hourly level are not necessarily statistically significant.

Figure 3.3-3 shows the absolute peak period load impacts for Rate 1 for CARE/FERA and non-CARE/FERA customers for the service territory as a whole and for each climate region. For the service territory as a whole, and in each climate region, both the percent and absolute load impacts in the peak period are greater for non-CARE/FERA customers than for CARE/FERA customers, often significantly greater. For example, in the hot climate region, the average weekday, peak period reduction is 7.0% and 0.12 kW for non-CARE/FERA customers whereas for CARE/FERA customers, the average reduction is 2.5% and 0.04 kW, which is less than half as much as for non-CARE/FERA customers. Load reductions in the cool climate region are not statistically significantly different from zero for CARE/FERA customers, and are very small for non-CARE/FERA customers.

Figure 3.3-3: Average Load Impacts for Peak Period for PG&E Rate 1 for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Percent Impact	2.4%	6.4%	2.5%	7.0%	3.0%	7.0%	0.2%	1.9%
kW Impact	0.03	0.07	0.04	0.12	0.02	0.06	0.00	0.01

Table 3.3-2 shows the estimated load impacts for each rate period and day type by climate zone and for the service territory as a whole for non-CARE/FERA customers and Table 3.3-3 shows the estimated values for CARE/FERA customers. It should be noted that, within each climate region, CARE/FERA customers have average peak-period reference loads on weekdays that are slightly smaller than non-CARE/FERA customers. However, for the service territory as a whole, CARE/FERA and non-CARE/FERA loads are very similar and, indeed, CARE/FERA loads are slightly larger. This change at the service territory level is because the distribution of CARE/FERA and non-CARE/FERA customers varies across climate regions, with a greater share of CARE/FERA customers being located in the hotter regions.

For the service territory as a whole, both customer segments reduced average daily usage on weekdays by a statistically significant amount. On weekends, non-CARE/FERA customers reduced electricity use by 2.4% while CARE/FERA customers had a statistically insignificant increase in electricity use (0.1%). In the hot climate region, non-CARE/FERA customers reduced total daily electricity use on weekdays by 4.1%. In the cool climate region, both non-CARE/FERA and CARE/FERA customers had a small but statistically significant increase in daily electricity use on weekdays.

Table 3.3-2: Rate 1 Load Impacts by Rate Period and Day Type – Non-CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Rate 1														
Day Type	Period	Hours	All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.07	0.07	6.4%	1.74	0.12	7.0%	0.92	0.06	7.0%	0.49	0.01	1.9%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.62	0.01	0.9%	0.91	0.02	2.6%	0.56	0.00	0.5%	0.36	-0.01	-3.2%
	Day	**All Hours**	**0.72**	**0.02**	**2.6%**	**1.08**	**0.04**	**4.1%**	**0.64**	**0.02**	**2.5%**	**0.39**	**-0.01**	**-1.9%**
Average Weekend	Off Peak	All Hours	0.79	0.02	2.4%	1.20	0.04	3.0%	0.72	0.02	3.2%	0.41	-0.01	-1.6%
	Day	**All Hours**	**0.79**	**0.02**	**2.4%**	**1.20**	**0.04**	**3.0%**	**0.72**	**0.02**	**3.2%**	**0.41**	**-0.01**	**-1.6%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.64	0.11	6.8%	2.70	0.20	7.2%	1.53	0.12	7.6%	0.52	0.00	0.7%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	0.00	0.3%	1.33	0.01	0.5%	0.77	0.01	1.6%	0.37	-0.01	-4.0%
	Day	**All Hours**	**1.01**	**0.03**	**2.5%**	**1.62**	**0.05**	**2.8%**	**0.93**	**0.03**	**3.7%**	**0.40**	**-0.01**	**-2.7%**

* A shaded cell indicates estimate is not statistically significant

Table 3.3-3: Rate 1 Load Impacts by Rate Period and Day Type – CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

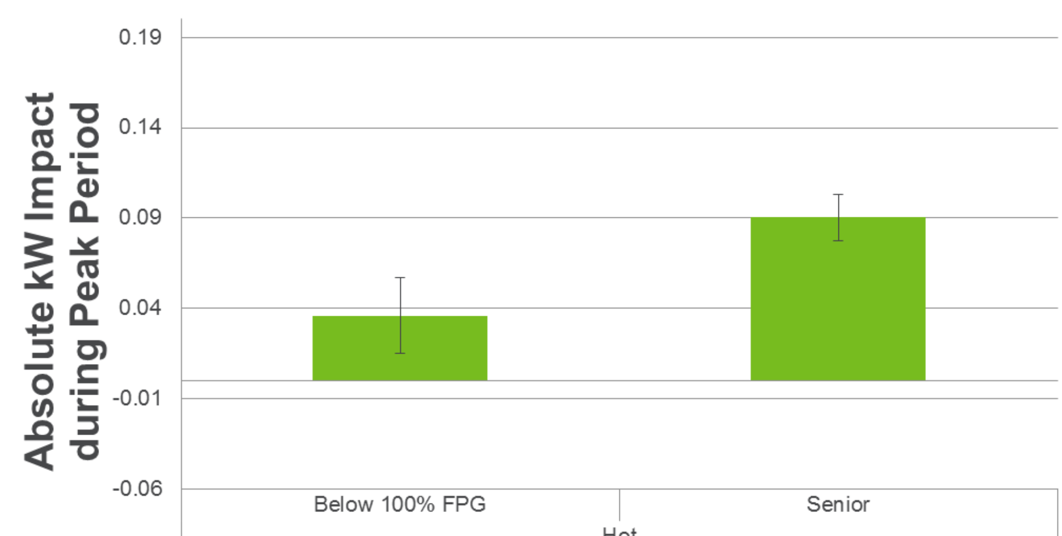
Day Type	Period	Hours	Rate 1											
			All, CARE			Hot, CARE			Moderate, CARE			Cool, CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.12	0.03	2.4%	1.53	0.04	2.5%	0.70	0.02	3.0%	0.44	0.00	0.2%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.64	0.00	-0.5%	0.83	-0.01	-1.0%	0.46	0.01	3.0%	0.31	-0.01	-2.7%
	Day	**All Hours**	**0.74**	**0.00**	**0.4%**	**0.97**	**0.00**	**0.1%**	**0.51**	**0.02**	**3.0%**	**0.34**	**-0.01**	**-1.9%**
Average Weekend	Off Peak	All Hours	0.80	0.00	-0.1%	1.05	0.00	-0.4%	0.55	0.02	3.0%	0.35	-0.01	-3.3%
	Day	**All Hours**	**0.80**	**0.00**	**-0.1%**	**1.05**	**0.00**	**-0.4%**	**0.55**	**0.02**	**3.0%**	**0.35**	**-0.01**	**-3.3%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.54	0.04	2.7%	2.14	0.05	2.5%	0.98	0.05	4.6%	0.44	0.00	0.1%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	0.00	-0.2%	1.15	-0.01	-0.7%	0.57	0.02	3.5%	0.32	-0.01	-2.4%
	Day	**All Hours**	**0.99**	**0.01**	**0.7%**	**1.35**	**0.00**	**0.3%**	**0.66**	**0.03**	**3.9%**	**0.35**	**-0.01**	**-1.8%**

* A shaded cell indicates estimate is not statistically significant

Figure 3.3-4 shows the absolute load reduction during the peak period on average weekdays for seniors and households with incomes below 100% of FPG in the hot climate region. Table 3.3-4 shows the estimated values for other rate periods and day types for each segment and for the hot climate region as a whole.

A comparison of the values in Figure 3.3-4 with those for the hot region in Figure 3.3-2 shows that load impacts for senior households were very similar to the hot climate region, participant population as a whole in both percentage (well over 5%) and absolute (0.09 kW) terms. The reference load for senior households (1.54 kW) is only slightly smaller than that of the general participant population in the hot climate region (1.66 kW). That is, senior households do not, on average, consume materially less electricity than the average customer in PG&E's hot climate region. Estimated load impacts in the off-peak period, which were statistically different from 0, and a 3.5% reduction in daily energy use on weekdays indicates that senior households did more conservation than load shifting. This conservation effect carried over into the weekend, which showed a 2.7% load reduction on average over the summer. Peak-period load reductions on the average monthly system peak day were smaller in percentage terms (5.3%) than on weekdays.

Figure 3.3-4: Average Load Impacts for Peak Period for PG&E Rate 1 for Senior Households and Households with Incomes Below 100% FPG in the Hot Climate Region (Positive values represent load reductions)



	Below 100% FPG	Senior
Percent Impacts	2.3%	5.8%
kW Impact	0.04	0.09

Load impacts for households with incomes less than or equal to 100% of FPG were quite different from those of senior households or the general population. These households have similar reference loads compared with senior households (1.54 kW) but only reduced peak usage by 2.3% or 0.04 kW. On weekdays and weekends, households with incomes less than or equal to 100% of FPG decreased overall daily consumption, but not by a statistically significant amount. On monthly system peak days, these customers did not have any statistically significant load reductions.

Table 3.3-4: Rate 1 Load Impacts by Rate Period and Day Type for PG&E for Senior Households and Households with Incomes Below 100% FPG in the Hot Climate Region*
(Positive values represent load reductions, negative values represent load increases)

Rate 1								
Day Type	Period	Hours	Hot, Below 100% FPG			Hot, Senior		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.54	0.04	2.3%	1.55	0.09	5.8%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.86	-0.01	-0.8%	0.81	0.02	2.4%
	Day	**All Hours**	**1.00**	**0.00**	**0.2%**	**0.97**	**0.03**	**3.5%**
Average Weekend	Off Peak	All Hours	1.07	0.00	0.4%	1.05	0.03	2.7%
	Day	**All Hours**	**1.07**	**0.00**	**0.4%**	**1.05**	**0.03**	**2.7%**
Monthly System Peak Day	Peak	4 PM to 9 PM	2.12	0.03	1.5%	2.36	0.13	5.3%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	1.17	-0.01	-1.1%	1.17	0.01	0.6%
	Day	**All Hours**	**1.37**	**0.00**	**-0.3%**	**1.42**	**0.03**	**2.3%**

* A shaded cell indicates estimate is not statistically significant

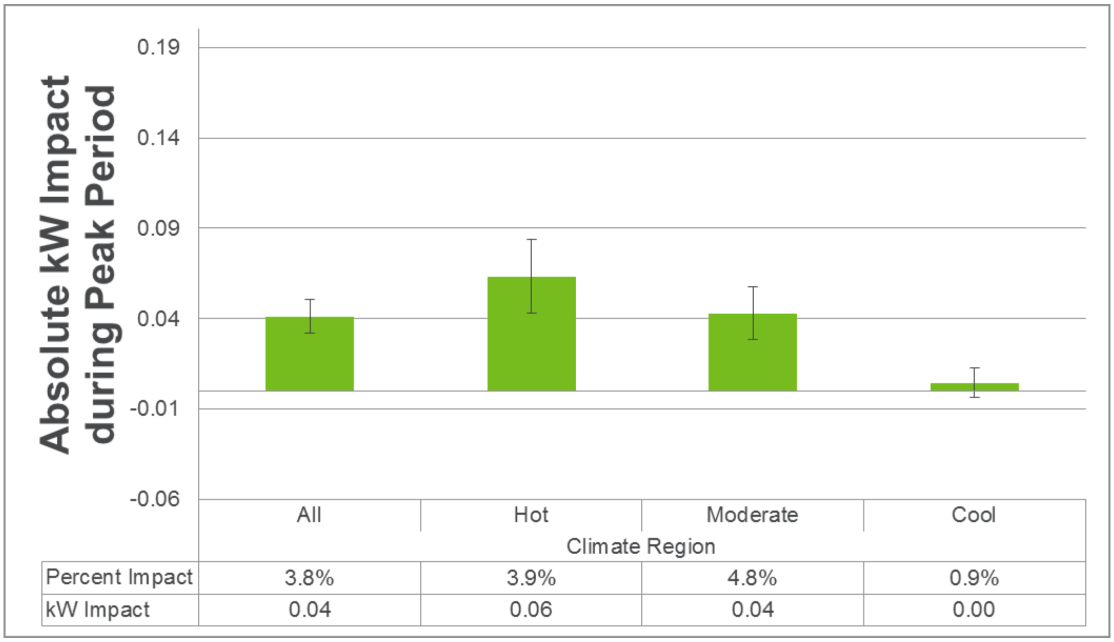
3.3.2 Rate 2

PG&E's Rate 2 differs from Rate 1 in several important ways. First, Rate 2 has three rate periods on weekdays in the summer, rather than two rate periods. Second, the Rate 2 peak period is shorter, with a three-hour peak period covering only the evening hours from 6 PM to 9 PM compared with the five-hour peak period from 4 PM to 9 PM in Rate 1. Rate 2 has a partial peak period from 4 PM to 6 PM and from 9 PM to 10 PM. Finally, on weekends, the same three rate periods as on weekdays are in effect with Rate 2, whereas for Rate 1, all weekend hours are charged at the off-peak, weekday price. Rate 2 peak-period prices above the baseline usage amount are about 2.5 ¢/kWh higher than Rate 1 peak period prices and the off-peak price for Rate 2 is roughly 2.0 ¢/kWh lower. The shoulder period price for Rate 2 is 38.3 ¢/kWh.

Figure 3.3-5 shows the absolute load impacts for the weekday peak period for Rate 2 for PG&E's service territory as a whole and for each climate region. From a policy perspective, it is important to note that there are statistically significant and materially significant load reductions in the Rate 2 peak period, which coincides completely with evening hours from 6 PM to 9 PM. The pattern of load reductions across climate regions is similar between Rates 1 and 2, but the impacts are slightly smaller for Rate 2. The average weekday peak-period load reduction for Rate 2 equals 3.8% and 0.04 kW, while for Rate 1 they are 5.3% and 0.06 kW. The estimated impact in the hot region is 3.9% or 0.06 kW. In the moderate climate region, the percent reduction in the peak period on weekdays for Rate 2, 4.8%, is smaller than the 6.5% reduction for Rate 1, but the difference is not statistically significant in percentage or absolute terms. The difference in peak-period impacts between the moderate and hot climate regions is not statistically significant, but the difference between the moderate and cool climate regions is, in percentage and absolute terms.

Table 3.3-5 contains load impact estimates for each rate period and day type for Rate 2. Importantly, peak-period load reductions are similar on weekends and weekdays, and larger on monthly system peak days. None of the day types show statistically significant decreases in daily usage for Rate 2, which is different from Rate 1.

Figure 3.3-5: Average Load Impacts for Peak Period for PG&E Rate 2[28]
(Positive values represent load reductions)



	All	Hot	Moderate	Cool
Percent Impact	3.8%	3.9%	4.8%	0.9%
kW Impact	0.04	0.06	0.04	0.00

[28] PG&E Rate 2 winter impacts represent October 2016 through May 2017.

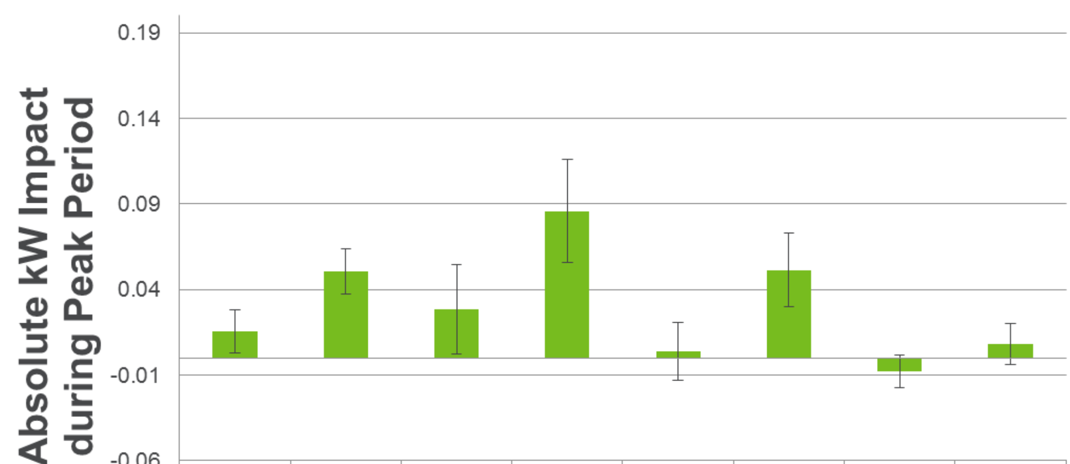
Table 3.3-5: Rate 2 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	6 PM to 9 PM	1.09	0.04	3.8%	1.62	0.06	3.9%	0.90	0.04	4.8%	0.52	0.00	0.9%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.04	0.03	2.5%	1.59	0.05	3.3%	0.85	0.02	2.3%	0.46	-0.01	-1.3%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.61	-0.01	-1.8%	0.85	-0.01	-1.7%	0.53	-0.01	-1.8%	0.34	-0.01	-2.2%
	Day	**All Hours**	**0.72**	**0.00**	**0.0%**	**1.04**	**0.00**	**0.3%**	**0.61**	**0.00**	**0.1%**	**0.38**	**-0.01**	**-1.5%**
Average Weekend	Peak	6 PM to 9 PM	1.16	0.04	3.5%	1.72	0.07	4.2%	0.99	0.03	2.9%	0.53	0.01	1.5%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.14	0.03	2.4%	1.72	0.05	2.9%	0.97	0.02	2.3%	0.48	0.00	-0.2%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.68	-0.01	-1.4%	0.95	-0.01	-1.3%	0.59	-0.01	-1.2%	0.36	-0.01	-2.5%
	Day	**All Hours**	**0.79**	**0.00**	**0.2%**	**1.14**	**0.01**	**0.5%**	**0.69**	**0.00**	**0.2%**	**0.40**	**-0.01**	**-1.5%**
Monthly System Peak Day	Peak	6 PM to 9 PM	1.58	0.09	5.5%	2.41	0.12	4.9%	1.41	0.11	7.8%	0.54	0.01	1.4%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.55	0.05	3.3%	2.38	0.10	4.3%	1.39	0.05	3.4%	0.49	-0.02	-4.6%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.82	-0.03	-3.2%	1.22	-0.04	-3.3%	0.71	-0.02	-2.5%	0.35	-0.02	-4.6%
	Day	**All Hours**	**1.01**	**0.00**	**-0.2%**	**1.51**	**0.00**	**-0.2%**	**0.88**	**0.01**	**0.7%**	**0.39**	**-0.01**	**-3.5%**

* A shaded cell indicates estimate is not statistically significant

Figure 3.3-6 shows the estimated peak period load impacts for Rate 2 for CARE/FERA and non-CARE/FERA households for the service territory as a whole and for each climate region. Unlike Rate 1, several segments did not have statistically significant load reductions during the peak period, including CARE/FERA customers in the cool and moderate climate regions and non-CARE/FERA customers in the cool climate region. Non-CARE/FERA customers had the greatest load impacts, equal to 5.0% or 0.09 kW. For the service territory as a whole, CARE/FERA customers had rather small but statistically significant load impacts equal to 1.4% or 0.02 kW. For all climate regions and for the service territory as a whole, non-CARE/FERA customers had greater load impacts than CARE/FERA customers.

Figure 3.3-6: Average Load Impacts for Peak Period for PG&E Rate 2 for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Percent Impact	1.4%	4.7%	1.9%	5.0%	0.5%	5.5%	-1.7%	1.5%
kW Impact	0.02	0.05	0.03	0.09	0.00	0.05	-0.01	0.01

Table 3.3-6 and Table 3.3-7 show the load impacts for non-CARE/FERA and CARE/FERA customers, respectively, for each rate period and day-type. As a reminder, the values in the first row of each table are the same as those found in Figure 3.3-6. CARE/FERA customers had small but statistically significant daily load increases on the average weekday in all climate regions and in the territory as a whole. Non-CARE/FERA customers had statistically significant daily load reductions on weekdays and weekends for the territory as a whole and the hot climate region, but not in the moderate or cool regions.

Table 3.3-6: Rate 2 Load Impacts by Rate Period and Day Type – Non-CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Day Type	Period	Hours	Rate 2											
			All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	6 PM to 9 PM	1.08	0.05	4.7%	1.71	0.09	5.0%	0.94	0.05	5.5%	0.53	0.01	1.5%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.02	0.03	3.3%	1.65	0.08	4.8%	0.88	0.02	2.6%	0.47	0.00	-1.1%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.60	-0.01	-1.2%	0.88	-0.01	-0.6%	0.54	-0.01	-1.8%	0.35	-0.01	-1.7%
	Day	**All Hours**	**0.72**	**0.01**	**0.7%**	**1.08**	**0.02**	**1.5%**	**0.64**	**0.00**	**0.3%**	**0.39**	**0.00**	**-1.1%**
Average Weekend	Peak	6 PM to 9 PM	1.17	0.05	4.4%	1.84	0.11	5.8%	1.04	0.03	3.0%	0.55	0.01	2.4%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.15	0.04	3.7%	1.83	0.09	5.1%	1.02	0.03	2.6%	0.50	0.00	0.8%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.67	-0.01	-0.8%	0.99	0.00	-0.2%	0.61	-0.01	-1.0%	0.38	-0.01	-2.0%
	Day	**All Hours**	**0.79**	**0.01**	**1.0%**	**1.20**	**0.02**	**2.0%**	**0.72**	**0.00**	**0.4%**	**0.41**	**0.00**	**-0.9%**
Monthly System Peak Day	Peak	6 PM to 9 PM	1.62	0.11	7.0%	2.62	0.16	6.2%	1.51	0.14	9.1%	0.56	0.01	2.1%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.57	0.06	4.1%	2.58	0.15	5.7%	1.47	0.06	4.0%	0.50	-0.03	-5.4%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.82	-0.02	-2.9%	1.29	-0.04	-2.9%	0.74	-0.02	-2.3%	0.36	-0.02	-4.6%
	Day	**All Hours**	**1.01**	**0.00**	**0.4%**	**1.62**	**0.01**	**0.7%**	**0.93**	**0.01**	**1.3%**	**0.40**	**-0.01**	**-3.6%**

* A shaded cell indicates estimate is not statistically significant

Table 3.3-7: Rate 2 Load Impacts by Rate Period and Day Type – CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Day Type	Period	Hours	Rate 2											
			All, CARE			Hot, CARE			Moderate, CARE			Cool, CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	6 PM to 9 PM	1.10	0.02	1.4%	1.48	0.03	1.9%	0.71	0.00	0.5%	0.46	-0.01	-1.7%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.09	0.00	0.3%	1.49	0.01	0.6%	0.69	0.00	0.1%	0.42	-0.01	-2.4%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.62	-0.02	-3.4%	0.80	-0.03	-3.6%	0.45	-0.01	-1.9%	0.30	-0.01	-4.0%
	Day	**All Hours**	**0.74**	**-0.01**	**-1.8%**	**0.97**	**-0.02**	**-1.7%**	**0.51**	**-0.01**	**-1.1%**	**0.34**	**-0.01**	**-3.3%**
Average Weekend	Peak	6 PM to 9 PM	1.14	0.01	1.1%	1.53	0.02	1.2%	0.74	0.02	2.5%	0.45	-0.01	-2.7%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.14	-0.01	-1.0%	1.56	-0.02	-1.0%	0.73	0.00	0.7%	0.42	-0.02	-4.2%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.68	-0.02	-3.3%	0.89	-0.03	-3.3%	0.49	-0.01	-2.3%	0.32	-0.01	-4.4%
	Day	**All Hours**	**0.80**	**-0.02**	**-2.1%**	**1.05**	**-0.02**	**-2.1%**	**0.55**	**-0.01**	**-1.0%**	**0.35**	**-0.01**	**-4.1%**
Monthly System Peak Day	Peak	6 PM to 9 PM	1.50	0.02	1.3%	2.08	0.04	2.2%	0.97	-0.02	-2.1%	0.47	-0.01	-1.6%
	Partial Peak	4 PM to 6 PM, 9 PM to 10 PM	1.49	0.02	1.1%	2.08	0.03	1.6%	0.96	-0.01	-0.5%	0.43	-0.01	-1.2%
	Off Peak	12 AM to 4 PM, 10 PM to 12 AM	0.82	-0.03	-4.0%	1.11	-0.04	-4.0%	0.55	-0.02	-4.0%	0.31	-0.01	-4.3%
	Day	**All Hours**	**0.99**	**-0.02**	**-2.1%**	**1.35**	**-0.02**	**-1.7%**	**0.66**	**-0.02**	**-3.0%**	**0.35**	**-0.01**	**-3.4%**

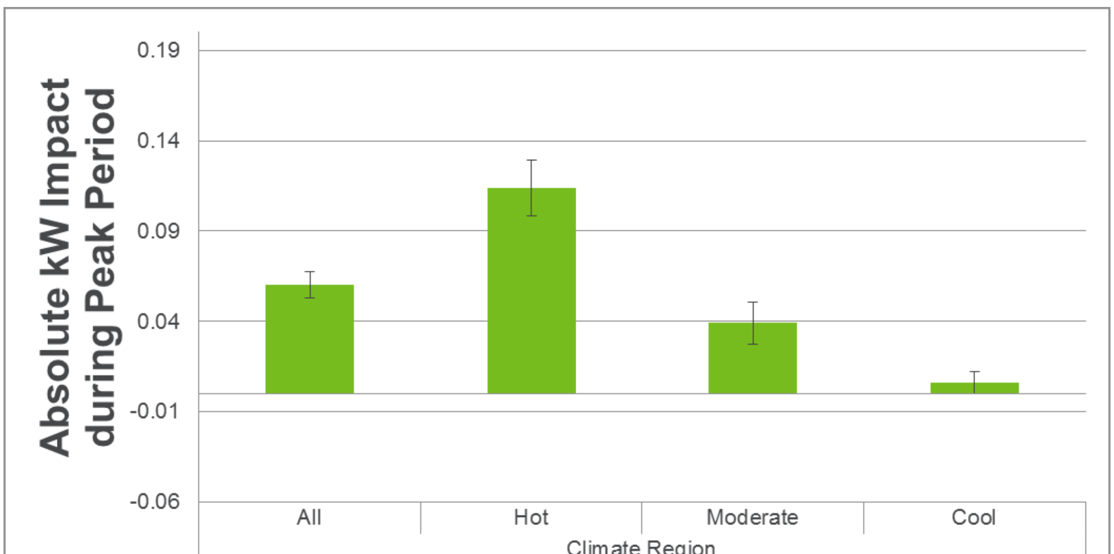
* A shaded cell indicates estimate is not statistically significant

3.3.3 Rate 3

PG&E's Rate 3 is structurally identical to Rate 1 in the summer (and winter) periods, with a peak period from 4 PM to 9 PM on weekdays and off-peak prices in effect for all hours on the weekends. In spring, Rate 3 has a super off-peak price in effect from 10 AM to 4 PM on weekdays to encourage increased electricity use during a time when high levels of hydroelectric generation combined with below average electricity use create minimum load issues for the CAISO. In summer, the peak-period price is significantly higher for Rate 3 than for Rate 1 (57.2 ¢/kWh for Rate 3 compared with 42.0 ¢/kWh for Rate 1), and the off-peak price is lower (28.6 ¢/kWh versus 31.7 ¢/kWh).

Figure 3.3-7 shows the peak period load reductions on average weekdays for Rate 3. Once again, the overall load reduction and the pattern in the load reductions across climate regions are very similar to Rates 1 and 2. The differences in absolute and percent load impacts across climate regions are all statistically significant, with customers in the hot climate region producing the greatest load impacts, 6.9% or 0.11 kW. Customers in the cool climate region had load impacts that were just barely statistically significant, at 1.3% or 0.01 kW.

Figure 3.3-7: Average Load Impacts for Peak Period for PG&E Rate 3[29]
(Positive values represent load reductions)



	All	Hot	Moderate	Cool
Percent Impact	5.6%	6.9%	4.4%	1.3%
kW Impact	0.06	0.11	0.04	0.01

Table 3.3-8 contains estimates of load impacts for all relevant rate periods and day types. On weekdays, customers in the hot climate region and the territory as a whole reduced their average weekday usage by 4.0% and 2.2%, respectively. Customers in the moderate climate region did not have statistically significant weekday usage reductions. On weekends, customers in PG&E's service territory reduced their overall consumption by 2.1% or 0.02 kW.

[29] PG&E Rate 3 winter impacts represent October 2016 through February 2017.

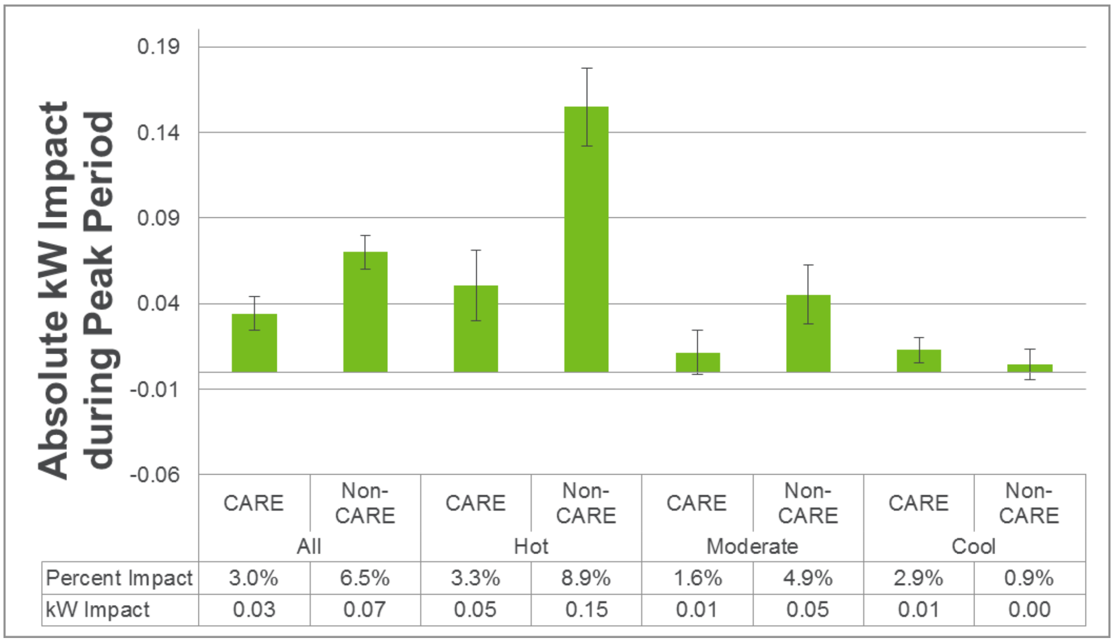
Table 3.3-8: Rate 3 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

Rate 3														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.09	0.06	5.6%	1.66	0.11	6.9%	0.88	0.04	4.4%	0.48	0.01	1.3%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.63	0.00	0.7%	0.88	0.02	2.6%	0.54	-0.01	-1.2%	0.35	-0.01	-2.6%
	Day	**All Hours**	**0.72**	**0.02**	**2.2%**	**1.04**	**0.04**	**4.0%**	**0.61**	**0.00**	**0.5%**	**0.38**	**-0.01**	**-1.6%**
Average Weekend	Off Peak	All Hours	0.79	0.02	2.1%	1.14	0.04	3.2%	0.69	0.01	1.8%	0.40	-0.01	-2.0%
	Day	**All Hours**	**0.79**	**0.02**	**2.1%**	**1.14**	**0.04**	**3.2%**	**0.69**	**0.01**	**1.8%**	**0.40**	**-0.01**	**-2.0%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.61	0.09	5.4%	2.48	0.12	4.9%	1.44	0.11	7.6%	0.50	0.00	0.6%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	0.00	-0.2%	1.26	0.00	0.2%	0.73	0.00	0.4%	0.36	-0.01	-3.6%
	Day	**All Hours**	**1.01**	**0.02**	**1.7%**	**1.51**	**0.03**	**1.8%**	**0.88**	**0.03**	**2.9%**	**0.39**	**-0.01**	**-2.5%**

* A shaded cell indicates estimate is not statistically significant

Figure 3.3-8 shows the peak period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers and Figure 3.3-9 and Figure 3.3-10 show the load impacts for each rate period and day type for the two segments. As seen in the figures, there are large and statistically significant differences in peak period load reductions between CARE/FERA and non-CARE/FERA customers in the service territory as a whole and in the hot and moderate regions. Except for in the cool climate region, non-CARE/FERA customers had greater load impacts than CARE/FERA customers.

Figure 3.3-8: Average Load Impacts for Peak Period for PG&E Rate 3 for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



As seen in Table 3.3-9 and Table 3.3-10 there are also significant differences in the load impacts between CARE/FERA and non-CARE/FERA customers for other rate periods and day types. While CARE/FERA customers generally did not reduce their daily electricity use, non-CARE/FERA customers did in the hot climate zone and in the PG&E territory as a whole – both on weekdays and weekends.

Table 3.3-9: Rate 3 Load Impacts by Rate Period and Day Type – Non-CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Rate 3														
Day Type	Period	Hours	All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.07	0.07	6.5%	1.74	0.15	8.9%	0.92	0.05	4.9%	0.49	0.00	0.9%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.62	0.01	1.4%	0.91	0.04	4.9%	0.56	-0.01	-1.2%	0.36	-0.01	-3.1%
	Day	**All Hours**	**0.72**	**0.02**	**3.0%**	**1.08**	**0.07**	**6.3%**	**0.64**	**0.00**	**0.6%**	**0.39**	**-0.01**	**-2.1%**
Average Weekend	Off Peak	All Hours	0.79	0.02	3.1%	1.20	0.06	5.3%	0.72	0.01	2.1%	0.41	-0.01	-2.4%
	Day	**All Hours**	**0.79**	**0.02**	**3.1%**	**1.20**	**0.06**	**5.3%**	**0.72**	**0.01**	**2.1%**	**0.41**	**-0.01**	**-2.4%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.64	0.11	6.4%	2.70	0.17	6.3%	1.53	0.12	8.1%	0.52	0.00	0.3%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	0.01	0.8%	1.33	0.03	2.1%	0.77	0.00	0.6%	0.37	-0.01	-4.0%
	Day	**All Hours**	**1.01**	**0.03**	**2.7%**	**1.62**	**0.06**	**3.5%**	**0.93**	**0.03**	**3.2%**	**0.40**	**-0.01**	**-2.9%**

* A shaded cell indicates estimate is not statistically significant

Table 3.3-10: Rate 3 Load Impacts by Rate Period and Day Type – CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Day Type	Period	Hours	All, CARE Ref. kW	All, CARE Impact kW	All, CARE % Impact	Hot, CARE Ref. kW	Hot, CARE Impact kW	Hot, CARE % Impact	Moderate, CARE Ref. kW	Moderate, CARE Impact kW	Moderate, CARE % Impact	Cool, CARE Ref. kW	Cool, CARE Impact kW	Cool, CARE % Impact
Average Weekday	Peak	4 PM to 9 PM	1.12	0.03	3.0%	1.53	0.05	3.3%	0.70	0.01	1.6%	0.44	0.01	2.9%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.64	-0.01	-1.1%	0.83	-0.01	-1.2%	0.46	0.00	-1.0%	0.31	0.00	-0.5%
	Day	**All Hours**	**0.74**	**0.00**	**0.2%**	**0.97**	**0.00**	**0.2%**	**0.51**	**0.00**	**-0.3%**	**0.34**	**0.00**	**0.4%**
Average Weekend	Off Peak	All Hours	0.80	0.00	-0.5%	1.05	-0.01	-0.6%	0.55	0.00	0.1%	0.35	0.00	-0.4%
	Day	**All Hours**	**0.80**	**0.00**	**-0.5%**	**1.05**	**-0.01**	**-0.6%**	**0.55**	**0.00**	**0.1%**	**0.35**	**0.00**	**-0.4%**
Monthly System Peak Day	Peak	4 PM to 9 PM	1.54	0.04	2.5%	2.14	0.05	2.2%	0.98	0.04	4.4%	0.44	0.01	2.3%
	Off Peak	12 AM to 4 PM, 9 PM to 12 AM	0.85	-0.02	-2.9%	1.15	-0.04	-3.3%	0.57	-0.01	-1.0%	0.32	-0.01	-1.9%
	Day	**All Hours**	**0.99**	**-0.01**	**-1.1%**	**1.35**	**-0.02**	**-1.5%**	**0.66**	**0.00**	**0.7%**	**0.35**	**0.00**	**-0.8%**

* A shaded cell indicates estimate is not statistically significant

3.3.4 Comparison Across Rates

Figure 3.3-9 compares the load impacts for the three rates tested by PG&E for the common set of peak-period hours, 6 PM to 9 PM, shared by all three tariffs. Using a common set of hours reduces differences in impacts across rates that might be due to differences in the number of hours included in the peak period or the timing of those hours. The hours from 6 PM to 9 PM define the peak period for Rate 2, which is a three-period rate with a shoulder period from 4 PM to 6 PM and 9 PM to 10 PM. Rates 1 and 3 are two-period rates with the same peak period, from 4 PM to 9 PM. Rate three has a higher peak to off-peak price ratio than Rate 1. As such, one would expect the peak-period load reductions to be higher for Rate 3 than for Rate 1. The peak to off-peak price ratio for Rate 2 is in between the other two but the partial peak period and the shorter peak period makes it difficult to predict whether the load reductions might be greater or less than for the other rates.

As seen in Figure 3.3-9, there are generally no statistically significant differences in load impacts for the common hours from 6 PM to 9 PM across the three rates in absolute terms for the service territory as a whole or in any climate region. Figure 3.3-10 shows the average daily kWh impact for each rate. The reduction in daily usage differs between Rate 2 and the other two rates for the service territory as a whole as well as in the hot climate region. This could be attributable to the shorter peak period on Rate 2, which makes it easier to shift loads from the peak to the off-peak period. It also means that the same percent reduction in peak period load for all three rates would produce a smaller overall conservation effect in Rate 2 compared to the other two rates because there are fewer hours in the Rate 2 peak period. Daily impacts also vary across rates in the cool climate region but the differences are not statistically significant.

Figure 3.3-9: Average Impacts from 6 PM to 9 PM Across Rates

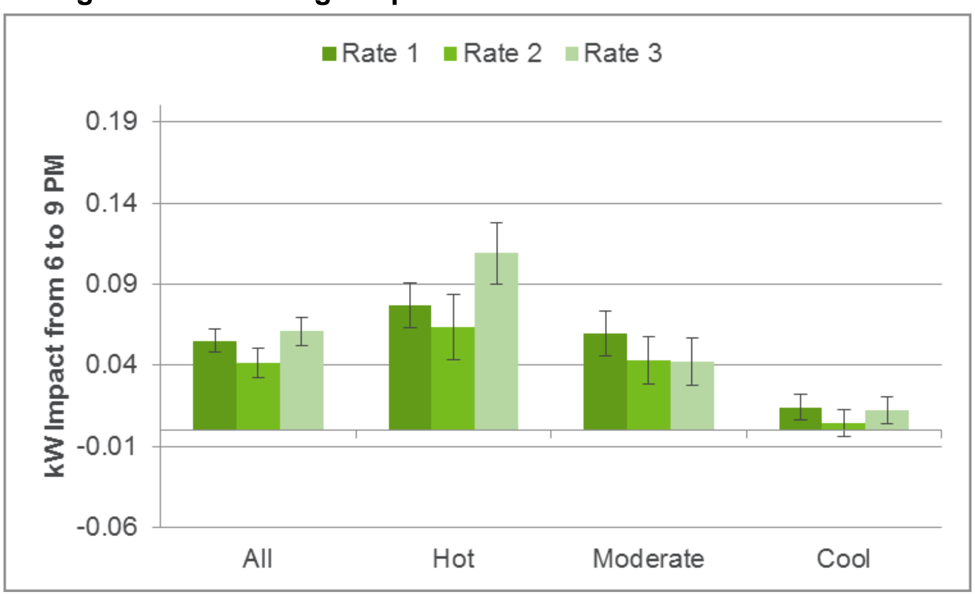
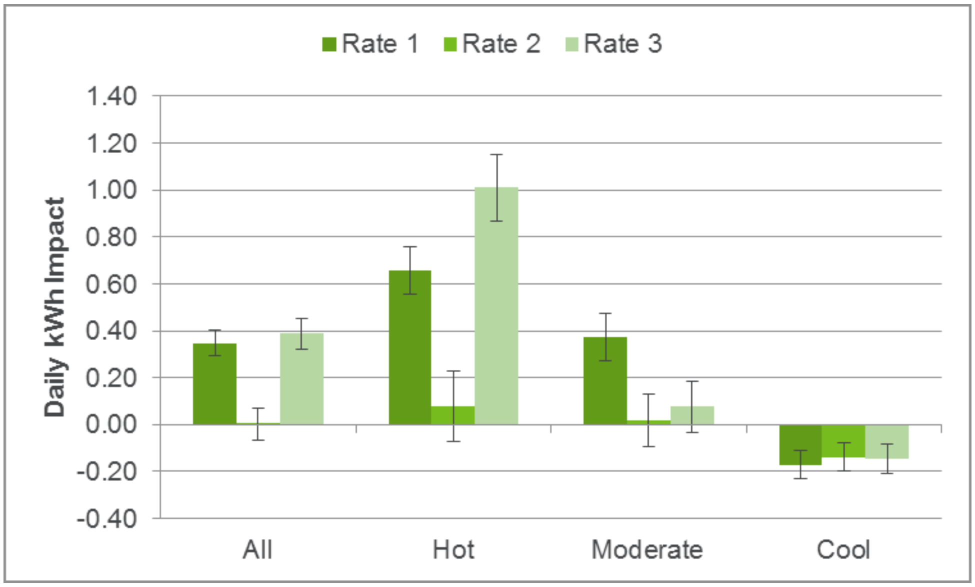


Figure 3.3-10: Average Daily kWh Impacts Across Rates



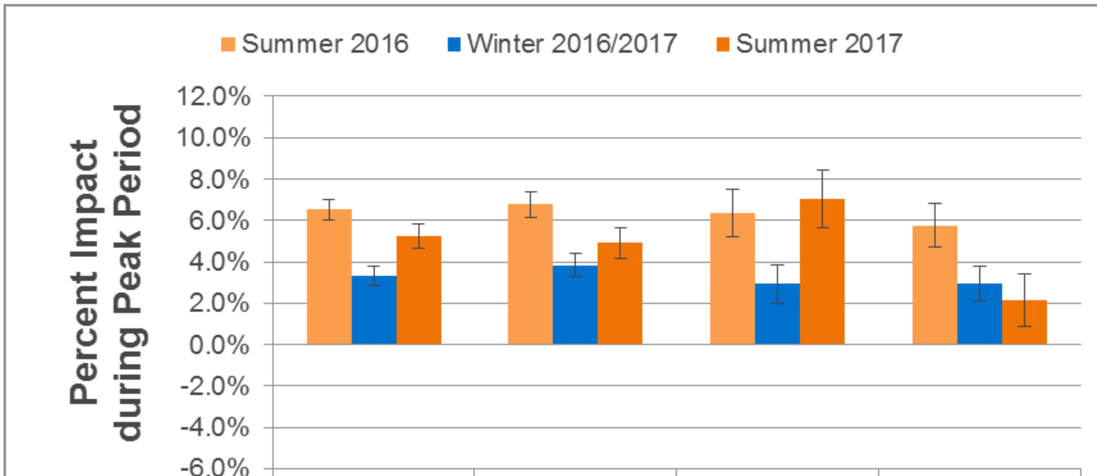
3.4 Persistence Analysis

This section examines the persistence of load impacts over the course of the pilot. Most relevant is whether load impacts in summer 2017 are greater, smaller or about the same as load impacts in 2016. When analyzing persistence, it is important to compare load impacts for the same group of customers over time. A comparison of load impacts for customers enrolled in 2016 with those enrolled in 2017 is not a valid estimate of persistence since any observed difference might be due in large part to changes in the participant population rather than changes in behavior of customers that participated in both summer periods. As such, load impacts presented in this section pertain to the population of customers that remained enrolled over the entire period starting in July 2016 through the end of September 2017. Because not all customers were enrolled until the end of June 2016, the summer load impacts reported here represent the months of July through September in each year. While there is not a second winter for persistence comparison, the winter and spring impacts for the subset of customers who were enrolled for the full duration of the pilot are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers. Winter and spring impacts presented in this section match the rate-specific winter and spring months described in Section 3.1.

3.4.1 Rate 1

Figure 3.4-1 shows percent impacts for the peak period for customers on Rate 1, for the territory as a whole and for each climate region. As seen, for the same group of customers, load impacts in winter were roughly half of what they were in summer 2016. Comparing load impacts across the two summer periods, for the territory as a whole, summer impacts fell from 6.5% in the first summer to 5.2% in the second summer, and the difference is statistically significant. Load impacts also fell by roughly the same percentage in the hot climate region and by a much greater percentage in the cool climate region, where 2017 load impacts were only about 35% as much as the 2016 load impacts for the same group of customers. In contrast, load impacts in the moderate climate region were very similar across the two summer periods. Indeed, load impacts appear to have increased a bit in the second summer although the difference in load impacts for the two summers is not statistically significant.

Figure 3.4-1: Percent[30] Impacts for Peak Period for PG&E Rate 1, by Season (Positive values represent load reductions)



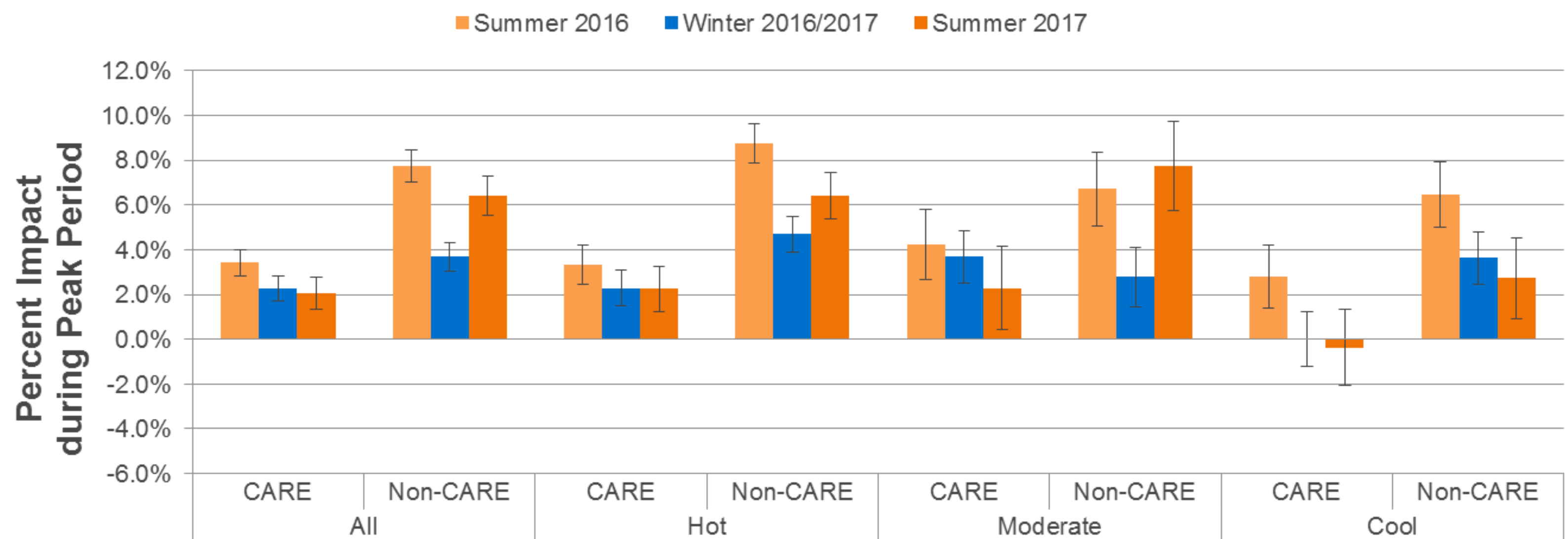
	All	Hot	Moderate	Cool
Summer 2016	6.5%	6.8%	6.4%	5.8%
Winter 2016/2017	3.3%	3.8%	2.9%	3.0%
Summer 2017	5.2%	4.9%	7.0%	2.1%

Figure 3.4-2 shows percent impacts by season for CARE/FERA and non-CARE/FERA customers on Rate 1. Summer impacts for CARE/FERA customers fell from 3.4% to 2.0% for the territory as a whole and this difference was statistically significant. In the hot and moderate climate regions, the difference in peak period load impacts across the two summers for CARE/FERA customers were not statistically significant, but in the cool climate region, the difference across summers was large and statistically significant for CARE/FERA customers.

For non-CARE/FERA customers on Rate 1 for the service territory as a whole, the difference in load impacts across summers was not statistically significant. However, the fall in percent impacts in the hot and cool climate regions were statistically significant, indicating that customers did not respond to TOU rates as well in the second summer.

[30] Percent load reductions rather than kW were evaluated for the persistence analysis to allow for comparison of impacts relative to the available load. For example: if the second summer were cooler than the first, the kW impacts may be lower due to less cooling load, but customers may still be responding similarly between summers given the available load to curtail. The percent impacts help to normalize for any level differences in usage between the summers.

Figure 3.4-2: Percent Impacts for Peak Period for PG&E Rate 1, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

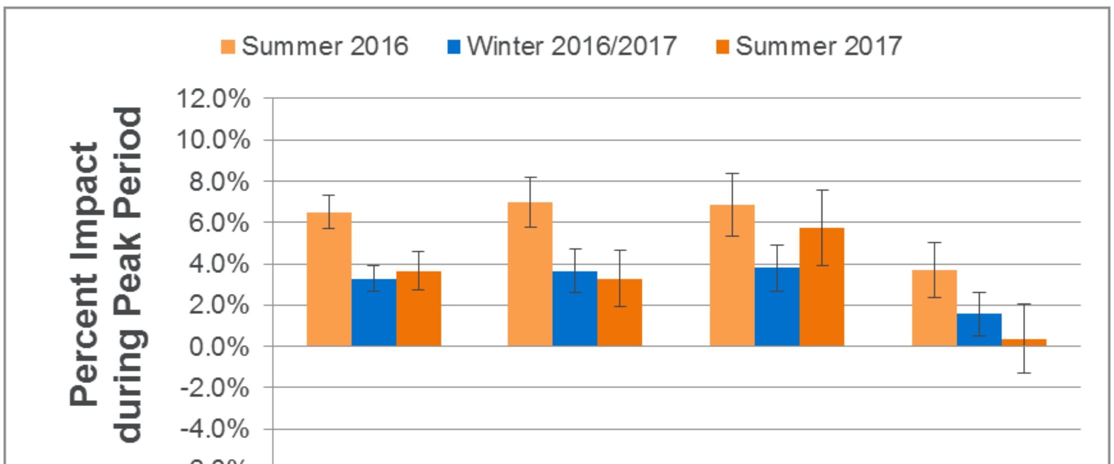


	All CARE	All Non-CARE	Hot CARE	Hot Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Summer 2016	3.4%	7.7%	3.3%	8.7%	4.2%	6.7%	2.8%	6.5%
Winter 2016/2017	2.3%	3.7%	2.3%	4.7%	3.7%	2.8%	0.0%	3.6%
Summer 2017	2.0%	6.4%	2.2%	6.4%	2.3%	7.8%	-0.4%	2.7%

3.4.2 Rate 2

Figure 3.4-3 shows peak percent impacts for customers on Rate 2 for each season of the pilot. Recall that the impacts presented here only include customers who were enrolled until September 2017- through the entire duration of the pilot. For the territory as a whole, load impacts fell from 6.5% to 3.7%, and the change was statistically significant. The hot and cool climate regions also had statistically significant reductions in peak impacts, about 4 and 3 percentage points, respectively. In fact, both climate regions had larger impacts in the winter months than in the summer of 2017. The cool climate region did not have statistically significant impacts in summer 2017, which could indicate that customers stopped responding to the rate. The moderate climate zone saw smaller summer 2017 impacts as well, but the reduction was not statistically significant.

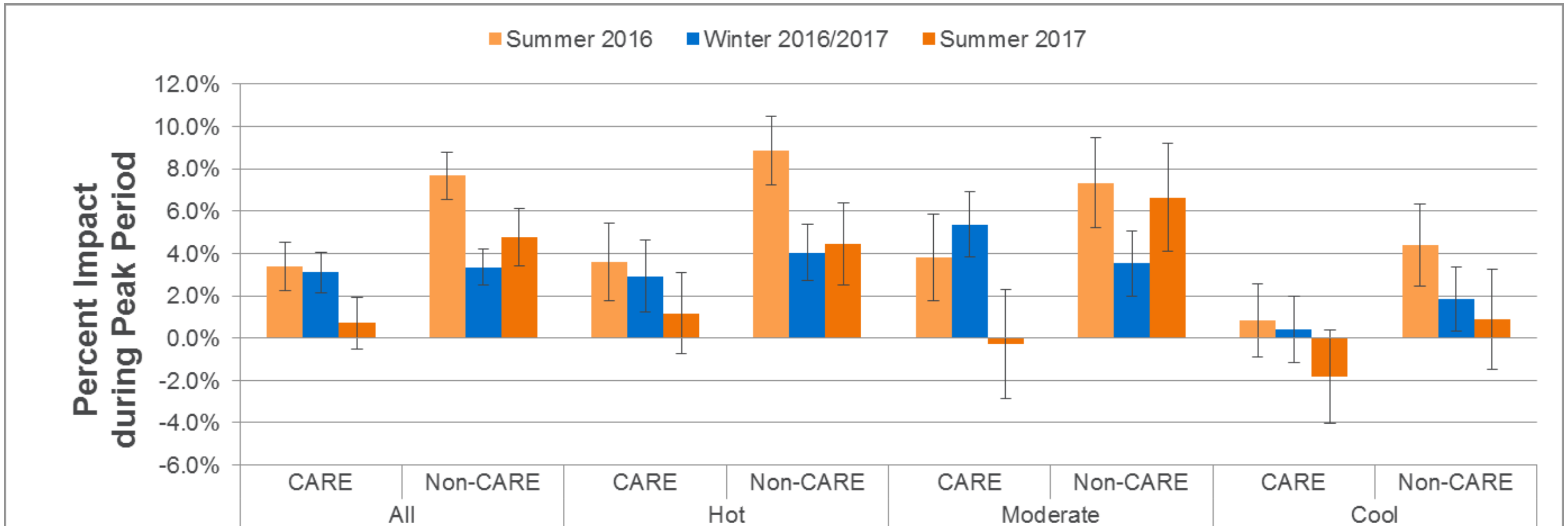
Figure 3.4-3: Percent Impacts for Peak Period for PG&E Rate 2, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	6.5%	7.0%	6.8%	3.7%
Winter 2016/2017	3.3%	3.6%	3.8%	1.6%
Summer 2017	3.7%	3.3%	5.7%	0.4%

Figure 3.4-4 shows peak period impacts for CARE/FERA and non-CARE/FERA customers on Rate 2. For the territory as a whole and for each climate region, there were very dramatic decreases in load response by CARE/FERA customers across the two summer periods. Indeed, in the second summer, load impacts for CARE/FERA customers were not statistically significant in the service territory as a whole or in any of the climate regions, whereas load impacts were statistically significant for this customer segment in the hot and moderate regions and for the service territory as a whole in summer 2016. For whatever reason, CARE/FERA customers on Rate 2 changed their behavior significantly over the course of the pilot. There were also statistically significant differences in load impacts across the two summer periods for non-CARE/FERA customers for the service territory as a whole and in the hot climate region. The difference across summers was very small and not statistically significant in the moderate climate zone for non-CARE/FERA customers. Load impacts for this segment in the cool climate region were statistically significant in 2016 but not in 2017.

Figure 3.4-4: Percent Impacts for Peak Period for PG&E Rate 2, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



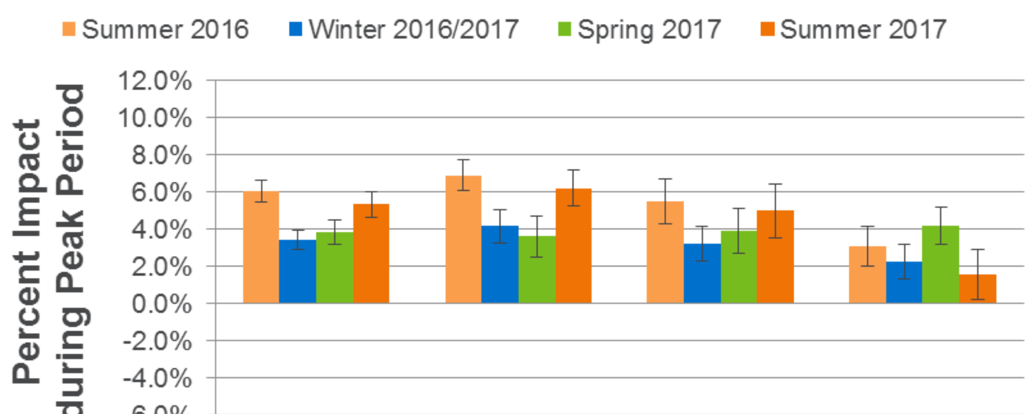
	All CARE	All Non-CARE	Hot CARE	Hot Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Summer 2016	3.4%	7.7%	3.6%	8.9%	3.8%	7.3%	0.8%	4.4%
Winter 2016/2017	3.1%	3.3%	2.9%	4.0%	5.4%	3.5%	0.4%	1.8%
Summer 2017	0.7%	4.8%	1.2%	4.4%	-0.3%	6.7%	-1.8%	0.9%

3.4.3 Rate 3

Figure 3.4-5 presents average percent impacts for customers on Rate 3 for each season in the pilot. Recall that unlike the previous two rates, PG&E's Rate 3 has three seasons: summer, winter, and spring. Compared to Rate 1 and Rate 2, the drop in peak impacts was small between summer 2016 and summer 2017, only 0.7 percentage points. This reduction was not statistically significant, nor was it statistically significant in the individual climate regions.

Customers on Rate 3 appeared to maintain meaningful load impacts in the second summer of the pilot, meaning they are still responding to the TOU rate even after a year. This finding is generally true even for CARE/FERA and non-CARE/FERA customers.

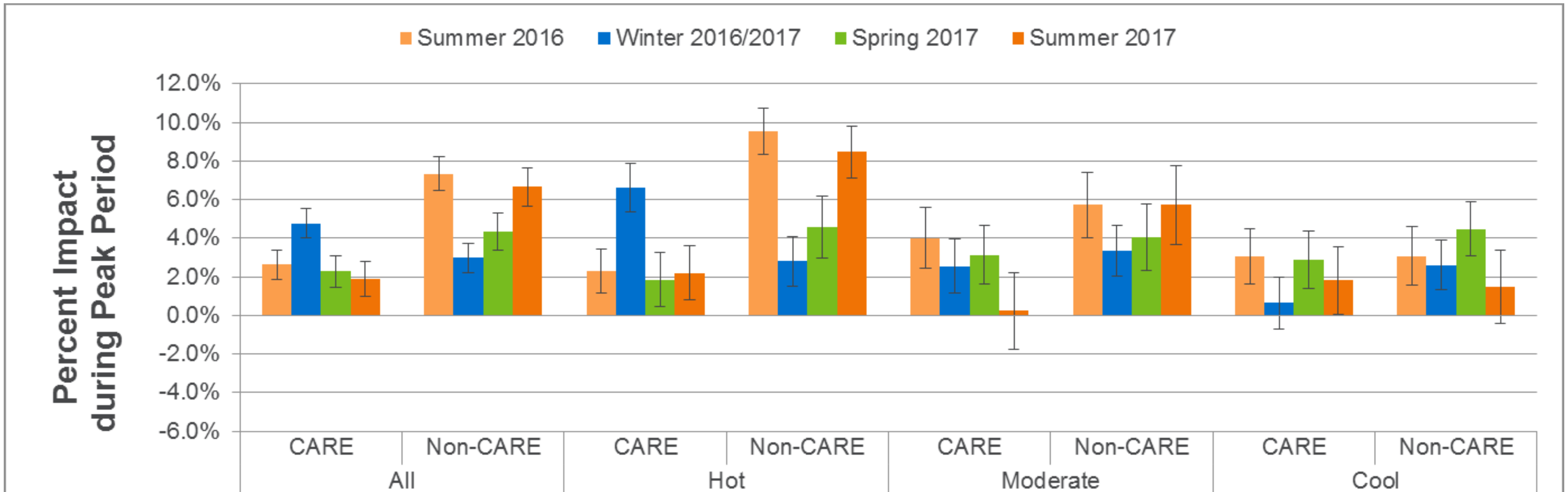
Figure 3.4-5: Percent Impacts for Peak Period for PG&E Rate 3, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	6.0%	6.9%	5.5%	3.1%
Winter 2016/2017	3.4%	4.2%	3.2%	2.3%
Spring 2017	3.8%	3.6%	3.9%	4.2%
Summer 2017	5.3%	6.2%	5.0%	1.6%

Figure 3.4-6 presents peak period impacts for each time period for CARE/FERA and non-CARE/FERA customers on Rate 3. In the hot and cool climate regions and for the service territory as a whole, CARE/FERA customers showed greater impacts in the first summer of the pilot compared to the second – but the differences were not statistically significant. For example, customers in the hot climate zone had impacts equal to 2.3% in 2016 and 2.2% in 2017. Non-CARE/FERA customers maintained meaningful summer impacts in both years, except in the cool climate region where impacts were not statistically significant in summer 2017.

Figure 3.4-6: Percent Impacts for Peak Period for PG&E Rate 3, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



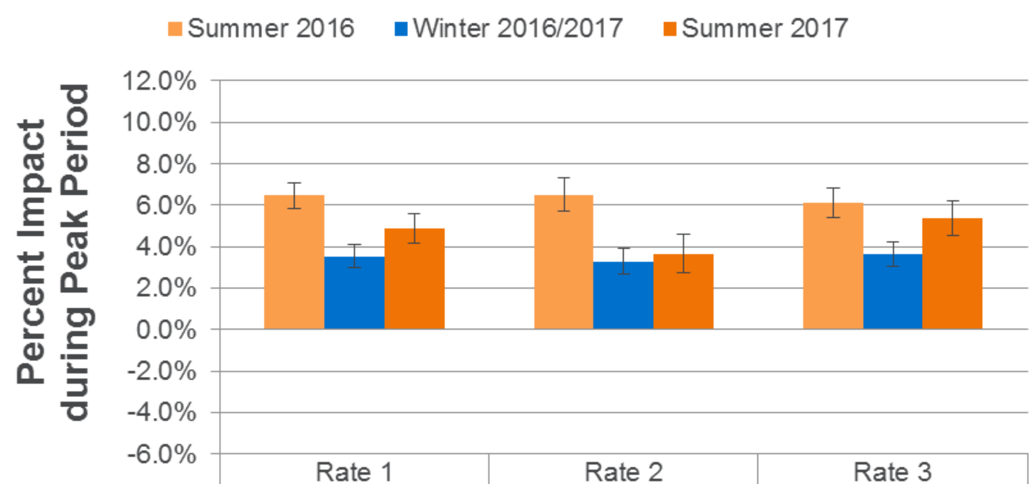
	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Summer 2016	2.6%	7.4%	2.3%	9.5%	4.0%	5.7%	3.1%	3.1%
Winter 2016/2017	4.8%	3.0%	6.6%	2.8%	2.6%	3.4%	0.7%	2.6%
Spring 2017	2.3%	4.4%	1.9%	4.6%	3.1%	4.1%	2.9%	4.5%
Summer 2017	1.9%	6.7%	2.2%	8.5%	0.2%	5.7%	1.8%	1.5%

3.4.4 Comparison Across Rates

Figure 3.4-7 compares the load impacts for the three rates tested by PG&E for the common set of peak-period hours from 6 PM to 9 PM for the summer months of July through September and the winter months of October through May.

All three rates had similar first summer impacts, when the program was relatively new. In the second summer, we see greater variation in load impact magnitude. This could be a result of customers better understanding how their bills change under the TOU rates, and responding (or not responding) to the price signal accordingly based on their experience with bills during the first summer. For all three rates, summer impacts decline slightly from 2016 to 2017, and the difference is statistically significant for Rate 1 and Rate 2. Winter impacts are smaller than summer impacts in every case.

Figure 3.4-7 Percent Impacts from 6 PM to 9 PM Across Rates, by Season



	Rate 1	Rate 2	Rate 3
Summer 2016	6.5%	6.5%	6.1%
Winter 2016/2017	3.5%	3.3%	3.6%
Summer 2017	4.9%	3.7%	5.4%

3.5 Synthesis for PG&E Pilot

This section compares input from the load impact and persistence analysis, the bill impact analysis, and the survey analysis. The objective of these comparisons, at least in part, is to determine if the information and conclusions observed for individual metrics are supported by findings from other metrics or, alternatively, findings for one metric contradict those for another metric. We also look for clues from the survey findings that might help explain why load or bill impacts for one rate differ from those for other rates. For example, if we find that the load impacts are significantly different across rates or across segments for a specific rate, we could turn to the survey questions concerning the level of understanding of rate features to see if there are significant differences in customer understanding of key rate features that might explain the observed differences across rates and/or customer segments.

When reviewing the synthesis tables and discussion below, it is important to keep in mind, as discussed in the interim reports, that the statistical analysis of survey questions is “over powered” That is, with the very large sample sizes for each treatment and control group, combined with the high survey response rate, even very small differences in values across segments can be statistically significant. While any decision regarding whether a statistically significant difference is meaningful from a policy perspective is inherently subjective, it nevertheless is critical. For example, reporting that there is a statistically significant difference in the satisfaction rating of one rate compared to another and concluding or recommending that the rate with the lower satisfaction rating is inferior from a customer engagement perspective would be very misleading if, for example, the satisfaction rating for one was 6.2 and the other was 6.7 on an 11 point scale.

3.5.1 Synthesis

Table 3.5-1 through Table 3.5-3 summarize relevant findings from the load impact, persistence, bill impact and survey analysis. No additional bill impact analysis or surveys were completed for this report. Therefore, results from the first and second interim report were carried forward to this synthesis section in order to provide a more complete overview of the pilot. Before summarizing the results, we provide the following guide to the information in Table 3.5-1 as well as a map to prior tables and figures from which the information was taken for Rate 1, including those contained in the separate RIA Report. This way, readers can easily refer back to those more complete tables and figures.

In each cell in the tables, in addition to the reported values, there is either a colored triangle facing up or down, a (-), N/A, I/S or nothing at all. Cells containing N/A indicate that the specific segment was not included in the analysis, and cells containing I/S indicate the segment was analyzed but didn't have sufficient sample size to warrant reporting the results. If there is a colored triangle in the cell, it means the value in the cell is statistically significantly different relative to the control group. Green triangles symbolize a desirable outcome (e.g., peak period load reductions are good) and red triangles an undesirable outcome (e.g., peak period load increases are not good). If (-) appears, the value is not statistically significant and if there is no symbol at all (as in the column labeled "Understanding TOU Pricing (None Correct)", it means a comparison to the control group is not relevant (in this example, the control group was not on a TOU rate so couldn't respond to questions about rate periods, etc.). N/A indicates that a statistical significance test was not appropriate. The content of each column and guidance on where the values can be found elsewhere in this report or in prior reports is explained below:

- **Summer 2016 Peak Period Load Reduction:** The percent reduction in peak-period electricity use on average weekdays for the months of July through September 2016. Positive values mean customers reduced use and negative values mean customers increased use during the peak period relative to the control group (e.g., reference load). Reductions are desirable, and therefore indicated by a green triangle, and increases are undesirable, and represented by a red triangle. These values carried over from the First Interim Report.
- **Winter Peak Period Load Reduction:** The percent reduction in peak-period electricity use on average weekdays for the months of October 2016 through May 2017.[31] Positive values mean

[31] PG&E's Rate 3 has a spring period in addition to the summer and winter. Results presented in the synthesis tables reflect the winter period specific to Rate 3 (October 2016 through February 2017).

customers reduced use and negative values mean customers increased use during the peak period relative to the control group (e.g., reference load). These values were carried over from the Second Interim Report.

- **Summer 2017 Peak Period Load Reduction:** The percent reduction in peak-period electricity use on average weekdays for the months of June through September 2017. Positive values mean customers reduced use and negative values mean customers increased use during the peak period relative to the control group (e.g., reference load). Once again, reductions are desirable, and therefore indicated by a green triangle, and increases are undesirable, and represented by a red triangle. These values are summarized in Section 3.3 of this report.
- **Net Annual kWh Change %:** The percent reduction in annual electricity use for the year starting July 2016 and ending June 2017. Positive values mean customers reduced use and negative values mean customers increased use. These values were carried forward from the Second Interim Report.
- **Persistence: Summer Impact Percent Point Change:** The percentage point difference between percent load impacts from July through September 2016 and July through September 2017 for the common set of customers who remained enrolled for the full duration of the pilot. Negative values represent a reduction in percent impacts between the first and second summer, which are undesirable and represented by a red triangle. Increases are desirable and represented with a green triangle. These findings were discussed in Section 3.4 of this report.
- **Annual Total Bill Impact ($ or %):** This is the change in the average customer's bill on Rate 1 due to the impact of both the structural change in the tariff, holding usage constant, and the change in the bill due to changes in usage. These values were carried forward from the Second Interim Report.

Note regarding all survey related values: All reported survey values are from the second (final) customer survey and have been carried forward from the RIA Second Interim Report. Table references relate to the document produced by Research Into Action as part of the Second Interim Report.

- **Health Index:** The values in this column represent the mean values of the health index for each customer segment. Values for Rate 1 were taken from Table 3-7 in the RIA Second Interim Report. Cells with red triangles indicate that the index mean value for the segment is higher than the mean value for the control group and the difference is statistically significant. Cells with green arrows mean that the treatment group index is actually lower than the control group value and the difference is statistically significant.
- **Bill Higher Than Expected:** The values in this column are taken from Table 3-49 in the RIA Report and equal the percent of customers reporting that their bills since December 2016 had been higher than they expected. The values do not represent the difference in the percentage between treatment and control customers. Many control customers also reported that bills were higher than expected, reflecting the usual seasonal variation in bills that occurs due to seasonal changes in rates, higher air conditioning use in the summer and the tiered structure of the rates. Cells with red triangles represent values that are higher than the percentage reported by control group customers and where the difference is statistically significant. These values were carried forward from the RIA Second Interim Report.
- **Difficulty Paying Bills:** The values in this column are taken from Table 3-26 in the RIA Report and represent the percent of customers reporting having difficulty paying bills since December 2016.

Cells with red or green triangles represent values that are higher or lower than control group values, respectively, and where the differences are statistically significant. These values were carried forward from the Second Interim Report.

- **Economic Index:** The values in this column represent the mean values of the economic index for each customer segment. Values for Rate 1 were taken from Table 3-6 in the RIA Second Interim Report. Cells with red triangles indicate that the index mean value for the segment is higher than the mean value for the control group and the difference is statistically significant.
- **Understanding TOU Pricing:** This variable is based on a survey question asking respondents to identify the hours of the day when prices are the highest. The values in the table come from Table 3-52 in the RIA Second Interim Report and indicate the percent of customers that failed to correctly identify ANY peak period hours associated with the TOU rate. The higher this percentage, the less likely that a group of customers would make significant reductions during the peak period- this is because fewer customers would know when the peak period was.
- **Satisfaction with Rate:** These values represent the average satisfaction rating for the rate plan on an 11 point scale, from 0 to 10, with higher values indicating higher satisfaction. These values are taken from Table 3-39 in the RIA Second Interim Report. Values with red triangles represent cells where the average rating for the treatment group on the TOU rate is lower than for the control group on the OAT, and the difference is statistically significant.
- **Satisfaction with Utility:** The same 11-point scale as above was used to assess satisfaction with PG&E. The values in the column are also taken from Table 3-39 in the RIA Second Interim Report. As above, red triangles represent statistically significant differences between average values for the control and treatment groups.

Looking across the various metrics for each customer segment and rate, we did not observe any internal inconsistencies. In fact, quite the opposite—overall, the load impact, bill impact and survey findings typically align quite well. Below is a summary by customer segment.

Table 3.5-1: Load Impacts, Bill Impacts, and Selected Survey Findings for PG&E Rate 1[32]

		Load Impacts					Bill Impacts		Survey							
Climate	Segment	Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	8.7% ▼	5.4% ▼	7.0% ▼	3.1% ▼	-2.3 ▼	$4 -	0% -	2.20 -	31% ▼	25% -	2.4 -	5%	6.2 -	6.8 -
	CARE/FERA	3.2% ▼	2.6% ▼	2.5% ▼	0.9% ▼	-1.1 -	$0 -	0% -	2.90 -	27% ▼	68% -	4.1 -	14%	6.9 -	7.4 -
	Senior	7.0% ▼	4.8% ▼	5.8% ▼	2.6% ▼	-2.1 ▼	-$8 ▼	-1% ▼	2.80 -	26% ▼	37% -	3.0 -	12%	6.9 ▲	7.4 -
	HH < 100% FPG	-0.4% -	0.8% -	2.3% ▼	-0.9% ▲	2.2 -	$37 ▲	4% ▲	2.90 -	31% ▼	70% -	4.3 -	13%	7.0 -	7.5 -
	100% FPG < HH < 200% FPG	N/A	N/A	N/A	N/A	N/A	-$23 ▼	-2% ▼	2.90 -	28% ▼	60% -	3.9 -	11%	6.7 -	7.2 -
Moderate	Non-CARE/FERA	4.7% ▼	3.5% ▼	7.0% ▼	0.3% ▼	1.1 -	-$20 ▼	-2% ▼	2.40 -	26% ▼	15% ▼	1.9 ▼	5%	6.6 ▲	6.8 -
	CARE/FERA	3.9% ▼	2.5% ▼	2.1% ▼	1.7% ▼	-2.0 -	-$36 ▼	-5.4% ▼	2.90 -	27% ▼	62% -	4.1 -	14%	7.3 -	7.7 -
Cool	Non-CARE/FERA	4.6% ▼	3.3% ▼	1.9% ▼	0.8% ▼	-3.8 ▼	-$26 ▼	-2.8% ▼	2.10 -	35% -	15% ▼	1.9 -	3%	6.3 -	6.6 -
	CARE/FERA	1.4% ▼	-0.9% -	0.2% -	-2.2% ▲	-3.2 ▼	-$8 ▼	-1.6% ▼	2.80 -	33% -	57% -	3.6 -	16%	7.1 -	7.4 -

Table 3.5-2: Load Impacts, Bill Impacts, and Selected Survey Findings for PG&E Rate 2

		Load Impacts					Bill Impacts		Survey							
Climate	Segment	Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	9.0% ▼	3.7% ▼	5.0% ▼	1.5% ▼	-4.4 ▼	$40 ▲	2.5% ▲	2.40 -	32% -	28% -	2.4 -	11%	6.0 -	6.5 -
	CARE/FERA	2.8% ▼	3.3% ▼	1.9% ▼	0.5% ▼	-2.4 -	$7 ▲	0.8% ▲	2.90 -	25% ▼	68% -	4.3 -	27%	7.1 -	7.6 ▲
Moderate	Non-CARE/FERA	6.8% ▼	4.3% ▼	2.4% -	-0.1% -	-0.7 -	-$18 ▼	-1.4% ▼	2.20 -	36% ▼	17% -	2.0 -	10%	6.3 -	6.9 -
	CARE/FERA	2.8% ▼	5.0% ▼	0.5% -	1.9% ▼	-4.1 -	-$31 ▼	-5.0% ▼	3.10 -	30% -	60% -	3.9 -	24%	7.3 -	7.6 -
Cool	Non-CARE/FERA	4.7% ▼	2.5% ▼	1.5% -	0.3% ▼	-3.5 -	-$16 ▼	-1.8% ▼	2.20 -	33% -	18% -	2.0 -	11%	6.3 -	6.9 -
	CARE/FERA	0.3% -	0.0% -	-1.7% -	-2.4% ▲	-2.6 -	-$4 ▼	-0.8% ▼	2.90 -	36% -	53% -	3.7 -	22%	7.2 -	7.5 -

Table 3.5-3: Load Impacts, Bill Impacts, and Selected Survey Findings for PG&E Rate 3

		Load Impacts					Bill Impacts		Survey							
Climate	Segment	Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	9.5% ▼	2.6% ▼	8.9% ▼	2.6% ▼	-1.1 -	$21 ▲	1.3% ▲	2.20 -	28% ▼	25% -	2.5 -	6%	6.2 -	6.7 -
	CARE/FERA	1.9% ▼	7.3% ▼	4.1% ▼	2.3% ▼	-0.1 -	-$5 ▼	-0.5% ▼	2.70 -	25% ▼	74% -	4.6 ▲	14%	7.3 ▲	7.6 ▲
Moderate	Non-CARE/FERA	4.1% ▼	3.7% ▼	4.9% ▼	0.5% ▼	0.0 -	-$8 ▼	-0.8% ▼	2.10 -	32% ▼	15% ▼	2.1 -	3%	6.6 ▲	7.0 ▲
	CARE/FERA	3.2% ▼	1.8% ▼	1.6% -	0.8% ▼	-3.8 ▼	-$28 ▼	-4.5% ▼	2.90 -	26% ▼	60% -	3.9 -	11%	7.4 -	7.7 -
Cool	Non-CARE/FERA	3.1% ▼	2.0% ▼	0.9% -	0.4% ▼	-1.6 -	-$24 ▼	-2.8% ▼	2.50 -	32% -	20% -	2.1 -	7%	6.4 -	6.8 -
	CARE/FERA	2.3% ▼	0.8% -	2.9% ▼	-0.1% -	-1.3 -	-$22 ▼	-4.4% ▼	2.70 ▼	31% -	57% -	3.7 -	13%	7.3 -	7.5 -

[32] In all three tables, a column with an (*) indicates the values are from the First Interim Report and a column with (**) indicates the values are from one of the two Second Interim Report volumes. A column with neither (*) or (**) means the values are found elsewhere in this report.

Non-CARE/FERA Customers

Non-CARE/FERA customers in the hot climate region have the highest percent reduction in summer 2017 peak-period energy usage among all segments, averaging 7.0% across the three rates.[33] This group had the highest percent reductions in summer 2016 and the second highest in the winter months. These results are consistent with the finding that non-CARE/FERA customers understood the rates better than nearly any other segment, as indicated by the very low percent that failed to identify at least one peak period hour. Non-CARE/FERA customers in the hot region had the highest net annual kWh savings, averaging 2.4% across all rates.

Across all rates and climate regions, population weighted peak period impacts in the second summer decreased by 1.8 percentage points when compared to the first summer for customers who remained on the pilot for the entire duration. Estimating load impacts for a common set of customers across the two summers controls for differences in impacts that might arise due to changes in the characteristics of enrolled customers. Put differently, this comparison focuses on whether or not customers who remain on a TOU rate continue to reduce loads during peak periods. The observed drop in load reductions of 1.8 percentage points from summer to summer may result, in part, from differences in weather or some other exogenous factor (e.g., a strengthening economy) between the first and second summer. Importantly, although there is an observed decline in average load impacts, impacts in the second summer are still quite strong for non-CARE/FERA customers, averaging 5.1% across the three rates.

As referenced in the Second Interim Report, all non-CARE/FERA customer segments across all rates experienced average total bill decreases in the winter but, as indicated in the First Interim Report, nearly all had much higher bills in summer than they would have had under the OAT. On an annual basis, non-CARE/FERA customers experienced the greatest annual total bill increases of approximately $20 per year due to a large portion of customers being structural non-benefiters. They were, however, able to offset 67% of their approximately $60 annual structural loss through behavior change. Total annual bill increases for non-CARE/FERA customers in the hot climate region ranged from a low of $4 on Rate 1 to a high of $40 on Rate 2. Average annual bills decreased for non-CARE/FERA customers in the moderate and cool climate regions for all three rates. In many cases, non-CARE/FERA customers had statistically significantly lower instances of customers receiving a higher bill than expected compared to the control group—meaning more control group customers were surprised by higher than expected bills than treatment group customers.

The non-CARE/FERA customers also had the lowest satisfaction ratings for the rate plan and for PG&E compared with any other segment. However, there were no cases in which the satisfaction levels were significantly lower relative to the control group. In some cases, the satisfaction levels for both the rate and for PG&E were actually higher for the treatment group compared to the control group in the moderate climate region. All of these metrics paint an internally consistent picture of a customer segment that understood the timing of the peak period well, worked hard to reduce usage and bills, and ultimately had satisfaction ratings very similar to those of the control group.

[33] Average based on peak period for each rate and not the common hours.

CARE/FERA Customers

In the summer months in 2017, CARE/FERA customers in the cool climate region had the lowest reductions in peak-period electricity use, an average of about 0.5% across all three rates. In each climate region, CARE/FERA customers had smaller load impacts than non-CARE/FERA customers. The smaller load reductions by CARE/FERA customers compared to non-CARE/FERA customers could be due to greater difficulty by CARE/FERA customers in reducing or shifting loads. For example, lower income households may lack quality insulation or may have undersized air conditioning equipment, resulting in a greater burden for them to reduce cooling energy use compared to a household with higher quality insulation or adequately sized air conditioning units. Low income customers may also work two jobs, or work longer hours, limiting their flexibility to shift loads such as laundry or cooking. It may also be that low income households have lower saturations of end uses such as dishwashers and clothes driers, that can easily be shifted from peak to off-peak periods.

When comparing load impacts with the previous summer for the set of customers who were enrolled for the entire pilot, the average customer impact dropped by 2.3 percentage points. However, for many customer segments the difference between the first and second summer was not statistically significantly different. The two exceptions were CARE/FERA customers in the cool climate region on Rate 1, and the moderate climate region customers on Rate 3. These segments experienced load impact reductions of 3.2 and 3.8 percentage points, respectively. This could be because CARE/FERA customers in the moderate and cool climate regions both had structural bill decreases of around $20 (3-4%) on an annual basis, which could have led customers to believe they do not need to shift their usage as much as they did in the first summer.

CARE/FERA customers on Rate 3 in the hot climate region had the highest percent of customers expressing difficultly paying bills, at 74%. While this metric was not statistically significantly different compared to the control group, they also had the highest economic index score of 4.6, which was significantly higher compared to the control group. In the first survey, 22% of these customers were not able to identify any of the TOU pricing periods correctly. In the second survey, this dropped by nearly one-third, to 14%. This group initially faced an annual structural loss of approximately $14, and through behavior change was able to reduce their bills by $19, resulting in a net savings of $5 per year.

CARE/FERA customers had significant economic challenges, and were successful in adjusting their energy consumption, at least in the winter period, in order to ultimately lower their bills. It should also be noted that these customers had some of the highest satisfaction scores with both the rate and with PG&E, with scores from both satisfaction metrics being significantly higher compared to the control group for customers in the hot climate region on Rate 3, and no worse compared to the control group for any rates across any climate region. This is consistent with findings from many other surveys of this customer class which in general tends to have higher satisfaction ratings overall for all IOU programs. In all climate regions, none of the satisfaction ratings for CARE/FERA customers were statistically significantly lower than the control group ratings—in fact, they were higher for the Rate 3 hot climate regions customers. CARE/FERA customers also had higher ratings for satisfaction with PG&E than non-CARE/FERA customers in all climate regions for all rates.

Turning to other metrics of interest, there was essentially no change in total annual bills in the hot climate region for CARE/FERA customers averaged across the three tariffs. These customers were able to offset 80% of their annual structural bill increase of around $9. While on an annual basis the difference is negligible, customers did experience higher bills in the summer that were ultimately offset by lower bills in the winter. Between 53% and 74% of CARE/FERA customers reported having difficulty paying bills, which was three times higher on average than for non-CARE/FERA customers, but this was also true for control customers. The economic index for CARE/FERA customers was roughly twice as high as for non-CARE/FERA customers in all climate regions and for all rate options, including the control group. In short, CARE/FERA customers had higher economic index scores compared with non-CARE/FERA customers, but the increase in the economic index scores moving from the OAT to TOU rates is not statistically significant except for the Rate 3 hot climate region customers noted above.

Senior Households

Senior households in the hot climate region had load reductions in the summer 2017 peak period for the average weekday that were comparable to average reductions for the overall population in the hot region. The average peak-period load impact of 5.8% is closer to the slightly larger load impacts of the non-CARE/FERA group of 7.0% than the smaller impacts from the CARE/FERA group with 2.5%. Senior household summer load impacts in 2017 were 2.1 percentage points lower than impacts in 2016 for a common set of customers, a change that was statistically significant. This indicates that these customers are less responsive to the rates in the second year, possibly as a result of small annual bill reductions not providing a strong price signal.

On Rate 1, 26% of seniors indicated that their bills were higher than expected. However, this percentage was statistically significantly lower for the customers on TOU rates compared to the OAT. There was no statistically significant difference in the percent of seniors reporting difficulty in paying bills, or in the economic index, compared with the control group.

Senior households appear to have a higher percentage of participants that could not identify any peak period hours compared with the population as a whole in the hot region. Weighted average values for CARE/FERA and non-CARE/FERA customers for this variable for Rate 1 is 8.5% compared to 12% for seniors. Though it should be noted this is an improvement over the first survey where 18% of seniors couldn't identify any of the peak periods. In addition, about 56% of combined CARE/FERA and non-CARE/FERA customers selected over half of the correct peak hours compared to 50% of seniors (see Table 3-52 in the RIA Report). This was also an improvement, up from 42% in the first survey.

Finally, satisfaction ratings by seniors for the rate plan (6.9) and for PG&E (7.4) were somewhat higher than the ratings for the hot climate zone population as a whole (as calculated by a weighted average for CARE/FERA and non-CARE/FERA households, whose ratings were 6.5 and 7.0 respectively). Seniors on TOU rates also had a statistically different higher average satisfaction rating for the rate plan compared with the control group, but did not have statistically significantly different ratings for satisfaction with PG&E.

Households with Incomes Below 100% of FPG

Households with incomes below 100% of FPG on Rate 1 in the hot climate region did not have statistically significant peak period load reductions in the first summer or winter months. However, they were able to reduce their peak period loads by 2.3% in summer 2017. Customers in this segment were among the highest percent of participants who could not identify any peak period hours among all segments on Rate 1, which may explain their small peak load impacts. This group had a statistically significant increase in net annual kWh electricity use equal to almost 1% in the hot climate region. Consistent with these changes, bill impacts due to behavior change actually led to higher bills over and above the structural bill impact for Rate 1. The average annual cost increase for this segment was $37 or 4%.

This segment was tied for the highest percentage on the health index compared to other segments on Rate 1.[34] However, the percentage was not statistically different for the treatment group compared to the control group on this index. 70% of customers with incomes below 100% of FPG reported that they had difficulty paying bills and this segment had the highest economic index score (4.3) of any segment. This may have led to the increase in load impacts in the second summer of the pilot. The difference in the economic index for TOU customers compared with the control group was not statistically significant for customers on Rate 1. The percentage of customers reporting difficulty paying bills was also not statistically different from the percent of control customers reporting difficulty. 31% of customers with incomes below 100% of FPG stated they received bills higher than expected. However, this was statistically significantly lower than the control group, and was a general trend across Rate 1 customer segments in the hot and moderate climate regions.

For Rate 1, this segment did not have statistically different levels of satisfaction with the rate or with PG&E. Satisfaction was not measured for this segment on Rates 2 or 3.

3.5.2 Key Findings

Key findings pertaining to second summer load impacts from the PG&E pilots include:

1. In the second summer, customers continued to respond to TOU rates with peak periods that extend well into the evening. During the second summer, customers achieved load reductions as high as 8.9% for non-CARE/FERA customers in the hot climate region on Rate 3.
2. Summer 2017 peak load reductions declined by small, and in several cases, statistically significant amounts compared to summer 2016. Statistically significant differences were observed among the following segments: non-CARE/FERA customers in the hot climate region on Rate 1 and Rate 2, CARE/FERA customers in the moderate climate region on Rate 3, and CARE/FERA and non-CARE/FERA customers in the cool climate region on Rate 1.
3. Households with incomes less than 100% of FPG and non-CARE/FERA customers in the moderate climate region on Rate 1 were the only two segments that increased their summer peak load impacts from 2016 to 2017. However, these increases were not statistically significant.
4. CARE/FERA customers had significantly lower peak period load reductions compared with non-CARE/FERA customers during the second summer.
5. Senior households on Rate 1 in the hot climate region had load impacts very similar to the hot climate region population as a whole in each season.

[34] This metric is not reported for Rates 2 or 3.

6. Households with incomes below 100% of FPG on Rate 1 in the hot climate region had no statistically significant reduction in peak period until summer 2017, where they reduced their demand by 2.3%.
7. In general, summer 2017 load impacts, in both absolute and percentage terms, were largest in the hot climate region, second largest in the moderate region, and lowest in the cool region, but these differences were not always statistically significant.

Overall findings and conclusions for the pilot include:

- Customers continued to respond to the TOU price signals at the end of the pilot. As expected, the load impacts were lower during the winter compared to the first summer. Load impacts decreased slightly from the first summer to the second, but the change was not always statistically significant.
- The majority of customers across all three rates experienced slight net annual total bill decreases. However, customers in the hot climate regions were more likely to experience net annual bill increases, especially non-CARE/FERA customers.
- Evidence continues to suggest that the more complex, three-period TOU rate (Rate 2) was harder for all customers to fully understand and this was especially true for low income customers. While peak period reductions are roughly the same for all three rates, the reduction in net annual electricity use for Rate 2 was significantly less than for Rates 1 and 3. Complexity may have also been a factor in lower impacts observed the second summer, as the largest single difference was observed on Rate 2. There is no evidence that Rate 2 has other advantages to offset the disadvantages summarized above although it may be possible with better education and outreach to overcome some of these shortcomings.
- After a year, there is no evidence indicating that senior households as a group in PG&E's service territory fare better or worse than the general population as a whole. Generally speaking, metrics such as load and bill impacts, and the scores on nearly all survey questions—including those related to hardship—were in between the scores for CARE/FERA and non-CARE/FERA customers in the same climate region, and is reflective of the composition of CARE/FERA and non-CARE/FERA customers within the Senior Segment.
- For households with incomes below 100% of FPG, there was no statistically significant increase in economic or health index scores after a full year on Rate 1 (the only rate where measurements are reported for this segment).

4 SCE Evaluation

This report section summarizes the attrition and load impacts for the second summer of SCE's pilot. It also includes a discussion of load impact persistence over the entire pilot. Load and bill impacts from the first summer season can be found in the First Interim Report and findings for the winter season are available in the Second Interim Report.

4.1 Summary of Pilot Treatments

Figure 4.1-1 through Figure 4.1-3 summarize the three tariffs that were tested in the SCE service territory. All three tariffs have peak periods that include the prime evening hours from 5 PM to 8 PM. The rates have changed since the launch of the pilot, and the figures represent the tariffs that were in effect in January 2017 and do not reflect the baseline credit of 9.1 ¢/kWh. Appendix B shows the prices that were in effect in each rate period for each tariff, including the OAT. Two sets of prices are shown in the appendix, one covering the period from pilot start through December 2016, and the other beginning on January 1, 2017. While several minor rate changes occurred over the course of the pilot, the rate adjustment that occurred on January 1, 2017 was more significant and, as such, was factored into the estimation of bill impacts in the Second Interim Report.

Figure 4.1-1: SCE Pilot Rate 1 (January 2017)[35]

<table>
<tr><th>Tariff</th><th>Season</th><th>1:00</th><th>2:00</th><th>3:00</th><th>4:00</th><th>5:00</th><th>6:00</th><th>7:00</th><th>8:00</th><th>9:00</th><th>10:00</th><th>11:00</th><th>12:00</th><th>13:00</th><th>14:00</th><th>15:00</th><th>16:00</th><th>17:00</th><th>18:00</th><th>19:00</th><th>20:00</th><th>21:00</th><th>22:00</th><th>23:00</th><th>24:00</th></tr>
<tr><td rowspan="2">Weekday</td><td>Summer</td><td colspan="8">Super Off-Peak (23.2¢)</td><td colspan="6">Off-Peak (27.8¢)</td><td colspan="6">Peak (34.8¢)</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>Winter</td><td colspan="8">Super Off-Peak (22.7¢)</td><td colspan="6">Off-Peak (22.7¢)</td><td colspan="6">Peak (27.3¢)</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td rowspan="2">Weekend</td><td>Summer</td><td colspan="8">Super Off-Peak (23.2¢)</td><td colspan="14">Off Peak (27.8¢)</td><td colspan="2"></td></tr>
<tr><td>Winter</td><td colspan="8">Super Off-Peak (22.7¢)</td><td colspan="14">Off Peak (22.7¢)</td><td colspan="2"></td></tr>
</table>

Figure 4.1-2: SCE Pilot Rate 2 (January 2017)

<table>
<tr><th>Tariff</th><th>Season</th><th>1:00</th><th>2:00</th><th>3:00</th><th>4:00</th><th>5:00</th><th>6:00</th><th>7:00</th><th>8:00</th><th>9:00</th><th>10:00</th><th>11:00</th><th>12:00</th><th>13:00</th><th>14:00</th><th>15:00</th><th>16:00</th><th>17:00</th><th>18:00</th><th>19:00</th><th>20:00</th><th>21:00</th><th>22:00</th><th>23:00</th><th>24:00</th></tr>
<tr><td rowspan="2">Weekday</td><td>Summer</td><td colspan="8">Super Off-Peak (17.6¢)</td><td colspan="9">Off-Peak (29.1¢)</td><td colspan="3">Peak (55.2¢)</td><td colspan="4"></td></tr>
<tr><td>Winter</td><td colspan="8">Super Off-Peak (17.7¢)</td><td colspan="9">Off-Peak (25.5¢)</td><td colspan="3">Peak (27.6¢)</td><td colspan="4"></td></tr>
<tr><td rowspan="2">Weekend</td><td>Summer</td><td colspan="8">Super Off-Peak (17.6¢)</td><td colspan="12">Off-Peak (29.1¢)</td><td colspan="4"></td></tr>
<tr><td>Winter</td><td colspan="8">Super Off-Peak (17.7¢)</td><td colspan="12">Off-Peak (25.5¢)</td><td colspan="4"></td></tr>
</table>

Figure 4.1-3: SCE Pilot Rate 3 (January 2017)

<table>
<tr><th>Tariff</th><th>Season</th><th>1:00</th><th>2:00</th><th>3:00</th><th>4:00</th><th>5:00</th><th>6:00</th><th>7:00</th><th>8:00</th><th>9:00</th><th>10:00</th><th>11:00</th><th>12:00</th><th>13:00</th><th>14:00</th><th>15:00</th><th>16:00</th><th>17:00</th><th>18:00</th><th>19:00</th><th>20:00</th><th>21:00</th><th>22:00</th><th>23:00</th><th>24:00</th></tr>
<tr><td rowspan="3">Weekday</td><td>Summer</td><td colspan="11">Off Peak (16.3¢)</td><td colspan="5">Peak (22.6¢)</td><td colspan="5">Super On-Peak (37.0¢)</td><td colspan="2"></td><td></td></tr>
<tr><td>Winter</td><td colspan="16">Off Peak (18.3¢)</td><td colspan="5">Mid Peak (21.1¢)</td><td colspan="3"></td></tr>
<tr><td>Spring</td><td colspan="11">Off Peak (18.3¢)</td><td colspan="5">Super Off Peak (10.0¢)</td><td colspan="5">Peak (25.0¢)</td><td colspan="3"></td></tr>
<tr><td rowspan="3">Weekend</td><td>Summer</td><td colspan="16">Off Peak (16.3¢)</td><td colspan="5">Mid Peak (18.7¢)</td><td colspan="3"></td></tr>
<tr><td>Winter</td><td colspan="11">Off Peak (18.3¢)</td><td colspan="5">Super Off Peak (10.39¢)</td><td colspan="5">Mid Peak (21.1¢)</td><td colspan="3"></td></tr>
<tr><td>Spring</td><td colspan="11">Off Peak (18.3¢)</td><td colspan="5">Super Off Peak (10.0¢)</td><td colspan="5">Mid Peak (21.1¢)</td><td colspan="3"></td></tr>
</table>

[35] See Appendix B for comparison of tariffs.

The prices shown in the above figures for Rates 1 and 2 do not reflect the credit of 9.1¢/kWh for usage below the baseline quantity in each climate zone. This credit significantly reduces average prices, especially for lower usage customers. Rate 3 does not include a baseline credit. Given this difference in baseline credits between Rates 1 and 2 and Rate 3, it is not possible to directly compare prices in each rate period from the above figures.

Rate 1 has three rate periods on summer weekdays and two on winter weekdays. The peak period on Rate 1 is the same all year long and runs from 2 PM to 8 PM. The peak to super-off-peak price ratio[18] (ignoring the baseline credit) is 1.2 to 1 in winter and 1.5 to 1 in summer. Customers on SCE's Rate 1 pay off-peak prices on weekends in the winter. In summer, off-peak prices are in effect on weekends from 8 AM to 10 PM, which is the time-period covered by the combination of peak and off-peak prices on weekdays.

SCE's Rate 2 has three rate periods on weekdays all year long. Compared with Rate 1, it has a much shorter peak period but a similar peak price in the winter months (27.6 ¢/kWh). The peak period runs from 5 PM to 8 PM. Rate 2 also features a super off-peak price of roughly 17.7 ¢/kWh between 10 PM and 8 AM on weekdays all year long. The ratio of peak to super-off-peak prices in the summer is roughly 3 to 1. In winter, the peak-to-super off-peak price ratio is roughly 1.6 to 1. On weekends, customers pay the off-peak price between 8 AM and 10 PM and the super off-peak price during the same overnight hours as on weekdays, from 10 PM to 8 AM.

Rate 3 has a peak-period length of five hours, which is in between the peak-period length for Rates 1 and 2. In addition, the peak period starts later in the day compared with Rate 1, and extends further into the evening (until 9 PM) than either of the other pilot rates. The weekday peak-to-super-off-peak price ratio in the winter on Rate 3 is roughly 2.1 to 1. Another difference between Rate 3 and the other rates is the presence of super off-peak pricing between 11 AM and 4 PM in spring, when excess supply conditions may exist in California. On weekends, Rate 3 has two rate periods in summer and three in spring and winter. The peak period on weekends shown in Figure 4.1-3 has a different color compared with weekday peak periods because the prices on weekends don't match any of the prices during peak, partial, off-peak, or super-off-peak periods on weekdays. Finally, as mentioned above, a very important difference is the lack of a baseline credit in Rate 3.

Figure 4.1-4 presents the seasons for each rate. For all three rates, the summer season covers the months of June through September. The winter season is October through May for Rates 1 and 2, and October through February for Rate 3. The spring period for Rate 3 is March through May.

Figure 4.1-4 Seasons by Rate

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Rate 1	Winter					Summer				Winter		
Rate 2	Winter					Summer				Winter		
Rate 3	Winter		Spring			Summer				Winter		

In addition to assessing the rate treatments summarized above based on customers recruited from the general, eligible residential population, SCE also recruited customers who were known to have purchased and installed a smart thermostat. The objective of this treatment group was to estimate load impacts for smart thermostat owners on TOU rates. The pilot plan called for SCE to partner with a smart thermostat vendor (in this case, Nest) to recruit smart thermostat owners into the study using the same "pay-to-play" recruitment strategy as was used for the general population. However, because Nest does not know the names or addresses of Nest thermostat owners, recruitment was done via email only (the same communication channel that Nest uses to send out monthly reports to each online Nest owner summarizing equipment run time and other behavioral information) rather than through the direct mail solicitation that was employed for the rate treatment groups. Target enrollment for the technology treatment was 3,750 customers and participants were to be randomly assigned to Rates 1 and 3 or to the control condition. In reality, enrollment fell well short of this target and those who enrolled were randomly assigned only to Rate 1 and to the control group.

SCE also varied the education and outreach provided to participants who were on the three TOU rates. The majority of customers (75%) on each of the three TOU rates received what SCE describes as enhanced education and outreach while the remainder received fewer contacts during the post enrollment phase.

The following section contains a discussion of customer attrition over the course of the pilot. Section 4.3 presents the load impact estimates for summer 2017 for each rate and Section 4.4 discusses the persistence of load impacts throughout the pilot.

4.2 Customer Attrition

Figure 4.2-1 through Figure 4.2-3 show the cumulative opt-out rates over time for each test cell and climate region. The cumulative number of opt-outs is highest in the hot region, second highest in the moderate region and lowest in the cool region. The number of control customers dropping out is very low in all climate regions. The cumulative opt-out rate in the moderate region is below 8% and the cumulative opt-out rate in the cool region is below 4% for all rates and for both CARE/FERA and non-CARE/FERA customers. The opt-out rates in the hot climate zone increase between July and August 2016 for Rates 1 and 2, and a bit later for Rate 3. This is likely due to the fact that enrollment in Rate 3 occurred later than it did for the other two rates. CARE/FERA customers in the hot climate region on Rate 3 had the greatest opt-out rate, reaching 14% by the end of the second summer of the pilot (September 2017). This is more than twice the opt-out rate for hot-CARE/FERA customers on Rate 2 and roughly seven times larger than for Rate 1. The opt-out rates generally level off after the first summer season, except for Rate 3 where the cumulative opt outs steadily increase over time.

Figure 4.2-1: Cumulative SCE Opt Outs by Month – Hot Climate Region

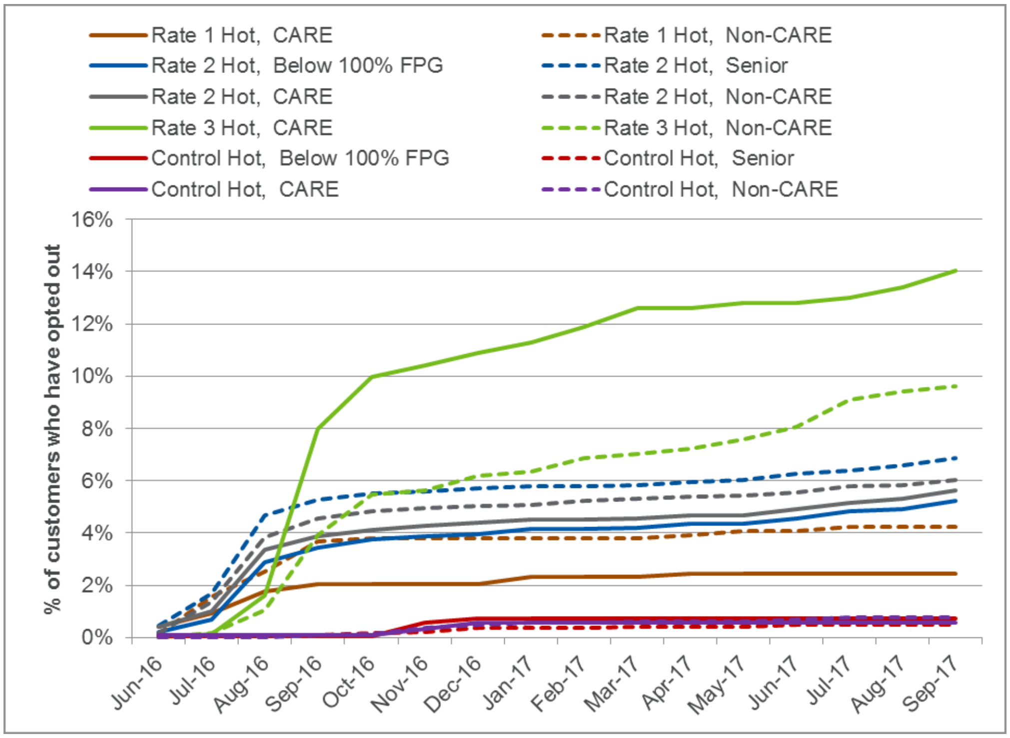


Figure 4.2-2: Cumulative SCE Opt Outs by Month – Moderate Climate Region

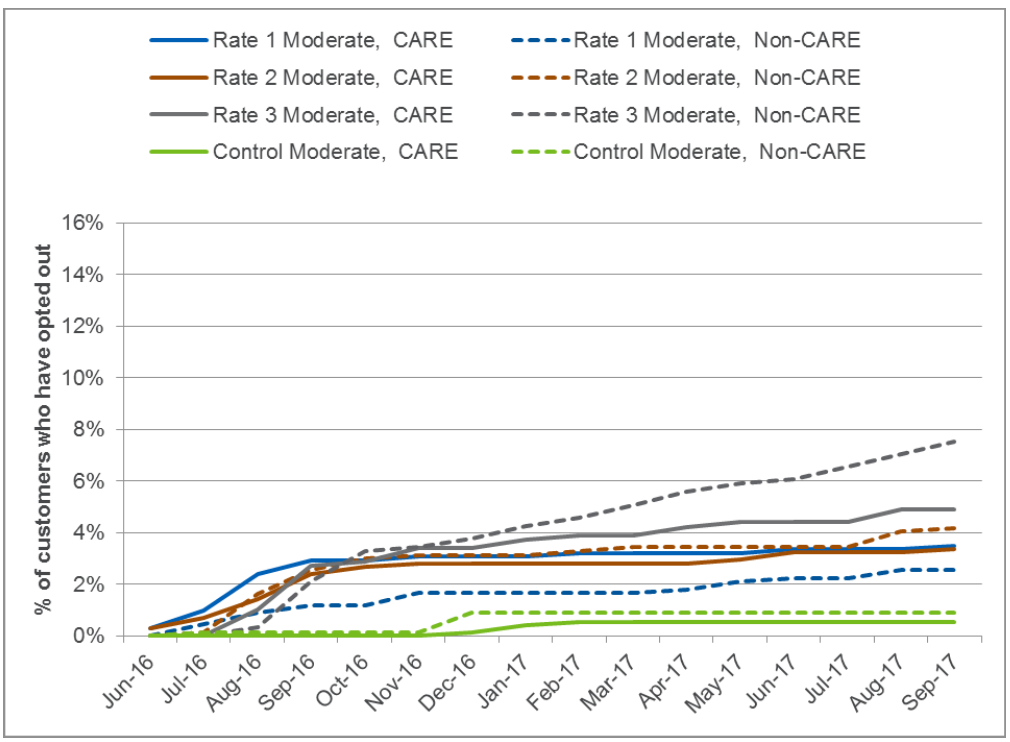


Figure 4.2-3: Cumulative SCE Opt Outs by Month – Cool Climate Region

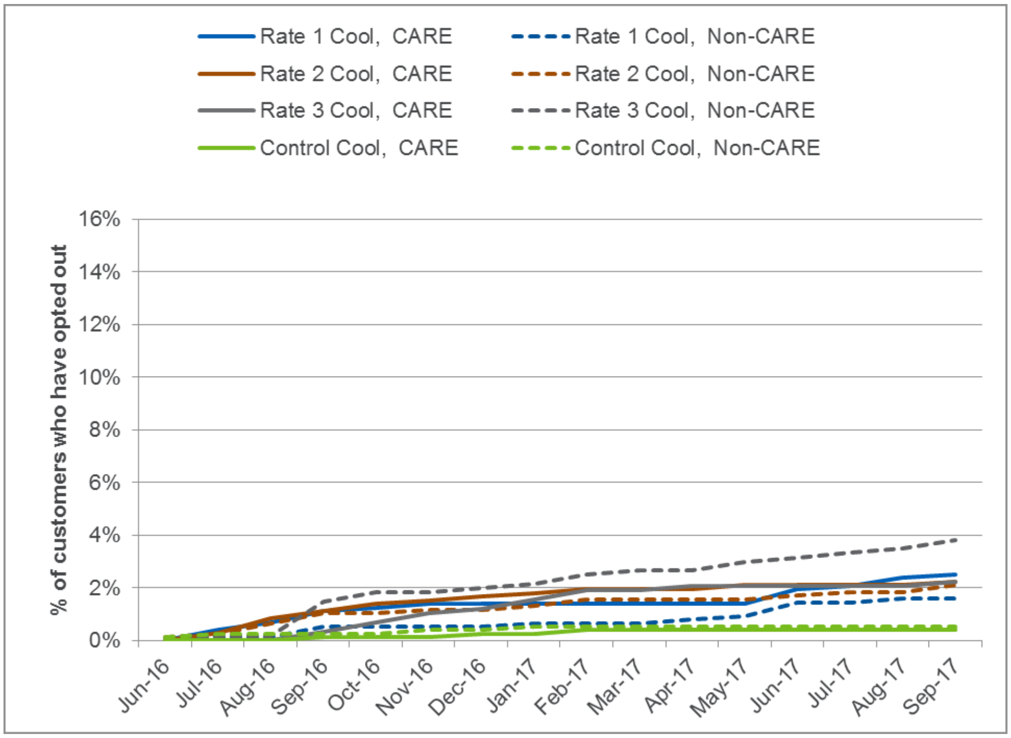


Figure 4.2-4 shows the cumulative percent of customers that opted out of each tariff for the CARE/FERA, non-CARE/FERA segments and for the total population across SCE's service territory as a whole. As seen, the cumulative percent of customers opting out was quite low for all rates and segments. The lowest cumulative percent opt out was for non-CARE/FERA customers on Rate 1 and the highest was for non-CARE/FERA customers on Rate 3. The opt-out percentage was highest for Rate 3 for both CARE/FERA and non-CARE/FERA customers and for the population as a whole. Recall that this is the rate with no baseline credit. The cumulative opt-out rate for each group showed a very rapid increase once bills began to be issued, and then the opt-out rates leveled off for Rate 1 and Rate 2- while Rate 3 continued to climb. There is a small increase in opt outs at the start of the second summer season (June 2017) but the number of opt outs is not nearly as large in the second summer as in the first. Having experienced two summers and one winter on the rate, and having realized that bills are much lower in winter than summer, it may be that customers who remained on the rate are more willing to manage the higher summer bills in anticipation of the lower winter bills.

Figure 4.2-4: Cumulative Opt Outs by Rate and Customer Segment for the SCE Service Territory

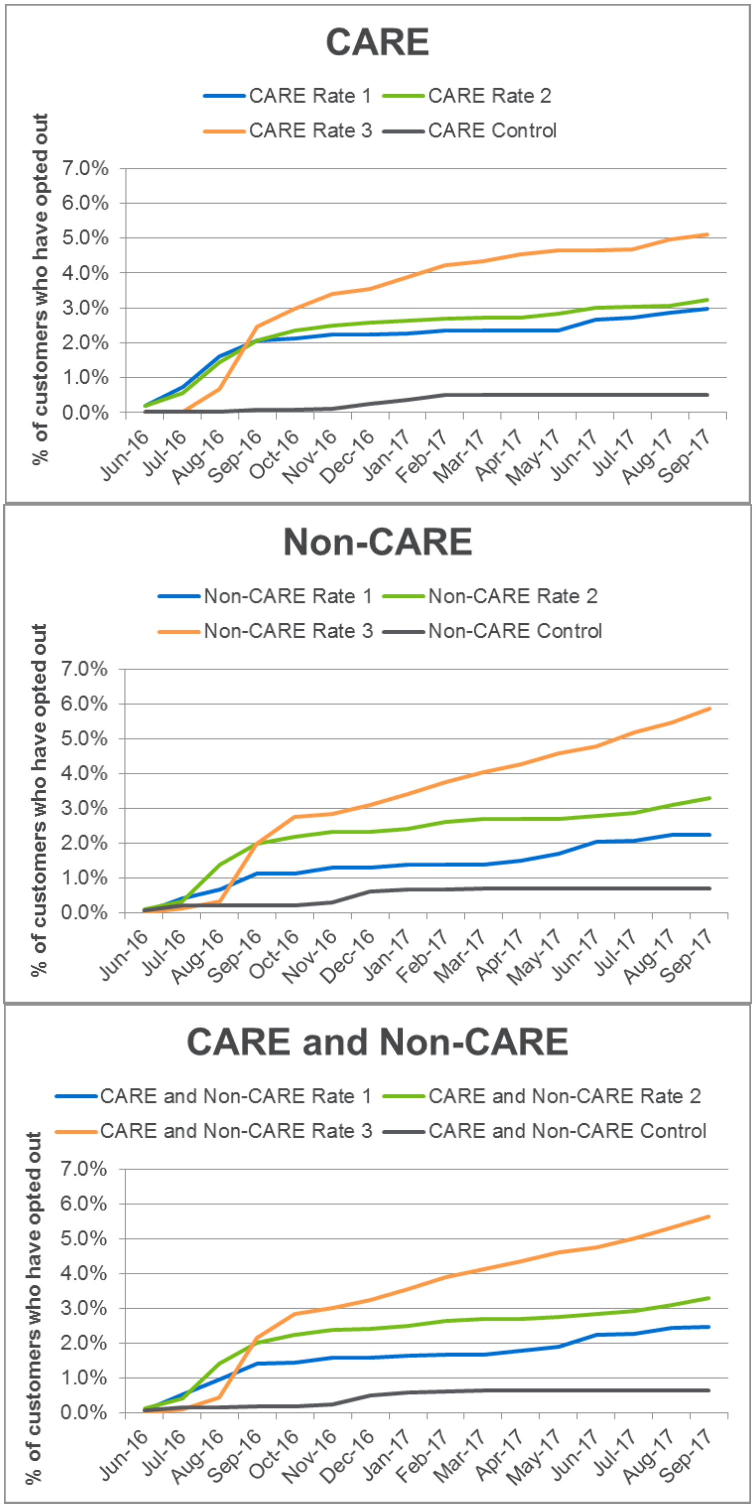


Figure 4.2-5 through Figure 4.2-7 show the overall attrition rate over time for each climate region, customer segment, and TOU rate. As seen in the figures, the cumulative attrition rate is quite constant over time in the moderate and cool climate regions, but not in the hot climate region. Roughly one third of the total attrition for Rate 3 CARE/FERA customers in the hot climate region was due to drop outs while the remainder was due either to customer churn or CCA activity. Overall attrition rates for this group reached nearly 40% by the end of the second summer of the pilot. Customers in the hot climate zone had a slight increase in attrition between March and April 2017 due to customers joining CCAs. Overall attrition rates are below 30% for the moderate climate region and below 25% for the cool climate region.

Figure 4.2-5: Cumulative SCE Attrition by Month – Hot Climate Region

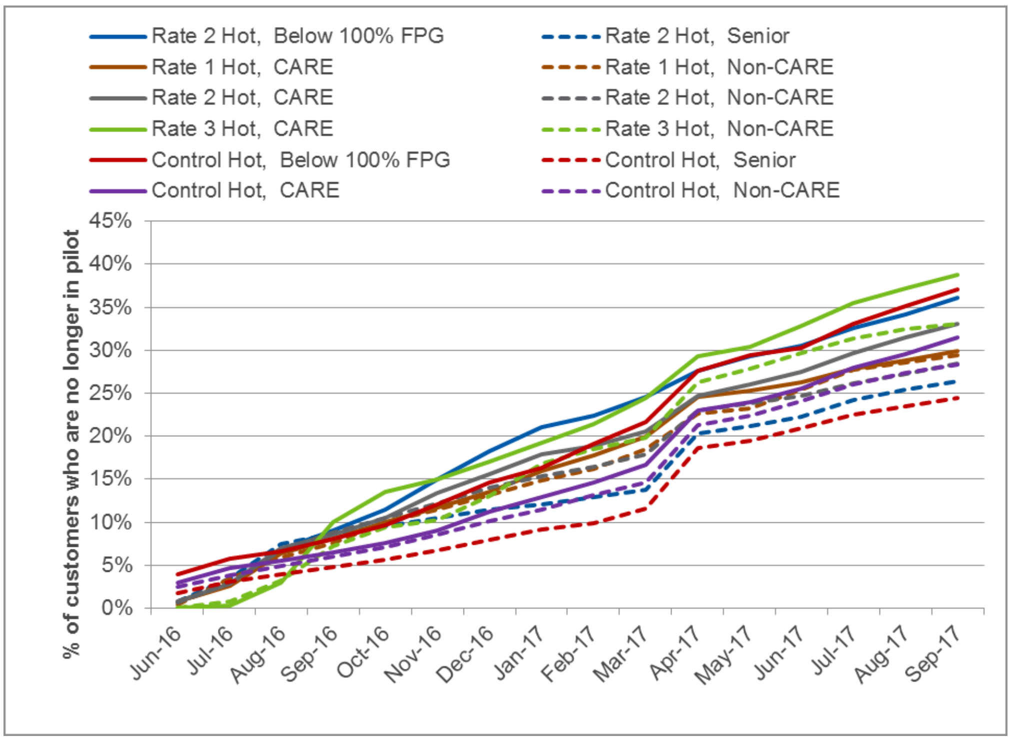


Figure 4.2-6: Cumulative SCE Attrition by Month – Moderate Climate Region

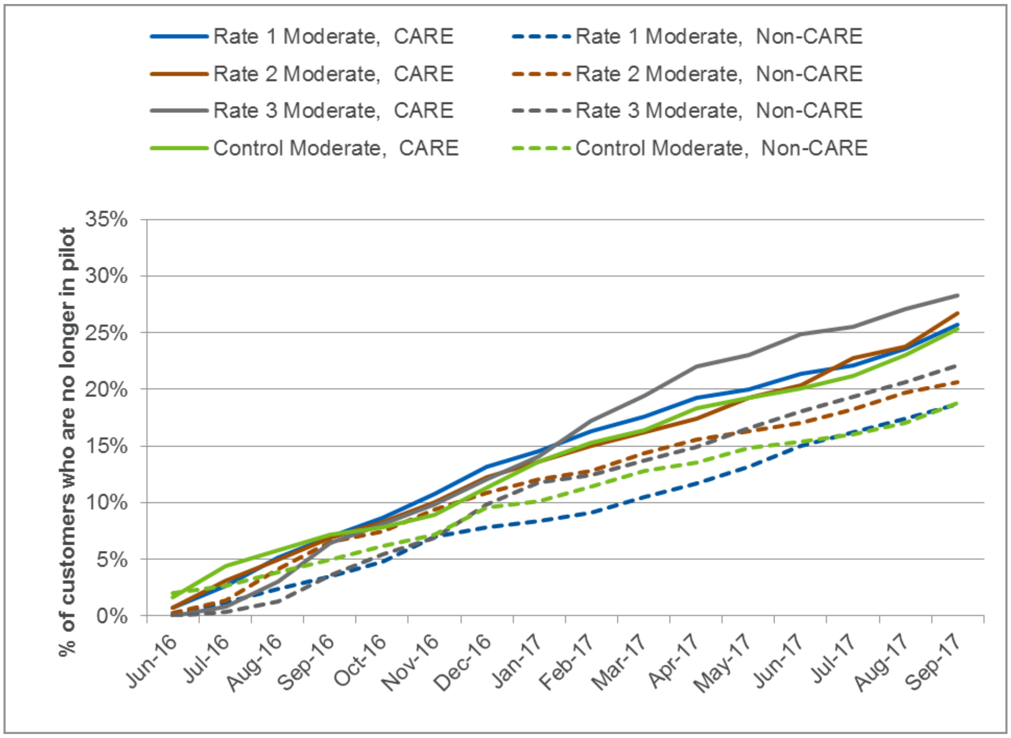
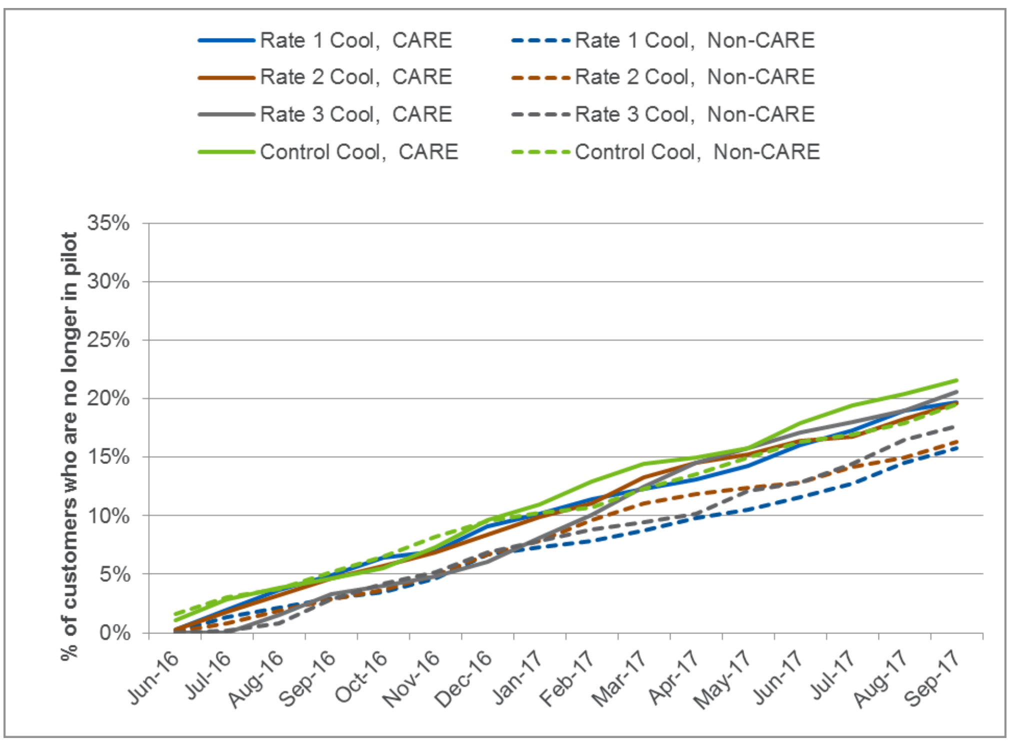


Figure 4.2-7: Cumulative SCE Attrition by Month – Cool Climate Region



4.3 Load Impacts

This section summarizes the load impact estimates for the three rate treatments tested by SCE. The CPUC resolution approving SCE's pilot requires that load impacts be estimated for the peak and off-peak periods and for daily energy use for the following rates, customer segments, and climate regions:

- Seniors, CARE/FERA customers, non-CARE/FERA customers and households with incomes below 100% of FPG in SCE's hot climate region for Rate 2;
- For all three rates for all customers in SCE's service territory as a whole and for all customers in SCE's hot and moderate climate regions; and
- For CARE/FERA and non-CARE/FERA customers on each rate across SCE's service territory as a whole.

In addition to these required segments, Nexant estimated load impacts for CARE/FERA and non-CARE/FERA customers for each rate for each climate region. Load impacts are reported here for each rate period for the average weekday, average weekend and average monthly peak day for the summer months of June through September 2017. Impacts are reported for each rate, climate zone and customer segment summarized above. Underlying the values presented in the report are electronic tables that contain estimates for each hour of the day for each day type, segment and climate zone and for each month separately. These values are contained in Excel spreadsheets that are available upon request through the CPUC.

Figure 4.3-1 shows an example of the content of these electronic tables for SCE Rate 1 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different customer segments, climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time period (individual months or seasons).

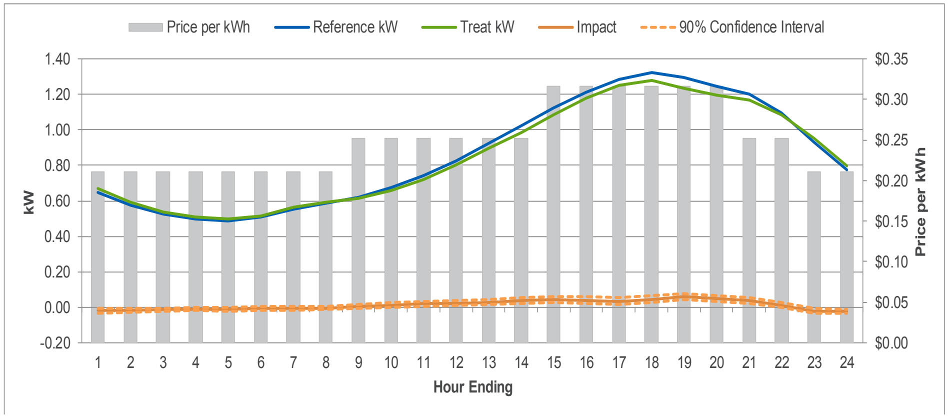
The remainder of this section is organized by rate treatment—load impacts are presented for each relevant customer segment and climate region for each of the three rates. Following the summary for each rate, load impacts are compared across rates. This comparison is made only for the hours within each peak period that are common across all three rates (5 PM to 8 PM). Because the rates differ with respect to the length and timing of peak and off-peak periods, differences in load impacts across rates for any particular rate period may be due not only to differences in prices within the rate period but also due to differences in the length or timing of the rate periods.

As discussed in Section 5 in the First Interim Report, in addition to the three rate treatments, SCE also recruited customers who were known to have purchased and installed a smart thermostat. The objective of this treatment group was to estimate load impacts for smart thermostat owners on TOU rates. Those who enrolled were randomly assigned only to Rate 1 and to the control group. Load impacts for these customers are presented in Section 4.3.1.

Figure 4.3-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SCE Rate 1, Average Summer 2017 Weekday, All Customers)

Segment	All
Rate	Rate 1
Month	Summer 2017
Day Type	Average Weekday
Treated Customers	3,487

Period	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval	
Super On Peak	N/A	N/A	N/A	N/A	N/A	N/A
Peak	1.25	1.20	0.04	3.6%	0.04	0.05
Mid Peak	N/A	N/A	N/A	N/A	N/A	N/A
Off Peak	0.89	0.87	0.02	2.4%	0.02	0.03
Super Off Peak	0.61	0.62	-0.01	-2.4%	-0.02	-0.01
Daily kWh	20.69	20.39	0.29	1.4%	0.22	0.36



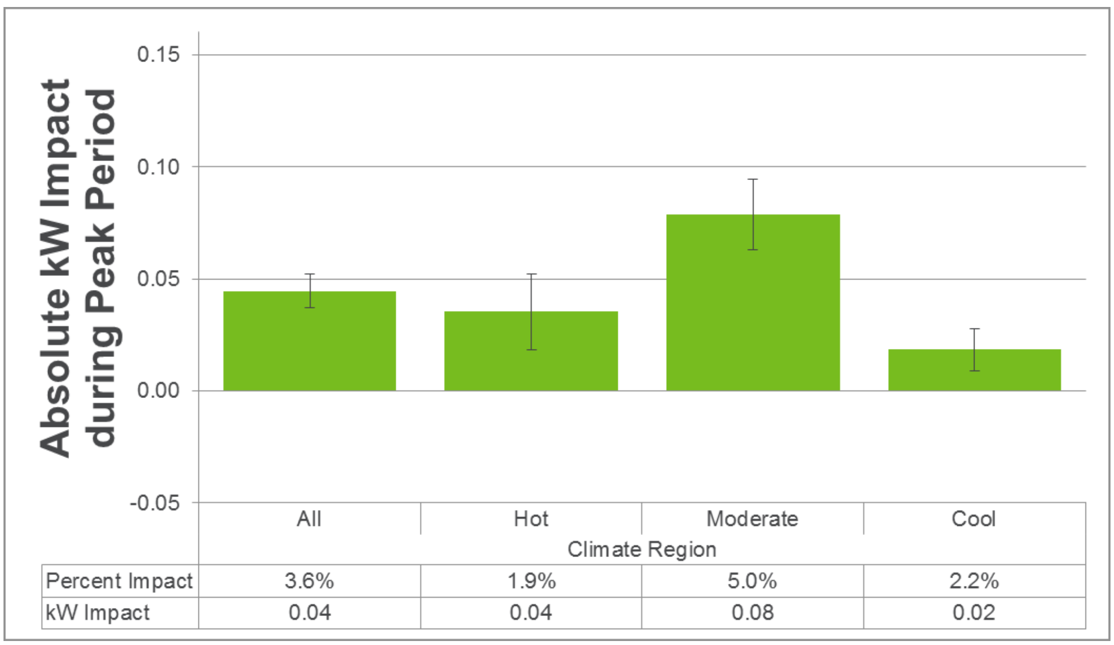
Hour Ending	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval		Price	Period
1	0.65	0.67	-0.02	-3.2%	-0.03	-0.01	$0.21	Super Off Peak
2	0.57	0.59	-0.02	-3.3%	-0.03	-0.01	$0.21	Super Off Peak
3	0.52	0.54	-0.01	-2.8%	-0.02	0.00	$0.21	Super Off Peak
4	0.50	0.51	-0.01	-2.1%	-0.02	0.00	$0.21	Super Off Peak
5	0.49	0.50	-0.01	-2.5%	-0.02	0.00	$0.21	Super Off Peak
6	0.51	0.52	-0.01	-1.6%	-0.02	0.00	$0.21	Super Off Peak
7	0.55	0.56	-0.01	-1.4%	-0.02	0.00	$0.21	Super Off Peak
8	0.59	0.59	0.00	-0.8%	-0.01	0.01	$0.21	Super Off Peak
9	0.62	0.62	0.00	0.7%	-0.01	0.01	$0.25	Off Peak
10	0.67	0.66	0.01	1.8%	0.00	0.02	$0.25	Off Peak
11	0.74	0.72	0.02	2.5%	0.01	0.03	$0.25	Off Peak
12	0.82	0.80	0.02	2.8%	0.01	0.04	$0.25	Off Peak
13	0.92	0.90	0.03	3.1%	0.01	0.04	$0.25	Off Peak
14	1.02	0.99	0.04	3.5%	0.02	0.05	$0.25	Off Peak
15	1.13	1.08	0.04	3.8%	0.02	0.06	$0.32	Peak
16	1.22	1.18	0.04	3.2%	0.02	0.06	$0.32	Peak
17	1.29	1.25	0.03	2.6%	0.01	0.05	$0.32	Peak
18	1.32	1.28	0.04	3.3%	0.02	0.06	$0.32	Peak
19	1.30	1.24	0.06	4.6%	0.04	0.08	$0.32	Peak
20	1.25	1.20	0.05	4.0%	0.03	0.07	$0.32	Peak
21	1.20	1.17	0.04	3.0%	0.02	0.05	$0.25	Off Peak
22	1.10	1.09	0.01	1.0%	0.00	0.03	$0.25	Off Peak
23	0.93	0.95	-0.02	-2.3%	-0.04	-0.01	$0.21	Super Off Peak
24	0.78	0.80	-0.02	-3.0%	-0.04	-0.01	$0.21	Super Off Peak
Daily kWh	**20.69**	**20.39**	**0.29**	**1.4%**	**0.22**	**0.36**	**N/A**	**N/A**

4.3.1 Rate 1

SCE's Rate 1 is a three-period rate with a peak-period from 2 PM to 8 PM on weekdays. In summer, for electricity usage above the baseline quantity, prices equal roughly 34.8 ¢/kWh in the peak period, 27.8 ¢/kWh in the off-peak period and 23.2 ¢/kWh in the super off-peak period. Usage on the weekends is priced at the off-peak price from 8 AM to 10 PM and the super off-peak price from 10 PM to 8 AM. For usage below the baseline quantify, a credit of 9.1 ¢/kWh is applied.

Figure 4.3-2 shows the average peak period load reduction in absolute terms for Rate 1 for SCE's service territory as a whole and for each climate region. The lines bisecting the top of each bar in the figure show the 90% confidence band for each estimate. If the confidence band includes 0, it means that the estimated load impact is not statistically different from 0 at the 90% level of confidence. If the confidence bands for two bars do not overlap, it means that the observed difference in the load impacts is statistically significant. If they do overlap, it does not necessarily mean that the difference is not statistically significant.[36] In these cases, t-tests were calculated to determine whether the difference is statistically significant.[37]

Figure 4.3-2: Average Load Impacts for Peak Period for SCE Rate 1[38]
(Positive values represent load reductions)



As seen in the figure, the average peak-period load impact for the service territory as a whole and for each climate region is statistically significant at the 90% level of confidence. On average, pilot

36 For further discussion of this topic, see https://www.cscu.cornell.edu/news/statnews/stnews73.pdf.

37 The test was applied at the 90% confidence level which means that a t-value exceeding 1.65 indicates statistical significance.

38 SCE Rate 1 winter impacts represent October 2016 through May 2017.

participants across SCE's service territory on Rate 1 reduced peak-period electricity use by 3.6%, or 0.04 kW, across the six-hour peak period from 2 PM to 8 PM. The average peak-period load reduction ranges from a high of 5.0% and 0.08 kW in the moderate climate region to a low of 1.9% and 0.04 kW in the hot climate region. In the cool climate region, the load reduction equals 2.2% or 0.02 kW.

Table 4.3-1 shows the average percent and absolute load impacts for each rate period for weekdays and weekends and for the average monthly system peak day for the SCE service territory as a whole and for the participant population in each climate region. The percent reduction equals the load impact in absolute terms (kW) divided by the reference load. Shaded cells in the table contain load impact estimates that are not statistically significant at the 90% confidence level. The percentage and absolute values in the first row of Table 4.3-1, which represent the load impacts in the peak period on the average weekday, equal the values shown in Figure 4.3-2, discussed above.

The reference loads shown in Table 4.3-1 represent estimates of what customers on the TOU rate would have used if they had not responded to the price signals contained in the TOU tariff. As seen in the table, average hourly usage during the peak period is roughly 1.25 kW for the service territory as a whole, and around 0.86 kW over the 24 hour average weekday. In the hot climate region, average usage in the peak period is larger at 1.90 kW. Average usage in the moderate climate region is 1.57 kW and in the cool region it is 0.83 kW, which is roughly half what it is in the moderate region.

The monthly system peak day estimates represent the average across the four weekdays, one in each summer month, when SCE's system peaked in 2017. Peak period reference loads are higher on these days than on the average weekday. For the service territory as a whole, the percent reduction in monthly system peak day peak period loads (3.5%) is nearly identical to the load reduction on the average weekday (3.6%); however, the absolute load reduction (0.07 kW) is significantly greater than on the average weekday (0.04 kW). Customers had small but statistically significant daily usage decreases on the average weekend even though off-peak prices were in effect for the majority of weekend hours and super off-peak prices were in effect for the remaining hours.

Table 4.3-1: Rate 1 Load Impacts by Period and Day Type *
(Positive values represent load reductions, negative values represent load increases)

Rate 1														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	2 PM to 8 PM	1.25	0.04	3.6%	1.90	0.04	1.9%	1.57	0.08	5.0%	0.83	0.02	2.2%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	0.89	0.02	2.4%	1.33	0.01	1.0%	1.04	0.04	4.0%	0.66	0.01	0.9%
	Super Off Peak	10 PM to 8 AM	0.61	-0.01	-2.4%	0.86	-0.03	-3.0%	0.69	-0.02	-2.4%	0.48	-0.01	-2.0%
	Day	All Hours	0.86	0.01	1.4%	1.27	0.00	0.2%	1.02	0.03	2.6%	0.63	0.00	0.4%
Average Weekend	Off Peak	8 AM to 10 PM	1.13	0.03	3.0%	1.70	0.01	0.8%	1.37	0.08	5.7%	0.79	0.00	0.3%
	Super Off Peak	10 PM to 8 AM	0.62	-0.01	-1.8%	0.90	-0.03	-3.0%	0.70	-0.01	-1.1%	0.49	-0.01	-2.0%
	Day	All Hours	0.92	0.02	1.7%	1.37	0.00	-0.2%	1.09	0.04	3.8%	0.66	0.00	-0.4%
Monthly System Peak Day	Peak	2 PM to 8 PM	1.89	0.07	3.5%	2.44	0.09	3.8%	2.57	0.09	3.7%	1.20	0.04	3.1%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	1.32	0.03	2.4%	1.75	0.05	2.6%	1.73	0.05	2.7%	0.88	0.02	1.9%
	Super Off Peak	10 PM to 8 AM	0.81	-0.01	-1.2%	1.11	-0.03	-2.8%	1.01	-0.01	-1.1%	0.58	0.00	-0.7%
	Day	All Hours	1.25	0.02	1.9%	1.65	0.03	1.5%	1.64	0.03	2.1%	0.83	0.01	1.6%

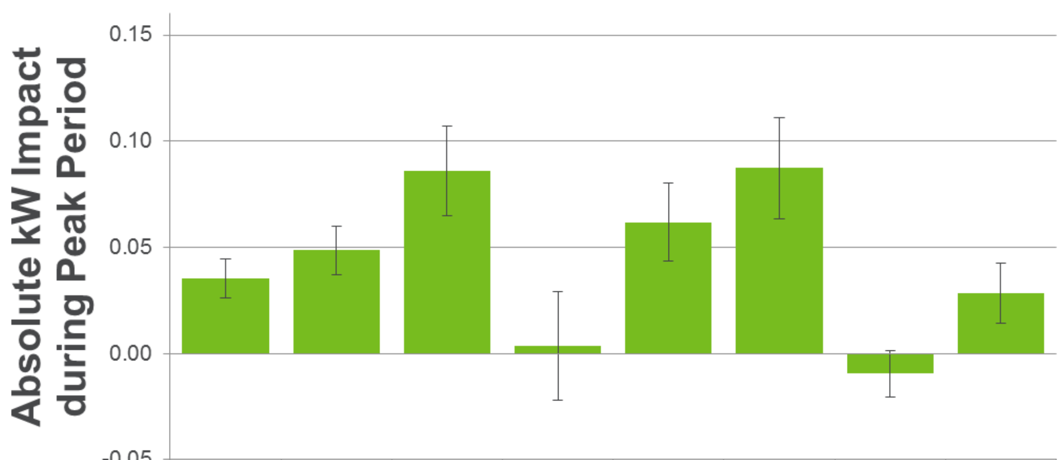
* A shaded cell indicates estimate is not statistically significant

Figure 4.3-3 shows the absolute peak period load impacts for Rate 1 for CARE/FERA and non-CARE/FERA customers for the service territory as a whole and for each climate region. In the moderate and cool climate regions, and the service territory as a whole, both the percent and absolute load impacts in the peak period appear to be greater for non-CARE/FERA customers than for CARE/FERA customers, although not all differences are statistically significant. For example, in the moderate climate region, the average weekday peak-period reduction is 5.1% and 0.09 kW for non-CARE/FERA customers whereas for CARE/FERA customers, the impact is equal to 4.9% or 0.06 kW. The difference between the two segments is statistically significant in both absolute and percentage terms in the cool climate region. Load reductions in the hot climate were not statistically significant for non-CARE/FERA customers, nor were they statistically significant for CARE/FERA customers in the cool climate region.

One potential reason the non-CARE/FERA customers may not be producing load impacts in that the hot climate region is the price signal is the weakest on Rate 1 relative to the other two rates. As seen in subsequent subsections, impacts for non-CARE/FERA customers in the hot climate zone on the other two rates are observed, so it may be possible the price signal wasn't strong enough to encourage higher income customers in the hottest region to take actions such as adjusting their thermostats. Having said that, the relative load impacts across customer segments and climate regions is quite different in PG&E's service territory compared with the results for SCE. In general, PG&E's service territory, load impacts were larger in the hot region compared with the moderate region, which, in turn, had larger impacts than in the cool region. In addition, non-CARE/FERA customers in each region and for the service territory as a whole, had larger impacts than non-CARE/FERA customers in PG&E's service territory.

Figure 4.3-3: Average Load Impacts for Peak Period for SCE Rate 1 for CARE/FERA and non-CARE/FERA Customers

(Positive values represent load reductions)



	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Percent Impact	3.3%	3.7%	5.1%	0.2%	4.9%	5.1%	-1.4%	3.2%
kW Impact	0.04	0.05	0.09	0.00	0.06	0.09	-0.01	0.03

Table 4.3-2 shows the estimated load impacts for each rate period and day type by climate zone and for the service territory as a whole for non-CARE/FERA customers and Table 4.3-3 shows the estimated values for CARE/FERA customers. For the service territory as a whole, non-CARE/FERA customers have average peak-period reference loads that are larger than CARE/FERA customers (1.33 kW for non-CARE/FERA and 1.07 kW for CARE/FERA). This pattern is consistent across all three climate regions and for daily electricity usage on average summer weekdays.

For the service territory as a whole, CARE/FERA customers decreased average daily usage on weekdays by 1.0% or 0.01 kW, whereas non-CARE/FERA customers decreased their usage by 1.6% or 0.01 kW. On the monthly system peak days, non-CARE/FERA customers reduced daily electricity use by 2.2% and CARE/FERA decreased their overall usage by 0.8%. CARE/FERA customers in the cool climate region increased their daily demand on monthly system peak days.

Table 4.3-2: Rate 1 Load Impacts by Rate Period and Day Type – Non-CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases

Rate 1															
Day Type	Period	Hours	All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	2 PM to 8 PM	1.33	0.05	3.7%	2.03	0.00	0.2%	1.72	0.09	5.1%	0.88	0.03	3.2%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	0.94	0.02	2.6%	1.42	-0.02	-1.1%	1.13	0.05	4.5%	0.71	0.01	1.9%
	Super Off Peak	10 PM to 8 AM	0.64	-0.01	-2.3%	0.91	-0.05	-5.2%	0.74	-0.01	-1.8%	0.51	-0.01	-1.9%
	Day	All Hours	0.91	0.01	1.6%	1.36	-0.02	-1.8%	1.11	0.03	3.0%	0.67	0.01	1.1%
Average Weekend	Off Peak	8 AM to 10 PM	1.21	0.04	3.1%	1.82	-0.03	-1.7%	1.52	0.09	6.2%	0.85	0.01	0.9%
	Super Off Peak	10 PM to 8 AM	0.65	-0.01	-1.6%	0.95	-0.05	-5.5%	0.76	0.00	-0.2%	0.51	-0.01	-1.7%
	Day	All Hours	0.98	0.02	1.8%	1.46	-0.04	-2.7%	1.20	0.05	4.6%	0.71	0.00	0.1%
Monthly System Peak Day	Peak	2 PM to 8 PM	2.05	0.07	3.5%	2.63	0.07	2.6%	2.89	0.11	3.7%	1.30	0.05	3.5%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	1.42	0.04	2.9%	1.89	0.01	0.5%	1.92	0.07	3.6%	0.95	0.02	2.6%
	Super Off Peak	10 PM to 8 AM	0.86	0.00	-0.5%	1.18	-0.06	-5.0%	1.09	0.00	0.2%	0.61	0.00	0.2%
	Day	All Hours	1.34	0.03	2.2%	1.78	0.00	-0.2%	1.82	0.05	2.8%	0.90	0.02	2.2%

* A shaded cell indicates estimate is not statistically significant

Table 4.3-3: Rate 1 Load Impacts by Rate Period and Day Type – CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Rate 1															
Day Type	Period	Hours	All, CARE			Hot, CARE			Moderate, CARE			Cool, CARE			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	
Average Weekday	Peak	2 PM to 8 PM	1.07	0.04	3.3%	1.69	0.09	5.1%	1.26	0.06	4.9%	0.66	-0.01	-1.4%	
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	0.77	0.01	1.7%	1.18	0.06	5.0%	0.85	0.02	2.8%	0.53	-0.01	-2.7%	
	Super Off Peak	10 PM to 8 AM	0.54	-0.01	-2.4%	0.78	0.01	1.1%	0.58	-0.02	-4.0%	0.41	-0.01	-2.4%	
	Day	All Hours	0.75	0.01	1.0%	1.14	0.05	3.9%	0.84	0.01	1.6%	0.51	-0.01	-2.2%	
Average Weekend	Off Peak	8 AM to 10 PM	0.95	0.03	2.7%	1.51	0.08	5.5%	1.08	0.04	4.0%	0.62	-0.01	-2.0%	
	Super Off Peak	10 PM to 8 AM	0.55	-0.01	-2.2%	0.81	0.01	1.7%	0.60	-0.02	-3.5%	0.41	-0.01	-3.1%	
	Day	All Hours	0.78	0.01	1.3%	1.22	0.05	4.5%	0.88	0.02	1.9%	0.53	-0.01	-2.3%	
Monthly System Peak Day	Peak	2 PM to 8 PM	1.53	0.05	3.4%	2.13	0.13	6.0%	1.93	0.07	3.5%	0.91	0.01	1.2%	
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	1.10	0.01	1.2%	1.53	0.10	6.8%	1.35	0.00	0.2%	0.68	-0.01	-0.9%	
	Super Off Peak	10 PM to 8 AM	0.71	-0.02	-3.1%	1.00	0.01	1.3%	0.84	-0.04	-4.5%	0.48	-0.02	-3.7%	
	Day	All Hours	1.04	0.01	0.8%	1.46	0.07	4.9%	1.28	0.00	0.2%	0.65	-0.01	-1.0%	

* A shaded cell indicates estimate is not statistically significant

Table 4.3-4 shows the estimated load impacts for smart thermostat customers who were enrolled on Rate 1. As a reminder, these load reductions represent the total reduction for customers who had previously purchased smart thermostats and are on Rate 1 relative to a control group of smart thermostat owners who are on the OAT. The impacts are not the incremental load impact of a smart thermostat for customers on a TOU rate relative to customers on a TOU rate who do not have a smart thermostat. These customers are distributed throughout the service territory and the vast majority are non-CARE/FERA customers.

In August 2017, Nest implemented a program named Time of Savings (TOS) on the smart thermostats of treatment customers. About 90% of treatment customers enrolled in the pilot at the time of the TOS launch were eligible and ran the program on their device. Only 12.3% opted out of the special programming between August 2 and the end of the summer season. While the experiment does not lend itself to measuring incremental impacts, as discussed below, it is clear that TOS has an effect on the overall load profiles of treatment customers, which results in larger peak period impacts.

Figure 4.3-4 and Figure 4.3-5 show the average August weekday load profile for customers in the smart thermostat segment, for 2016 and 2017, respectively. In 2017, after implementation of TOS, customers in the treatment group show evidence of pre-cooling prior to the TOU period with noticeable snapback after peak pricing ends. Load reductions during the peak period are also markedly larger, especially in the initial peak period hours. While it is not possible to compare load reductions for those with and without TOS for the same months, it is possible to compare impacts across summers for those in the thermostat group as a crude estimate of the incremental effect of TOS support while adjusting for differences in weather across seasons. This can be done by using the ratio of loads for the control group in 2016 to those in 2017 as an adjustment to the load impacts in 2017. Using this method, the load impacts were about twice as large with TOS compared to the same month in the prior year when TOS was not offered. While it's impossible to be certain this is all directly attributable to the TOS, it seems reasonable that a good portion of it is.

Figure 4.3-4: Technology Segment – Average August 2016 Weekday

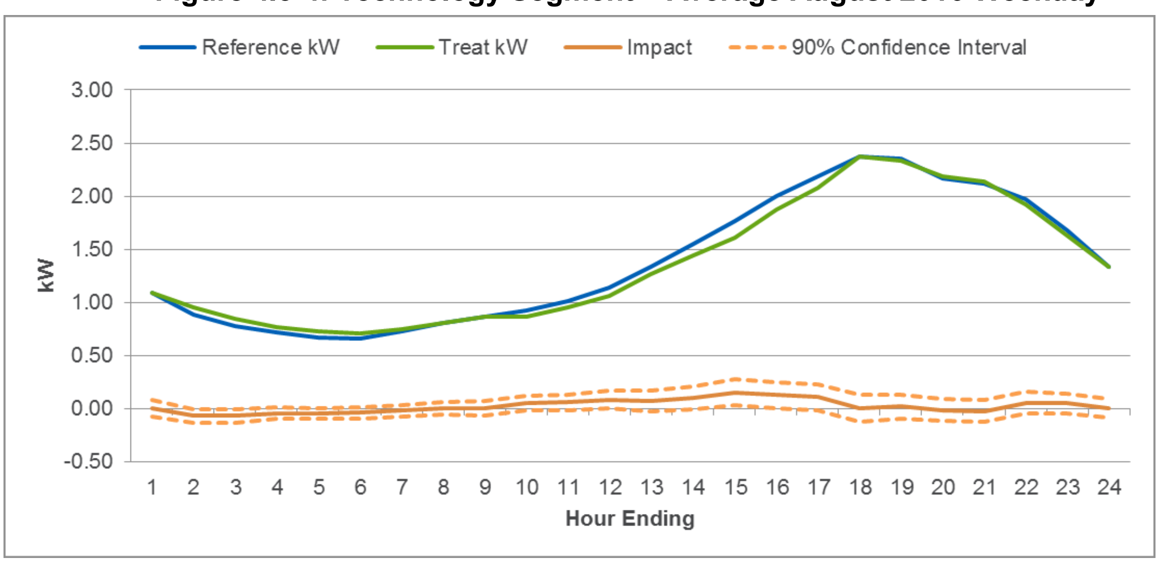


Figure 4.3-5: Technology Segment – Average August 2017 Weekday

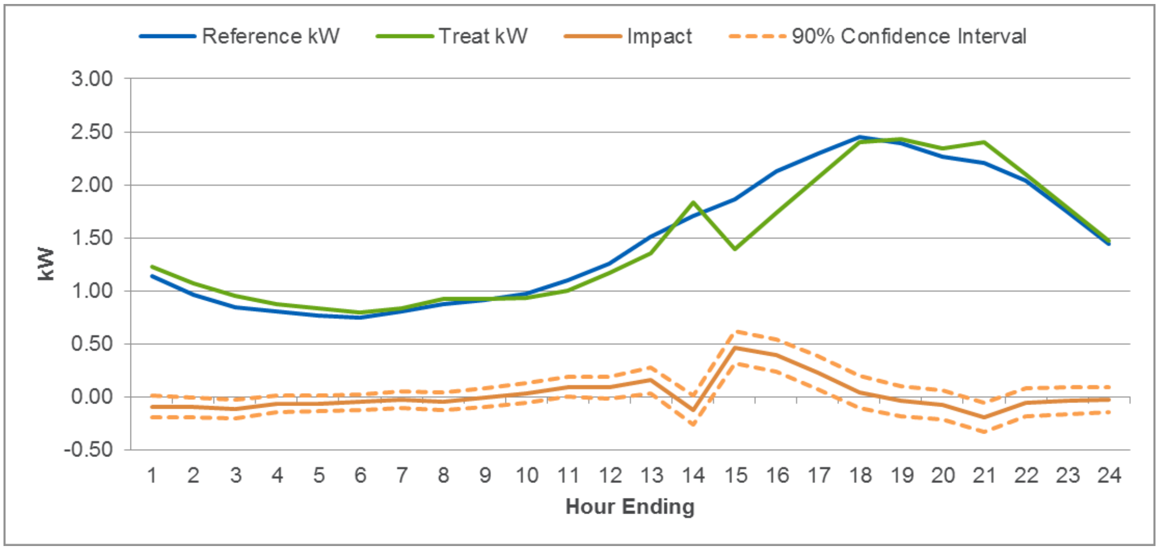


Table 4.3-4 shows the average weekday peak-period reference load for these households (1.99 kW) is higher than the average for households in the service territory as a whole (1.25 kW). The average load reduction for smart thermostat households during the peak period, 6.7% or 0.13 kW, was nearly double the average for all households in the service territory (3.6% or 0.04 kW). This result is in contrast to what was found in the first summer, as reported in the First Interim Report, where smart thermostat households had reductions similar to those of the general population. In the second summer, smart thermostat households reduced average daily use by 2.5%, or 0.03 kW, and had comparable reductions in daily usage on weekends. Peak-period load reductions on the monthly system peak day were greater than those on the average weekday in absolute terms (0.14 kW versus 0.13 kW) but smaller in percentage terms (4.7% versus 6.7%).

**Table 4.3-4: Rate 1 Load Impacts by Rate Period and Day Type – Technology Customers*
(Positive values represent load reductions, negative values represent load increases)**

Rate 1					
			Technology		
Day Type	Period	Hours	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	2 PM to 8 PM	1.99	0.13	6.7%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	1.34	0.06	4.4%
	Super Off Peak	10 PM to 8 AM	0.91	-0.05	-5.2%
	Day	All Hours	1.32	0.03	2.5%
Average Weekend	Off Peak	8 AM to 10 PM	1.75	0.07	4.2%
	Super Off Peak	10 PM to 8 AM	0.93	-0.04	-4.8%
	Day	All Hours	1.41	0.02	1.7%
Monthly System Peak Day	Peak	2 PM to 8 PM	3.06	0.14	4.7%
	Off Peak	8 AM to 2 PM, 8 PM to 10 PM	2.04	0.04	1.8%
	Super Off Peak	10 PM to 8 AM	1.21	-0.11	-8.7%
	Day	All Hours	1.95	0.00	0.2%

* A shaded cell indicates estimate is not statistically significant

4.3.2 Rate 2

SCE's Rate 2 differs from Rate 1 in several important ways. While both rates have three rate periods on summer weekdays, the Rate 2 peak period is only three hours long, from 5 PM to 8 PM, compared to the six-hour peak period for Rate 1. The Rate 2 peak period price is 55.2 ¢/kWh, which is much greater than the Rate 1 peak price of 34.8 ¢/kWh. The structures of Rate 1 and Rate 2 are identical on weekends, but Rate 2 has a lower super off-peak price at 17.6 ¢/kWh (compared to 23.2 ¢/kWh for Rate 1). The off-peak prices are similar between the two rates, 27.8 ¢/kWh for Rate 1 and 29.1 ¢/kWh for Rate 2. For usage below the baseline quantify, a credit of 9.1 ¢/kWh is applied in both cases.

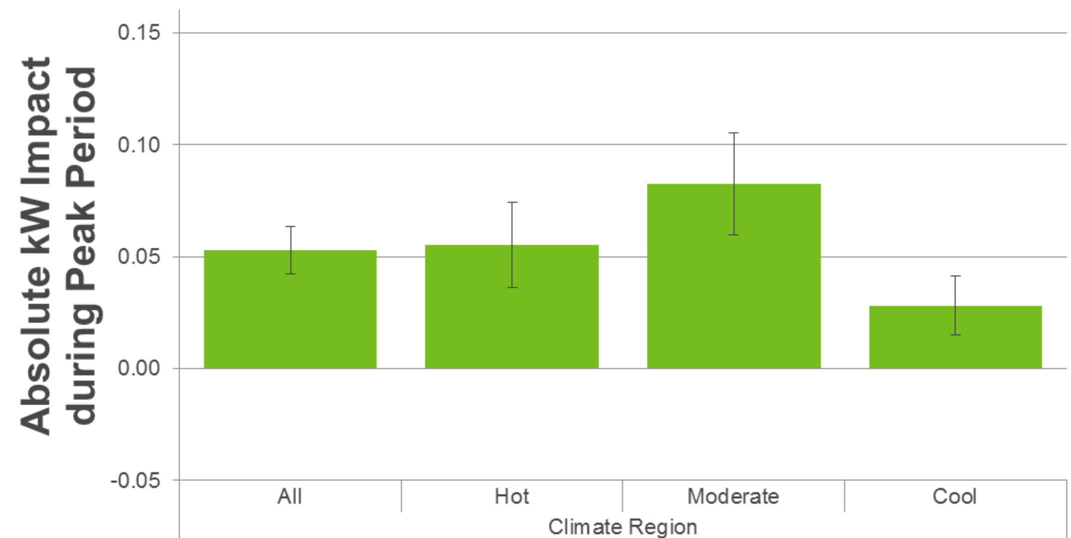
Figure 4.3-6 shows the percent and absolute load impacts for the weekday peak period for Rate 2 for SCE's service territory as a whole and for each climate region. Percent and absolute impacts for the service territory as a whole, 4.1% and 0.05 kW, are greater than those for Rate 1 (3.6% and 0.04 kW), but this difference is not statistically significant in percent or absolute terms. The average weekday peak-period load reduction for customers in the hot climate region on Rate 2, 2.9% and 0.06 kW, are also larger than the impacts for Rate 1, but again this difference is not statistically significant.

Looking at the pattern of load impacts across climate regions for customers on Rate 2, the difference in impacts between the hot and moderate regions is not statistically significant on an absolute basis, but they are on a percentage basis. The cool region has the lowest absolute and percentage impacts and differences between the cool and moderate or hot regions are statistically significant on an absolute basis but not on a percentage basis.

Table 4.3-5 contains load impact estimates for each rate period and day type for Rate 2. For the service territory as a whole, daily electricity usage was similar on average summer weekdays and weekends, 0.86 kW and 0.92 kW. Reductions in daily electricity use were also similar on weekdays and weekends, although quite small in both percentage and absolute terms (1.1% and 0.01 kW). Electricity use and impacts were the largest on monthly system peak days, with load reductions of about 1.4% or 0.02 kW.

Customers in every climate region provided statistically significant peak and off-peak demand reductions for Rate 2 during all three day-types except for customers in the cool climate region on the average monthly system peak day. Customers in each climate region increased their electricity use during the super off-peak period on weekdays, weekends, and monthly system peak days, which could indicate load shifting or increased consumption of selected end uses during the lower priced period.

Figure 4.3-6: Average Load Impacts for Peak Period for SCE Rate 2[39] (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Percent Impact	4.1%	2.9%	5.1%	3.2%
kW Impact	0.05	0.06	0.08	0.03

[39] SCE Rate 2 winter impacts represent October 2016 through May 2017.

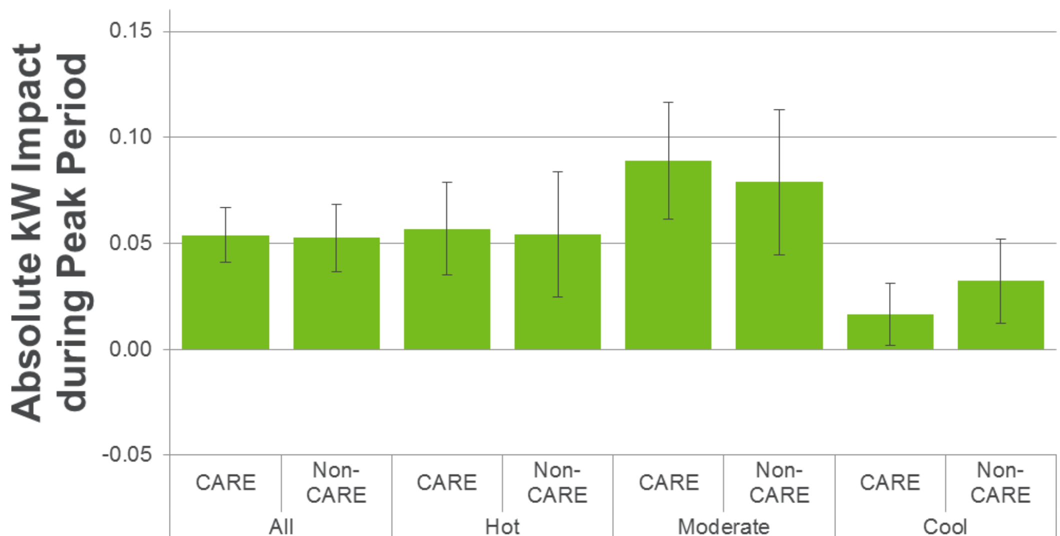
Table 4.3-5: Rate 2 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	1.29	0.05	4.1%	1.89	0.06	2.9%	1.61	0.08	5.1%	0.88	0.03	3.2%
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	0.98	0.03	2.6%	1.48	0.04	2.7%	1.17	0.04	3.8%	0.69	0.01	1.0%
	Super Off Peak	10 PM to 8 AM	0.61	-0.02	-3.5%	0.86	-0.02	-2.8%	0.69	-0.04	-5.3%	0.48	-0.01	-1.6%
	Day	All Hours	0.86	0.01	1.1%	1.27	0.02	1.2%	1.02	0.02	1.5%	0.63	0.00	0.5%
Average Weekend	Off Peak	8 AM to 10 PM	1.13	0.03	2.9%	1.70	0.03	2.1%	1.37	0.05	4.0%	0.79	0.01	1.7%
	Super Off Peak	10 PM to 8 AM	0.62	-0.02	-3.4%	0.90	-0.02	-2.4%	0.70	-0.03	-4.6%	0.49	-0.01	-2.3%
	Day	All Hours	0.92	0.01	1.1%	1.37	0.01	0.8%	1.09	0.02	1.7%	0.66	0.00	0.5%
Monthly System Peak Day	Peak	5 PM to 8 PM	1.91	0.09	4.6%	2.39	0.11	4.4%	2.56	0.14	5.5%	1.25	0.04	3.1%
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.47	0.04	2.5%	1.95	0.07	3.4%	1.96	0.07	3.4%	0.95	0.01	0.7%
	Super Off Peak	10 PM to 8 AM	0.81	-0.03	-3.1%	1.11	-0.02	-2.0%	1.01	-0.04	-4.1%	0.58	-0.01	-2.2%
	Day	All Hours	1.25	0.02	1.4%	1.65	0.03	2.0%	1.64	0.03	1.9%	0.83	0.00	0.3%

* A shaded cell indicates estimate is not statistically significant

Figure 4.3-7 shows the estimated peak period load impacts for Rate 2 for CARE/FERA and non-CARE/FERA households for the service territory as a whole and for each climate region. There were no statistically significant differences in absolute load reductions between CARE/FERA and non-CARE/FERA customers within any climate region or across the entire service territory. In the moderate climate region, CARE/FERA customers had the greatest reduction in peak-period energy use at 7.0% and 0.09 kW and the percent reduction was significantly larger for non-CARE/FERA customers.

Figure 4.3-7: Average Load Impacts for Peak Period for SCE Rate 2 for CARE/FERA and non-CARE/FERA Customers (Positive values represent load reductions)



	All CARE	All Non-CARE	Hot CARE	Hot Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Percent Impact	4.9%	3.8%	3.4%	2.7%	7.0%	4.4%	2.3%	3.4%
kW Impact	0.05	0.05	0.06	0.05	0.09	0.08	0.02	0.03

Table 4.3-6 and Table 4.3-7 show the load impacts for non-CARE/FERA and CARE/FERA customers, respectively, for each rate period and day-type. Once again, the values in the first row of each table are the same as those found in Figure 4.3-7. For the service territory as a whole, non-CARE/FERA customers have higher peak period usage, 1.38 kW, than CARE/FERA customers, 1.09 kW. Daily consumption is also greater for non-CARE/FERA customers than for CARE/FERA customers on Rate 2. However, the CARE/FERA group was able to reduce their average weekday use by about 1.5% while non-CARE/FERA customers reduced their usage by 0.9%.

Table 4.3-6: Rate 2 Load Impacts by Rate Period and Day Type – Non-CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Day Type	Period	Hours	Rate 2											
			All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	1.38	0.05	3.8%	2.02	0.05	2.7%	1.78	0.08	4.4%	0.94	0.03	3.4%
Average Weekday	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.03	0.03	2.5%	1.59	0.04	2.7%	1.28	0.04	3.1%	0.74	0.01	1.6%
Average Weekday	Super Off Peak	10 PM to 8 AM	0.64	-0.02	-3.6%	0.91	-0.04	-4.0%	0.74	-0.04	-5.9%	0.51	0.00	-0.9%
Average Weekday	Day	All Hours	0.91	0.01	0.9%	1.36	0.01	0.8%	1.11	0.01	0.9%	0.67	0.01	1.1%
Average Weekend	Off Peak	8 AM to 10 PM	1.21	0.03	2.8%	1.82	0.02	1.4%	1.52	0.06	3.8%	0.85	0.02	2.0%
Average Weekend	Super Off Peak	10 PM to 8 AM	0.65	-0.02	-3.5%	0.95	-0.04	-3.9%	0.76	-0.04	-4.9%	0.51	-0.01	-1.7%
Average Weekend	Day	All Hours	0.98	0.01	1.0%	1.46	0.00	-0.1%	1.20	0.02	1.5%	0.71	0.01	0.9%
Monthly System Peak Day	Peak	5 PM to 8 PM	2.07	0.09	4.3%	2.57	0.12	4.6%	2.88	0.15	5.3%	1.36	0.04	2.7%
Monthly System Peak Day	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.59	0.04	2.5%	2.11	0.08	3.7%	2.19	0.07	3.1%	1.03	0.01	1.0%
Monthly System Peak Day	Super Off Peak	10 PM to 8 AM	0.86	-0.03	-3.2%	1.18	-0.03	-2.9%	1.09	-0.05	-4.6%	0.61	-0.01	-1.4%
Monthly System Peak Day	Day	All Hours	1.34	0.02	1.3%	1.78	0.04	2.0%	1.82	0.03	1.6%	0.90	0.01	0.7%

* A shaded cell indicates estimate is not statistically significant

Table 4.3-7: Rate 2 Load Impacts by Rate Period and Day Type – CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Rate 2															
Day Type	Period	Hours	All, CARE			Hot, CARE			Moderate, CARE			Cool, CARE			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	
Average Weekday	Peak	5 PM to 8 PM	1.09	0.05	4.9%	1.69	0.06	3.4%	1.27	0.09	7.0%	0.70	0.02	2.3%	
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	0.85	0.03	3.1%	1.32	0.04	2.9%	0.96	0.05	5.7%	0.56	-0.01	-1.4%	
	Super Off Peak	10 PM to 8 AM	0.54	-0.02	-3.2%	0.78	0.00	-0.6%	0.58	-0.02	-3.9%	0.41	-0.02	-4.1%	
	Day	All Hours	0.75	0.01	1.5%	1.14	0.02	2.0%	0.84	0.03	3.2%	0.51	-0.01	-1.6%	
Average Weekend	Off Peak	8 AM to 10 PM	0.95	0.03	3.2%	1.51	0.05	3.4%	1.08	0.05	4.6%	0.62	0.00	0.6%	
	Super Off Peak	10 PM to 8 AM	0.55	-0.02	-3.1%	0.81	0.00	0.4%	0.60	-0.02	-3.9%	0.41	-0.02	-4.3%	
	Day	All Hours	0.78	0.01	1.4%	1.22	0.03	2.6%	0.88	0.02	2.2%	0.53	-0.01	-1.0%	
Monthly System Peak Day	Peak	5 PM to 8 PM	1.53	0.08	5.4%	2.10	0.09	4.1%	1.91	0.12	6.2%	0.93	0.04	4.8%	
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.22	0.03	2.7%	1.70	0.05	2.7%	1.51	0.06	4.2%	0.74	0.00	-0.6%	
	Super Off Peak	10 PM to 8 AM	0.71	-0.02	-2.9%	1.00	0.00	-0.3%	0.84	-0.02	-2.9%	0.48	-0.02	-4.8%	
	Day	All Hours	1.04	0.02	1.6%	1.46	0.03	2.1%	1.28	0.03	2.7%	0.65	-0.01	-0.9%	

* A shaded cell indicates estimate is not statistically significant

Figure 4.3-8 shows the load impacts in absolute terms for senior households and households with incomes below 100% of FPG. Table 4.3-8 shows the estimated values for other rate periods and day types for each segment. Of greatest interest is whether load impacts for these two customer segments differ from those of the average population in the hot climate region. As seen previously in Figure 4.3-2, average load impacts for the hot climate region population overall equaled 0.06 kWh or 2.9%. As seen in Figure 4.3-8, load impacts for households with incomes below 100% of FPG were actually larger in both absolute and percentage terms compared with the general population and load impacts for senior households were even larger. The difference in percentage terms was statistically significant.

Figure 4.3-8: Average Load Impacts for Peak Period for SCE Rate 2 for Senior Households and Households with Incomes Below 100% of FPG in the Hot Climate Region

(Positive values represent load reductions)

	Below 100% FPG	Senior
Percent Impact	4.9%	5.6%
kW Impact	0.08	0.11

Table 4.3-8: Rate 2 Load Impacts by Rate Period and Day Type for Senior Households and Households with Incomes Below 100% of FPG in the Hot Climate Region*

(Positive values represent load reductions, negative values represent load increases)

Rate 2								
Day Type	Period	Hours	Hot, Below 100% FPG			Hot, Senior		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	1.58	0.08	4.9%	1.88	0.11	5.6%
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.25	0.06	5.0%	1.50	0.05	3.7%
	Super Off Peak	10 PM to 8 AM	0.76	0.00	0.0%	0.78	-0.02	-2.4%
	Day	All Hours	1.08	0.04	3.5%	1.25	0.03	2.5%
Average Weekend	Off Peak	8 AM to 10 PM	1.41	0.06	4.5%	1.67	0.06	3.5%
	Super Off Peak	10 PM to 8 AM	0.79	0.01	0.9%	0.81	-0.02	-1.9%
	Day	All Hours	1.15	0.04	3.4%	1.31	0.03	2.1%
Monthly System Peak Day	Peak	5 PM to 8 PM	1.95	0.11	5.8%	2.37	0.17	7.4%
	Off Peak	8 AM to 5 PM, 8 PM to 10 PM	1.57	0.08	4.9%	2.00	0.08	4.0%
	Super Off Peak	10 PM to 8 AM	0.97	0.01	1.2%	1.02	-0.03	-2.8%
	Day	All Hours	1.37	0.05	4.0%	1.64	0.05	2.8%

* A shaded cell indicates estimate is not statistically significant

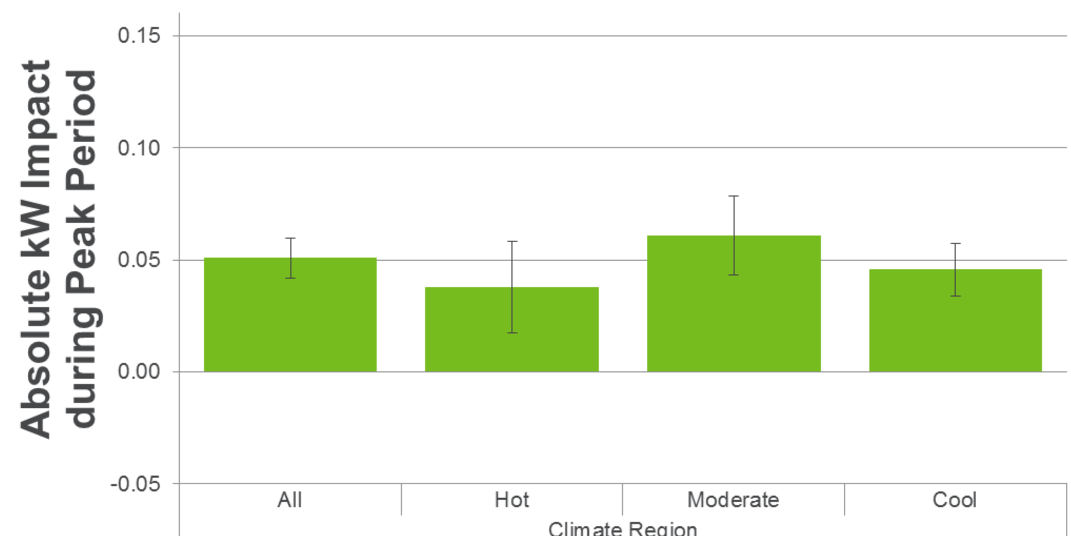
4.3.3 Rate 3

SCE's Rate 3 also has three rate periods on summer weekdays, and two rate periods on summer weekends. For this tariff, SCE refers to the highest price period during weekdays as the super peak period, which is five hours long, from 4 PM to 9 PM, with a price of 37.0 ¢/kWh for non-CARE/FERA customers. While this price is greater than the Tier 2 peak price for Rate 1 and smaller than the Tier 2 price for Rate 2, these prices are not directly comparable because Rate 3 does not include a baseline credit like Rates 1 and 2. As such, average prices for Rate 3 may be higher for low use customers and lower for high use customers than Rate 1 and 2 average prices. The Rate 3 peak period (or shoulder period in this instance) runs from 11 AM to 4 PM and 9 PM to 11 PM, which is significantly shorter than the Rate 2 shoulder period and is the same length as the Rate 1 shoulder period but covering different hours.

Figure 4.3-9 shows the mid peak period load reductions on average weekdays for Rate 3. The load reductions for the SCE territory as a whole, 4.0% or 0.05 kW, are very similar to those for Rate 2 (4.1% or 0.05 kW). Load impacts were greatest in the moderate climate region (3.8% or 0.06 kW), but the differences between the moderate region and the other two climate regions were not statistically significant in absolute terms.

Table 4.3-9 contains estimates of load impacts for all relevant rate periods and day types. Super on-peak peak demand was the smallest among customers in the cool climate region at 0.87 kW, but percent impacts were the greatest (5.2%). On the average weekend, customers in the moderate climate region had the greatest percent impacts at 4.9% (0.08 kW). On weekdays, the average reduction in daily electricity use was statistically significant overall in each climate region, ranging from 1.3% in the moderate zone to 3.1 % in the cool zone.

Figure 4.3-9: Average Load Impacts for Mid Peak Period for SCE Rate 3[40]
(Positive values represent load reductions)



	All	Hot	Moderate	Cool
Percent Impact	4.0%	2.0%	3.8%	5.2%
kW Impact	0.05	0.04	0.06	0.05

[40] SCE Rate 3 winter impacts represent October 2016 through February 2017.

Table 4.3-9: Rate 3 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

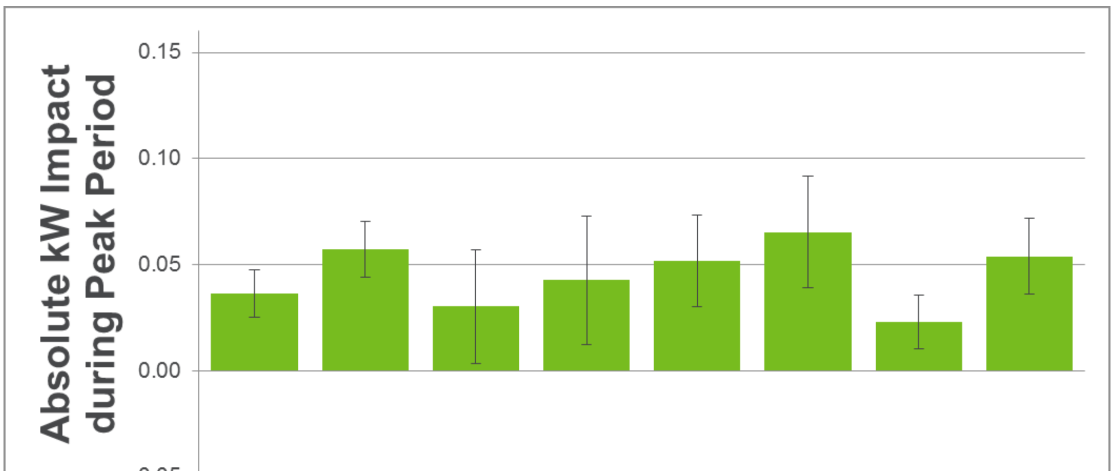
Rate 3															
Day Type	Period	Hours	All			Hot			Moderate			Cool			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Super On Peak	4 PM to 9 PM	1.27	0.05	4.0%	1.87	0.04	2.0%	1.58	0.06	3.8%	0.87	0.05	5.2%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	1.02	0.02	2.3%	1.55	0.04	2.7%	1.24	0.02	1.8%	0.71	0.02	2.8%
	Off Peak	11 PM to 11 AM	0.60	0.00	-0.1%	0.86	0.00	-0.2%	0.66	-0.01	-1.8%	0.48	0.01	1.8%
	Day	All Hours	0.86	0.02	2.0%	1.27	0.02	1.5%	1.02	0.01	1.3%	0.63	0.02	3.1%
Average Weekend	Mid Peak	4 PM to 9 PM	1.31	0.05	4.0%	1.95	0.01	0.6%	1.64	0.08	4.9%	0.88	0.04	4.4%
	Off Peak	9 PM to 4 PM	0.81	0.01	1.1%	1.21	0.00	-0.3%	0.95	0.00	0.4%	0.61	0.02	2.7%
	Day	All Hours	0.92	0.02	2.0%	1.37	0.00	0.0%	1.09	0.02	1.8%	0.66	0.02	3.2%
Monthly System Peak Day	Super On Peak	4 PM to 9 PM	1.88	0.06	3.2%	2.36	0.05	2.2%	2.53	0.07	2.8%	1.24	0.05	4.3%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	1.59	0.02	1.1%	2.07	0.08	4.0%	2.15	0.02	0.8%	1.01	0.00	0.1%
	Off Peak	11 PM to 11 AM	0.79	-0.01	-1.3%	1.12	0.00	-0.4%	0.97	-0.03	-2.8%	0.56	0.00	0.4%
	Day	All Hours	1.25	0.01	1.0%	1.65	0.03	2.0%	1.64	0.01	0.4%	0.83	0.01	1.5%

* A shaded cell indicates estimate is not statistically significant

Figure 4.3-10 shows the peak period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers, and Table 4.3-10 and Table 4.3-11 show the load impacts for each rate period and day type for the two segments. Load reductions were statistically significant for all customer segments and climate regions. The differences in absolute impacts between CARE/FERA and non-CARE/FERA customers were statistically significant for the service territory as a whole as well as in the cool climate regions.

As seen in Table 4.3-10 and Table 4.3-11, there are significant average weekday load reductions for non-CARE/FERA and CARE/FERA customers in the SCE territory as a whole. Load reductions were also significant, and over 3%, for non-CARE/FERA and CARE/FERA customers on average weekends and monthly system peak days.

Figure 4.3-10: Average Load Impacts for Peak Period for SCE Rate 3 for CARE/FERA and Non-CARE/FERA Customers
(Positive values represent load reductions)



	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Percent Impact	3.4%	4.2%	1.8%	2.1%	4.1%	3.7%	3.3%	5.8%
kW Impact	0.04	0.06	0.03	0.04	0.05	0.07	0.02	0.05

Table 4.3-10: Rate 3 Load Impacts by Rate Period and Day Type – Non-CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Rate 3														
Day Type	Period	Hours	All, Non-CARE			Hot, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Super On Peak	4 PM to 9 PM	1.35	0.06	4.2%	1.99	0.04	2.1%	1.74	0.07	3.7%	0.93	0.05	5.8%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	1.08	0.02	1.7%	1.65	0.06	3.5%	1.35	0.00	0.1%	0.76	0.02	3.2%
	Off Peak	11 PM to 11 AM	0.63	0.00	-0.8%	0.92	-0.01	-1.3%	0.72	-0.02	-3.3%	0.51	0.01	2.1%
	Day	All Hours	0.91	0.01	1.6%	1.36	0.02	1.5%	1.11	0.00	0.2%	0.67	0.02	3.6%
Average Weekend	Mid Peak	4 PM to 9 PM	1.40	0.05	3.9%	2.09	-0.01	-0.4%	1.82	0.08	4.6%	0.95	0.05	4.9%
	Off Peak	9 PM to 4 PM	0.86	0.01	0.9%	1.29	-0.02	-1.5%	1.04	-0.01	-0.5%	0.65	0.02	3.6%
	Day	All Hours	0.98	0.02	1.8%	1.46	-0.02	-1.2%	1.20	0.01	1.1%	0.71	0.03	3.9%
Monthly System Peak Day	Super On Peak	4 PM to 9 PM	2.04	0.06	3.0%	2.54	0.04	1.7%	2.84	0.07	2.5%	1.35	0.06	4.2%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	1.71	0.00	-0.1%	2.22	0.12	5.3%	2.40	-0.02	-0.8%	1.09	-0.01	-1.0%
	Off Peak	11 PM to 11 AM	0.84	-0.02	-2.3%	1.20	-0.01	-1.2%	1.05	-0.05	-5.0%	0.60	0.01	0.8%
	Day	All Hours	1.34	0.00	0.2%	1.78	0.04	2.0%	1.82	-0.02	-0.9%	0.90	0.01	1.2%

* A shaded cell indicates estimate is not statistically significant

Table 4.3-11: Rate 3 Load Impacts by Rate Period and Day Type –CARE/FERA Customers*
(Positive values represent load reductions, negative values represent load increases)

Rate 3														
Day Type	Period	Hours	All, CARE			Hot, CARE			Moderate, CARE			Cool, CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Super On Peak	4 PM to 9 PM	1.08	0.04	3.4%	1.67	0.03	1.8%	1.26	0.05	4.1%	0.70	0.02	3.3%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	0.89	0.03	3.7%	1.40	0.02	1.1%	1.03	0.06	6.2%	0.58	0.01	1.1%
	Off Peak	11 PM to 11 AM	0.52	0.01	1.6%	0.77	0.01	1.8%	0.56	0.01	2.2%	0.40	0.00	0.6%
	Day	All Hours	0.75	0.02	2.9%	1.14	0.02	1.6%	0.84	0.04	4.2%	0.51	0.01	1.5%
Average Weekend	Mid Peak	4 PM to 9 PM	1.10	0.05	4.2%	1.73	0.04	2.6%	1.27	0.07	5.8%	0.69	0.02	2.8%
	Off Peak	9 PM to 4 PM	0.70	0.01	1.7%	1.08	0.02	2.0%	0.78	0.02	2.8%	0.49	0.00	-0.3%
	Day	All Hours	0.78	0.02	2.4%	1.22	0.03	2.2%	0.88	0.03	3.7%	0.53	0.00	0.5%
Monthly System Peak Day	Super On Peak	4 PM to 9 PM	1.52	0.06	3.8%	2.08	0.06	3.1%	1.90	0.07	3.7%	0.93	0.04	4.7%
	Peak	11 AM to 4 PM, 9 PM to 11 PM	1.32	0.06	4.4%	1.82	0.02	1.3%	1.66	0.09	5.5%	0.79	0.04	4.5%
	Off Peak	11 PM to 11 AM	0.68	0.01	1.4%	0.99	0.01	1.2%	0.80	0.02	3.0%	0.46	-0.01	-1.3%
	Day	All Hours	1.04	0.03	3.3%	1.46	0.03	1.8%	1.28	0.05	4.2%	0.65	0.02	2.5%

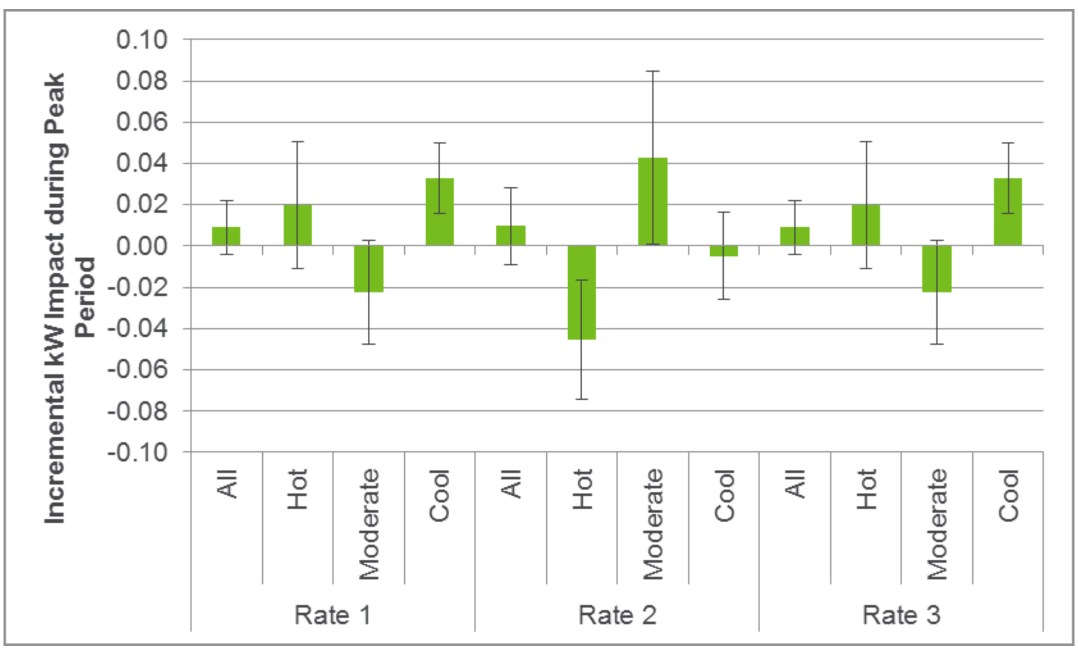
* A shaded cell indicates estimate is not statistically significant

4.3.4 Advanced ME&O

SCE varied the education and outreach provided to participants who were on the three TOU rates. The majority of customers (75%) on each of the three TOU rates received what SCE describes as enhanced education and outreach while the remainder received fewer contacts during the post enrollment phase. The customers chosen at random to receive the enhanced education treatment for each rate received a postcard at the end of August containing tips and reminders about their rate. Starting in late September, the roughly 19% of participants in the enhanced education group who indicated at the time of enrollment that they were willing to receive information via text messages were sent additional reminders and tips via text message.

Figure 4.3-11 shows the average incremental impact attributable to the enhanced education and outreach for each climate region and rate, as well as for the territory as a whole. Positive values in the figure indicate an incremental increase in load reductions (e.g., load reductions are larger with enhanced education) while a negative value means load reductions were smaller for the enhanced education group relative to the less frequent communication. As seen, incremental impacts were both positive and negative although hardly any incremental impacts were statistically significant. A key exception is for customers on Rate 2 in the moderate climate region, where incremental impacts were much larger in absolute terms compared with the non-enhanced group. Just the opposite is seen for Rate 2 customers in the hot climate region, where impacts were much lower for customers in the enhanced education test cell.

Figure 4.3-11: Incremental Impacts among Customers Receiving Advanced ME&O



4.3.5 Comparison Across Rates

Figure 4.3-12 compares the load impacts for the three rates tested by SCE for the common set of peak-period hours from 5 PM to 8 PM for the entire summer of 2017. Using a common set of hours reduces differences in impacts across rates that might be due to differences in the number of hours included in the peak period or the timing of those hours. The hours from 5 PM to 8 PM define the peak period for SCE's Rate 2. Rate 1 has a six hour peak period, from 2 PM to 8 PM and Rate 3 has a five hour peak period from 4 PM to 9 PM. All three tariffs have three rate periods in summer. The peak and shoulder periods combined cover the same hours for Rates 1 and 2 (8 AM to 10 PM) while the two periods combined for Rate 3 cover fewer hours, from 11 AM to 11 PM. Recall that Rate 3 also differs from Rates 1 and 2 in that it does not provide a baseline credit while Rates 1 and 2 do.

With a shorter peak period and a much higher Tier 2, peak period price (and lower Tier 2 super off-peak price), one might expect the peak period load reductions for Rate 2 to be higher than for Rate 1. As seen in the figures, for the service territory as a whole and for the moderate and cool climate regions, this is not always the case. In fact, the pattern of differences between the rates is not consistent across climate regions and none of the differences are statistically significant. Figure 4.3-13 presents the average daily kWh impacts for each rate during the summer 2017 period. Daily impacts vary across rates and climate regions with no clear pattern.

Figure 4.3-12: Average Impacts from 5 PM to 8 PM Across Rates

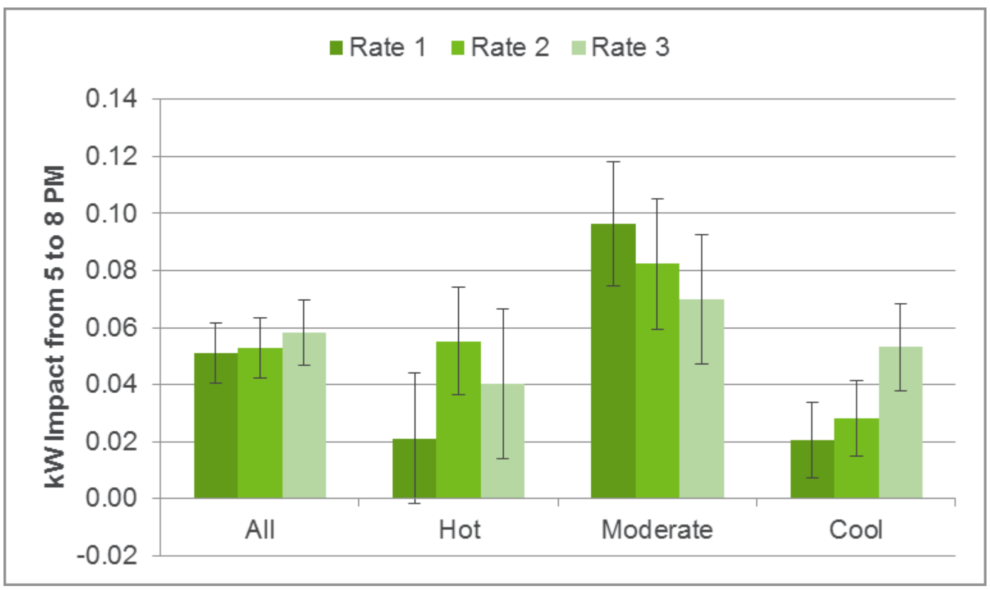
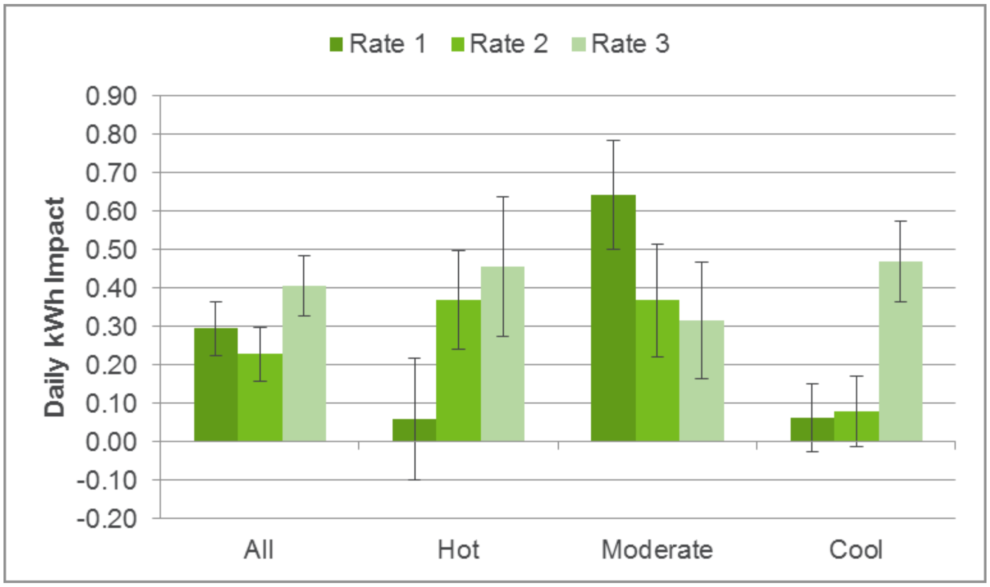


Figure 4.3-13: Average Daily kWh Impacts Across Rates



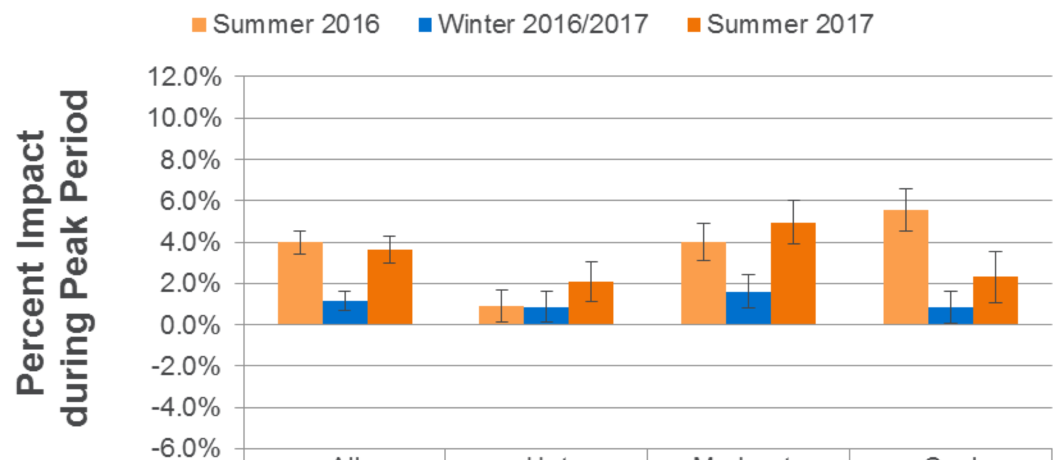
4.4 Persistence Analysis

The impacts in this section represent customers who were enrolled in the pilot until the end of September 2017- the full duration of the pilot. Using this method, it is possible to compare impacts between seasons for a single group of customers, rather than a changing population. It is important to keep in mind that these customers may not be representative of a typical customer on a default TOU rate. In other words, people who were unhappy with their new rate and opted out of the pilot are not included in this analysis. Because enrollment was not complete in June 2016, only the months of July through September are included for the summer estimates (and only August and September are included for Rate 3 because enrollment for Rate 3 occurred roughly a month later than for the other two rates). While there is not a second winter for persistence comparison, the winter and spring impacts for the subset of customers who were enrolled for the full duration of the pilot are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers. Winter and spring impacts presented in this section match the rate-specific winter and spring months described in Section 4.1.

4.4.1 Rate 1

Figure 4.4-1 presents the average percent impacts for the peak period for customers who remained on Rate 1 throughout the entire pilot. All three seasons are presented for the territory as a whole and for each climate region. For the territory as a whole and for each climate, load impacts were smaller in winter than in the summer seasons. Impacts for the first and second summer were very similar for the territory as a whole, about 4.0% in 2016 and 3.6% in 2017. The difference was not statistically significant. Summer impacts increased for customers in the hot and moderate climate regions, but not for customers in the cool climate region where percent impacts decreased from 5.6% to 2.3%.

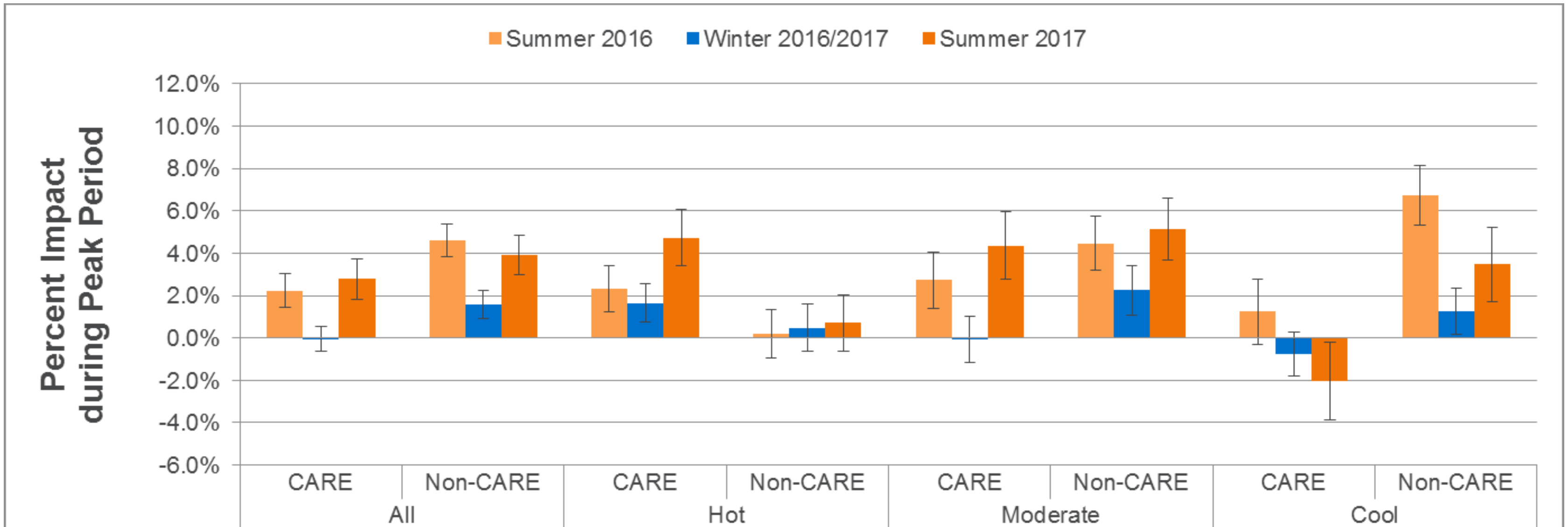
Figure 4.4-1: Percent Impacts for Peak Period for SCE Rate 1, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	4.0%	0.9%	4.0%	5.6%
Winter 2016/2017	1.2%	0.9%	1.6%	0.8%
Summer 2017	3.6%	2.1%	4.9%	2.3%

Figure 4.4-2 presents average seasonal impacts for non-CARE/FERA and CARE/FERA customers on Rate 1. Except for the cool climate region, CARE/FERA customers increased their percent impacts between the first and second summer, but these increases were not statistically significant. Both CARE/FERA and non-CARE/FERA customers in the cool climate region showed smaller impacts in the second summer compared with the first, but the different was only statistically significant for non-CARE/FERA customers. In fact, CARE/FERA customers in the cool region increased their peak period usage by 2.0% in summer 2017. Winter impacts were generally smaller than summer impacts, and in many cases were not statistically significant.

Figure 4.4-2: Percent Impacts for Peak Period for SCE Rate 1, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

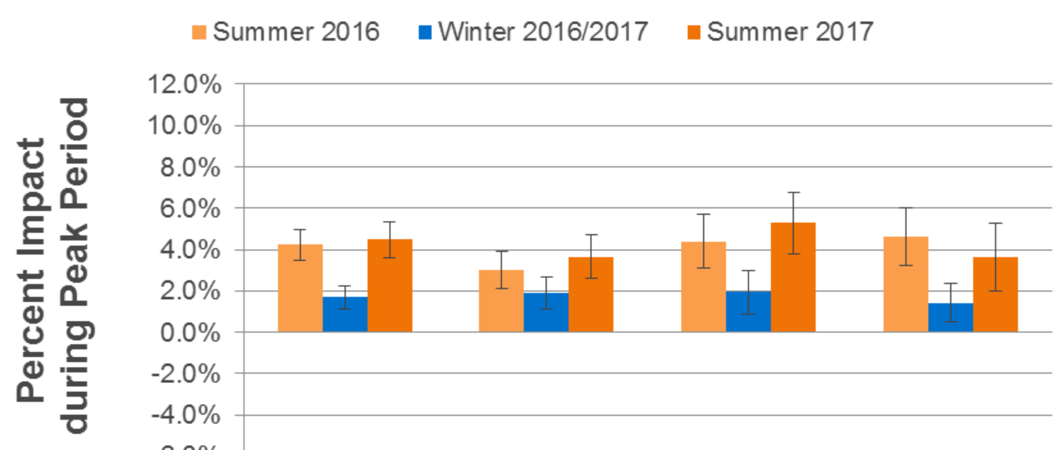


	All CARE	All Non-CARE	Hot CARE	Hot Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Summer 2016	2.2%	4.6%	2.3%	0.2%	2.7%	4.5%	1.2%	6.7%
Winter 2016/2017	0.0%	1.6%	1.6%	0.5%	-0.1%	2.3%	-0.8%	1.3%
Summer 2017	2.8%	3.9%	4.7%	0.7%	4.4%	5.2%	-2.0%	3.5%

4.4.2 Rate 2

Figure 4.4-3 presents seasonal load impacts for Rate 2 customers in SCE’s territory as a whole and for each climate region. Recall that these load impacts only represent customers who remained on the pilot until the end of summer 2017. Customers on Rate 2 have a similar pattern to those on Rate 1. Winter impacts were between 1.4% and 1.9% while summer impacts were between 3.0% and 5.3% during each summer season. Unlike Rate 1, customers in SCE’s service territory as a whole showed greater impacts during the second summer (compared with the first), though the difference is not statistically significant. This is true in the hot and moderate climate regions as well. Customers in the cool climate region had smaller summer impacts in 2017, a reduction from 4.6% to 3.6%. None of the differences are statistically significant, however.

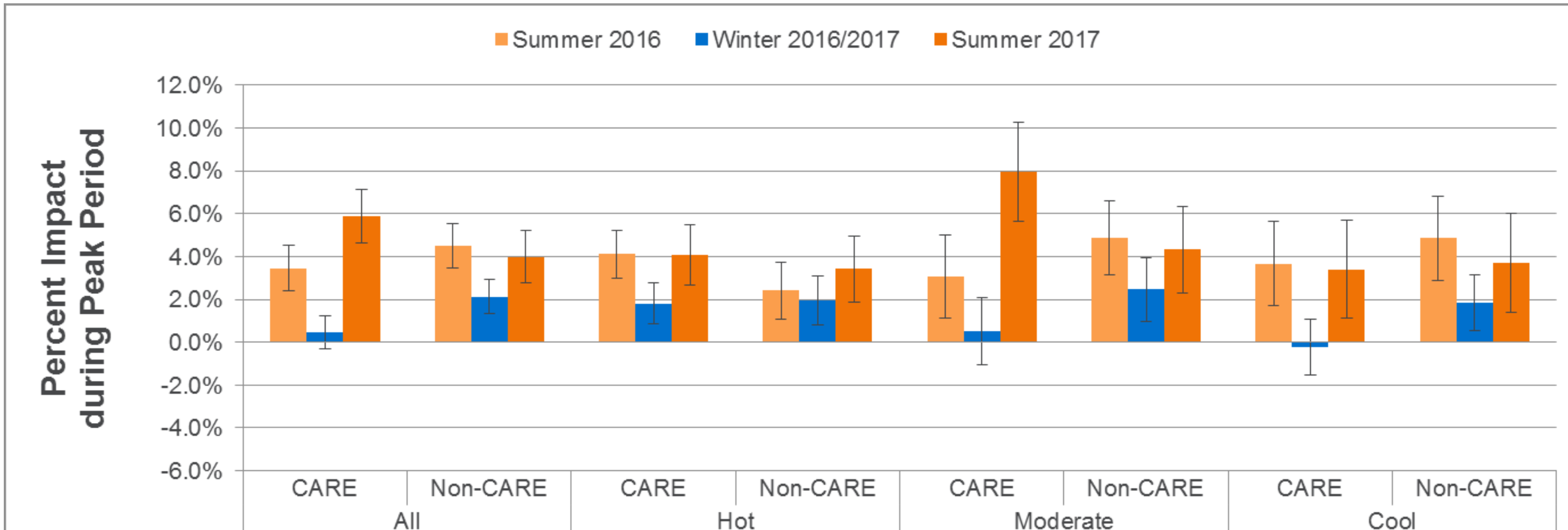
Figure 4.4-3: Percent Impacts for Peak Period for SCE Rate 2, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	4.2%	3.0%	4.4%	4.6%
Winter 2016/2017	1.7%	1.9%	1.9%	1.4%
Summer 2017	4.5%	3.6%	5.3%	3.6%

Figure 4.4-4 summarizes the seasonal load impacts for CARE/FERA and non-CARE/FERA customers on SCE’s Rate 2. In general, summer impacts did not change drastically between 2016 and 2017, except for CARE/FERA customers in the moderate climate region for which load impacts more than doubled across the two summers, from 3.1% to 8.0%. Except in the hot climate region, CARE/FERA customers did not have statistically significant impacts in the winter months. The difference in the percent impact from summer to summer for non-CARE/FERA customers were small and not statistically significant.

Figure 4.4-4: Percent Impacts for Peak Period for SCE Rate 2, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

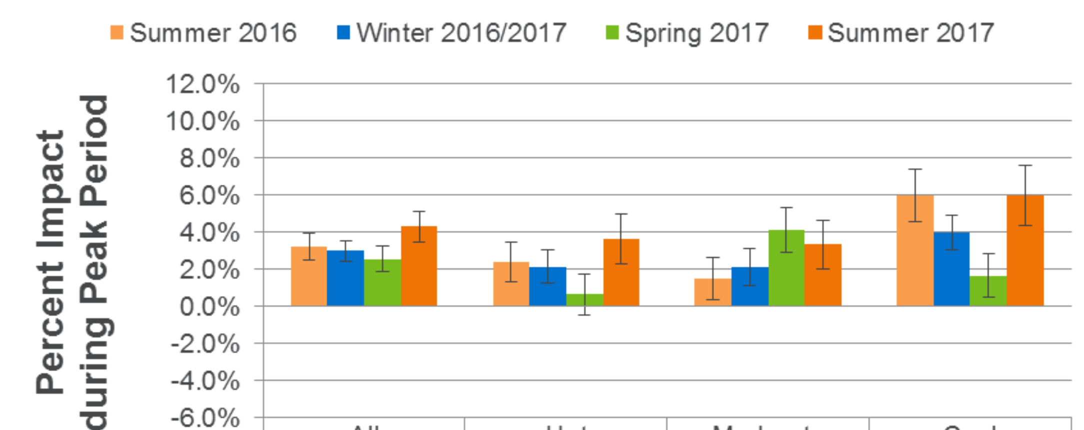


	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Summer 2016	3.5%	4.5%	4.1%	2.4%	3.1%	4.9%	3.7%	4.9%
Winter 2016/2017	0.5%	2.1%	1.8%	1.9%	0.5%	2.5%	-0.2%	1.9%
Summer 2017	5.9%	4.0%	4.1%	3.4%	8.0%	4.3%	3.4%	3.7%

4.4.3 Rate 3

Figure 4.4-5 presents average percent impacts for customers on Rate 3 for each season in the pilot. Recall that unlike the previous two rates, SCE’s Rate 3 has three seasons: summer, winter, and spring. Summer impacts represent August and September only, due to the later launch of Rate 3. In the territory as a whole, summer impacts were greater than those in winter and spring. Between 2016 and 2017, customers increased their summer peak period impacts by about one percentage point, from 3.2% to 4.3%. Customers in the hot and moderate climate regions also increased their summer impacts from 2016 to 2017, while customers in the cool region had impacts equal to 6.0% in both years. This shows that customers continue to respond to peak period prices even after participating in the pilot for more than one year.

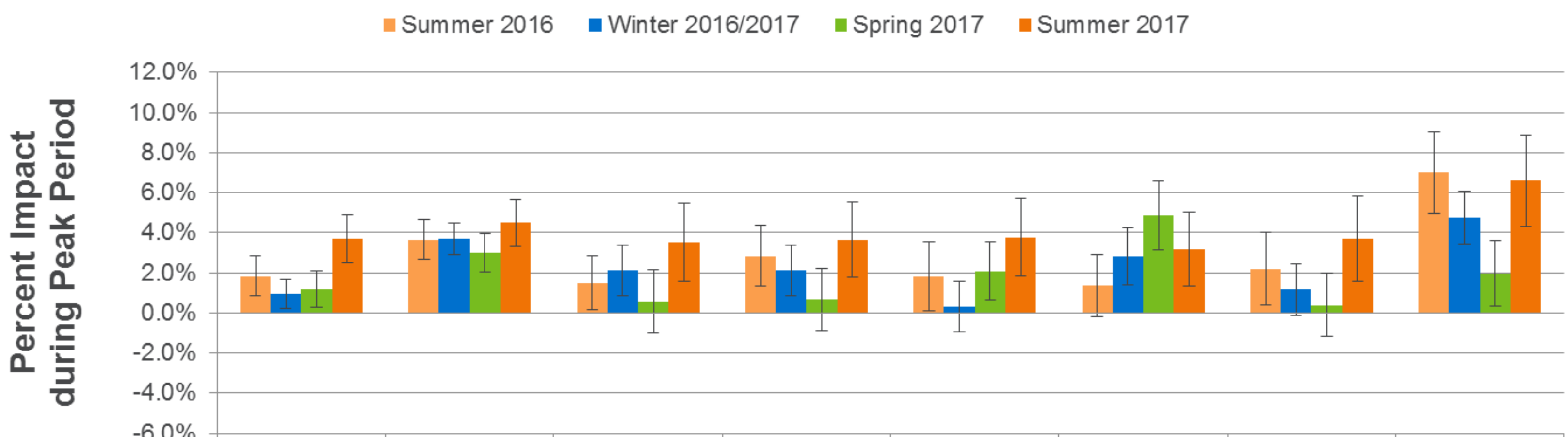
Figure 4.4-5: Percent Impacts for Peak Period for SCE Rate 3, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	3.2%	2.4%	1.5%	6.0%
Winter 2016/2017	3.0%	2.1%	2.1%	4.0%
Spring 2017	2.5%	0.6%	4.1%	1.6%
Summer 2017	4.3%	3.6%	3.3%	6.0%

Figure 4.4-6 presents peak period impacts for each time period for CARE/FERA and non-CARE/FERA customers on Rate 3. In every climate region and for the territory as a whole, CARE/FERA customers showed greater impacts in the second summer of the pilot compared to the first – but the differences were not statistically significant. For example, customers in the moderate climate zone more than doubled their percent impact, from 1.8% to 3.8%. Non-CARE/FERA customers also increased their impacts, although to a lesser degree. The exception was non-CARE/FERA customers in the cool climate region, where impacts decreased by a statistically insignificant amount.

Figure 4.4-6: Percent Impacts for Peak Period for SCE Rate 3, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

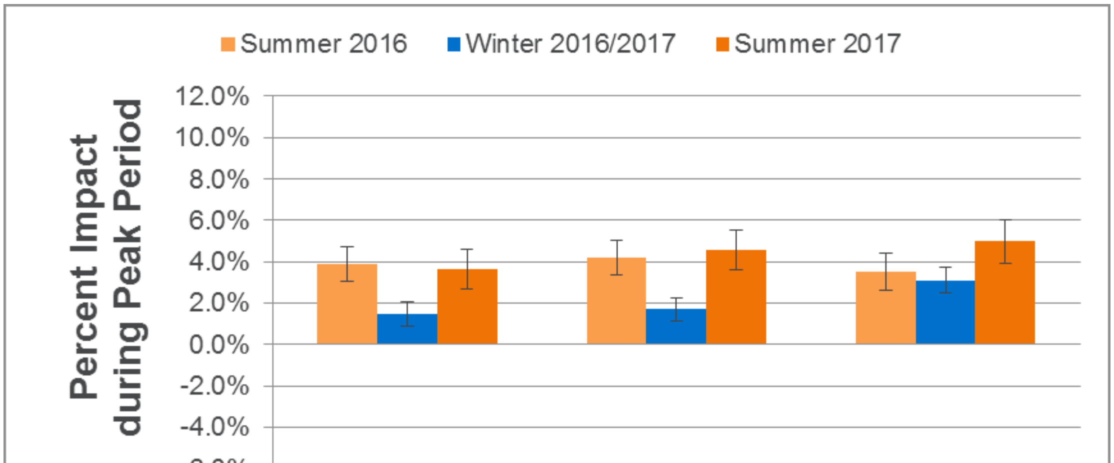


	All		Hot		Moderate		Cool	
	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE	CARE	Non-CARE
Summer 2016	1.9%	3.7%	1.5%	2.8%	1.8%	1.4%	2.2%	7.0%
Winter 2016/2017	0.9%	3.7%	2.1%	2.1%	0.3%	2.8%	1.2%	4.8%
Spring 2017	1.2%	3.0%	0.6%	0.7%	2.1%	4.9%	0.4%	2.0%
Summer 2017	3.7%	4.5%	3.5%	3.7%	3.8%	3.2%	3.7%	6.6%

4.4.4 Comparison Across Rates

Figure 4.4-7 compares the load impacts for the three rates tested by SCE for the common set of peak-period hours from 5 PM to 8 PM for the summer months of August and September and the winter months of October through May. For all three rates, summer impacts persist from 2016 to 2017. The difference in impacts between summers is not statistically significant, and winter impacts are smaller than summer impacts in every case.

Figure 4.4-7 Percent Impacts from 5 PM to 8 PM Across Rates, by Season



	Rate 1	Rate 2	Rate 3
Summer 2016	3.9%	4.2%	3.5%
Winter 2016/2017	1.5%	1.7%	3.1%
Summer 2017	3.6%	4.6%	5.0%

4.5 Synthesis for SCE Pilot

This section compares input from the load impact and persistence analysis, the bill impact analysis and the survey analysis. The objective of these comparisons, at least in part, is to determine if the information and conclusions observed for individual metrics are supported by findings from other metrics or, alternatively, findings for one metric contradict those for another metric. We also look for clues from the survey findings that might help explain why load or bill impacts for one rate differ from those for other rates.

Readers are referred to the beginning of Section 3.5 for an important caution when interpreting these results—namely that given the large samples underlying the survey analysis, statistically significant differences may not reflect meaningful differences from a policy perspective.

4.4.1 Synthesis

Table 4.5-1 through Table 4.5-3 summarize some of the relevant findings from the load impact, persistence, bill impact and survey analysis. No additional bill impact analysis or surveys were completed for this report. Results from the first and second interim report were carried forward to this synthesis section in order to provide a more complete overview of the pilot. Readers are directed to Section 3.5.1

for an explanation of the variables and symbols contained in the tables. As a reminder, unlike with PG&E where two pilot rates had two pricing periods and one had three, SCE's pilot Rates 1 and 2 had three pricing periods on weekdays and two on weekends. Rate 3 had two pricing periods on winter weekdays, and three pricing periods on spring weekdays and weekends in the winter and spring. The shoulder periods for all three-period rates were long, beginning at 8 AM for two of the rates and at 11 AM for the third. Also, Rate 3 has no baseline credit whereas Rates 1 and 2 do.

Non-CARE/FERA Customers

Unlike at PG&E, non-CARE/FERA customers in SCE's hot climate region tended to have smaller peak period reductions compared to customers in the moderate and cool climate regions in summer 2017. Indeed, load impacts for non-CARE/FERA customers on Rate 1 were statistically insignificant. This pattern of smaller impacts in the hot climate region is consistent with results from the first summer and winter as well. Average peak-period impacts for non-CARE/FERA customers ranged from not statistically significant in the hot climate region on Rate 1 to 5.8% in the cool climate region on Rate 3. As shown by the persistence variable in the tables, differences in load impacts across the two summers for this segment were positive for some climate zone/rate combinations and negative for others but none of these differences is statistically significant. The contrast in the magnitude of load impacts for non-CARE/FERA customers between PG&E and SCE may be due, in part, to the fact that SCE's hot climate region is much hotter than PG&E's. The average number of cooling degree days in SCE's hot climate region across the two summer periods was 569 whereas the same average for PG&E's hot climate region was 423, roughly 35% lower. It may be that customers with higher incomes in really hot regions are less responsive to modest TOU price signals than lower income customers or all customers in cooler regions.

Total annual bill impacts for non-CARE/FERA customers in the hot climate region ranged from a reduction of $4 on Rate 3 to an increase of $64 on Rate 1. Customers on Rates 1 and 2 were ineffective at making behavioral changes that offset the structural loss during the first year of the pilot. Rate 3 customers started out with the smallest structural loss, but ultimately made the largest behavioral changes.

Average annual bills decreased for non-CARE/FERA customers in the moderate and cool climate regions on Rates 1 and 3, and in the cool climate region on Rate 2. This could explain why summer impacts dropped by a statistically significant 3.3 percentage points for non-CARE/FERA customers in the cool region on Rate 1. These customers experienced average annual bill decreases equal to about $28 or 2.6%, which may have affected their motivation to respond to the rate. Conversely, the same segment in the hot climate region faced comparatively large annual bill increases ($64 or 3.8%) but only increased their summer impacts by 0.5 percentage points. This change was not statistically significant. In fact, all other non-CARE/FERA segments did not show statistically significant changes in summer impacts from 2016 to 2017 for the common set of customers enrolled for the full duration of the pilot. In other words, customers continue to respond to the rate at the same level as they did in the first summer.

Table 4.5-1: Load Impacts, Bill Impacts, and Selected Survey Findings for SCE Rate 1[41]

Climate	Segment	Load Impacts					Bill Impacts		Survey						
		Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	1.1% ▼	-0.2% -	0.2% -	1.8% ▲	0.5 -	$64 ▲	3.8% ▲	1.9 ▼	23% -	22% -	2.2 -	11%	6.5 -	7.1 -
	CARE/FERA	1.8% ▼	0.5% -	5.1% ▼	0.3% ▼	2.4 -	$47 ▲	5.4% ▲	2.5 -	23% -	60% -	3.9 -	20%	7.3 -	7.9 -
Moderate	Non-CARE/FERA	5.5% ▼	3.3% ▼	5.1% ▼	2.2% ▼	0.7 -	-$16 ▼	-1.1% ▼	2.0 -	19% ▼	24% -	2.2 -	14%	6.9 ▲	7.2 -
	CARE/FERA	3.3% ▼	0.6% -	4.9% ▼	0.2% ▲	1.6 -	$24 ▲	3.4% ▲	2.5 -	24% -	57% -	3.7 -	23%	7.6 -	7.9 -
Cool	Non-CARE/FERA	5.8% ▼	1.1% ▼	3.2% ▼	0.6% ▼	-3.3 ▼	-$28 ▼	-2.6% ▼	2.2 -	22% -	20% -	2.1 -	12%	6.9 -	7.4 -
	CARE/FERA	2.4% ▼	-0.4% -	-1.4% -	1.1% ▲	-3.3 -	$10 ▲	1.8% ▲	2.2 ▼	18% -	60% -	3.7 -	18%	8.0 -	8.3 -

Table 4.5-2: Load Impacts, Bill Impacts, and Selected Survey Findings for SCE Rate 2

Climate	Segment	Load Impacts					Bill Impacts		Survey						
		Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	2.9% ▼	1.5% ▼	2.7% ▼	0.2% ▼	1.0 -	$42 ▲	2.6% ▲	2.1 -	24% -	24% -	2.3 -	27%	6.5 -	7.0 -
	CARE/FERA	3.5% ▼	1.4% ▼	3.4% ▼	1.2% ▼	0.0 -	$40 ▲	4.6% ▲	2.7 -	24% -	67% -	4.1 -	37%	7.2 -	7.8 -
	Senior	4.1% ▼	1.1% ▼	5.6% ▼	0.4% ▼	2.8 -	$57 ▲	4.1% ▲	2.6 -	23% -	36% -	2.9 -	34%	7.0 -	7.5 -
	HH < 100% FPG	3.1% ▼	2.7% ▼	4.9% ▼	1.9% ▼	2.0 -	$19 ▲	1.9% ▲	2.8 -	27% -	59% -	3.9 -	35%	7.3 -	7.8 -
	100% FPG < HH < 200% FPG	N/A	N/A	N/A	N/A	N/A	$38 ▲	3.4% ▲	2.7 -	24% -	58% -	3.5 -	33%	6.7 -	7.4 -
Moderate	Non-CARE/FERA	5.6% ▼	3.1% ▼	4.4% ▼	1.1% ▼	-0.5 -	$19 ▲	1.3% ▲	2.0 -	20% -	23% -	2.2 -	26%	6.9 ▲	7.4 ▲
	CARE/FERA	1.7% ▼	1.1% -	7.0% ▼	1.0% ▼	4.9 ▲	$16 ▲	2.2% ▲	2.5 -	22% -	58% -	3.6 ▼	44%	7.8 -	8.0 -
Cool	Non-CARE/FERA	4.2% ▼	2.2% ▼	3.4% ▼	1.2% ▼	-1.2 -	-$42 ▼	-3.6% ▼	2.0 -	20% -	19% -	2.0 -	28%	7.0 -	7.4 -
	CARE/FERA	4.6% ▼	-0.5% -	2.3% ▼	1.4% ▲	-0.2 -	$4 ▲	0.8% ▲	2.5 -	20% -	61% -	3.7 -	40%	8.0 -	8.4 -

Table 4.5-3: Load Impacts, Bill Impacts, and Selected Survey Findings for SCE Rate 3

Climate	Segment	Load Impacts					Bill Impacts		Survey						
		Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	Non-CARE/FERA	3.0% ▼	2.3% ▼	2.1% ▼	0.8% ▼	0.8 -	-$4 -	-0.3% -	2.3 -	30% -	23% -	2.3 -	7%	6.4 -	7.0 -
	CARE/FERA	-0.1% ▼	1.9% ▼	1.8% ▼	0.8% ▼	2.0 -	$56 ▲	7.6% ▲	2.5 -	29% -	70% ▲	4.2 -	19%	7.4 -	7.9 -
Moderate	Non-CARE/FERA	1.4% -	3.8% ▼	3.7% ▼	0.3% ▼	1.8 -	-$18 ▼	-1.4% ▼	1.8 ▼	29% -	22% -	2.2 -	10%	6.5 -	7.1 -
	CARE/FERA	4.8% ▼	0.4% -	4.1% ▼	1.5% ▼	2.0 -	$39 ▲	6.4% ▲	2.9 -	25% -	60% -	3.9 -	20%	7.4 -	7.9 -
Cool	Non-CARE/FERA	4.3% ▼	4.7% ▼	5.8% ▼	1.7% ▼	-0.4 -	-$47 ▼	-4.4% ▼	2.1 -	30% ▲	18% -	2.0 -	6%	6.8 -	7.3 -
	CARE/FERA	2.0% ▼	0.5% -	3.3% ▼	-0.4% ▲	1.5 -	$35 ▲	7.3% ▲	2.5 -	24% -	62% -	3.7 -	18%	7.8 -	8.3 -

[41] In all three tables, a column with an (*) indicates the values are from the First Interim Report and a column with (**) indicates the values are from one of the two Second Interim Report volumes. A column with neither (*) or (**) means the values are found elsewhere in this report.

Non-CARE/FERA customers understood the rates better than nearly any other segment (as indicated by the very low percent that failed to identify at least one peak period hour on Rates 1 and 3). However, it is worth noting that on average, Rate 1 and 2 customers performed worse on being able to identify the highest price hours on the second survey compared to the first. Additionally, Rate 2 customers generally had much lower performance across all customer segments regarding identifying the highest price hours compared to Rates 1 and 3.

The non-CARE/FERA customers had a low percentage of customers having difficulty paying their bills compared to other segments, and also had the lowest satisfaction ratings for the rate plan and for SCE compared with any other segment. However, there were no cases in which the satisfaction levels were significantly lower relative to the control group. In some cases the satisfaction levels for both the rate and for SCE were actually higher for the treatment group compared to the control group in the moderate climate region.

CARE/FERA Customers

In summer 2017, there was no distinct pattern of load impacts between CARE/FERA and non-CARE/FERA customers. Summer 2017 peak period impacts for CARE customers ranged from not statistically significant for Rate 1 in the cool climate region to 7.0% in the moderate climate region on Rate 2.

The average CARE/FERA customer was an annual structural non-benefiter across all rates and climate regions, ultimately resulting in all CARE/FERA customers experiencing higher total annual electricity costs, ranging from a low of a $4 increase for Rate 2 CARE/FERA customers in the cool climate region to a high of $56 for Rate 3 customers in the hot climate region. Although they faced higher bills, CARE/FERA customers generally did not increase their load impacts from summer 2016 to summer 2017, except in the moderate climate region whose impacts grew by 4.9 percentage points from one summer to the next. This change was statistically significant. This group did not experience an especially high annual bill increase, so it is unclear what motivated them to respond to the rate in the second summer. Load impacts from this group were significantly below average during in the first summer, and were the highest the second summer. These customers also had the highest level of not understanding the correct TOU hours on the second survey. If customer understanding improved after that point, it may help to explain the sudden increase in customer performance.

Rate 3 hot climate region CARE/FERA customers were the only segment to have a statistically significantly higher percentage of TOU customers having difficulty paying their bill compared to control group customers. In all other segments and rates, a comparable percentage of treatment and control group customers expressed difficulty in paying bills. Generally speaking, CARE/FERA customers were not able to offset a significant portion of the structural bill increases, with the largest offset of 50% ($16) from Rate 2 customers in the moderate climate region.

The economic index for CARE/FERA customers was roughly twice as high as for non-CARE/FERA customers in all climate regions and for all rate options, including the control group. In short, CARE/FERA customers had higher economic index scores compared with non-CARE/FERA customers, but the increase in the economic index scores moving from the OAT to TOU rates is not statistically significant for any rate in any climate region.

Importantly, in spite of the above, CARE/FERA customers had higher satisfaction ratings for the TOU rates than non-CARE/FERA customers for all rates and climate regions. In all climate regions, none of the satisfaction ratings for CARE/FERA customers were statistically significantly lower than the control group ratings. CARE/FERA customers also had higher ratings for satisfaction with SCE than non-CARE/FERA customers in all climate regions for all rates.

Senior Households

Senior households in the hot climate region had summer 2017 load reductions in the peak period for the average weekday that were larger than average reductions for the overall population in the hot region, as reported for Rate 2 in Section 4.3.2. The average peak-period load impact of 5.6% is statistically significantly larger than the load impacts for the non-CARE/FERA group of 2.7% and for the CARE/FERA group (3.4%). The net annual kWh change of 0.4% was between the values for non-CARE/FERA and CARE/FERA. Customers in this group increased their summer impacts from 2016 by 2.8 percentage points, but this change was not statistically significant, indicating that their large annual bill impacts of $57 or 4.1% was not enough to motivate them to increase their response to the rate, but it was enough for them to maintain it.

Total annual bill impacts are similar between senior households and the hot general population in percentage terms, reflecting the split between non-CARE/FERA and CARE/FERA customers. On Rate 2, 23% of senior households, along with around a quarter of the customers from other segments, indicated that their bills were higher than expected. However, this percentage was not statistically significantly different for the customers on TOU rates compared to the OAT. There was no statistically significant difference in the percent of seniors reporting difficulty in paying bills, or in the economic index, compared with the control group.

Senior households had a higher percentage of participants that could not identify any peak period hours (34%) compared with non-CARE/FERA customers (27%) in the hot region. However, they performed slightly better than the CARE/FERA customers (37%). Performance on the second survey declined from the first survey where 30% of senior households couldn't identify any of the peak periods. The percentage of customers not identifying any correct peak period hours tended to be higher in general for Rate 2 compared to the other rates.

Finally, satisfaction ratings by senior households for the rate plan (7.0) and for SCE (7.5) were somewhat higher than the ratings for the hot climate zone population as a whole (as calculated by a weighted average for CARE/FERA and non-CARE/FERA households, whose ratings were 6.7 and 7.3 respectively). Seniors on TOU rates did not have statistically different satisfaction ratings for the rate plan or SCE compared with the control group.

Households with Incomes Below 100% of FPG

In summer 2017, households with incomes below 100% of FPG on Rate 2 in the hot climate region had load impacts equal to 4.9%, which is greater than the 3.4% impact achieved by CARE/FERA customers in the same region on Rate 2 (but this difference is not statistically significant). Compared to the winter months, summer 2017 impacts were nearly twice as large. This group had the largest decrease in net annual kWh electricity use in the hot climate region, equal to almost 2%. Annual structural bill impacts averaged $39, and these customers were able to offset around half of the increase, or around $20, resulting in an average annual cost increase for this segment of $19 or 1.9%. Households with incomes below 100% of FPG did not increase their load impacts by a statistically significant amount between the first and second summer of the pilot, but they continue to respond to the rate. It appears that the bill impacts they faced in the first year were enough to keep them motivated to respond.

This segment had the highest score on the health index compared to other segments on Rate 2.[42] However, the score was not statistically different for the treatment group compared to the control group on this index.

59% of households with incomes below 100% of FPG reported that they had difficulty paying bills and this segment had the second highest economic index score (3.9) of any segment on Rate 2. However, the difference in the economic index for TOU customers compared with the control group was not statistically significant for customers on Rate 2. The percentage of treatment customers reporting difficulty paying bills was also not statistically different from the percent of control customers reporting difficulty. 27% of households with incomes below 100% of FPG stated they received bills higher than expected. However, this was not statistically significantly different from the control group.

Customers in this segment were among the highest percent of participants who could not identify any peak period hours among all segments on Rate 2. For Rate 2, this segment did not have statistically different levels of satisfaction with the rate or with SCE. Satisfaction was not measured for this segment on Rates 2 or 3.

4.4.2 Key Findings

Key findings pertaining to second summer load impacts from the SCE pilots include:

1. In the second summer, customers continued to respond to TOU rates with peak periods that extend well into the evening. During the second summer, customers achieved load reductions as high as 7% for CARE/FERA customers in the moderate climate region on Rate 2.
2. In general, customers achieved similar peak-period load reductions in the first and second summer. One exception was CARE/FERA customers in the moderate climate region on Rate 2, who increased their impacts by about 4.9 percentage points – a statistically significant change. These customers showed difficulty in understanding the peak period hours, and perhaps improved their understanding of the rate in the second summer.
3. For Rate 3, which has the same peak period prices in effect on weekends as on weekdays, the peak period load reductions were similar on the two day types– that is, customers continued to reduce loads on weekends in the second summer.
4. Unlike for PG&E’s customers, where CARE/FERA customers generally had significantly lower peak period load reductions compared with non-CARE/FERA customers, the load impacts for CARE/FERA and non-CARE/FERA customers in SCE’s service territory were not statistically significantly different in the hot climate region, except for Rate 1.
5. Senior households and households with incomes below 100% of FPG on Rate 2 in the hot climate region had summer 2017 load impacts of 5.6% and 4.9%, respectively. Both were

[42] This metric is not reported for Rates 1 or 3.

statistically significantly higher in percentage terms compared to the Rate 2 hot climate region population as a whole (2.9%).

6. Households who had previously purchased smart thermostats reduced summer 2017 peak period usage by approximately 6.7%, which was significantly higher compared to non-CARE/FERA population weighted load reductions of 3.7%. Nest offered its “Time of Savings” support service for the second summer, which significantly increased[43] the magnitude of peak load reductions relative to the first summer.
7. The pattern of summer 2017 load reductions across climate regions in both percentage and absolute terms was not consistent across rates and was quite different from the pattern seen in PG&E’s service territory, which showed a significant decline in load reductions in both percentage and absolute terms moving from the hot to the cool climate regions. For SCE, summer 2017 peak-period load reductions for customers on Rate 1 were largest in the moderate region. For Rates 2 and 3, differences across climate regions were not always statistically significant.

Overall findings and conclusions for the pilot include:

- Customers continued to respond to the TOU price signals at the end of the pilot. As expected, the load impacts were lower during the winter compared to the summer months. Load impacts persisted in the second summer, with very few segments changing their percent reductions by a statistically significant amount.
- The population weighted majority of customers across all three rates experienced slight net annual total bill decreases. However, customers in the hot climate regions and CARE/FERA customers were more likely to experience net annual bill increases.
- For seniors and households with incomes below 100% of FPG, there was no statistically significant increase in economic or health index scores after a full year on Rate 2 (the only rate where measurements are reported for this segment).

[43] The “Time of Savings” service was not implemented via a controlled experiment, therefore the incremental effects of the service are not measurable with the same level of rigor as the rest of the pilot. Consequently, additional factors such as weather may explain part of the year over year performance difference observed.

5 SDG&E Evaluation

This report section summarizes the attrition and load impacts for the second summer of SDG&E's pilot. It also includes a discussion of load impact persistence over the entire pilot. Load and bill impacts from the first summer season can be found in the First Interim Report and for the winter season in the Second Interim Report.

5.1 Summary of Pilot Treatments

Figure 5.1-1 and Figure 5.1-2 summarize the two tariffs that were tested in the SDG&E service territory. Both tariffs have peak periods that include the evening hours from 4 PM to 9 PM. The rates have changed since the launch of the pilot, and the figures represent the tariffs that were in effect in March 2017 and do not reflect the baseline credit of 22 ¢/kWh in the summer and 20 ¢/kWh in the winter. Appendix B shows the prices that were in effect in each rate period for each tariff, including the OAT. Two sets of prices are shown in the appendix, one covering the period from pilot start through February 2017, and the other beginning on March 1, 2017. While several minor rate changes occurred over the course of the pilot, the rate adjustment that occurred on March 1, 2017 was more significant and, as such, it was factored into the estimation of bill impacts in the Second Interim Report. A third, hourly dynamic, pilot rate was included in the Pilot as a proof of concept, but due to low expected enrollment levels there was no plan to conduct a load impact evaluation.[44]

Figure 5.1-1: SDG&E Pilot Rate 1 (March 2017)[45]

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Super Off-Peak (32¢)						Off-Peak (38¢)										Peak (62¢)							
	Winter	Super Off-Peak (39¢)						Off-Peak (40¢)										Peak (41¢)							
Weekend	Summer	Super Off-Peak (32¢)														Off-Peak (38¢)		Peak (62¢)							
	Winter	Super Off-Peak (39¢)														Off-Peak (40¢)		Peak (41¢)							

Figure 5.1-2: SDG&E Pilot Rate 2 (March 2017)

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off-Peak (36¢)																Peak (62¢)							
	Winter	Off-Peak (39¢)																Peak (41¢)							
Weekend	Summer	Off-Peak (36¢)																Peak (62¢)							
	Winter	Off-Peak (39¢)																Peak (41¢)							

Rate 1 has three rate periods in all seasons and all days of the week. The peak period, from 4 PM to 9 PM, is constant across all days of the week and seasons. The timing and length of the off-peak and super-off-peak periods are also constant across seasons but differ on weekdays and weekends. The peak to super-off-peak price ratio[18] (without the baseline credit) is roughly 1.9 to 1 in summer and a very modest 1.06 to 1 in winter. The summer peak to off-peak price ratio is roughly 1.6 to 1.

[44] Enrollment levels were too low to produce statistically significant impacts.

[45] See Appendix B for comparison of tariffs.

The primary difference between SDG&E's Rate 2 and Rate 1 is that Rate 2 has only two rate periods whereas Rate 1 has three. Rate 2 has the same peak period, from 4 PM to 9 PM, as Rate 1 and the peak period price is also the same as Rate 1. The timing of the peak period and peak period prices are the same between the two rates in each season. In winter, the peak-to-off-peak price ratio for Rate 2 is roughly 1.05 to 1, making the rate relatively flat.

Figure 5.1-3 presents the seasons for each rate. For both rates, the summer season covers the months of May through October, which is two months longer than the summer periods at PG&E and SCE, which run from June 1 through September 30. The winter season at SDG&E covers November through April.

Figure 5.1-3 Seasons by Rate

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Rate 1	Winter				Summer						Winter	
Rate 2	Winter				Summer						Winter	

In addition to the above rate options, SDG&E's pilot tested the impact of weekly usage alerts, known as Weekly Alert Emails (WAE), on demand response under TOU rates. The WAE used in summer 2016 provided weekly emails to participants that report the prior week's electricity usage by rate period. A new WAE was launched in mid-October. This version includes a bill-to date forecast, an updated usage chart displaying usage by peak period, and a doughnut chart illustrating the total amount of usage by peak period for the billing period. A random sample of 2,500 Rate 2 customers were chosen to receive the WAEs on a default basis. SDG&E had email addresses on just over 70% of this sample, so WAE's actually were sent to roughly 1,775 customers out of the target group of 2,500. Another test conducted at SDG&E involved the offer of smart thermostats to TOU customers under different incentive levels, with detailed presented in Section 5.3.4.

The following section contains a summary of customer opt-out decisions and attrition over the first year of the pilot. Section 5.3 presents load impact estimates for summer 2017 for each rate, impacts from the WAE treatment, and details on the smart thermostat offering. Section 5.4 discusses the persistence of load impacts throughout the pilot.

5.2 Customer Attrition

Figure 5.2-1 through Figure 5.2-3 show the cumulative opt-out rates over time for each test cell and climate region. The cumulative number of opt-outs is low in the hot and moderate climate regions, between 2.0% and 3.9%. The most prominent reason cited for opting out was "Bill is too high" (48%) followed by "Other" (38%). No other reasons cited exceeded 5% of the total. Any customers installing rooftop solar were deemed ineligible for the pilot and included in the total attrition, but were not considered as a customer opting out of the pilot. For reasons discussed in the First Interim Report, the control group in the hot climate region is comprised of customers who were turned away from the pilot rather than those who enrolled and were assigned to the treatment conditions. As such, control customers in the hot zone cannot opt out because they never enrolled. The opt-out rate in the cool climate region is very low for all customer segments, only reaching about 2% by the end the second summer. In the moderate and cool climate regions, non-CARE/FERA customers had slightly higher opt-out rates than CARE/FERA customers. Opt-out rates appear to level off near the beginning of November, when customers were transitioned to the winter rate period and they remain generally level through June 2017.

Figure 5.2-1: Cumulative SDG&E Opt Outs by Month – Hot Climate Region[46]

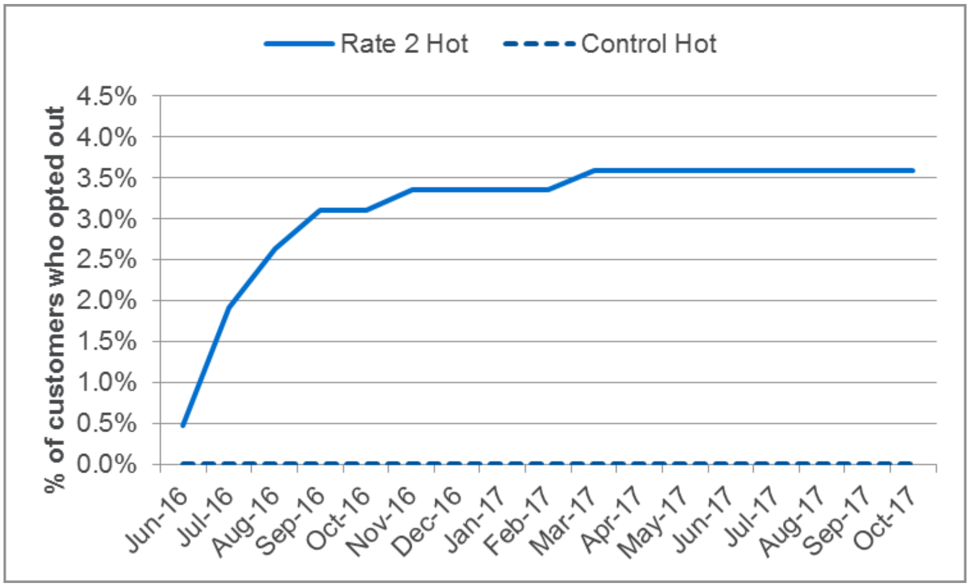
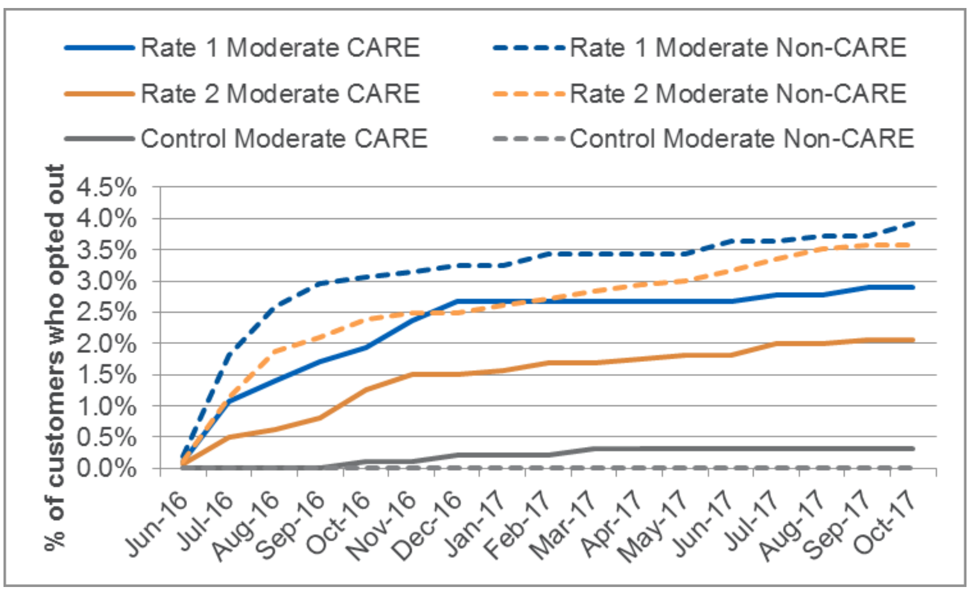


Figure 5.2-2: Cumulative SDG&E Opt Outs by Month – Moderate Climate Region



46 Only Rate 2 was offered in the Hot Climate Region

Figure 5.2-3: Cumulative SDG&E Opt Outs by Month – Cool Climate Region

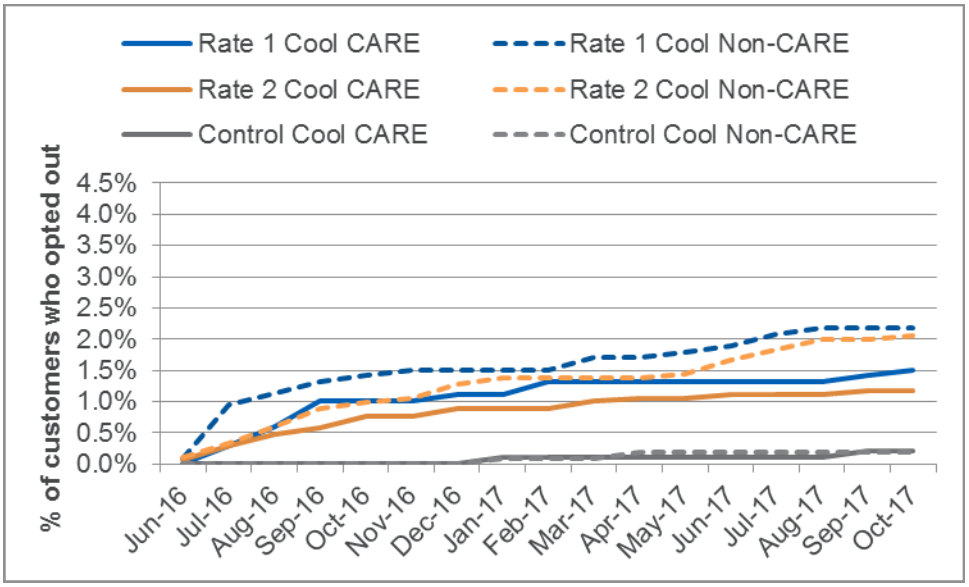


Figure 5.2-4 through Figure 5.2-6 show the overall attrition rate over time for each climate region, customer segment, and TOU rate. Generally, attrition rates are fairly steady in the time period between June 2016 and October 2017. Among treated customers, those in the moderate and cool climate region have similar attrition rates. Attrition rates are lowest in the hot climate region.

Figure 5.2-4: Cumulative SDG&E Attrition by Month – Hot Climate Region

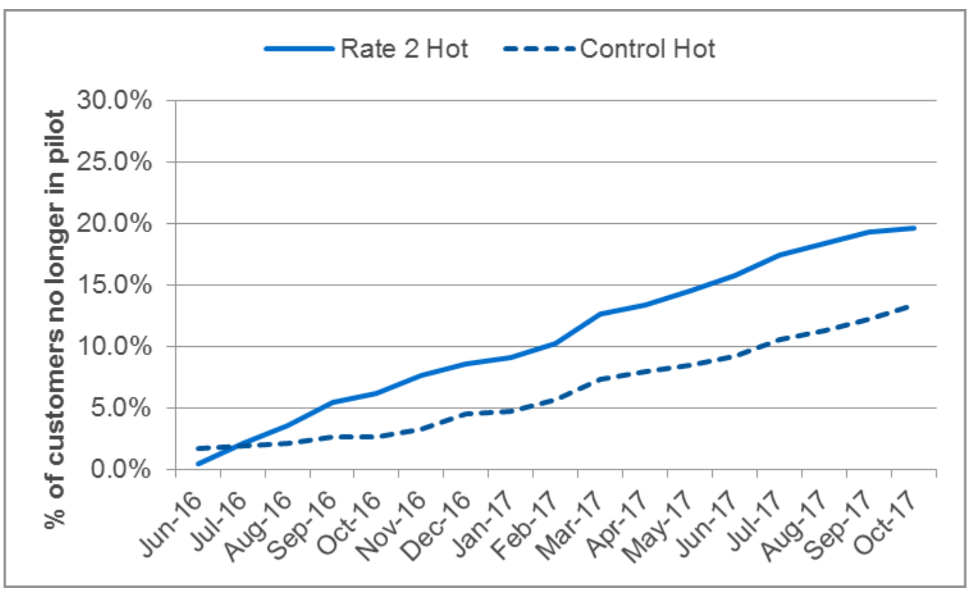


Figure 5.2-5: Cumulative SDG&E Attrition by Month – Moderate Climate Region

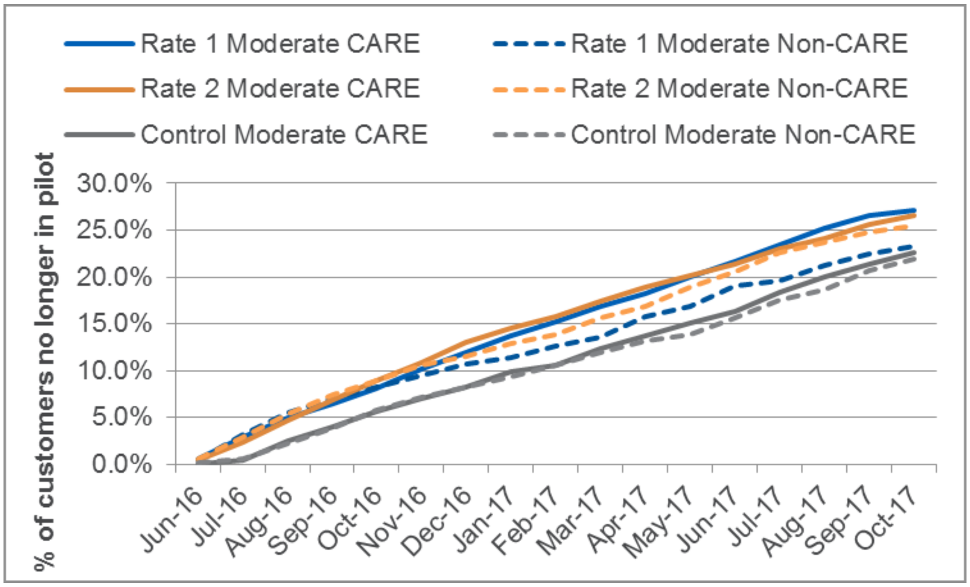
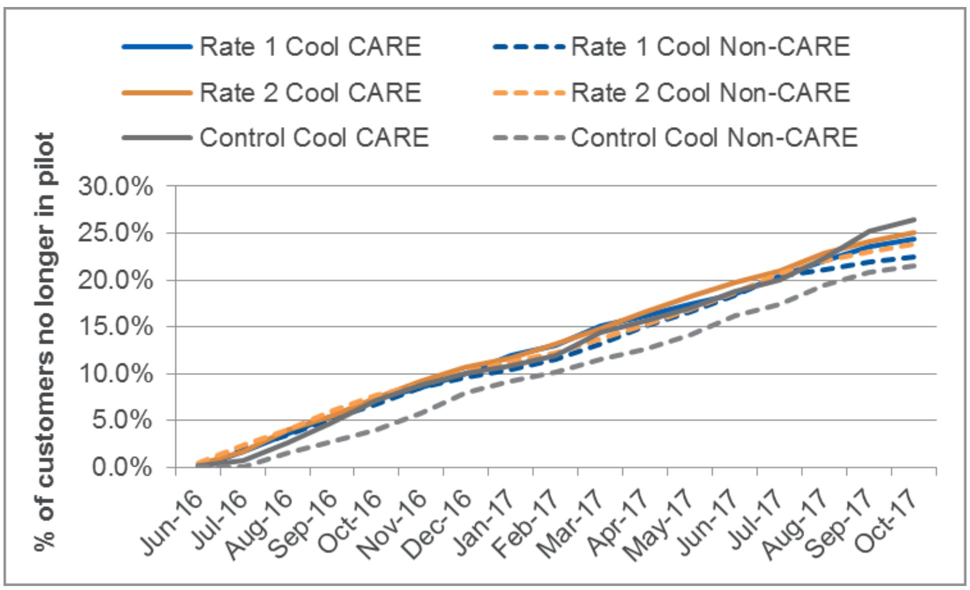


Figure 5.2-6: Cumulative SDG&E Attrition by Month – Cool Climate Region



5.3 Load Impacts

This section summarizes the load impact estimates for the two rate treatments tested by SDG&E. Load impacts are reported for each rate period for the average weekday, average weekend, and the average monthly peak day for the summer months of May through October 2017 for CARE/FERA and non-CARE/FERA customers in SDG&E's moderate and cool climate regions. As discussed previously, SDG&E's hot climate region is quite small and the sample of customers recruited into the pilot is not large enough to support estimation of load impacts separately for CARE/FERA and non-CARE/FERA customers nor to support segmentation of the sample into seniors or various income groups as was done in the hot regions for PG&E and SCE. All customers in the hot region were placed on Rate 2 or were in the control group.

As with PG&E and SCE, electronic tables that contain estimates for each hour of the day for each day type and climate zone and for each month separately are also available upon request through the CPUC.

Figure 5.3-1 shows an example of the content of these tables for SDG&E Rate 2 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time periods (individual months or the average of the summer period).

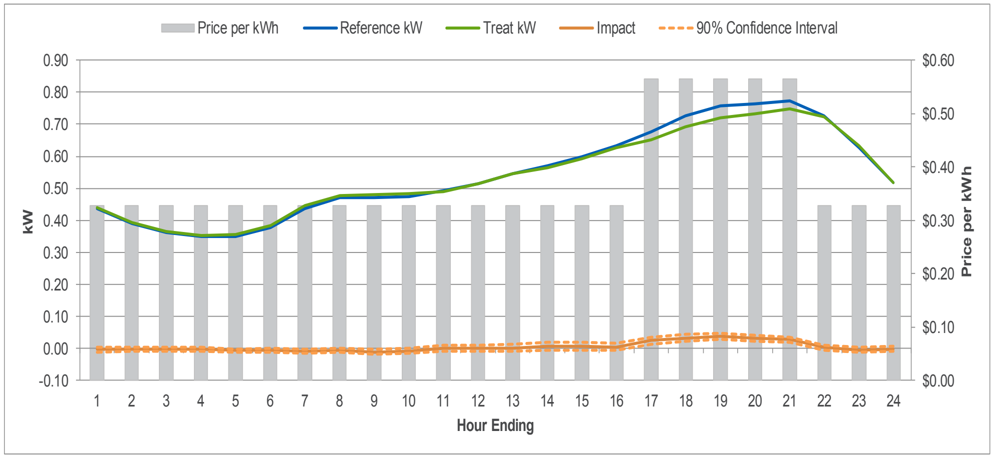
The remainder of this section is organized by rate treatment—that is, load impacts are presented for each relevant climate region and each customer segment for each of the two rates. Following the summary for each rate, load impacts are compared across rates.

As discussed in Section 6 of the First Interim Report, in addition to the two rate treatments, SDG&E tested the incremental impact of Weekly Alert Emails (WAEs) sent to customers on a default basis. Results of this analysis are presented in Section 5.3.3. The smart thermostat offering to pilot customers is covered in Section 5.3.4.

Figure 5.3-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SDG&E Rate 2, Average Summer 2017 Weekday, All Customers)

Segment	All
Rate	Rate 2
Month	Summer 2017
Day Type	Average Weekday
Treated Customers	6,050

Period	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval	
Peak	0.74	0.71	0.030	4.1%	0.03	0.03
Partial Peak	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	0.49	0.49	0.00	-0.6%	0.00	0.00
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A
Daily kWh	13.03	12.93	0.10	0.8%	0.06	0.14



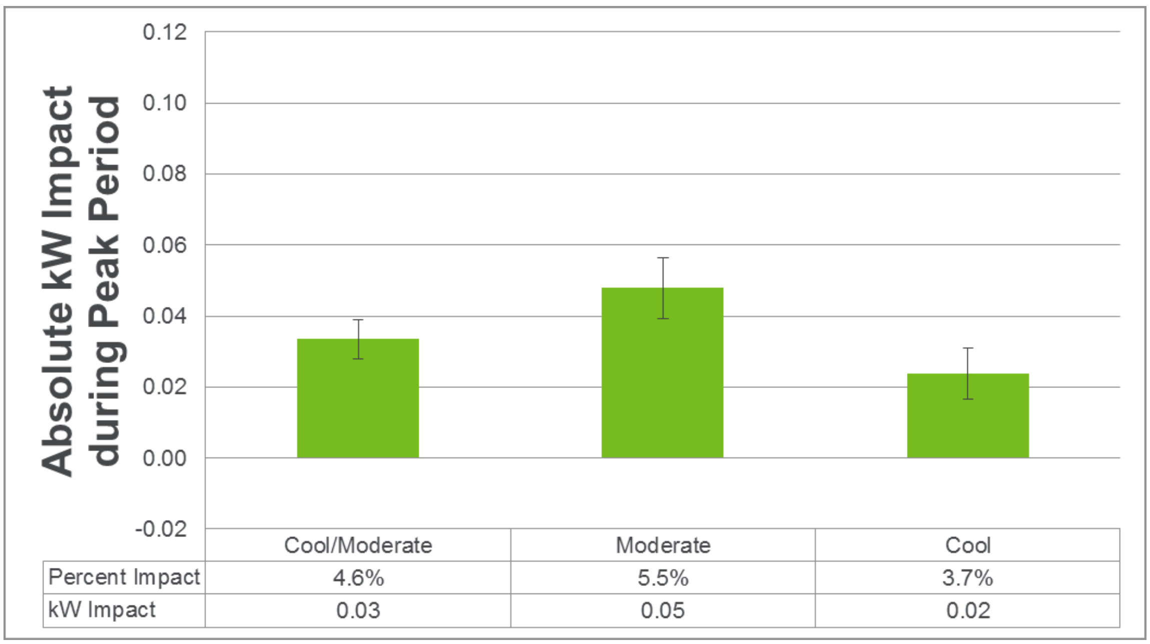
Hour Ending	Reference kW	Treat kW	Impact	Percent Impact	90% Confidence Interval		Price	Period
1	0.44	0.44	0.00	-1.0%	-0.01	0.00	$0.33	Off-Peak
2	0.39	0.39	0.00	-0.7%	-0.01	0.00	$0.33	Off-Peak
3	0.36	0.36	0.00	-0.7%	-0.01	0.00	$0.33	Off-Peak
4	0.35	0.35	0.00	-1.2%	-0.01	0.00	$0.33	Off-Peak
5	0.35	0.36	-0.01	-2.1%	-0.01	0.00	$0.33	Off-Peak
6	0.38	0.38	-0.01	-1.7%	-0.01	0.00	$0.33	Off-Peak
7	0.44	0.45	-0.01	-2.3%	-0.02	0.00	$0.33	Off-Peak
8	0.47	0.48	-0.01	-1.4%	-0.01	0.00	$0.33	Off-Peak
9	0.47	0.48	-0.01	-2.4%	-0.02	0.00	$0.33	Off-Peak
10	0.47	0.48	-0.01	-1.8%	-0.02	0.00	$0.33	Off-Peak
11	0.49	0.49	0.00	0.1%	-0.01	0.01	$0.33	Off-Peak
12	0.51	0.51	0.00	0.0%	-0.01	0.01	$0.33	Off-Peak
13	0.55	0.55	0.00	0.0%	-0.01	0.01	$0.33	Off-Peak
14	0.57	0.57	0.01	1.1%	-0.01	0.02	$0.33	Off-Peak
15	0.60	0.59	0.01	1.0%	-0.01	0.02	$0.33	Off-Peak
16	0.63	0.63	0.00	0.6%	-0.01	0.01	$0.33	Off-Peak
17	0.67	0.65	0.02	3.6%	0.01	0.04	$0.56	Peak
18	0.73	0.69	0.03	4.4%	0.02	0.04	$0.56	Peak
19	0.76	0.72	0.04	5.0%	0.03	0.05	$0.56	Peak
20	0.77	0.73	0.03	4.2%	0.02	0.04	$0.56	Peak
21	0.77	0.75	0.03	3.4%	0.02	0.04	$0.56	Peak
22	0.73	0.72	0.00	0.2%	-0.01	0.01	$0.33	Off-Peak
23	0.63	0.63	-0.01	-0.9%	-0.01	0.00	$0.33	Off-Peak
24	0.52	0.52	0.00	-0.5%	-0.01	0.00	$0.33	Off-Peak
Daily kWh	**13.03**	**12.93**	**0.10**	**0.8%**	**0.06**	**0.14**	**N/A**	**N/A**

5.3.1 Rate 1

SDG&E's Rate 1 is a three-period rate with a peak period from 4 PM to 9 PM on weekdays and weekends. On weekdays, the off-peak (or shoulder) period runs from 6 AM to 4 PM and 9 PM to midnight. On weekends, this period is much shorter, running from 2 PM to 4 PM and 9 PM to midnight. In summer, for electricity usage above 130% of the baseline quantity, prices equal roughly 62 ¢/kWh in the peak period, 38 ¢/kWh in the off-peak (or shoulder) period and 32 ¢/kWh in the super off-peak period. For usage below 130% the baseline quantity, a credit of 22 ¢/kWh is applied.

Figure 5.3-2 below shows the average peak-period load reduction in absolute terms for Rate 1 for customers in the moderate and cool climate regions, separately and combined.[47] As with the other IOUs, the lines bisecting the top of each bar in the figures show the 90% confidence band for each estimate.

Figure 5.3-2: Average Load Impacts For Peak Period for SDG&E Rate 1 (Positive values represent load reductions)



As seen in the figure, the average peak load impacts for the cool and moderate climate regions, separately and combined, is statistically significant at the 90% level of confidence in both percentage and absolute terms. On average, pilot participants in both climate regions combined reduced electricity use by 4.6% or 0.03 kW across the five hour peak period from 4 PM to 9 PM. Customers in the moderate climate region reduced their usage by 5.5% or 0.05 kW, which is greater than the impact in the cool climate region (3.7% or 0.02 kW)

[47] Recall that Rate 1 was not offered in the hot climate region.

Table 5.3-1 shows the average percent and absolute load impacts for Rate 1 for each rate period for weekdays and weekends and for the average monthly system peak day for the cool and moderate climate regions. The percent reduction equals the load impact in absolute terms (kW) divided by the reference load. Shaded cells in the table contain load impact estimates that are not statistically significant at the 90% confidence level. The percentage and absolute values in the first row of Table 5.3-1 which represent the load impacts in the peak period on the average weekday, equal the values shown in Figure 5.3-2, discussed above.

The reference loads shown in Table 5.3-1 represent estimates of what customers on the TOU rate would have used if they had not responded to the price signals contained in the TOU tariff. As seen in the table, average hourly usage during the peak period is roughly 0.73 kW for the moderate and cool climate regions combined and around 0.54 kW for the 24 hour average weekday. In the moderate climate region, average usage in the peak period is larger at 0.86 kW than in the cool climate region (0.65 kW).

As seen in Table 5.3-1, peak-period load reductions were statistically significant for all climate regions and day types. In the moderate climate region, both the percent and absolute impacts were largest on the average monthly system peak day. Both percent and absolute peak-period load reductions were nearly identical on the average weekday and weekend. In the cool climate region, peak-period load reductions were statistically significant and very similar across all three day-types.

In the off-peak (or shoulder period), which varied in timing and length between weekdays and weekends, load reductions were quite modest in some climate regions and day types and statistically insignificant in others. In the super off-peak period, which runs from midnight to 6 AM, for the moderate and cool regions combined, there were statistically significant load increases on both the average weekday and average system peak day.

For the moderate and cool climate regions combined, there was a 1.2% reduction in daily electricity use on the average weekday. In the moderate climate region the daily savings was 2.5% and in the cool climate region it was 0.1% and not statistically significant. While the daily reduction in energy use for Rate 1 is small in percentage and absolute terms, this average is spread over 24 hours each day, so the average reduction in electricity use on weekdays equals roughly 0.15 kWh. Over six months, this adds up to about 28 kWh per customer.

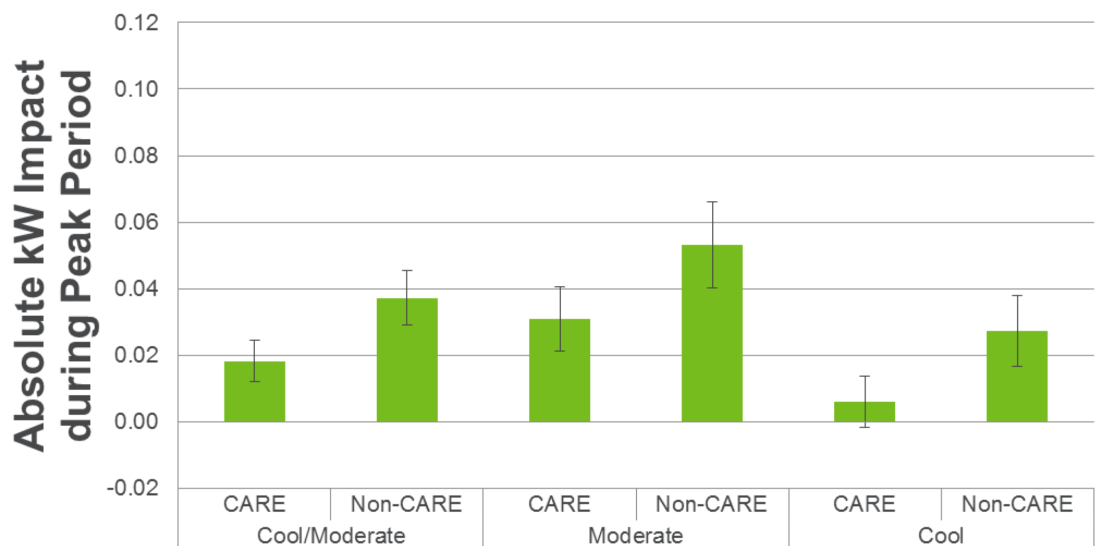
Table 5.3-1: Rate 1 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

Rate 1											
Day Type	Period	Hours	Cool/Moderate			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.73	0.03	4.6%	0.86	0.05	5.5%	0.65	0.02	3.7%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.54	0.01	1.3%	0.61	0.02	2.6%	0.50	0.00	0.3%
	Super Off-Peak	12 AM to 6 AM	0.37	-0.02	-4.8%	0.41	-0.01	-3.3%	0.35	-0.02	-6.0%
	Day	**All Hours**	0.54	0.01	1.2%	0.61	0.02	2.5%	0.49	0.00	0.1%
Average Weekend	Peak	4 PM to 9 PM	0.74	0.04	4.7%	0.87	0.05	5.3%	0.66	0.03	4.2%
	Off-Peak	2 PM to 4 PM, 9 PM to 12 AM	0.65	0.01	1.0%	0.74	0.01	1.0%	0.58	0.01	1.1%
	Super Off-Peak	12 AM to 2 PM	0.47	-0.01	-1.6%	0.52	0.00	0.4%	0.44	-0.01	-3.2%
	Day	**All Hours**	0.56	0.00	0.8%	0.64	0.01	1.9%	0.51	0.00	-0.2%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.06	0.05	4.7%	1.34	0.08	6.3%	0.87	0.03	2.9%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.70	0.00	0.3%	0.85	0.01	1.5%	0.61	0.00	-0.8%
	Super Off-Peak	12 AM to 6 AM	0.43	-0.02	-4.2%	0.49	-0.01	-2.6%	0.39	-0.02	-5.5%
	Day	**All Hours**	0.71	0.01	1.0%	0.86	0.02	2.5%	0.61	0.00	-0.4%

* A shaded cell indicates estimate is not statistically significant

Figure 5.3-3 shows the absolute peak period load impacts for Rate 1 for CARE/FERA and non-CARE/FERA customers for the moderate and cool climate regions combined and separately. In the combined region and in each region separately, both the percent and absolute load impacts were greater for non-CARE/FERA customers than for CARE/FERA customers and the differences were statistically significant. The load reduction for CARE/FERA customers in the cool climate was not statistically significant. The greatest load reductions came from non-CARE/FERA customers in the moderate climate region, at 5.9% and 0.05 kW.

Figure 5.3-3: Average Load Impacts for Peak Period for SDG&E Rate 1 for CARE/FERA and non-CARE/FERA Customers
(Positive values represent load reductions)



	Cool/Moderate CARE	Cool/Moderate Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Percent Impact	2.8%	4.9%	4.2%	5.9%	1.1%	4.1%
kW Impact	0.02	0.04	0.03	0.05	0.01	0.03

Table 5.3-2shows the estimated load impacts for each rate period and day type for the moderate and cool climate zones separately and combined for non-CARE/FERA customers.

Table 5.3-3 shows the same but for CARE/FERA customers. For both climate regions, non-CARE/FERA customers have greater peak period demand than CARE/FERA customers. For example, on the average weekday in the two climate zones combined, peak period demand is equal to 0.76 kW for non-CARE/FERA customers and 0.64 kW for CARE/FERA customers. Average hourly overall weekday consumption is also greater for non-CARE/FERA customers (0.55 kW versus 0.49 kW).

Customers in the non-CARE/FERA segments had load impacts of 1.4% during the off-peak period on average weekdays, and no significant changes during off-peak hours on the average weekend or the monthly system peak day. CARE/FERA customers also showed modest reductions in usage during the off-peak period on the average weekday and also on the monthly system peak day, but not on weekends when the off-peak period was longer.

Table 5.3-2: Rate 1 Load Impacts by Rate Period and Day Type – Non-CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Rate 1											
Day Type	Period	Hours	Cool/Moderate, Non-CARE			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.76	0.04	4.9%	0.90	0.05	5.9%	0.67	0.03	4.1%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.55	0.01	1.4%	0.63	0.02	3.0%	0.51	0.00	0.2%
	Super Off-Peak	12 AM to 6 AM	0.38	-0.02	-5.5%	0.42	-0.02	-3.7%	0.36	-0.02	-6.7%
	Day	**All Hours**	0.55	0.01	1.2%	0.63	0.02	2.8%	0.50	0.00	0.1%
Average Weekend	Peak	4 PM to 9 PM	0.77	0.04	5.3%	0.91	0.06	6.1%	0.68	0.03	4.6%
	Off-Peak	2 PM to 4 PM, 9 PM to 12 AM	0.66	0.01	1.2%	0.77	0.01	1.2%	0.60	0.01	1.2%
	Super Off-Peak	12 AM to 2 PM	0.48	-0.01	-1.8%	0.54	0.00	0.7%	0.45	-0.02	-3.5%
	Day	**All Hours**	0.58	0.01	0.9%	0.66	0.02	2.3%	0.53	0.00	-0.2%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.10	0.05	4.8%	1.43	0.10	6.9%	0.90	0.03	2.9%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.72	0.00	0.2%	0.89	0.02	1.8%	0.62	-0.01	-1.3%
	Super Off-Peak	12 AM to 6 AM	0.44	-0.02	-4.6%	0.50	-0.01	-2.7%	0.40	-0.02	-6.1%
	Day	**All Hours**	0.73	0.01	0.9%	0.90	0.03	2.9%	0.63	-0.01	-0.8%

* A shaded cell indicates estimate is not statistically significant

Table 5.3-3: Rate 1 Load Impacts by Rate Period and Day Type – CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Rate 1											
Day Type	Period	Hours	Cool/Moderate, CARE			Moderate, CARE			Cool, CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.64	0.02	2.8%	0.74	0.03	4.2%	0.55	0.01	1.1%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.49	0.00	0.8%	0.55	0.00	0.9%	0.43	0.00	0.7%
	Super Off-Peak	12 AM to 6 AM	0.35	-0.01	-1.8%	0.39	-0.01	-1.9%	0.32	-0.01	-1.6%
	Day	**All Hours**	0.49	0.00	0.9%	0.55	0.01	1.3%	0.43	0.00	0.4%
Average Weekend	Peak	4 PM to 9 PM	0.63	0.01	2.0%	0.72	0.02	2.2%	0.55	0.01	1.8%
	Off-Peak	2 PM to 4 PM, 9 PM to 12 AM	0.57	0.00	0.2%	0.65	0.00	0.1%	0.50	0.00	0.4%
	Super Off-Peak	12 AM to 2 PM	0.43	0.00	-0.7%	0.47	0.00	-0.4%	0.39	0.00	-1.0%
	Day	**All Hours**	0.50	0.00	0.3%	0.56	0.00	0.4%	0.44	0.00	0.1%
Monthly System Peak Day	Peak	4 PM to 9 PM	0.86	0.03	3.7%	1.04	0.04	4.1%	0.69	0.02	3.2%
	Off-Peak	6 AM to 4 PM, 9 PM to 12 AM	0.61	0.01	1.1%	0.71	0.00	0.2%	0.52	0.01	2.3%
	Super Off-Peak	12 AM to 6 AM	0.41	-0.01	-2.2%	0.47	-0.01	-2.6%	0.35	-0.01	-1.8%
	Day	**All Hours**	0.61	0.01	1.3%	0.72	0.01	0.9%	0.51	0.01	1.9%

* A shaded cell indicates estimate is not statistically significant

5.3.2 Rate 2

SDG&E's Rate 2 differs from Rate 1 in that it is a two-period rate, rather than a three-period rate. Like Rate 1, the peak period is from 4 PM to 9 PM on weekdays and weekends. In summer, for electricity usage above 130% of the baseline quantity, prices equal roughly 62 ¢/kWh in the peak period and 36 ¢/kWh in the off-peak period. Like Rate 1, a credit of 22 ¢/kWh is applied to usage below 130% the baseline quantity.

Figure 5.3-4 shows the absolute load impacts for the weekday peak period for Rate 2 for SDG&E's service territory as a whole and for each climate region. For the service territory as a whole, load impacts were equal to 4.1% or 0.03 kW. Like Rate 1, customers in the moderate and cool climate regions had similar load impacts of 4.3% and 3.9% respectively. Customers in the hot climate zone had the greatest peak period impacts at 6.5% or 0.08 kW. Impacts in the hot climate zone are statistically significantly greater than those in the cool and moderate climate regions. It should be that, in addition to significant differences in climate, there may also be significant differences in the mix of customers by housing type, CARE/FERA and non-CARE/FERA segments and perhaps other characteristics.

Figure 5.3-4: Average Load Impacts For Peak Period for SDG&E Rate 2
(Positive values represent load reductions)

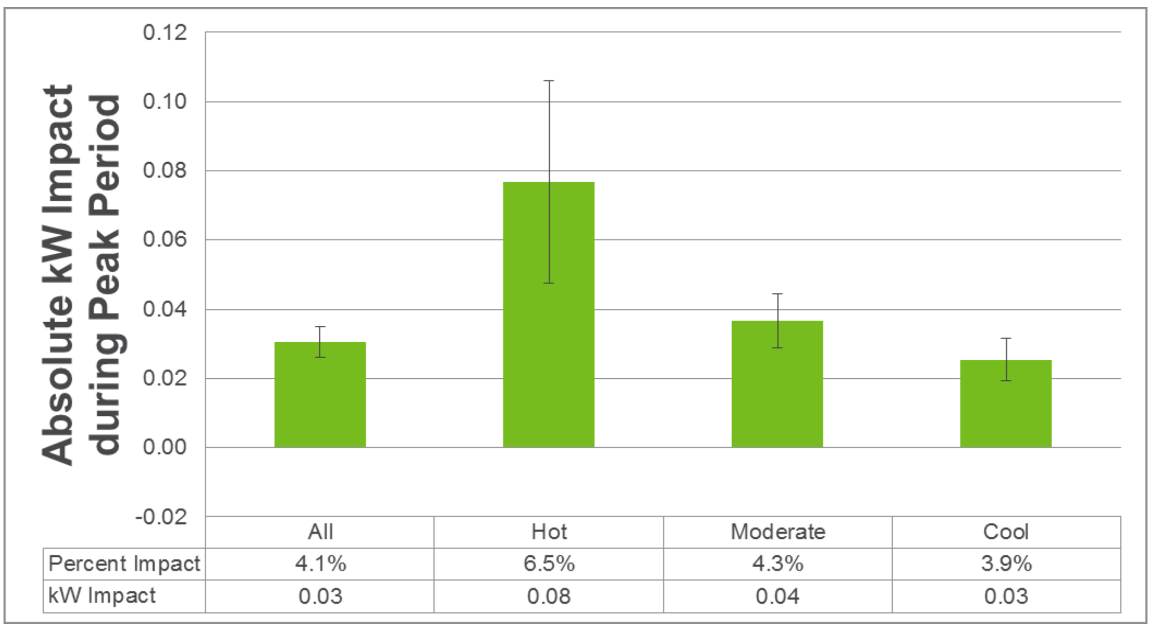


Table 5.3-4 contains estimates of load impacts for all relevant rate periods and day types. Reference loads and load impacts in each rate period and over the course of the day were similar between weekends and weekdays for the service territory as a whole and also for each climate region. In the hot region, there were relatively large and statistically significant increases in electricity use in the off-peak period on all day types. On the average weekday and weekend, these increases more than offset the peak-period load reductions so that there was a small but statistically significant increase in usage across the day. This pattern is not evident in the moderate and cool climate regions where the increase in usage in the off-peak period was not large enough to offset the peak period reductions and there were small but statistically significant decreases in daily electricity use for most day types and climate regions.

Table 5.3-4: Rate 2 Load Impacts by Rate Period and Day Type*
(Positive values represent load reductions, negative values represent load increases)

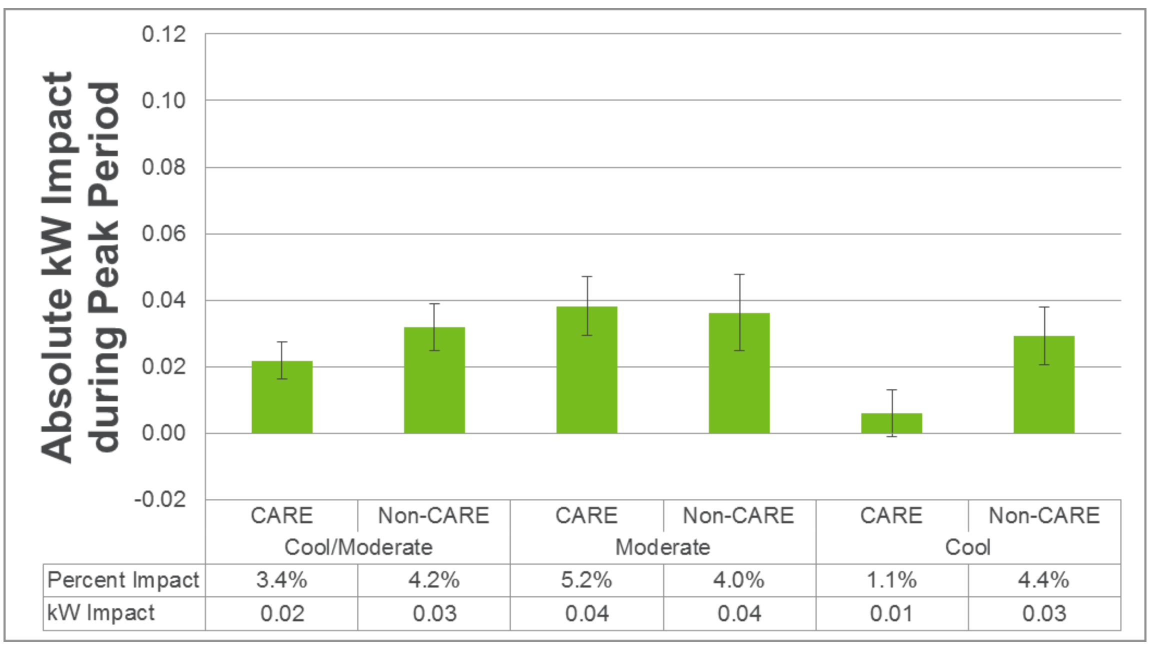
Rate 2														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.74	0.03	4.1%	1.18	0.08	6.5%	0.86	0.04	4.3%	0.65	0.03	3.9%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.49	0.00	-0.6%	0.73	-0.04	-5.9%	0.55	0.00	-0.3%	0.45	0.00	-0.7%
	Day	**All Hours**	0.54	0.00	0.8%	0.82	-0.02	-2.2%	0.61	0.01	1.1%	0.49	0.00	0.6%
Average Weekend	Peak	4 PM to 9 PM	0.75	0.03	4.5%	1.24	0.09	6.9%	0.87	0.04	4.6%	0.66	0.03	4.4%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.52	0.00	-0.3%	0.77	-0.04	-5.5%	0.58	0.00	-0.2%	0.48	0.00	-0.3%
	Day	**All Hours**	0.57	0.01	1.0%	0.87	-0.02	-1.8%	0.64	0.01	1.1%	0.51	0.00	1.0%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.06	0.04	3.5%	1.64	0.14	8.5%	1.34	0.06	4.2%	0.87	0.02	2.7%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.62	-0.01	-0.9%	0.95	-0.03	-2.8%	0.73	-0.01	-0.8%	0.54	0.00	-0.8%
	Day	**All Hours**	0.71	0.00	0.5%	1.09	0.01	0.7%	0.86	0.01	0.8%	0.61	0.00	0.2%

* A shaded cell indicates estimate is not statistically significant

Figure 5.3-5 shows the peak period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers and Table 5.3-5 and Table 5.3-6 show the load impacts for each rate period and day type for the two segments. There are not enough customers in the hot climate region to segment between CARE/FERA and non-CARE/FERA, so these tables only include customers in the moderate and cool climate regions, separately and combined.

Like Rate 1, non-CARE/FERA customers in the cool climate region had greater percent impacts (4.4% and 0.03 kW) than their CARE/FERA counterparts (1.1% and 0.01 kW) and these differences are statistically significant in both absolute and percentage terms. This is not the case in the moderate climate region, where load impacts for CARE/FERA and non-CARE/FERA customers were more similar and the observed difference is not statistically significant.

Figure 5.3-5: Average Load Impacts for Peak Period for SDG&E Rate 2 for CARE/FERA and non-CARE/FERA Customers
(Positive values represent load reductions)



As seen in Table 5.3-5 and Table 5.3-6 non-CARE/FERA customers had greater on-peak and average weekday demand than CARE/FERA customers. Both groups reduced their overall consumption. For example, non-CARE/FERA customers in the moderate and cool climate regions combined reduced their average weekday electricity demand by 0.7% or less than 0.01 kW. CARE/FERA and non-CARE/FERA segments were not available in the hot climate region due to the small population of customers, resulting in insufficient sample size to allow for segmentation.

Table 5.3-5: Rate 2 Load Impacts by Rate Period and Day Type – Non-CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	Cool/Moderate, Non-CARE			Hot			Moderate, Non-CARE			Cool, Non-CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.76	0.03	4.2%	1.18	0.08	6.5%	0.90	0.04	4.0%	0.67	0.03	4.4%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.50	0.00	-0.8%	0.73	-0.04	-5.9%	0.56	0.00	-0.9%	0.46	0.00	-0.7%
	Day	**All Hours**	0.55	0.00	0.7%	0.82	-0.02	-2.2%	0.63	0.00	0.6%	0.50	0.00	0.7%
Average Weekend	Peak	4 PM to 9 PM	0.77	0.04	4.8%	1.24	0.09	6.9%	0.91	0.04	4.7%	0.68	0.03	4.9%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.53	0.00	-0.6%	0.77	-0.04	-5.5%	0.60	-0.01	-0.9%	0.49	0.00	-0.3%
	Day	**All Hours**	0.58	0.01	0.9%	0.87	-0.02	-1.8%	0.66	0.00	0.7%	0.53	0.01	1.1%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.10	0.04	3.3%	1.64	0.14	8.5%	1.43	0.05	3.8%	0.90	0.03	2.8%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.63	-0.01	-1.0%	0.95	-0.03	-2.8%	0.77	-0.01	-1.0%	0.55	-0.01	-1.0%
	Day	**All Hours**	0.73	0.00	0.4%	1.09	0.01	0.7%	0.90	0.01	0.6%	0.63	0.00	0.2%

* A shaded cell indicates estimate is not statistically significant

Table 5.3-6: Rate 2 Load Impacts by Rate Period and Day Type –CARE/FERA*
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	Cool/Moderate, CARE			Hot			Moderate, CARE			Cool, CARE		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.64	0.02	3.4%	1.18	0.08	6.5%	0.74	0.04	5.2%	0.55	0.01	1.1%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.45	0.00	0.8%	0.73	-0.04	-5.9%	0.50	0.01	1.9%	0.40	0.00	-0.5%
	Day	**All Hours**	0.49	0.01	1.5%	0.82	-0.02	-2.2%	0.55	0.02	2.8%	0.43	0.00	-0.1%
Average Weekend	Peak	4 PM to 9 PM	0.63	0.02	2.8%	1.24	0.09	6.9%	0.72	0.03	4.2%	0.55	0.01	1.1%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.46	0.01	1.2%	0.77	-0.04	-5.5%	0.52	0.01	2.3%	0.42	0.00	-0.1%
	Day	**All Hours**	0.50	0.01	1.6%	0.87	-0.02	-1.8%	0.56	0.02	2.8%	0.44	0.00	0.2%
Monthly System Peak Day	Peak	4 PM to 9 PM	0.86	0.04	4.1%	1.64	0.14	8.5%	1.04	0.06	5.8%	0.69	0.01	1.7%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	0.55	0.00	0.0%	0.95	-0.03	-2.8%	0.64	0.00	-0.2%	0.46	0.00	0.2%
	Day	**All Hours**	0.61	0.01	1.2%	1.09	0.01	0.7%	0.72	0.01	1.6%	0.51	0.00	0.6%

* A shaded cell indicates estimate is not statistically significant

5.3.3 Weekly Alert Emails

Table 5.3-7 shows peak period impacts for customers who are not receiving alerts ("controls") and those who are ("recipients") and Table 5.3-8 contains estimated impacts for all rate periods and day types. As seen, the incremental impacts during the peak period were very small and, as shown by the fact that the 90% confidence interval includes 0, incremental impacts for the territory as a whole were not statistically significant. It is worth noting that the incremental impact for the moderate climate region (0.02 kW) is statistically significant at the 90% confidence level. The incremental impact of 0.02 kW indicates that customer with the WAE treatment produced load impacts 0.02 kW greater than those customers without the treatment. It should also be noted that, although the % increase in the impact is large in percentage terms, this is a bit misleading since the estimated values are based on a very small impact to begin with. That is, the denominator in the calculation is quite small so that even very small incremental effects represent a reasonably large percent of the impact.

Table 5.3-7: Incremental Impacts of SDG&E Weekly Alert Emails

Climate Zone	Number of Customers		kW Impact during Peak Period					% Increase in Impact
	Controls	Recipients	Controls	Recipients	Incremental	90% Confidence Interval		
Cool	1,480	816	0.027	0.022	-0.004	-0.013	0.004	-16%
Moderate	1,336	732	0.029	0.051	0.023	0.011	0.035	80%
Cool/Moderate	2,816	1,548	0.028	0.034	0.007	-0.001	0.014	24%

Table 5.3-8: Incremental Impacts of SDG&E Weekly Alert Emails by Rate Period and Day Type*

Rate 2											
Day Type	Period	Hours	WAE - Cool/Moderate			WAE - Moderate			WAE - Cool		
			Non-WAE Impact	Inc. Impact	% Inc. Impact	Non-WAE Impact	Inc. Impact	% Inc. Impact	Non-WAE Impact	Inc. Impact	% Inc. Impact
Average Weekday	Peak	4 PM to 9 PM	0.028	0.007	23.5%	0.029	0.023	80.2%	0.027	-0.004	-16.5%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	-0.003	0.000	9.6%	-0.006	0.004	-64.3%	-0.001	-0.003	281.7%
	Day	**All Hours**	0.003	0.001	32.5%	0.002	0.008	506.9%	0.005	-0.003	-66.5%
Average Weekend	Peak	4 PM to 9 PM	0.031	0.011	36.2%	0.034	0.024	69.0%	0.028	0.003	9.3%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	-0.001	0.000	32.4%	-0.005	0.001	-28.7%	0.001	-0.002	-213.1%
	Day	**All Hours**	0.005	0.002	37.0%	0.004	0.006	167.0%	0.006	-0.001	-11.3%
Monthly System Peak Day	Peak	4 PM to 9 PM	0.033	0.005	13.9%	0.041	0.044	105.3%	0.027	-0.022	-79.5%
	Off-Peak	12 AM to 4 PM, 9 PM to 12 AM	-0.007	-0.001	10.1%	-0.011	0.011	-98.0%	-0.005	-0.008	173.5%
	Day	**All Hours**	0.001	0.000	33.2%	0.000	0.017	49532.5%	0.002	-0.011	-599.5%

* A shaded cell indicates estimate is not statistically significant

5.3.4 Smart Thermostat

SDG&E offered rebates for smart thermostats through a program named Whenergy. The primary focus of this treatment was to assess differential take rates for each rebate amount for both TOU rate and control customers. SDG&E offered two different rebates, $100 and $200, to customers who purchased a smart thermostat. The utility contacted 2,214 customers via direct mail and 4,889 customers via email for a $100 rebate offer. A similar number of customers were offered a $200 rebate. SDG&E received 349 applications for the rebates and 246 of those were deemed eligible and were ultimately accepted. Of the 246 applications accepted, 95 were for the $100 rebate offer and 151 were for the $200 rebate offer. Acceptance rates were not large enough to estimate load impacts for smart thermostat owners.

5.3.5 Comparison Across Rates

Figure 5.3-6 shows the average peak period impact for Rate 1 and Rate 2 in the summer months. The peak period covers the same hours for each rate (4 PM to 9 PM) and the peak-period prices are the same in both cases. As such, it is not very surprising that the differences in impacts between the two rates are not statistically significant. Recall that there are no customers in SDG&E's hot climate region on Rate 1, meaning that the "All" category is not an apples to apples comparison. Figure 5.3-7 shows the average daily kWh impact during the summer period for Rate 1 and Rate 2. Impacts are somewhat similar in the cool climate region, but not in the moderate climate region.

Figure 5.3-6: Average Peak Period Impacts Across Rates

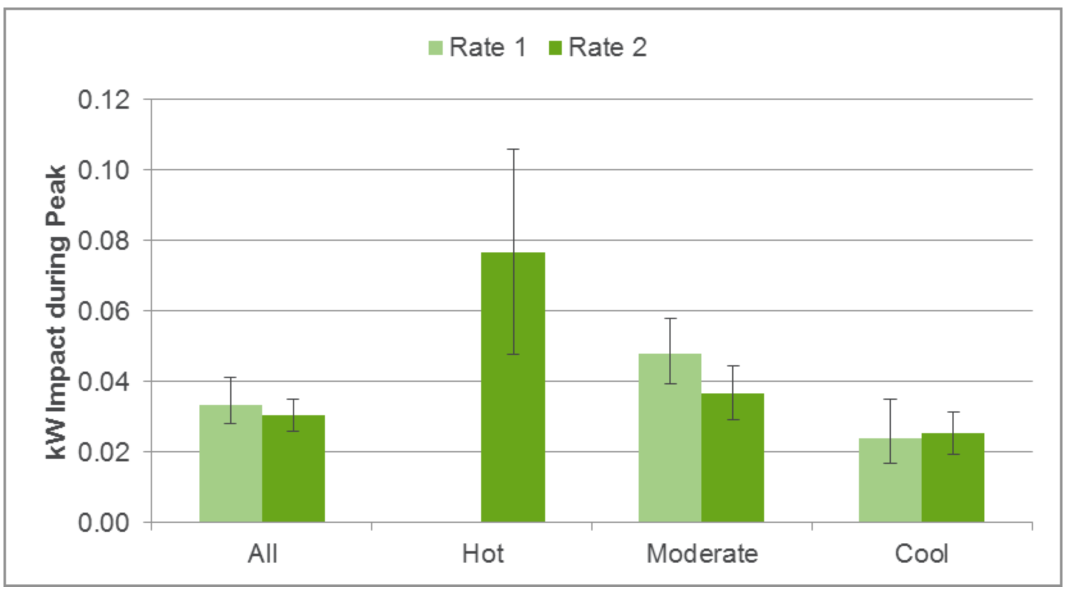
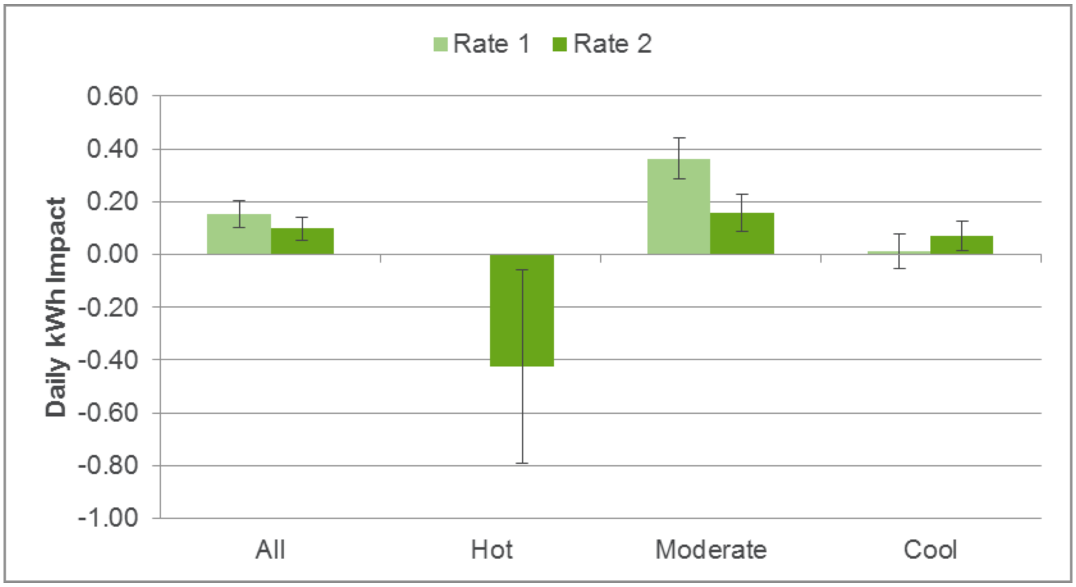


Figure 5.3-7: Average Daily kWh Impacts Across Rates



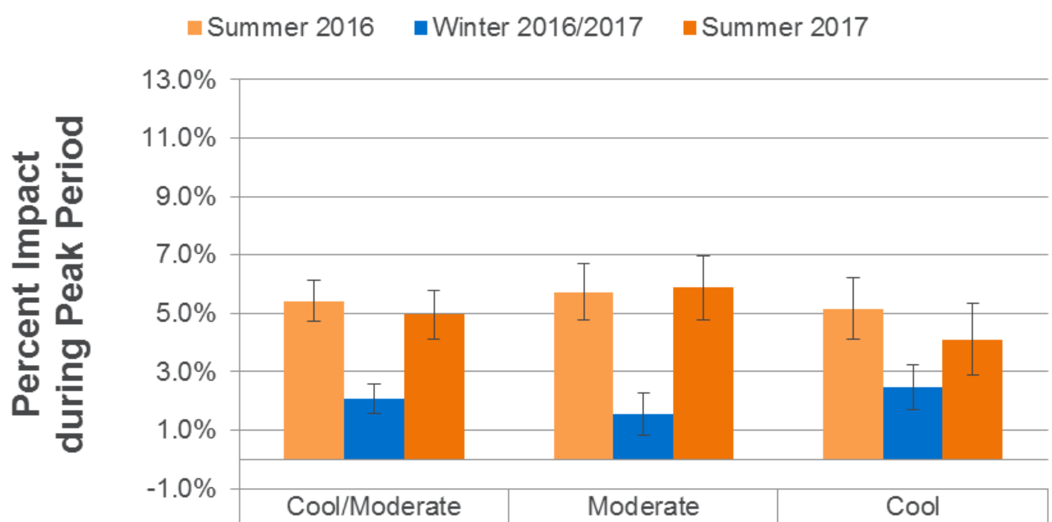
5.4 Persistence Analysis

This section examines the persistence of load impacts for each across the two summer periods for the same group of customers who remained enrolled over the entire course of the pilot. That is, the estimates eliminate any differences that might occur due to changes in the mix of participants over time. The graphs also contain winter period estimates for completeness although the focus is on whether summer impacts increased, decreased or stayed roughly the same over the two summers. In conducting this analysis, the summer period is reduced just to the months of July through October, since enrollment was not complete on both rates prior to July 2016. While there is not a second winter for persistence comparison, the winter impacts for the subset of customers who were enrolled for the full duration of the pilot are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers.

5.4.1 Rate 1

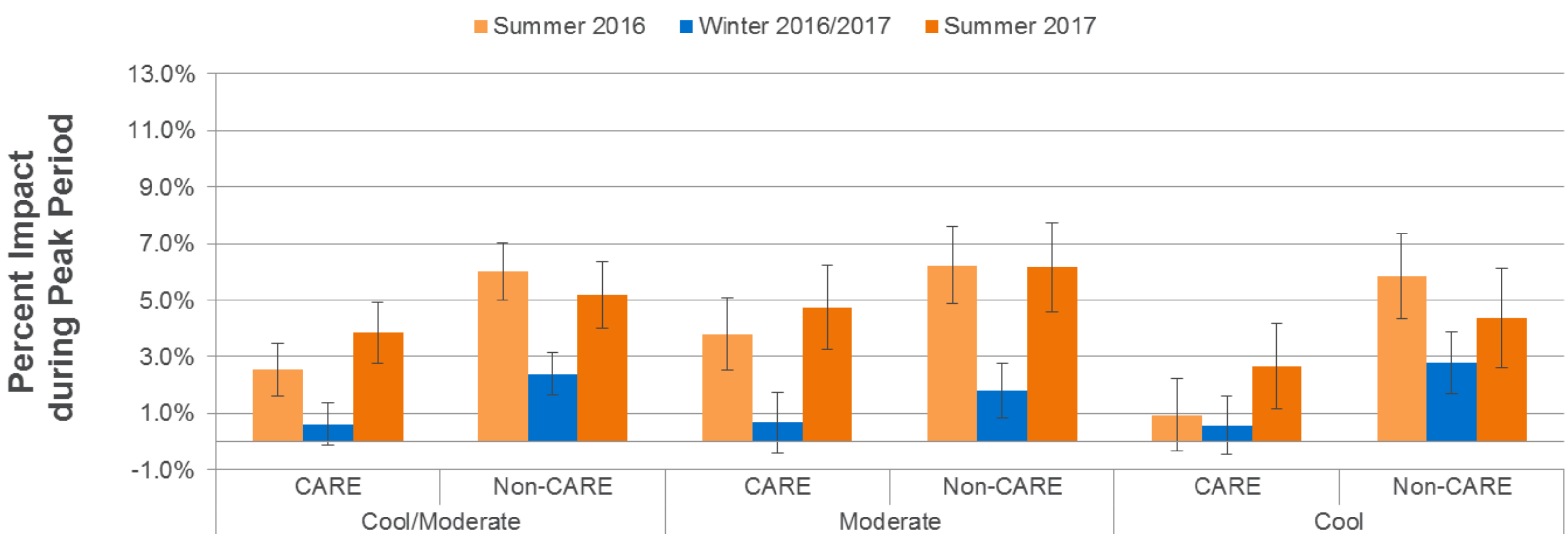
Figure 5.4-1 shows the peak period load reductions for a common group of customers who remained on Rate 1 for the entire pilot for each summer and for the winter period. Figure 5.4-2 contains the same comparison for CARE/FERA and non-CARE/FERA segments. As seen in Figure 5.4-1, there were no statistically significant differences in load impacts across the two summer periods in either climate region or in the two regions combined. This is generally true for both the CARE/FERA and non-CARE/FERA segments separately, as seen in Figure 5.4-2. It should be noted that the trends across the two summers seem to show an increase in load reductions for CARE/FERA customers and a small decrease for non-CARE/FERA customers, but the differences within each segment are not statistically significant for any region.

Figure 5.4-1: Percent Impacts for Peak Period for SDG&E Rate 1, by Season (Positive values represent load reductions)



	Cool/Moderate	Moderate	Cool
Summer 2016	5.4%	5.7%	5.2%
Winter 2016/2017	2.1%	1.5%	2.5%
Summer 2017	4.9%	5.9%	4.1%

Figure 5.4-2: Percent Impacts for Peak Period for SDG &E Rate 1, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

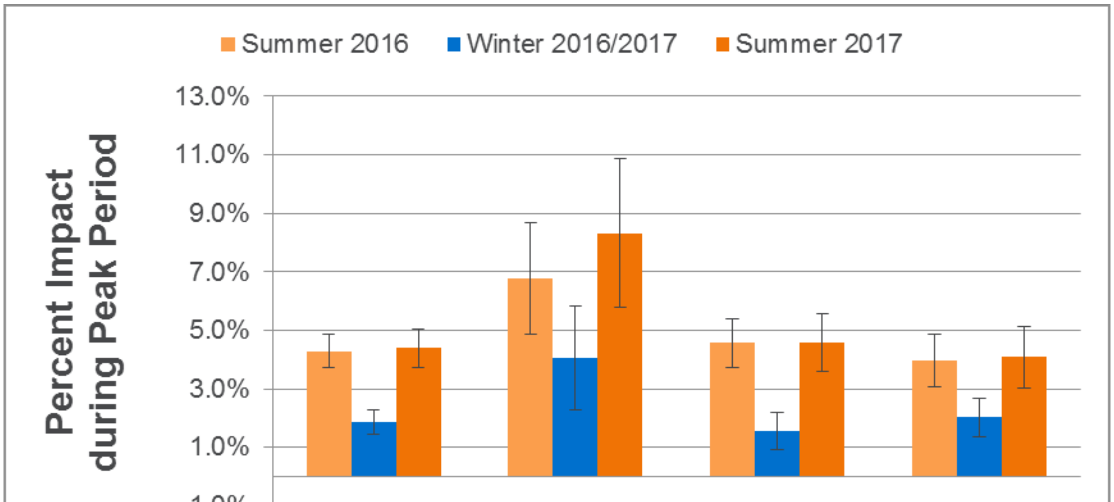


	Cool/Moderate CARE	Cool/Moderate Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Summer 2016	2.5%	6.0%	3.8%	6.2%	0.9%	5.8%
Winter 2016/2017	0.6%	2.4%	0.7%	1.8%	0.6%	2.8%
Summer 2017	3.8%	5.2%	4.7%	6.2%	2.7%	4.3%

5.4.2 Rate 2

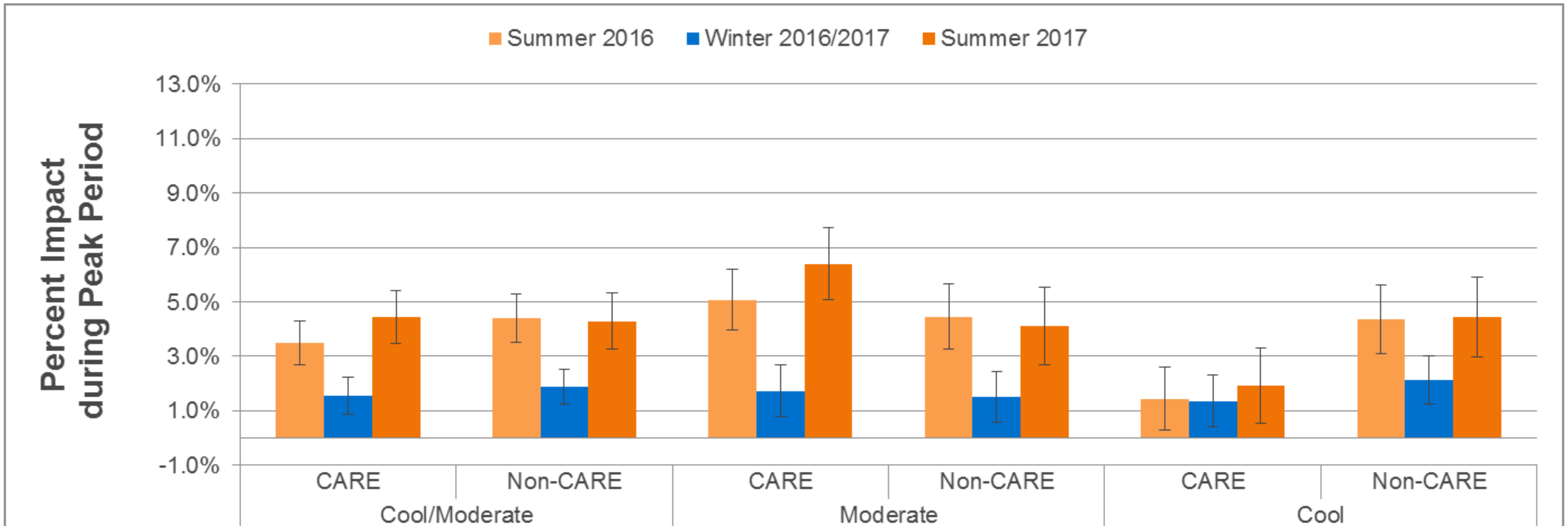
Figure 5.4-3 and Figure 5.4-4 show the peak-period load impacts for each summer and the winter period for Rate 2 for the group of customers that were enrolled on the rate for the entire pilot. As with rate 1, impacts persisted across the two summers in all climate regions and for both customer segments.

Figure 5.4-3: Percent Impacts for Peak Period for SDG &E Rate 2, by Season (Positive values represent load reductions)



	All	Hot	Moderate	Cool
Summer 2016	4.3%	6.8%	4.6%	3.9%
Winter 2016/2017	1.9%	4.0%	1.5%	2.0%
Summer 2017	4.4%	8.3%	4.6%	4.1%

Figure 5.4-4: Percent Impacts for Peak Period for SDG&E Rate 2, by Season for CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

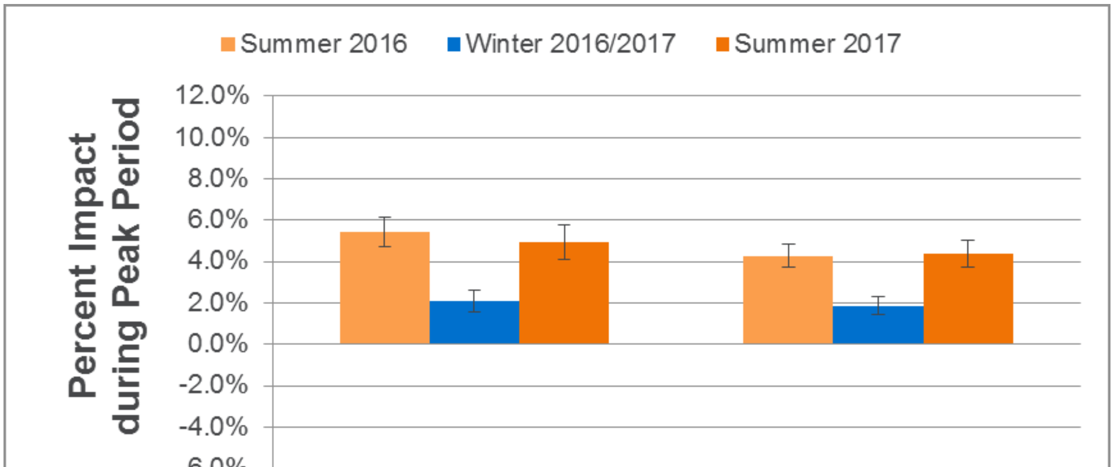


	Cool/Moderate CARE	Cool/Moderate Non-CARE	Moderate CARE	Moderate Non-CARE	Cool CARE	Cool Non-CARE
Summer 2016	3.5%	4.4%	5.1%	4.4%	1.4%	4.4%
Winter 2016/2017	1.5%	1.9%	1.7%	1.5%	1.4%	2.1%
Summer 2017	4.4%	4.3%	6.4%	4.1%	1.9%	4.4%

5.4.3 Comparison Across Rates

Figure 5.4-5 compares the load impacts for the two rates tested by SDG&E for the peak-period hours from 4 PM to 9 PM for the summer months of July through October and the winter months of November through April. Rate 1 had slightly higher first and second summer impacts, when the program was relatively new. The two rates have the same peak hours and prices, but Rate 1 has a super off-peak period in the early morning, which could influence customers to shift more of their usage out of the peak period, as seen in Table 5.3-1. For both rates, summer impacts did not decline or grow by a statistically significant amount. In fact, for Rate 2 the impacts are essentially identical in the two summers.

Figure 5.4-5 Percent Peak Period Impacts Across Rates, by Season



	Rate 1	Rate 2
Summer 2016	5.4%	4.3%
Winter 2016/2017	2.1%	1.9%
Summer 2017	4.9%	4.4%

5.5 Synthesis for SDG&E Pilot

This section compares input from the load impact and persistence analysis, the bill impact analysis, and the survey analysis. The objective of these comparisons, at least in part, is to determine if the information and conclusions observed for individual metrics are supported by findings from other metrics or, alternatively, findings for one metric contradict those for another metric. We also look for clues from the survey findings that might help explain why load or bill impacts for one rate differ from those for other rates. As in the other synthesis sections, readers are reminded once again that, given the large samples underlying the survey analysis, statistically significant differences may not reflect meaningful differences from a policy perspective.

5.5.1 Synthesis

Table 5.5-1 and Table 5.5-2 summarize some of the relevant findings from the load impact, bill impact and survey analysis. No additional bill impact analysis or surveys were completed for this report. Results from the first and second interim report were carried forward to this synthesis section in order to provide a more complete overview of the pilot. Readers are directed to Section 3.5.1 for an explanation of the variables and symbols contained in the tables. As a reminder, SDG&E had two pilot rates, one with two pricing periods during the winter and the other with three. The peak periods were the same for both rates and start at 4 PM and end at 9 PM. Each rate has the same number of periods on weekdays and weekends, but the shoulder period on weekends is much shorter for the three period rate (Rate 1). The weekday shoulder period for the three period rate is long, beginning at 6 AM, whereas on weekends, the shoulder period begins at 2 PM.

Looking across the various metrics for each customer segment, the load impact and bill impact findings are typically similar across rates. During both seasons, the weekday peak period prices are identical for the two rates, and the off-peak prices are within two cents of one another. This leaves the primary difference between the rates being the super off peak rate period for Rate 1.

Table 5.5-1: Load Impacts, Bill Impacts, and Selected Survey Findings for SDG&E Rate 1[48]

Climate	Segment	Load Impacts					Bill Impacts		Survey						
		Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	General Population	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Moderate	Non-CARE/FERA	6.3% ▼	2.6% ▼	5.9% ▼	1.3% ▼	-0.1 -	-$14 ▼	-1% ▼	2.2 -	26% -	26% -	2.4 -	6%	6.4 ▲	6.8 -
	CARE/FERA	5.2% ▼	0.4% -	4.2% ▼	0.1% ▼	1.0 -	-$1 -	0% -	2.7 -	26% -	68% -	4.2 ▲	13%	7.2 -	7.6 -
Cool	Non-CARE/FERA	5.2% ▼	2.9% ▼	4.1% ▼	1.3% ▼	-1.5 -	-$24 ▼	-2% ▼	2.0 -	29% -	18% ▼	2.0 ▼	5%	6.6 ▲	7.0 -
	CARE/FERA	1.7% ▼	-0.3% -	1.1% -	-0.6% ▲	1.7 -	$2 -	0% -	2.6 -	21% ▼	60% -	3.8 -	12%	7.4 ▲	7.8 -

Table 5.5-2: Load Impacts, Bill Impacts, and Selected Survey Findings for SDG&E Rate 2

Climate	Segment	Load Impacts					Bill Impacts		Survey						
		Summer 2016 Peak Period Load Reduction* %	Winter Peak Period Load Reduction** %	Summer 2017 Peak Period Load Reduction %	Net Annual kWh Change** %	Persistence: Summer Impact Pct. Point Change	Annual Total Bill Impact** $	Annual Total Bill Impact** %	Health Index (Range 0-10)**	Bill Higher than Expected**	Difficulty Paying Bills**	Economic Index (Range 0-10)**	Understanding TOU Pricing (None-Correct)**	Satisfaction w/ Rate (11 pt. Scale)**	Satisfaction w/ Utility (11 pt. Scale)**
Hot	General Population	6.8% ▼	3.9% ▼	6.5% ▼	-1.2% ▲	1.6 -	$20 ▲	1% ▲	N/A	N/A	35% N/A	N/A	14%	5.8 N/A	6.5 N/A
Moderate	Non-CARE/FERA	5.1% ▼	1.7% ▼	4.0% ▼	0.4% ▼	-0.3 -	$0 -	0% -	2.2 -	26% -	28% -	2.4 -	14%	6.4 ▲	6.8 -
	CARE/FERA	5.3% ▼	1.3% ▼	5.2% ▼	1.6% ▼	1.3 -	-$13 ▼	-2% ▼	3.0 ▲	26% -	64% -	4.1 -	28%	7.3 -	7.7 -
Cool	Non-CARE/FERA	4.3% ▼	1.9% ▼	4.4% ▼	1.2% ▼	0.1 -	-$28 ▼	-3% ▼	2.0 -	27% -	18% ▼	2.1 -	13%	6.5 ▲	7.1 -
	CARE/FERA	2.6% ▼	0.5% -	1.1% -	0.2% ▼	0.5 -	-$4 ▼	-1% ▼	2.5 -	23% ▼	63% -	3.8 -	25%	7.6 ▲	8.0 ▲

48 In all three tables, a column with an (*) indicates the values are from the First Interim Report and a column with (**) indicates the values are from one of the two Second Interim Report volumes. A column with neither (*) or (**) means the values are found elsewhere in this report.

Non-CARE/FERA Customers

Non-CARE/FERA customers had larger load reductions in summer 2017 than CARE/FERA customers for both Rates 1 and 2 in both absolute and percentage terms for the cool/moderate climate regions combined and also in the cool climate region. In the moderate climate region, the non-CARE/FERA absolute and percentage load reductions were also greater for Rate 1, but were not statistically different from the impacts for Rate 2. The average peak-period load reduction for non-CARE/FERA customers in the cool/moderate regions combined equaled 4.9% and 0.04 kW for Rate 1 and 4.2% and 0.03 kW for Rate 2. The difference in load impacts across the two rates was not statistically significant. Absolute impacts were larger in the moderate region for Rate 1 compared with the cool climate region. For Rate 2, the absolute difference across climate regions was not statistically significant for Rate 2, non-CARE/FERA customers. Non-CARE/FERA customers did not display statistically significant changes in peak-load reductions between the first and second summer for a common group of customers that participated throughout the entire pilot.

Non-CARE/FERA customers in the moderate climate region on Rates 1 and 2 experienced the largest structural bill impacts, which were almost as large as the structural impacts of the general population in the hot climate region on Rate 2. Non-CARE/FERA customers on Rates 1 and 2 in both the moderate and cool climate regions were able to achieve either no total annual bill impact or annual bill reductions up to $28 for the cool climate region customers on Rate 2.

Non-CARE/FERA customers tended to have a low percentage of customers receiving bills higher than expected, and also had a low percentage of customers having difficulty paying bills. Neither of these metrics have statistically significant differences between the treatment and control groups. Similarly, there were no statistically significant difference in the economic index. In fact, there was actually a statistically significant decrease for the non-CARE/FERA customers in the cool climate region on Rate 1.

When excluding the hot climate region, non-CARE/FERA customers had the highest bill reduction due to behavior change in three out of the four segments. Non-CARE/FERA customers understood the rates better than CARE/FERA customers (as indicated by the low percent that couldn't identify at least some hours that fell into the peak period).

All non-CARE/FERA segments had statistically significantly higher satisfaction ratings for the rate plan compared to the control group. These metrics paint an internally consistent picture of a customer segment that understood the rate features relatively well, worked to reduce usage which resulted in bills similar or less than what they would have experienced on the OAT, and were ultimately more satisfied with their rate than control group customers.

CARE/FERA Customers

As discussed above, CARE/FERA customers tended to have load reductions that were smaller than non-CARE/FERA customers overall and in the cool climate region on both rates. In the moderate climate region, the difference in load impacts between the two segments was not statistically significant for Rate 2. CARE/FERA customers on average produced behavioral bill reductions significantly smaller than non-CARE/FERA customers in the cool climate region on both rates and produced a mix of higher and lower impacts in the moderate climate region. Similar to non-CARE/FERA customers, CARE/FERA customers did not provide any statistically significant changes in peak load reductions between the first and second summer. In other words, CARE/FERA customers continue to respond to peak pricing in a similar manner during the second summer of the pilot.

One potentially important finding related to the rates that could affect performance of CARE/FERA customers is the lower understanding of the timing of the peak period, as evidenced by the much higher percent of customers who could not identify any hours that fell during the high priced period. Taking a simple average across climate regions and rates for this metric, only about 10% of non-CARE/FERA customers were unable to correctly identify any peak-period hours, whereas twice as many (20%) CARE/FERA customers fell into this category.

Turning to other metrics of interest, in stark contrast to the bill impacts at PG&E and SCE, the average structural bill increase for CARE/FERA customers at SDG&E was less than $4 per year in the moderate climate region, and customers in the cool climate region actually saw a bill reduction of a dollar or more on average. On average, customers experienced a $2 per year structural loss, but were able to offset this loss through behavioral change so that there was no statistically significant change in total annual cost.

Most CARE/FERA customers produced behavioral bill reductions, although only behavioral bill reductions from the moderate climate region segment on Rate 2 were statistically significant. This resulted in all CARE/FERA segments either experiencing total bill impacts that weren't statistically significant—on Rate 1— or were in the range of $4 to $13 savings per year on Rate 2.

CARE/FERA customers in both climate regions on both rates reported greater difficulty in paying bills compared to non-CARE/FERA customers, but the difference was not statistically different compared to the control group. CARE/FERA customers in the moderate climate region on Rate 1 had the highest economic index score of 4.2, and it was statistically significantly higher for the treatment group compared to the control group even though bill impacts were quite modest on average. This group also had the highest percentage of customers with difficulty paying bills at 68%. Interestingly, this segment produced among the largest impacts in the summer, but negligible impacts in the winter.

CARE/FERA customers tended to be more satisfied with the rate and with SDG&E compared to non-CARE/FERA customers. In the cool climate region, CARE/FERA customers had statistically significantly higher levels of satisfaction with the rate compared to the control group. On Rate 2, these customers also had a statistically significantly higher level of satisfaction with SDG&E compared to the control group as well.

Hot Climate Region General Population

General population households in the hot climate region on Rate 2 had summer 2017 load reductions in the peak period equal to 6.5%, which was greater than the load impacts for any other customer segment or climate region. The next closest comparable impact was from non-CARE/FERA customers on Rate 1 in the moderate climate region with peak-period reductions equal to 5.9%. Net annual kWh reductions for general population customers in the hot climate region, at negative 1.2%, were the largest increases in total energy use, and with the relatively large peak period reduction, suggest that these customers are shifting use to the off peak hours, or actually increasing off peak hour energy use.

Structural bill impacts for the hot region were slightly higher than those for non-CARE/FERA customers in the moderate region, and the highest across all segments. Due to the increase in net annual kWh, customers weren't able to produce behavioral bill impacts large enough to offset these structural increases, resulting in total annual bill increases of approximately $20. Customers in this climate region had one of the greater increases in summer peak load reductions between 2016 and 2017 when evaluating impacts for a common set of customers enrolled for the full duration of the pilot (1.6 percentage points),[49] which could have been motivated by their relatively large bill increases. However, this change in load impacts was not statistically significant.

Customer surveys were not administered to the control group in the hot region due to implementation decisions made by SDG&E, so several of the survey related metrics that require comparisons between the treatment and control group (e.g., being uncomfortably hot or cold, higher bill than expected, difficulty of paying bills, and the economic index), could not be calculated. 14% of treatment households in the hot region could not correctly identify any of the peak period hours, which was similar to the other non-CARE/FERA segments on Rate 2. Finally, the satisfaction scores for Rate 2 customers in the hot climate region are the lowest across all other segments, at 5.8 and 6.5 for satisfaction with the rate and the utility, respectively. This is reasonable given these customers also have the highest structural bill impacts, and the highest overall bills. These scores are lower than the scores from the non-CARE/FERA customers on both rates in the moderate climate region, which were 6.4 and 6.8 for the rate and utility satisfaction, respectively.

5.5.2 Key Findings

Key findings pertaining to second summer load impacts from the SDG&E pilots include:

1. In the second summer, customers continued to respond to TOU rates with peak periods that extend well into the evening. During the second summer, customers achieved load reductions as high as 6.5% for the general population in the hot climate region on Rate 2.
2. Between the first and second summer, impacts persisted for each customer segment and for the territory as a whole. In other words, customers continued to provide statistically significant load reductions in the last few months of the pilot.
3. For Rate 2, which has the same prices in effect on weekends as on weekdays, the pattern of load impacts across rate periods on weekends was very similar to weekdays for all climate regions combined– that is, customers can and will reduce loads on weekends.
4. For Rate 2, load impacts, in both absolute and percentage terms, were largest in the hot climate region, and there was no statistically significant difference between the moderate and cool climate regions on a percentage basis.
5. CARE/FERA customers generally had lower peak period load reductions compared with non-CARE/FERA customers—although not all differences were statistically significant.
6. Load impacts are not available for senior households or households with incomes below 100% of FPG because the sample sizes (and population) in SDG&E's hot region are too small.

[49] The average impact between the first and second summer decreased for the second summer when all customers enrolled at the time are included. Limiting the analysis to customers enrolled for the entire pilot shows in increase between the first and second summer.

7. Customers who received Weekly Alert Emails in the moderate climate region had incremental load reduction improvements of approximately 0.02 kW, which was a statistically significant impact.

Overall findings and conclusions for the pilot include:

- Customers continued to respond to the TOU price signals at the end of the pilot. As expected, the load impacts were lower during the winter compared to the first summer. Load impacts persisted through the second summer, with no statistically significant change in percent load reductions in any segment.
- The majority of customers across both rates experienced slight net annual total bill decreases. However, customers in the hot climate were more likely to experience net annual bill increases.
- CARE/FERA customers in the moderate climate region on Rate 1 experienced a statistically significant increase in the Economic Index. The similar customer segment on Rate 2 experienced a statistically significant increase in the health index.
- Results are not available for senior households or households with incomes below 100% of FPG because the sample sizes (and population) in SDG&E's hot region are too small.

6 Cross Utility Comparison of Load Impacts and Summary of Key Findings

This section begins with a comparison of load impacts across utility service territories and rate options. Although the experiment was not designed to make cross-utility comparisons, such comparisons are likely to be made nonetheless and it is important that any observed differences be put into the proper perspectives so that they are not misinterpreted. Following that discussion is a very brief summary of the key conclusions from the analysis of load impacts from the second summer. The pattern of load impacts across customer segments and climate regions in the second summer was similar to that of the first summer, which was summarized in the First Interim Report. As such, the summary of key findings here is limited only to the issue of persistence of load impacts across the two summers.

6.1 Cross Utility Comparison of Load Impacts

When comparing rate impacts or bill impacts across utility service territories, it is very important to keep in mind that any observed differences could easily be due to differences in the populations or climate regions across the service territories rather than due to differences in the tariffs themselves. Another possible explanation for any observed differences is variation in the months included in the analysis – recall that average impacts for PG&E and SCE's Rate 1 and Rate 2 span June through September. SDG&E's summer period covers May through October. Finally, as discussed in each utility section, when comparing peak period load impacts across rates, even within a service territory, differences could be due to variation in the timing and length of the peak periods rather than to differences in price ratios, for example.

Some of the above factors can be controlled for by limiting the cross-utility comparisons to only the hours that all utility tariffs have in common and only the months that are common across all rates and service territories. As such, in the discussion below, peak period load impacts are presented only for the hours from 6 PM to 8 PM and peak period and daily load impacts and bill impacts are presented only for the months of June through September 2017.[50] For all of the figures below, the following legend applies:

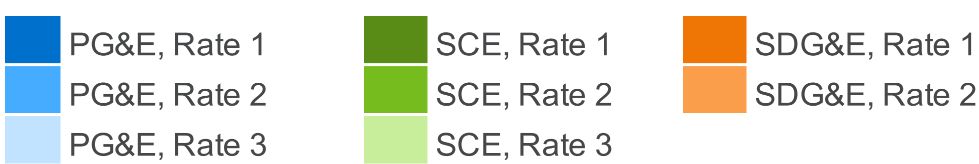


Figure 6.1-1 shows the load reduction from 6 PM to 8 PM on the average weekday in June, July, August, and September 2017 for each service territory as a whole for the eight different tariffs tested across the three utilities and for CARE/FERA and non-CARE/FERA customers within each service territory. The bar

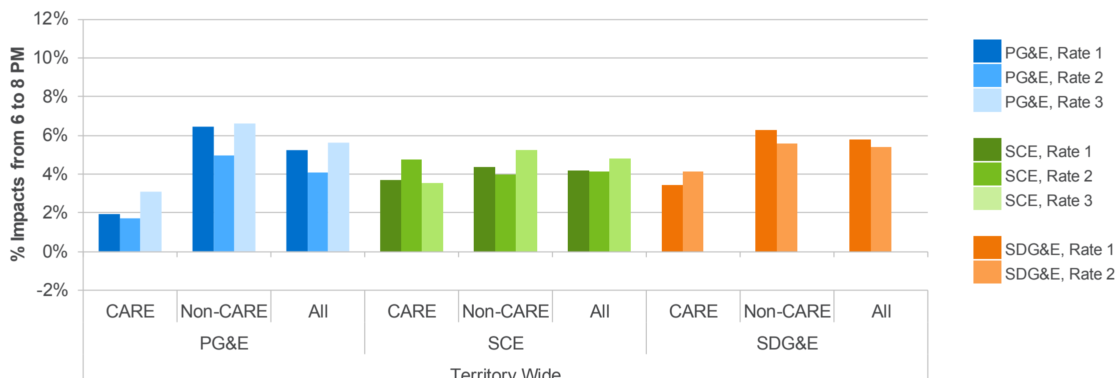
[50] Because the impacts presented here cover only the hours from 6 PM to 8 PM and are only for the months of June through September 2017, they will differ from the load reductions reported in prior sections of the report, which represent the average across the full peak period and different months for the summer period at SDG&E.

graphs show the percent reduction across these hours while absolute reductions are shown below the graph.[51]

All rates in all service territories show reductions for these early evening hours, ranging from a low of 4.1% for customers on PG&E's Rate 2 to a high of 5.8% for customers on SDG&E's Rate 1. The average percent load reduction across all three rates for PG&E was 5.0%, while SCE's average was 4.4%. SDG&E's average reduction across its two rates was 5.6%.

For non-CARE/FERA customers, the largest load reduction, 6.6%, occurred for PG&E's Rate 3 and the smallest, 4.0%, was for SCE's Rate 2. The average reduction across the multiple rate treatments in each service territory for non-CARE/FERA customers was 6.0% for PG&E, 4.5% for SCE and 6.0% for SDG&E. For CARE/FERA customers, the average reductions were 2.3%, 4.0%, and 3.8% for PG&E, SCE, and SDG&E, respectively. On average, CARE/FERA customers had lower percent reductions in peak period usage than non-CARE/FERA customers. This difference could explain, in part, why SCE's average reduction for all customers in its service territory is lower than PG&E as SCE has a greater percent of CARE/FERA customers among the pilot eligible population (31%) compared with PG&E (27%).

Figure 6.1-1: Load Reductions Between 6 PM and 8 PM by Rate and Service Territory, Average Summer 2017 Weekday



		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
Rate 1	% Impact	2.0%	6.5%	5.2%	3.7%	4.4%	4.2%	3.4%	6.3%	5.8%
	kW Impact	0.02	0.07	0.06	0.04	0.06	0.05	0.02	0.05	0.05
Rate 2	% Impact	1.7%	5.0%	4.1%	4.7%	4.0%	4.2%	4.1%	5.6%	5.4%
	kW Impact	0.02	0.06	0.05	0.05	0.05	0.05	0.03	0.05	0.04
Rate 3	% Impact	3.1%	6.6%	5.6%	3.5%	5.2%	4.8%			
	kW Impact	0.03	0.07	0.06	0.04	0.07	0.06			

Table 6.1-1 shows the peak period prices for each pilot rate as well as the Tier 2 and 3 prices for the otherwise applicable tariff faced by the control group. As indicated in the title to the table, the treatment group prices represent the marginal price excluding the baseline discount. The most

[51] The comparisons are primarily described in percentage terms due to the level differences in average customer energy usage across utilities. The percentage results help to normalize the level differences and show the proportion of load being curtailed. The average kW impacts are provided; however, caution should be used when making any sort of direct comparison of average impacts.

comparable OAT price is the price that applies between 100% and 200% of the baseline quantity. As seen in the table, there is significant variation in the marginal price that applies to peak period hours across rates within a service territory as well as across service territories.

Table 6.1-1: Peak Period Price Above Baseline Quantity (¢/kWh)

Utility	Customer Segment	Rate 1	Rate 2	Rate 3	Control Group Tariff (OAT)	
					101 – 400% of Baseline	>400% of Baseline
PG&E	Non-CARE	41.0	43.5	55.6	27.6	40.1
	CARE	24.3	24.8	31.8	17.3	24.0
	Total	36.5	38.4	49.1	24.8	35.7
SCE	Non-CARE	34.8	55.2	37.0	24.9	31.4
	CARE	24.3	39.0	25.9	16.7	21.1
	Total	31.5	50.2	33.6	22.4	28.2
SDG&E	Non-CARE	62.0	62.0	n/a	43.0	n/a
	CARE	38.7	38.7	n/a	26.6	n/a
	Total	57.3	57.3	n/a	39.7	n/a

A useful way of comparing the change in usage caused by a change in price is what economists call price elasticity. The price elasticity is simply the percentage change in quantity demanded given a percentage change in price. While price elasticities are best estimated as coefficients on the price variable in a demand model, they can also be calculated by hand for a given set of prices and quantities. These are known as arc price elasticities. When there are tiered rates as there are here, where prices vary with quantity, a question arises as to what is the relevant price term to use in a demand model or when calculating price elasticities. Is it the price you pay for the next unit of electricity, which is known as the marginal price, or is it the average price? With tiered rates, both marginal and average prices vary with consumption, which means that the prices paid differ across customers, across months within seasons, and across seasons. For simplicity, we ignore all of these complexities and, in Table 6.1-2, show the arc price elasticities for each rate using prices above the baseline quantity for the TOU rates and prices between 100% and 200% of baseline for the OAT. Readers are reminded, once again, that the usage values pertain only to the two hours from 6 PM to 8 PM and only for the months of June through September.

As seen in the table, SDG&E's customers are the most price responsive of the three utilities, and PG&E and SCE show lower, similar, price responsiveness both overall as well as within the non-CARE/FERA customer segments. While SDG&E was the most price responsive in both the first and second summers, the average price elasticity dropped from 0.15 in the first summer to 0.13 in the second summer, indicating customers remaining on the pilot in the second summer were slightly less price responsive. The opposite was true for PG&E as SCE, with both utilities showing slightly higher elasticities in the second summer—an average value of 0.08 for both utilities compared to 0.07 and 0.05 for PG&E and SCE in the first summer, respectively. Even with the slight changes in the second summer, all of the arc price elasticities have values in the range that economists refer to as highly inelastic demand, which means that it takes a large percentage change in price to produce a significant change in demand compared with products and services that are much more elastic. A price elasticity of 0.10 means that a 100% increase in price would produce a 10% reduction in demand for a good or service. If the price elasticity equaled 0.50, a 100% increase in price would produce a decrease in demand of 50%.

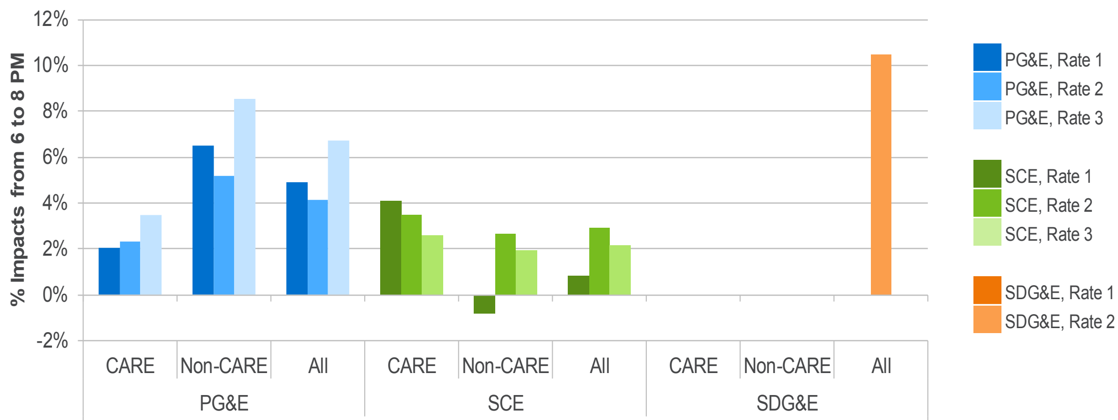
Table 6.1-2: Arc Price Elasticities Using Marginal Prices Above Baseline Quantities

Utility	Customer Segment	Rate 1	Rate 2	Rate 3
PG&E	Non-CARE	0.13	0.09	0.07
	CARE	0.05	0.04	0.04
	Total	0.11	0.07	0.06
SCE	Non-CARE	0.11	0.03	0.11
	CARE	0.08	0.04	0.06
	Total	0.10	0.03	0.11
SDG&E	Non-CARE	0.14	0.13	n/a
	CARE	0.07	0.09	n/a
	Total	0.13	0.12	n/a

Figure 6.1-2 shows the average load reduction for each rate for the hours from 6 PM to 8 PM in the hot climate region for the population as a whole as well as for CARE/FERA and non-CARE/FERA segments. Non-CARE/FERA customers in PG&E's hot climate region had larger load reductions than in SCE's service territory. In fact, Rate 1 non-CARE/FERA customers in SCE's hot climate region had load increases of 0.8%[52] during the common summer period. The greatest percent impacts came from customers in SDG&E's hot climate region on Rate 2 (10.5% or 0.14 kW).

[52] The load increase is not statistically significant, indicating there was essentially no load impact.

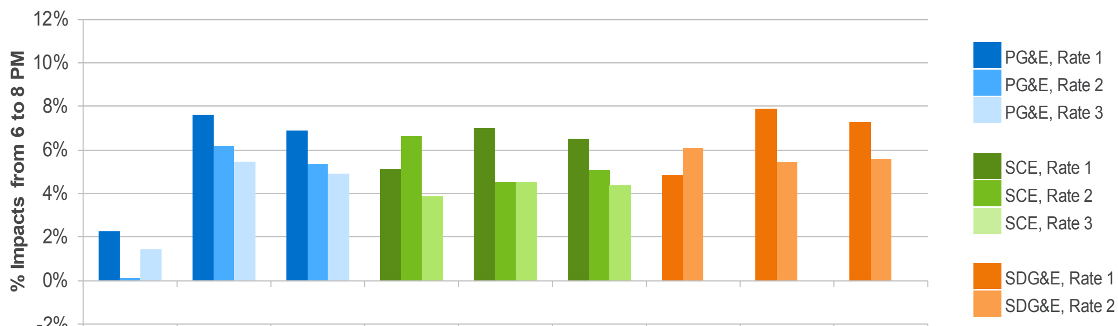
Figure 6.1-2: Load Reductions Between 6 PM and 8 PM for Hot Climate Regions by Customer Segment, Average Summer 2017 Weekday



		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
Rate 1	% Impact	2.1%	6.5%	4.9%	4.1%	-0.8%	0.9%			
	kW Impact	0.03	0.12	0.08	0.07	-0.02	0.02			
Rate 2	% Impact	2.3%	5.2%	4.2%	3.5%	2.7%	2.9%			10.5%
	kW Impact	0.04	0.09	0.07	0.06	0.05	0.05			0.14
Rate 3	% Impact	3.5%	8.6%	6.7%	2.6%	2.0%	2.2%			
	kW Impact	0.05	0.15	0.11	0.04	0.04	0.04			

Figure 6.1-3 shows the average load reductions from 6 PM to 8 PM for CARE/FERA and non-CARE/FERA customers and for the population as a whole in the moderate climate regions in each service territory. As in the hot climate region, non-CARE/FERA PG&E customers had greater load impacts than their counterparts at SCE. CARE/FERA customers in PG&E's moderate climate region had the smallest load impacts, on average (about 1.3%) while their counterparts at SCE and SDG&E had load impacts of about 5.2% and 5.5%, respectively. Load impacts were generally over 5% for non-CARE/FERA customers across all rates within each utility; about 6.4% at PG&E, 5.4% at SCE, and 6.7% at SDG&E on average.

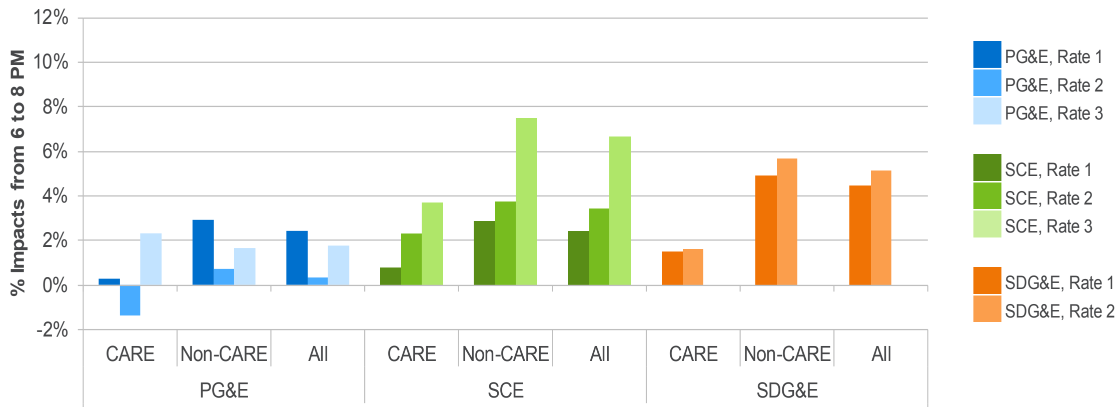
Figure 6.1-3: Load Reductions Between 6 PM and 8 PM for Moderate Climate Regions by Customer Segment, Average Summer 2017 Weekday



		PG&E			SCE			SDG&E		
		CARE	Non-CARE	All	CARE	Non-CARE	All	CARE	Non-CARE	All
		Moderate								
Rate 1	% Impact	2.3%	7.6%	6.9%	5.1%	7.0%	6.5%	4.9%	7.9%	7.3%
	kW Impact	0.02	0.07	0.06	0.06	0.12	0.10	0.04	0.08	0.07
Rate 2	% Impact	0.1%	6.2%	5.4%	6.6%	4.5%	5.1%	6.1%	5.5%	5.6%
	kW Impact	0.00	0.06	0.05	0.08	0.08	0.08	0.05	0.05	0.05
Rate 3	% Impact	1.4%	5.5%	4.9%	3.8%	4.6%	4.4%			
	kW Impact	0.01	0.05	0.04	0.05	0.08	0.07			

Figure 6.1-4 shows the load reductions from 6 PM to 8 PM for CARE/FERA and non-CARE/FERA customers and for the population as a whole in the cool climate region for each service territory. The cool climate region is the only area where PG&E saw negative load impacts (load increases) during the common summer period,[53] with Rate 2 having the smallest impacts in general. Average impacts between 6 PM and 8 PM for PG&E, SCE, and SDG&E were 1.5%, 4.2%, and 4.8%, respectively. Non-CARE/FERA customers in SDG&E's cool climate region had the greatest load impacts, about 5.3% on average.

Figure 6.1-4: Load Reductions Between 6 PM and 8 PM for Cool Climate Regions by Customer Segment, Average Summer 2017 Weekday

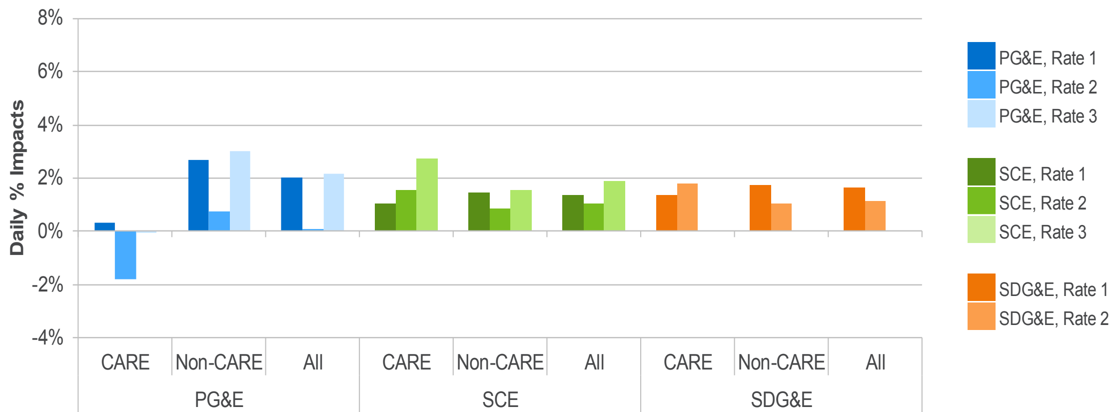


		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
		Cool								
Rate 1	% Impact	0.3%	2.9%	2.4%	0.8%	2.9%	2.4%	1.5%	4.9%	4.5%
	kW Impact	0.00	0.02	0.01	0.01	0.03	0.02	0.01	0.04	0.03
Rate 2	% Impact	-1.4%	0.8%	0.3%	2.3%	3.7%	3.4%	1.6%	5.7%	5.1%
	kW Impact	-0.01	0.00	0.00	0.02	0.04	0.03	0.01	0.04	0.04
Rate 3	% Impact	2.3%	1.7%	1.8%	3.7%	7.5%	6.7%			
	kW Impact	0.01	0.01	0.01	0.03	0.07	0.06			

[53] The load increase is not statistically significant, indicating there was essentially no load impact.

Figure 6.1-5 shows the average reduction in daily electricity use for each of the 8 rate treatments tested across the three utilities. At the utility level, daily electricity use fell between about 0.1% and 2.2%. In PG&E's service territory, CARE/FERA customers on Rate 2 increased their daily consumption by 1.8%.[54] All other customer segments reduced their daily consumption, though not all reductions were meaningful or statistically significant.

Figure 6.1-5: Daily Average Demand[55] Reductions by Rate and Service Territory, Average Summer 2017 Weekday



Territory Wide

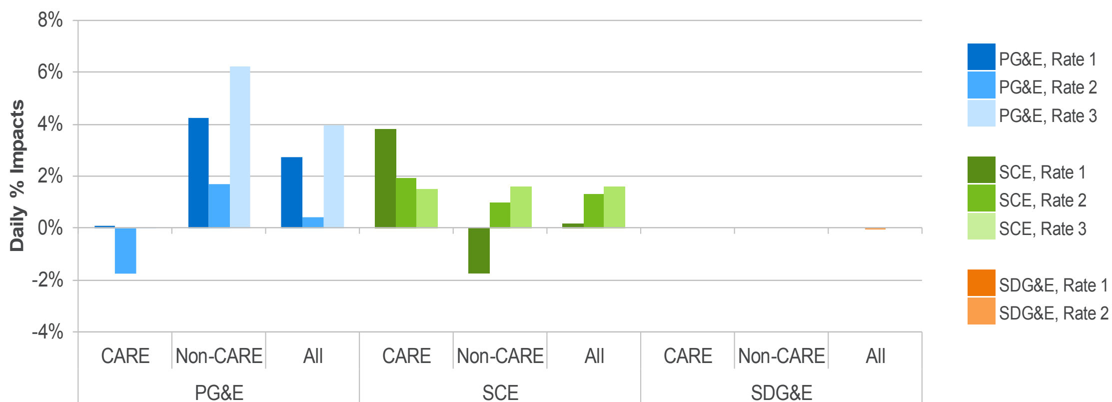
		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
Rate 1	% Impact	0.3%	2.7%	2.0%	1.0%	1.5%	1.3%	1.4%	1.7%	1.7%
	kW Impact	0.00	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Rate 2	% Impact	-1.8%	0.8%	0.1%	1.6%	0.9%	1.0%	1.8%	1.0%	1.1%
	kW Impact	-0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Rate 3	% Impact	0.0%	3.0%	2.2%	2.7%	1.6%	1.9%			
	kW Impact	0.00	0.02	0.02	0.02	0.01	0.02			

[54] This increase in usage was statistically significant.

[55] The table reports impacts in average hourly kW. The total daily kWh can be calculated by multiplying the kW values by 24.

Figure 6.1-6 shows the variation in daily load impacts across tariffs, segments, and service territories for selected customer segments in the hot climate region. Recall that the participant sample in SDG&E's hot region is not large enough to support segmentation for reasons discussed previously. Like the service territory as whole, CARE/FERA customers on PG&E's Rate 2 increased their daily consumption by about 1.7%. Customers in SDG&E's hot climate region did not show any usage reductions or increases throughout the average summer weekday. Between PG&E and SCE's hot climate regions, there is no clear pattern between CARE/FERA and non-CARE/FERA customers.

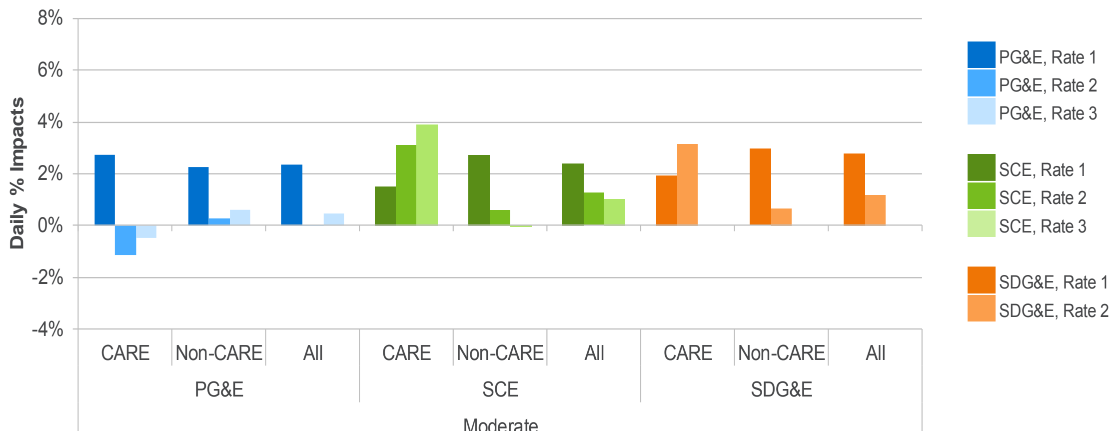
Figure 6.1-6: Daily Average Demand Reductions for Hot Climate Regions by Customer Segment, Average Summer 2017 Weekday



		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
		Hot								
Rate 1	% Impact	0.1%	4.2%	2.7%	3.8%	-1.7%	0.2%			
	kW Impact	0.00	0.05	0.03	0.04	-0.02	0.00			
Rate 2	% Impact	-1.7%	1.7%	0.4%	2.0%	1.0%	1.3%			0.0%
	kW Impact	-0.02	0.02	0.00	0.02	0.01	0.02			0.00
Rate 3	% Impact	0.0%	6.2%	3.9%	1.5%	1.6%	1.6%			
	kW Impact	0.00	0.07	0.04	0.02	0.02	0.02			

Figure 6.1-7 shows the variation in daily load impacts across tariffs, segments, and service territories for selected customer segments in the moderate climate region on the average summer weekday. CARE/FERA customers on Rate 3 in SCE's moderate climate region provided the greatest daily impacts, about 3.9%, while CARE/FERA customers on PG&E's Rate 2 increased their daily consumption by 1.1%. In the service territories as a whole, PG&E, SCE, and SDG&E demonstrated daily reductions of 1.0%, 1.6%, and 2.0%, respectively.

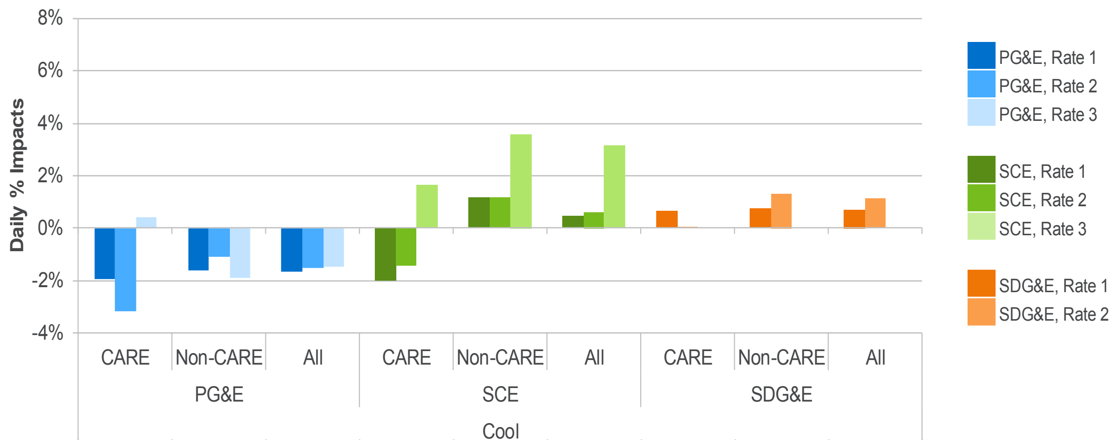
Figure 6.1-7: Daily Average Demand Reductions for Moderate Climate Regions by Customer Segment, Average Summer 2017 Weekday



		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
Rate 1	% Impact	2.7%	2.3%	2.3%	1.5%	2.7%	2.4%	1.9%	3.0%	2.8%
	kW Impact	0.01	0.01	0.01	0.01	0.03	0.02	0.01	0.02	0.02
Rate 2	% Impact	-1.1%	0.3%	0.1%	3.1%	0.6%	1.3%	3.1%	0.7%	1.2%
	kW Impact	-0.01	0.00	0.00	0.03	0.01	0.01	0.02	0.00	0.01
Rate 3	% Impact	-0.5%	0.6%	0.5%	3.9%	0.0%	1.0%			
	kW Impact	0.00	0.00	0.00	0.03	0.00	0.01			

Finally, Figure 6.1-8 shows the average reduction in daily electricity use in the cool climate regions for each rate, segment, and service territory. The average reduction across the three rates for the population as a whole equaled negative 1.6% (increase in usage), positive 1.4% (reduction in usage), and 0.9% (reduction) for PG&E, SCE, and SDG&E respectively. CARE/FERA customers at PG&E and SCE had an average increase in daily electricity use while non-CARE/FERA customers did not follow a clear pattern.

Figure 6.1-8: Daily Average Demand Reductions for Cool Climate Regions by Customer Segment, Average Summer 2017 Weekday



		PG&E CARE	PG&E Non-CARE	PG&E All	SCE CARE	SCE Non-CARE	SCE All	SDG&E CARE	SDG&E Non-CARE	SDG&E All
Rate 1	% Impact	-1.9%	-1.6%	-1.7%	-2.0%	1.2%	0.5%	0.7%	0.7%	0.7%
	kW Impact	-0.01	-0.01	-0.01	-0.01	0.01	0.00	0.00	0.00	0.00
Rate 2	% Impact	-3.1%	-1.1%	-1.5%	-1.4%	1.2%	0.6%	0.0%	1.3%	1.1%
	kW Impact	-0.01	0.00	-0.01	-0.01	0.01	0.00	0.00	0.01	0.01
Rate 3	% Impact	0.4%	-1.9%	-1.5%	1.6%	3.6%	3.2%			
	kW Impact	0.00	-0.01	-0.01	0.01	0.02	0.02			

6.2 Summary of Load Impact Persistence

As mentioned at the outset of this section, the variation in load impacts across climate regions, rates and customer segments were summarized in detail in prior reports for both summer and winter. These prior summaries also discussed bill impacts. Load impacts varied between the first and second summer periods but the variation across segments and regions was similar to what was reported previously. As such, in the remainder of this section, we focus exclusively on the issue of persistence of load impacts across the two summer periods. Keep in mind that the persistence analysis pertains to the group of customers who were enrolled over the entire duration of the pilot. Key findings concerning load impact persistence include the following:

- **At PG&E, summer load reductions either declined or remained the same between the first and second summer of the pilot.** Some of largest declines were seen in the non-CARE/FERA segments in the hot climate region on Rate 1 and Rate 2 and for both CARE/FERA and non-CARE/FERA customers in the cool climate region on Rate 1 (separately and combined). No customer segment increased their percent load reductions by a statistically significant amount. For nearly all customer segments, summer load impacts were greater than those in the winter months.
- **Most customer segments at SCE showed persistence in summer load reductions from the first summer to the second.** In general, the differences in load impacts between the two summers were not statistically significant. Notable exceptions include CARE/FERA customers in the moderate climate region on Rate 2 and Non-CARE/FERA customers in the cool climate region on Rate 1. CARE/FERA customers in the moderate climate region on Rate 2 more than doubled their percent load reductions, from 3.1% to 8.0%. They did not face especially high summer bill increases in 2016, so it is unclear what motivated these customers to raise their response to the rate. Load impacts for non-CARE/FERA customers in the cool climate region on Rate 1dropped by approximately one half. These customers also had net savings on their total annual bill impacts, indicating many customers were likely structural benefiters and not receiving a strong price signal.
- **At SDG&E, percent load reductions in the first and second summer were nearly identical.** For both rates and for all customer segments, there were no statistically significant differences in load reductions between the two summers. This was true for the territory as a whole as well. Customers in SDG&E's pilot continue to have load impacts over 4% for nearly all customer segments in the summer months.

Also of interest is whether load impacts are likely to changer over a longer period of time than the two summers studies in these pilots. Unfortunately, there is very limited empirical evidence from other TOU rate pilots on this issue since most rate pilots last only a year or two. There is substantial evidence, however, both theoretical and empirical, indicating that long run price elasticities for electricity are larger than short run price elasticities. This is because in the short run, price response is purely behavioral whereas in the long run, it reflects changes in the capital stock of energy using equipment. For example, in the short run, people can adjust their temperature settings for air conditioning to reduce usage whereas in the long run, they can purchase a more efficient air conditioner and/or install a smart thermostat to reduce usage in response to price increases. This difference in the factors at play underlying short run and long run price response in general logically applies to both peak-period energy use and load shifting behavior as well. It suggests that peak-period load reductions could easily be larger in the long run compared with the short run impacts obtained from just the two summers of the TOU pilots where short run behavior dominates the observed reductions in peak period energy use.

The growing penetration of smart thermostats for reasons unrelated to price changes (e.g., remote accessibility and control), combined with the interest of thermostat providers in providing value added services such as those offered in SCE's service territory that showed evidence of substantial increases in price responsiveness, also suggests that load reductions could grow over time.

Finally, long run demand reductions could also increase in response to ongoing education and outreach (E&O). The default pilots that are now in the field in California will provide new evidence on the potential impact of ongoing E&O and useful insights that will help guide IOU strategies to improve response to TOU rates in the future. It is also expected that the IOUs will continue to experiment with and evolve ongoing E&O strategies to improve TOU rate response.

Appendix A Listing of Electronic Tables

The following Microsoft Excel files have been filed as electronic tables in conjunction with the primary report. Given the large volume of different rates and customer segments across utilities, electronic tables are the most efficient medium to present this data. Within these tables, users are able to select options such as the rate or customer segment of interest. The numbering of the tables corresponds to the section of the report containing the corresponding static figures and tables. In cases where more than one table corresponds to a section, each electronic table is labeled as X.X-1 and X.X-2. The file names for the electronic tables do not directly tie to any particular figure or table numbers, even though the naming convention is similar. These electronic tables allow the reader to access the underlying data that created the figures, and to determine actual values for data points within figures.

E-Table 3.3-1 - PG&E Load Impacts by Hour

E-Table 3.3-2 - PG&E Load Impact Tables & Figures

E-Table 4.3-1 - SCE Load Impacts by Hour

E-Table 4.3-2 - SCE Load Impact Tables & Figures

E-Table 5.3-1 - SDG&E Load Impacts by Hour

E-Table 5.3-2 - SDG&E Load Impact Tables & Figures

E-Table 6.1 - Cross Utility Comparison

Appendix B Comparison of Original and Updated Tariffs

Table B-1: PG&E Tariff Summary

Rate	Season	Period/Percent of Baseline	Non-CARE June 2016	Non-CARE March 2017	CARE June 2016	CARE March 2017
Rate 1	Summer	Off Peak	31.7	30.7	17.8	17.8
		Peak	42.0	41.0	24.3	24.3
	Winter	Off Peak	27.1	26.1	14.9	14.8
		Peak	29.0	28.0	16.1	16.0
	Baseline Credit		-11.7	-8.8	-4.7	-4.8
Rate 2	Summer	Off Peak	29.6	28.6	16.5	16.5
		Partial Peak	39.3	38.3	21.9	21.9
		Peak	44.5	43.5	24.9	24.8
	Winter	Off Peak	27.0	26.0	15.0	15.0
		Peak	29.6	28.6	16.5	16.5
	Baseline Credit		-11.7	-8.8	-4.7	-4.8
Rate 3	Spring	Off Peak	26.7	25.8	14.9	14.8
		Peak	36.0	34.7	20.1	20.0
		Super Off Peak	18.0	17.4	10.0	10.0
	Summer	Off Peak	28.6	27.8	16.0	15.9
		Peak	57.2	55.6	31.9	31.8
	Winter	Off Peak	27.1	26.1	15.1	15.0
		Peak	29.0	28.0	16.1	16.1
	Baseline Credit		-11.7	-8.8	-4.7	-4.8
OAT	Spring	0%-100%	18.2	20.0	11.9	12.6
		101%-200%	24.1	27.6	14.7	17.3
		200-400%	40.0	27.6	21.7	17.3
		Over 400%	40.0	40.1	21.7	24.0
	Summer	0%-100%	18.2	20.0	11.9	12.6
		101%-200%	24.1	27.6	14.7	17.3
		200-400%	40.0	27.6	21.7	17.3
		Over 400%	40.0	40.1	21.7	24.0
	Winter	0%-100%	18.2	20.0	11.9	12.6
		101%-200%	24.1	27.6	14.7	17.3
		200-400%	40.0	27.6	21.7	17.3
		Over 400%	40.0	40.1	21.7	24.0
Delivery Minimum Bill Amount			32.9	32.9	16.4	16.4
FERA Discount			12% discount on bill			

Table B-2: SCE Tariff Summary

Rate	Season	Period/Percent of Baseline	Non-CARE		CARE	
			June 2016	January 2017	June 2016	January 2017
Rate 1	Summer	On Peak	34.5	34.8	24.2	24.3
		Off Peak	27.6	27.8	19.2	19.3
		Super Off Peak	23.0	23.2	15.9	16.0
	Winter	On Peak	27.5	27.3	19.1	18.9
		Off Peak	22.9	22.7	15.8	15.6
		Super Off Peak	22.9	22.7	15.8	15.6
	Baseline Credit		-9.9	-9.1	-6.9	-6.4
Rate 2	Summer	On Peak	53.3	55.2	37.8	39.0
		Off Peak	29.3	29.1	20.5	20.3
		Super Off Peak	17.3	17.6	11.8	12.0
	Winter	On Peak	27.9	27.6	19.4	19.1
		Off Peak	26.0	25.5	18.1	17.7
		Super Off Peak	17.4	17.7	11.9	12.0
	Baseline Credit		-9.9	-9.1	-6.9	-6.4
Rate 3	Spring	On Peak	24.9	25.0	17.2	17.3
		Mid Peak	21.0	21.1	14.4	14.4
		Off Peak	18.2	18.3	12.5	12.5
		Super Off Peak	9.9	10.0	6.5	6.5
	Summer	Super On Peak	37.0	37.0	26.0	25.9
		On Peak	22.6	22.6	15.6	15.5
		Mid Peak	18.8	18.7	12.8	12.7
		Off Peak	16.4	16.3	11.1	11.0
	Winter	Mid Peak	21.0	21.1	14.4	14.4
		Off Peak	18.2	18.3	12.5	12.5
		Super Off Peak	10.4	10.2	6.8	6.6
	All Seasons	0%-100%	15.7	16.3	10.2	11.0
		101%-200%	22.9	24.9	15.7	16.7
		200%- 400%	29.2	24.9	21.7	16.7
		400%+	29.2	31.4	21.7	21.1
Single Family Basic Charge/day			3.1	3.1	2.4	2.4
Multi Family Basic Charge/day			2.4	2.4	1.8	1.8
Min Charge/day			32.9	32.9	16.4	16.4
FERA Discount			12% discount on bill			

Table B-3: SDG&E Tariff Summary

Rate	Season	Period/Percent of Baseline	Non-CARE		CARE	
			August 2016	March 2017	August 2016	March 2017
Rate 1	Summer	Off Peak	34.9	38.0	22.1	23.5
		Peak	56.6	62.0	36.4	38.7
		Super Off Peak	29.7	32.0	18.9	20.3
		Baseline Credit	-20.3	-22.0	-13.0	-13.9
	Winter	Off Peak	36.2	40.0	22.8	24.7
		Peak	37.3	41.0	24.1	25.4
		Super Off Peak	35.1	39.0	22.1	24.1
		Baseline Credit	-18.6	-20.0	-12.4	-12.7
Rate 2	Summer	Off Peak	32.9	36.0	20.8	22.2
		Peak	56.6	62.0	36.4	38.7
		Baseline Credit	-20.3	-22.0	-13.0	-13.9
	Winter	Off Peak	35.8	39.0	22.8	24.7
		Peak	37.3	41.0	24.1	25.4
		Baseline Credit	-18.6	-20.0	-12.4	-12.7
OAT	Summer	130	19.1	21.0	11.7	12.7
		Over 130%	40.0	43.0	25.4	26.6
	Winter	130	17.5	20.0	11.1	12.0
		Over 130%	36.2	40.0	22.8	24.7
FERA Discount			12% discount on bill			

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 2
Page 1 of 1

Refer to the Alvarez Testimony, page 12, lines 15-16. Identify features and details that will not be mimicked in the broader rollout and how they should be modified.

RESPONSE:

As described on page 13, Mr. Alvarez believes the two most critical features and details which will not be mimicked in a broader rollout include the rebate rate per kWh (DEK proposes $0.33/kWh), and the feedback approach (DEK proposes a monthly bill credit, not specific as to any individual critical peak event, reflected on bills as long as two billing cycles after an event). Mr. Alvarez believes the proposed one-hour advance notice of some events serves as a third example of a feature or detail which will not be mimicked in a broader roll-out (testimony page 20).

As proposed on pages 19 and 20 of his testimony, Mr. Alvarez proposes the rebate rate per kWh be increased to between $1.00 and $1.25 per kWh, reflecting both energy and capacity value, to more closely mimic a broader rollout. As proposed on pages 21 through 23 of his testimony, Mr. Alvarez proposes prompt, event-specific rebate feedback be employed to more closely mimic a broader roll-out.

Regarding the proposed one-hour advance notice of some events, Mr. Alvarez recommends that such limited notice events be excluded from the pilot to more closely mimic a broader rollout.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 3
Page 1 of 1

Refer to the Alvarez Testimony, page 15, line 7, through page 16, line 2. Also refer to Duke Energy Kentucky, lnc.'s (Duke Kentucky) Response to the Attorney General's First Request for Information, Item 8. Provide a prioritization of the pilot program questions.

RESPONSE:

Mr. Alvarez's testimony at pp. 15-16 lists the questions to be answered in the priority Mr. Alvarez recommends. Regarding the questions DEK proposes in its response to AG DR 1-008, Mr. Alvarez notes that, other than question (f), responses to the questions DEK proposes are "yes/no" in nature. Given that the answers to Mr. Alvarez's questions will also answer the questions DEK proposes, Mr. Alvarez would prioritize his quantifiable response questions ahead of DEK's "yes/no" response questions. Of the DEK questions, Mr. Alvarez would prioritize question (f), "What reasonable enhancements, if any, could be made cost effectively to continue the PTR Program?"

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 4
Page 1 of 1

Refer to the Alvarez Testimony, page 19, lines 14-15. Provide support that the climate in Maryland is similar to that in Kentucky.

RESPONSE:

Mr. Alvarez responds that the latitude of DEK's service territory, as measured at Covington, KY, is 39.087° North, almost precisely the same as Maryland's largest population center, Baltimore, at 39.290° North.

Since receiving this data request, Mr. Alvarez has researched heating and cooling degree days in Covington and Baltimore in 2019, finding that the climates were similar (Source: www.weatherdatadepot.com).

	Heating Degree Days	Cooling Degree Days	Total Degree Days
Baltimore, MD	2,939	2,958	5,740
Covington, KY	3,453	2,385	5,838

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 5
Page 1 of 1

In his support for the recommended summer rebate rate, Mr. Alvarez used Duke Kentucky's July 2019 energy and avoided capacity costs. Explain why the other summer months for which the proposed critical rebate can occur were not also factored in the calculation.

RESPONSE:

Mr. Alvarez simply used July as an example. His example was not meant to serve as an exhaustive or definitive analysis.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 6
Page 1 of 1

Refer to the Alvarez Testimony, page 20, lines 5-14. Explain why a winter critical peak rebate was not calculated in a similar manner as the summer critical peak rebate, i.e. using the marginal price for energy at Duke Kentucky's three local pricing nodes and avoided capacity costs during PJM's winter peak.

RESPONSE:

As DEK is a summer-peaking utility, and as PJM is a summer-peaking capacity market, Mr. Alvarez believes that reductions in winter peaks will not reduce system peak, and further that reductions in winter peaks will have little generation capacity value and virtually zero transmission and distribution capacity value. As such, Mr. Alvarez questions the value of including winter peak events in the pilot at all, and explains why his testimony is less concerned with the winter critical peak rebate amount. He is unaware of any utilities which have used peak-time rebate for winter peak reductions, has no basis for making any winter peak rebate recommendations, and simply prioritized his testimony regarding rebate rates around the pilot question of greatest interest (summer demand reductions). His testimony admits that a different rebate for winter months might be preferable, but his experience base prohibited him from making informed recommendations as to what that amount should be.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 7
Page 1 of 1

Refer to the Alvarez Testimony, page 20, line 17 through page 21, line 15, which states that Duke Kentucky is prohibited from calling a critical peak event (CPE) if notice cannot be given by 9:00 p.m. the evening before, as many participants will not be home and thus will be unable to shift their loads. State whether Mr. Alvarez supports differing rebates as part of the pilot study based upon a call the evening before and "emergency" CPEs called an hour before.

RESPONSE:

Mr. Alvarez supports different rebates as part of the pilot study, as long as the sample size takes into account the variations introduced. For example, different rebate rates could be used with different test groups (for example, a high rebate group and a low rebate group), or for different types of notices (such as "evening before" vs. "emergency"), or for critical peak events called at different times of the year (summer vs. winter). However, Mr. Alvarez cautions that the greater the number of variables introduced, and the greater the number of questions the pilot is to answer, the larger the sample size required for a statistically significant result.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 8
Page 1 of 1

Refer to the Alvarez Testimony, page 22, lines 15-28. If the CPE program were a "default" program, as recommended, explain how those who have not chosen a notice channel should be notified of the amount of rebate earned.

RESPONSE:

Mr. Alvarez recommends mass media (local television and radio broadcasts) and social media (DEK's Twitter account, Facebook page, website, etc.) be used to distribute notifications of critical peak events to customers who have not chosen a notice channel. Obviously, these channels could not be used to notify individual customers of rebates earned, though these types of customers could always check their accounts online within a few days of an event to see if any rebate was posted. Finally, customers will eventually see any credits earned on their next bill. Mr. Alvarez notes that prompt feedback is an objective, not a requirement, for peak-time rebate programs.

WITNESS/RESPONDENT RESPONSIBLE:
Paul Alvarez

QUESTION No. 9
Page 1 of 1

Refer to the Alvarez Testimony, page 24, line 14, which states that, in Maryland, CPEs are limited to ten per summer. Also refer to the Alvarez Testimony, page 9, line 5, which states that a utility is authorized to call a CPE up to six times a summer. Reconcile these two statements.

RESPONSE:

Mr. Alvarez is familiar with peak-time rebate programs which allow up to six critical peak events per summer (Baltimore Gas and Electric) as well as programs which allow up to ten critical peak events per summer (Pepco).