Application No: A.18-11-______________
Exhibit No.: ______________________
Witness: Darren Hanway

Application of SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) to Establish a Demand Response Program	Application 18-11-___ (Filed November 6, 2018)

CHAPTER 1

SOUTHERN CALIFORNIA GAS COMPANY DEMAND RESPONSE PROGRAM

PREPARED DIRECT TESTIMONY OF

DARREN HANWAY

ON BEHALF OF

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

November 6, 2018

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DIRECT TESTIMONY OF DARREN HANWAY

I. OVERVIEW AND SUMMARY

A. Purpose

The purpose of my prepared direct testimony is to describe Southern California Gas Company's (SoCalGas) overall proposal for SoCalGas' Demand Response (DR) Program, including its scale and timeframe, after the 2018-2019 winter season DR program[1] is scheduled to end on March 31, 2019. The SoCalGas DR Program is intended to be specific to its service territory and builds on SoCalGas' actual experience with the 2016-2017 and 2017-2018 winter season DR programs with an overall structure modeled after DR programs the California Public Utilities Commission (Commission) has authorized for electric utilities. The total estimated costs included for approval in this Application are $62.8 million.

This amount includes the cost estimates associated with the proposed DR Program discussed in this testimony, the Energy Data Sharing Platform (EDSP) described in Chapter 2, Direct Testimony of Nancy Carrell Lawrence, and the winter notification marketing campaign component described in Chapter 3, Direct Testimony of Toni Mathews, as well as the costs recorded in the Winter Demand Response Memorandum Account (WDRMA) and specific costs recorded in the Marketing, Education and Outreach Memorandum Account (MEOMA) as described in Chapter 4, Direct Testimony of Reginald M. Austria and Michael Foster. Additionally, my testimony will provide an overview and background for the WDRMA discussed in Chapter 4.

[1] The 2018-2019 winter season DR Program was authorized in Resolution (Res.) G-3522, Advice Letter No. (AL) 5223 and AL 5303.

B. Background

On August 22, 2016, the Joint Agency Winter Action Plan determined that there was a possibility of gas curtailments in winter 2016, particularly on peak winter days.[2] The Joint Winter Action Plan proposed ten measures to mitigate the risk and magnitude of natural gas curtailments and electricity service interruptions for the 2016-2017 winter season. Among those recommended measures was the development and implementation of natural gas DR programs for core and noncore customers. In accordance with the Winter Action Plan, on September 13, 2016, the Director of the Commission's Energy Division required SoCalGas to develop and submit to the Commission a proposal for DR programs in its service territory for the winter of 2016-2017.[3] Pursuant to the Commission's Energy Division directive to develop a Winter DR Program for customer participation by December 1, 2016, SoCalGas submitted an expedited advice letter (AL 5027) requesting approval for the establishment of the WDRMA On September 15, 2016.[4] Additionally, SoCalGas submitted AL 5035 on September 27, 2016, which proposed three new winter DR programs that ran from December 1, 2016 through March 31, 2017: (1) the Natural Gas Conservation Notification Campaign (2) the Noncore, Non-Electric Generation, Natural Gas Conservation Notifications, and (3) the Natural Gas Conservation Pilot Rebate Program.

SoCalGas' Natural Gas Conservation Notification Campaign (also known as SoCalGas Advisory) targeted all core customers in SoCalGas' service territory with the goal to stimulate

[2] Aliso Canyon Gas and Electric Reliability Winter Action Plan.
[3] Letter from Energy Division Director to SoCalGas directing SoCalGas to file winter demand response programs for the winter of 2016, http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/9-13-016%20Letter%20from%20Energy%20Division%20to%20SCG%20on%20Winter%20Demand%20Response%20Programs.pdf.
[4] AL 5027 was made effective on September 30, 2016.

voluntary reductions in gas usage on days when SoCalGas system reliability was anticipated to be stressed – similar to the statewide California Independent System Operator (CAISO) "Flex Alert" campaign. On event days, public notifications encouraging consumers to reduce gas usage were deployed through mass media channels, such as radio, digital radio, and digital displays.

SoCalGas' Noncore, Non-Electric Generation, Natural Gas Conservation Notifications targeted all noncore customers with a goal similar to the Natural Gas Conservation Notification Campaign by posting "Natural Gas Conservation" notifications to SoCalGas' Electronic Bulletin Board (EBB) on days when SoCalGas system reliability was anticipated to be stressed. These notifications were supplemented by direct communication between SoCalGas Account Executives to noncore customers requesting customers voluntarily reduce gas consumption to decrease stress on the gas system.

SoCalGas' Natural Gas Conservation Pilot Rebate Program targeted core customers in SoCalGas' service territory and launched as a pilot rebate program that would evaluate the effectiveness of using rebates to incent reduced gas usage in response to Natural Gas Conservation Notification Campaign events. The program focused on several different segments such as residential customers with MyAccount, residential customers without MyAccount, highest using core commercial and industrial (C&I) customers, and core transport agents (CTA) customers, and also included a pilot tailored to residential customers with smart thermostats. During a Natural Gas Conservation event, SoCalGas emailed SoCalGas Advisory notifications to the four pilot groups and worked with smart thermostat vendors to automatically adjust customers' temperature settings in response to the event for those customers in the smart thermostat group. A primary goal of this pilot was to determine the program's ability to produce energy reductions on peak days.

SoCalGas called two events during the 2016-2017 winter season and issued mass market messaging to all core customers as well as targeted messaging for the pilot rebate programs. The first event was from December 18 through 20, 2016 and the second from January 23 through 26, 2017 for a total of seven days. The load impact evaluation is attached as Appendix A. The total amount of gas usage reduced was 792 therms.[5]

On November 16, 2017, the Director of the Commission's Energy Division issued a letter directing SoCalGas to submit an expedited Tier 2 advice letter proposing a device-based DR program by November 28, 2017. Additionally, the letter directed SoCalGas to include in its proposal a technology assessment for hot water heaters. On November 28, 2017, SoCalGas submitted AL 5223 proposing winter demand response program pilots focused on reducing natural gas usage during morning and evening system peak periods by adjusting temperature settings on customers' smart thermostats. In its 2017-2018 DR programs, SoCalGas continued implementation of the smart thermostat load control program first established as part of the 2016-2017 winter season DR programs. SoCalGas enrolled 9,267 customers and 10,798 smart thermostats into the program and called 13 activations during the 2017-2018 winter season. The load impact evaluation results showed that, on average, each participant reduced their usage between 16-25% equating to 0.03-0.05 therms during the morning event period and between 10.7%-15.6% equating to 0.012-0.019 therms during the evening event period.[6] The impact evaluation report is attached as Appendix B.

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[5] SoCalGas 2016-2017 Demand Response Impact Evaluation, p. 2.
[6] SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation, pp. 1-3.

SoCalGas also performed a demonstration project for gas water heaters to receive a signal during a DR event. SoCalGas conducted equipment testing on a Wi-Fi module controller (module) that can be attached to gas water heaters. Several testing scenarios were developed that focused on water heater temperature, hot water consumption, and household occupants by simulating a hypothetical morning event during which the water heater setpoints were lowered for a period of one to three hours. The results of the demonstration showed that the module was able to control the water heater temperature as intended by the manufacturer. The average water temperature change in the hot water output did not exceed 10 degrees Fahrenheit while the average temperature in the storage tank dropped based on the amount of water used during the event.[7] The full demonstration report is attached as Appendix C.

On April 12, 2018, the Director of the Commission's Energy Division issued a letter requesting SoCalGas to submit a Tier 2 advice letter to continue the smart thermostat device-based DR program by June 2018 and to file an application for DR programs by November 2018. This Application is filed consistent with this direction.

In addition, the United States Senate is reviewing introduced legislation that would direct the Department of Energy (DOE) to establish pilot programs and to study the benefits and challenges of natural gas DR programs.[8] The legislation would require the DOE to also identify areas that would most benefit from gas DR programs. Should the legislation be adopted and the DOE selects Southern California as a regional pilot area, SoCalGas will apply to implement one of the gas DR pilot programs.

II. OVERVIEW OF SOCALGAS' DR PROGRAM

SoCalGas' DR Program is comprised of the following four primary components:

[7] Rheem Econet WiFi Water Heater Control Module Test, p. 14.
[8] United States Senate Bill S.2649, https://www.congress.gov/bill/115th-congress/senate-bill/2649/text.

1. DR Pilot Programs – SoCalGas proposes to establish the following four DR pilot programs that are aimed at voluntarily reducing and deferring natural gas usage during system peak periods.

- Space Heating Load Control (SHLC) Pilot;
- Water Heating Load Control (WHLC) Pilot;
- Load Reduction Pilot (LRP); and
- Behavioral Messaging Pilot.

The pilots will run for a three-year period (2019-2022)[9] and are focused on several areas including residential customers, nonresidential customers, and behavioral programs. A description of these pilot programs is below.

2. Gas DR Emerging Technologies Program – SoCalGas proposes to establish an emerging technology program with the purpose of testing new gas equipment that may support future DR efforts. Additional details for the Gas DR Emerging Technologies Program is below.

3. Winter Notification Marketing Campaign – SoCalGas proposes to implement a winter notification marketing campaign, which is presented in Chapter 3, Direct Testimony of Toni Mathews.

SoCalGas is also proposing to develop an EDSP that complements the DR Program as presented in Chapter 2, Direct Testimony of Nancy Carrell Lawrence.

III. PROPOSED DR PILOT PROGRAMS

SoCalGas is one of the first natural gas utilities to pilot natural gas DR programs in the country and, therefore, many of the proposed pilot designs were designed and adapted based on

[9] Depending on the success of these DR pilot programs and consistent with the electric DR program regulatory structure, SoCalGas will consider filing another application to continue the implementation of natural gas DR programs beyond 2022.

electric DR programs that are being implemented today.[10] Thus, one of the main goals of the pilots is to develop the data and experience necessary to analyze the appropriate DR program designs for natural gas. The pilots will allow SoCalGas to assess whether its customers are receptive to the DR Program's incentives and program designs and whether the DR Program can impact reliability of the natural gas system during times of system stress.

A. Space Heating Load Control (SHLC) Pilot

The SHLC pilot will be aimed at connecting with open automated demand response (OpenADR)[11] enabled equipment connected to space heating equipment and calling on those capabilities to reduce gas usage during periods when there is anticipated stress on the gas system.[12] The SHLC pilot has been structured based on lessons learned from SoCalGas' prior winter DR programs. As discussed in more detail below, the SHLC pilot will continue to target residential customers, with added participation of nonresidential customers with eligible smart thermostats. SoCalGas will also allow other space heating controls and energy management systems to participate, thus increasing the potential for SoCalGas to recruit more participants and to pilot the effectiveness of commercial and industrial buildings in load reduction.

1. Program Background and Overview – Residential Customers

For residential customers, SoCalGas proposes to continue its Smart Thermostat Load Control Pilot (also known as Smart Savings Program) that offers customers with smart thermostat incentives for deferring their energy usage during scheduled DR event periods during

[10] On August 9, 2018, the New York State Public Service Commission approved a $5 million program for Consolidated Edison Company of New York, Inc. to reduce residential and commercial customer demand for natural gas.
[11] OpenADR refers to a standardized communications data model and specifications for sending and receiving DR signals.
[12] SoCalGas may activate "DR event(s)" during these times.

the winter season. Participants receive an initial one-time $50 incentive for signing up and a yearly $25 incentive at the conclusion of every winter for participating in the program.

As more smart thermostats continue to penetrate into SoCalGas' territory, SoCalGas expects that the number of participants will increase year over year. SoCalGas has targeted 50,000 thermostats enrolled in the Smart Savings Program by the end of the 2018-2019 winter season. It is anticipated that 7,000 new enrollments will occur every year.

SoCalGas hired a contractor to conduct an impact evaluation on the 2017-2018 winter season Smart Thermostat Load Control Program, which involved two smart thermostat vendors.[13] Gas load impacts (usage reductions) on DR event days were estimated by applying the best practices that have been developed for electric DR program measurement and evaluation in California. The study showed thermostat setback strategy was important and can significantly affect the size of the load reductions and the post-event "snap back," as shown by the difference in vendor performance. The average load reduction for a Vendor 1 morning DR activation was 0.031 therms per participant leading to an aggregate reduction of 217.152 therms, or 16.0%.[14] The average load reduction for a Vendor 1 evening DR activation was 0.012 therms, leading to an aggregate reduction of 81.795 therms, or 10.7%.[15] The average load reduction for a Vendor 2 morning DR activation was 0.050 therms, leading to an aggregate reduction of 102.308 therms, or 25.0%.[16] The average load reduction for a Vendor 2 evening DR activation was 0.014 therms, leading to an aggregate reduction of 37.768 therms, or 15.6%.[17] Vendor 2 DR impacts were

[13] Nexant, *SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation*, August 14, 2018, p 1.
[14] SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation, p 2.
[15] *Id.*
[16] *Id.*
[17] *Id.*

consistently larger than Vendor 1 DR impacts, and both vendors saw morning DR impacts that were larger than evening DR impacts.

a) Revisions from Previous Program

During the 2017-2018 winter season, SoCalGas partnered with two smart thermostat manufacturers. SoCalGas intends to partner with at least four smart thermostat manufacturers during the 2018-2019 winter season. The Smart Savings Program will continue to allow other manufacturers and their customers' participation through 2022. SoCalGas will be changing the current yearly $25 participation incentive into a performance-based model to increase participation during events. SoCalGas anticipates that a performance-based model will increase participation, decrease free-ridership, and ultimately result in bigger load impacts than the results evaluated in the 2017-2018 winter season.

Finally, SoCalGas will be introducing new features that will allow participants to be notified of their energy usage reduction via email reports and smart speaker voice assistants. This is an innovative pilot to provide near real-time feedback to participants about how much energy they saved during DR events.

b) Incentive Structure

For residential customers with smart thermostats, new participants that sign up for the program will continue to receive an initial $50 per thermostat incentive from SoCalGas. SoCalGas proposes that the participation incentive be changed to reflect actual participation such that participants will need to participate in at least 50% of the events to be eligible for the performance incentive. Each participant would be eligible for the performance incentive every winter. The total amount of gas consumption deferred and the customers' participation will be evaluated and totaled after the winter period.

2. Program Background and Overview – Non-residential Customers

Non-residential customers with load control devices on space heating equipment such as furnaces, boilers, thermostats, and energy management systems may participate in the pilot. SoCalGas will also explore the inclusion of controls that will signal direct load control devices to shut down the electric components of the equipment rather than shutting off the pilot light on furnaces, boilers, or other natural gas-fired equipment, as is currently being tested in New York.[18]

Similar to residential thermostats, non-residential customers will receive an OpenADR signal that there is a pending DR event. Signaled equipment will then implement control strategies to reduce natural gas consumption. Customers will have the option of overriding the adjustments; however, this would result in disqualification from the performance incentive for that DR event. DR events may be activated during times of system stress for both the morning and evening periods.

a) Incentive Structure

For nonresidential customers, SoCalGas proposes an initial sign-up incentive based on the gas energy input rating of their space heating equipment. This incentive will be $500 per million BTUH input, up to $1,000 per application per facility. Customers will also be eligible for a performance incentive based on their performance during DR events, provided they participate in at least 50% of events called. Performance payments are calculated based on an established customer baseline and will be paid on a $10/therm saved for core customers and

[18]Navigant Research, *Natural Gas Demand Response and Non-Pipes Solutions as Alternatives to Pipeline Expansion*, Q32018, available at https://navigantresearch.com/reports/natural-gas-demand-response-and-non-pipes-solutions-as-alternatives-to-pipeline-expansion

$5/therm saved for noncore customers, with a maximum of $10,000 per winter season per facility.

3. SHLC Pilot Budget

SoCalGas proposes a total budget of $19.767 million for the SHLC pilot for the winter seasons between 2019-2022. A breakdown of the SoCalGas' requested SHLC Pilot budget by winter season is provided in Table 1-1 below. The program budget reflects the anticipated increase in enrollments for residential and non-residential customers every year and considers marketing and implementation costs by SoCalGas and its future program partners.

Table 1-1: Proposed Budgets Space Heating Load Control Pilot

	Winter 2019/20	Winter 2020/21	Winter 2021/2022	Total
Budget ($000's)	$5,786	$6,575	$7,406	$19,767

B. Water Heating Load Control (WHLC) Pilot

1. Program Background and Overview

The WHLC pilot will be aimed at connecting with OpenADR-enabled equipment connected to water heating equipment to reduce gas usage during DR events when the gas system is stressed. The pilot will be available to residential and nonresidential customers.

This pilot is informed with the results of SoCalGas' concluded demonstration project on DR capabilities and potential savings on residential gas water heaters as submitted in AL 5223. The results of the demonstration project estimate that residential water heater controllers can be used to reduce gas consumption load. The most impactful event strategy would be to turn the gas water heater to vacation mode rather than reducing the water temperature setpoint.[19]

Under this pilot, water heaters will be signaled to lower water temperatures during times of system stress. The pilot will recruit residential as well as nonresidential customers with DR-

[19] Rheem Econet WiFi Water Heater Control Module Test, p. 18.

enabled water heating equipment by promoting the sign-up and performance incentive detailed below. SoCalGas plans to leverage its existing energy efficiency (EE) rebates program to cross-promote more efficient water heating equipment with DR capabilities and the WHLC pilot. Customers will be able to apply for EE rebates and enroll in the water heater DR pilot through a single application in a seamless process.

The WHLC pilot will also include a direct install component, similar to the direct install programs under SoCalGas' Energy Efficiency portfolio, to get more DR-enabled devices into the market. SoCalGas will be install water heating controllers on compatible water heating equipment for interested customers. Customers who receive direct install water heating equipment will be automatically enrolled into the pilot. Existing vendors under contract with SoCalGas through the EE Program will be used to install water heating equipment controllers.

Events under the WHLC pilot will be structured around gas system morning and/or evening peak periods and customers will be notified beforehand that a DR event will be occurring. An hour before the DR event occurs, the water heating equipment will pre-heat the water and then automatically adjust the water heater to vacation mode or to a lower temperature setting. Once the DR event is over, water heating setpoints will be restored to their initial settings. SoCalGas will also explore the inclusion of controls that will shut down the electric components of gas equipment to prevent usage of equipment during peak periods without shutting off the pilot light.

SoCalGas estimates that there are about 300 DR-enabled residential water heaters in its service territory. The number of participants in the pilot period is estimated to be 500 for the 2019-2020 winter season, 1,000 for the 2020-2021 winter season, and 1,500 for the 2021-2022 winter season.

2. Incentive Structure

Residential customers with existing water heater DR capabilities will receive a $50 incentive for signing up for the pilot and a $25 performance incentive, which is based on participation in at least 50% of the DR events called. Customers who receive a controller through the direct install approach will only be eligible for the performance incentive based on participation in at least 50% of the DR events called. Customers that have already enrolled in the Smart Savings Program will not be eligible for the sign-up incentive under the WHLC pilot; however, these participants will be eligible for the performance incentive.

Nonresidential customers with existing water heater DR capabilities will receive a sign-up incentive based on the gas energy input rating of their equipment. This incentive will be $500 per million BTUH input, up to $1,000 per application. Customers who receive a controller through the direct install approach will only be eligible for the performance incentive based on participation in at least 50% of the DR events called. Similar to the SHLC Pilot, the performance incentive will be based on established baselines and customers will receive $10/therm reduction for core customers, $5/therm reduction for noncore customers, with a maximum of $10,000 per season per facility. Customers are eligible for a performance incentive only if they participate in at least 50% of the DR events called.

3. WHLC Pilot Budget

SoCalGas proposes a total budget of $6.137 million for the WHLC pilot for the winter seasons between 2019-2022. A breakdown of the SoCalGas' requested WHLC Pilot budget by winter season is provided in Table 1-2 below. The program budget reflects the anticipated increase in enrollments every year and considers marketing and implementation costs by SoCalGas and its future program partners.

Table 1-2: Proposed Budgets of Water Heating Load Control Pilot

	Winter 2019/20	Winter 2020/21	Winter 2021/2022	Total
Budget ($000's)	$1,445	$2,049	$2,643	$6,137

C. Load Reduction Pilot (LRP)

1. Program Background and Overview

The LRP is a voluntary program targeted at commercial and industrial customers for reducing natural gas consumption during the winter season. SoCalGas' commercial and industrial customers can be segmented based on the end-use of natural gas, how much they consume, and which tariff rate they are on.[20] In 2017, SoCalGas' commercial and industrial customers consumed over 4 billion therms. Natural gas is used in a variety of ways, including water heating, space heating, cooking, manufacturing, and feedstock for the production of industrial gases. With adequate economic incentives, commercial and industrial customers may be able to reduce gas load by shifting or delaying processes to an off-peak time.

SoCalGas expects that most LRP participants will be commercial and service establishments that do not have a strong dependency on natural gas to provide the majority of their services. These establishments such as retail, warehouses, schools, and office buildings typically use natural gas mainly for space heating and/or water heating. Reductions in this type of usage could be less impactful to these customers in contrast to industrial customers who would need to curb manufacturing process loads in order to participate. Although SoCalGas expects more applicants from the lower natural gas consuming commercial sector, it is possible for a small number of high natural gas consuming industrial customers to substantially reduce natural gas consumption during a DR event. Generally, the manufacturing of products is highly dependent on natural gas usage for many industrial customers. For some industrial customers,

[20] Tariff rate schedules include portions or all of GM, G-10, G-EN, G-AC, GT-NC, GT-TLS.

however, it may be economically beneficial to reduce usage or shift a portion of their output to another time in order to take advantage of the pilot's DR incentive. SoCalGas expects to concentrate its outreach efforts for the LRP on its largest gas users in an effort to achieve the most load reduction during DR events. SoCalGas account executives will conduct outreach and educate large gas users about LRP and will be available to help with submitting applications.

At the program application stage, applicants will indicate how they plan on reducing load and will be required to estimate how much load can be reduced for each DR event day. DR events will be called by SoCalGas during periods of anticipated system stress. Test events may also be called from time to time in order to assess the effectiveness of the program. Customers will receive performance incentives for participation in events but will not be penalized for not participating. DR events (including test events) will, at a minimum, last for 24 hours starting from 12:00 am and may be extended depending on system needs. DR events will not last more than five days. There will be up to ten DR event days per winter season. Customers will be notified at least 24 hours in advance of the start of a DR event. SoCalGas will enroll customers directly as well as explore having customers participate through DR aggregators, similar to electric DR providers.

SoCalGas estimates that the LRP has the potential to reduce consumption by 22,172 therms per day. This estimate is based on results achieved in the DR Program for the 2017-2018 winter season. Assuming SoCalGas enrolls 1% of commercial and industrial customers in the LRP, and if the average savings per DR event was 20% (or between 16% to 25%), SoCalGas has estimated total therm savings achieved through the LRP as presented in Table 1-3.

Table 1-3: Estimated Annual Consumption and Incentive Payout of LRP

Segment	Usage (therms)	# of customers	Avg Usage (therms/yr/acct)	Avg Usage (therms/day/acct)	Therms saved/day
Core C&I	1,149,793,577	211,444	5,438	14.9	6,300
Noncore C&I	2,896,383,633	574	5,045,965	13,825	15,872
				Total	**22,172**

2. Incentive Structure

The incentive structure consists of three main components – Base usage, Reservation, and Performance incentives. Table 1-4 provides an overview of the incentive structure for these three components.

a) Base Usage Methodology

For each DR event, SoCalGas will establish a customer base usage value against which gas savings during the event can be measured. Weekday base usage is calculated by taking average of the highest five of ten previous weekdays. Saturday and Sunday base usage will be calculated by taking the average of the highest two of four previous Saturdays and Sundays, respectively. SoCalGas may consider other methodologies to the extent this method appears to be unsuccessful.

b) Reservation Incentive

When a customer enrolls in the LRP, they will specify how much gas demand they plan to reduce per DR event day. This is used to calculate the reservation value portion of the incentive rate. The reservation incentive is calculated monthly and is based on a performance ratio, which is the ratio of actual load reduction compared to the specified reservation volume. Actual load reduction is the difference between the customer's calculated base usage minus their actual consumption during the event day. The performance ratio used to calculate the reservation value will not exceed 100%. For months that have multiple DR events, the performance ratio for the month will be the average performance ratio of all events in the month, including test events. If there is no DR event (including test events) called in a given month, the performance ratio will default to 1. Customers earn their monthly reservation incentive by having an average performance ratio of at least 10% of their reservation value. Average performance ratios below 10% of reservation value will not receive incentives. The maximum reservation incentive will be $50,000 per month, per facility.

c) Performance Incentive

For each DR event day, actual usage reduction will be incentivized for each therm reduction achieved. The maximum incentive payout for a DR event will not exceed $50,000 per event day, per customer, and will be paid out only if the customer achieves performance ratios exceeding 10% of the stated reservation value. Table 1-4 outlines the incentive rate structure for commercial and industrial customers:

Table 1-4: Incentive Structure for LRP

Incentive	**Description**	**Core Rate**	**Noncore Rate**
Reservation Incentive	Base rate provided for participation during each event	$10/Therm-day per DR month	$5/ Therm-day per DR month
Performance Ratio	Estimated and actual load reduction will be compared, and results applied to the Reservation Incentive	<=100%	<=100%
Performance Incentive	Performance incentive provided for participation during each event.	$2/Therm	$1/Therm

3. LRP Budget

Table 1-5 below provides SoCalGas' requested budget for the 2019-2022 winter seasons. The budget is based on incentive levels and targeted number of participants as described above.

Table 1-5: Proposed Budget of LRP

	Winter 2019/20	Winter 2020/21	Winter 2021/2022	Total
Budget ($000's)	$926	$1,437	$1,950	$4,313

D. Behavioral Messaging Pilot

1. Program Background and Overview

SoCalGas proposes to pilot different messaging tactics to engage customers to reduce natural gas usage during periods of system stress. SoCalGas will also be utilizing several tactics to engage customers through behavioral messaging to achieve these purposes and will solicit third-party implementers to pursue the campaigns mentioned below. The success of these pilots also depends on being able to automatically transfer customer usage data to third-party implementers under contract to SoCalGas. In this Application, SoCalGas is requesting funds to develop an EDSP which aims at providing capabilities to transfer customer usage data to third-party implementers as stated in Chapter 2, Direct Testimony of Nancy Carrell Lawrence.

a) Application-Based Messaging

Similar to programs implemented on the electric DR side,[21] SoCalGas will solicit a mobile application-based company to sign-up and notify customers of event days during periods of system stress and request customers to reduce their gas usage. Potentially, customers would be eligible for points and rewards that could be used to purchase equipment and other items. Design of the application-based messaging will be solicited by SoCalGas and proposed by third-party vendors.

[21] Southern California Edison AL3797-E, Pacific Gas & Electric AL 5284-E, and San Diego Gas & Electric AL 3218-E

b) Energy Report and Email Messaging

SoCalGas has concluded several winter seasons of sending home energy reports to customers to promote gas conservation and energy savings. The results of this action show that customers save between 1% - 3% of gas usage during the winter months.[22] SoCalGas proposes to implement a similar type report focusing on peak day and event day education and messaging via paper reports and emails. Customers will receive reports showing the impact they had during event and non-event days.

2. Behavioral Messaging Pilot Budget

SoCalGas proposes a total budget of $1.310 million for the Behavioral Messaging Pilot for the winter seasons between 2020-2022. A breakdown of the SoCalGas' requested Behavioral Messaging budget per winter season is provided in Table 1-6 below. SoCalGas has budgeted for compensating an Application-Based Messaging vendor based on an administration fee and a performance fee for actual therms saved during events. Budgets relating to the Energy Report and Email Messaging pilot is based on SoCalGas' historical experience with Home Energy Reports.

Table 1-6: Proposed Budgets of Behavioral Messaging Pilot

Behavioral Messaging Pilot				
	Winter 2019/20	Winter 2020/21	Winter 2021/2022	Total
Budget ($000's)	$0	$594	$716	$1,310

E. Gas DR Emerging Technologies Program

1. Program Overview

Similar to the demonstration project on connectivity and load reduction for residential gas water heaters conducted during 2017/2018, SoCalGas proposes to research, demonstrate, and test

[22] Evaluation of Southern California Gas Company's 2016-2017 Conservation Campaign, pp 1-4.

new gas equipment and add-on controls that would be able to respond to OpenADR signals for the residential and commercial sectors. These signals will then automatically cycle off or reduce gas usage via shutting down the electronic ignition, adjust temperature settings to a lower setpoint, or turn equipment to vacation mode. Testing will be conducted at SoCalGas' Engineering Analysis Center (EAC) located in Pico Rivera. SoCalGas will seek to incorporate equipment and controls that are successfully tested into the DR pilots proposed in this Application for the following winter season. SoCalGas plans to use the funds dedicated here to engage original equipment manufacturers (OEMs) to develop integrated, interconnected equipment. Funds may also be used to test equipment with a DR management system (DRMS) to verify connectivity.

The program will explore the increasing role of integrated distributed energy resources (IDER) and how gas DR equipment may play a bigger role in the future to address system needs. Additionally, funds will be used to develop a roadmap and execute integrated DR and EE incentives via integrated demand side management (IDSM). Providing additional incentives for equipment that serve both EE and DR functions will help customers overcome cost barriers, while helping to defer gas usage during peak periods. Bundling EE and DR measures is another avenue SoCalGas will explore so customers receive holistic solutions to cover multiple systems and whole building approaches to energy management.

2. Program Budget

SoCalGas proposes a total budget of $2.552 million for the Gas DR Emerging Technologies Program for the winter seasons between 2020-2022. A breakdown of the SoCalGas' requested Gas DR Emerging Technologies budget per year is provided in Table 1-7 below. The program budget is based upon testing approximately two to three technologies per year as well as providing funds to aid research and development of interconnected equipment with OEMs.

Table 1-7: Proposed Budgets of DR Emerging Technologies Program

Gas DR Emerging Technologies				
	2020	2020	2022	**Total**
Budget ($000's)	$843	$850	$859	$2,552

IV. EVALUATION, MEASUREMENT & VERIFICATION (EM&V)

The following section describes the measurement & evaluation (M&E) and load impact activities associated with SoCalGas' DR pilots. SoCalGas' evaluation plan includes load impact and process evaluations to look at the design, operation, and effectiveness of the DR pilots. Load impacts will use the best practices that have been developed for electric DR program measurement and evaluation in California. Additionally, SoCalGas will conduct a market assessment on gas DR and compile a whitepaper to develop a cost-effectiveness methodology looking at the benefits and costs associated with natural gas DR implementation.

A. EM&V Studies Overview

SoCalGas will conduct studies on the proposed pilots to help identify successfulness, barriers, and lessons learned to inform future program designs. The studies may be staggered based on current knowledge (i.e., SoCalGas has already conducted a residential smart thermostat pilot and associated evaluation), timing since most studies need at least one year of data, and resource constraints due to budget and staff time. Table 1-8 below provides an overview of potential evaluations and assessments based on study type and by DR pilot.

Table 1-8: Proposed EM&V Studies

Study Type	Description & Pilots to Cover	Year to Begin Study
Load Impact Evaluations	Load impact evaluations will evaluate and measure the gas usage reduced during DR events. Evaluations will utilize advanced meter hourly interval data to determine *ex post* load impacts. Load impacts will be compared against *ex ante* impacts. Load impact evaluations will cover the following pilots: • SHLC Pilot • WHLC Pilot • LRP • Behavioral Messaging Pilot	Internal analysis: After every Winter Season Full Impact Evaluation: After each Winter Season
Process Evaluations	Process evaluations will measure customer experience with the DR pilots. Surveys, interviews and/or focus groups of participants and non-participants will be utilized. Evaluation will also develop metrics that look at successes that may differ from load impacts. Process evaluations will cover the following Pilots: • SHLC Pilot • WHLC Pilot • LRP • Behavioral Messaging Pilot	Preliminary analysis: After each Winter Season Full Process Evaluation: After 2020/2021 Winter Season
Market Assessment	Market assessment will investigate potential customer participation in gas DR programs. The assessment will be broad enough to cover multiple customer segment including customers who may be enrolled in electric DR programs already.	2020
Cost-Effectiveness Whitepaper	SoCalGas will launch a study to develop a cost-effectiveness methodology for gas DR and develop inputs. The methodology and inputs will be used to calculate the cost-effectiveness of the pilots at the end of the pilot period.	2020-2021

B. *Ex Ante* Load Impacts

Table 1-9 estimates *ex ante* load impacts based on the 2017-2018 load impact evaluation on Smart Thermostat Load Control program, SoCalGas' demonstration project on gas water heater controllers, and anticipated enrollment and gas usage reduction from the other pilots. *Ex post* load impact results from EM&V studies will provide more accurate *ex ante* load impacts once completed. SoCalGas plans to update *ex ante* load impacts after every winter season.

Table 1-9: Estimated Load Reduction Impacts by DR Pilot

Pilot	Winter 2019/20	Winter 2020/21	Winter 2021/22	Total
SHLC Pilot	16,400	17,800	21,700	55,900
WHLC Pilot	2,650	5,300	7,950	15,900
LRP	50,000	110,000	221,720	381,720
Behavioral Messaging Pilot	N/A	3,000	5,000	10,000

C. Modifying Pilots Based on Evaluation Results

SoCalGas expects to refine pilot designs season by season with the learnings, experiences, and customer feedback obtained in the following areas through EM&V evaluations:

1. Test Customer Engagement

The level of customer participation and engagement in each pilot will be used to evaluate success of the pilot designs and incentive payment structures. SoCalGas will interview participants after every season to improve upon pilot structures and to analyze the appropriate incentive levels that will move customers to enroll in the DR Programs.

2. Test Third-Party Engagement

Third-party DR implementers that participate in gas DR will be vital to the success of the pilots. SoCalGas will explore using DR management systems and third-party aggregators with expertise in designing programs and recruiting customers. Engagement from the vendor community will help determine if there is a long-term interest in gas DR programs. This is a new developing area that would require interest from the DR industry for long-term success.

3. Evaluate Load Impacts

Finally, SoCalGas will use data from the pilots to evaluate load impacts attributable to the pilot and to determine the overall amount of each pilot's impact on the natural gas system. Pilots that show the ability to defer and/or reduce gas usage during events could be scaled up. Pilots that show a lack of success can be ramped down and learnings from such pilots could be used to inform the development of future programs.

D. Cost-effectiveness

Given the newness of natural gas DR programs, SoCalGas has not included a cost-effectiveness showing in this Application. At this time, there is no established methodology to measure the cost-effectiveness of natural gas DR programs. To address this, SoCalGas proposes to develop a cost-effectiveness methodology during the pilot period and conduct a cost-effectiveness analysis of the DR pilots at the end of the 2021-2022 winter season. SoCalGas proposes that the cost-effectiveness methodology be subject to an Energy Division-led workshop, similar to the process used to develop a cost-effectiveness protocol for electric demand response as outlined in D.10-12-024.

V. BUDGET

SoCalGas requests a total of $36.123 million to implement the DR Pilots, Gas DR Emerging Technologies Program, and EM&V activities discussed above. Subject to Commission approval, SoCalGas anticipates that pilots will start by December 2019 and conclude March 2022. Incentive payments to customers will continue beyond March 2022 but the calling of DR events will conclude after the 2021/22 winter season. SoCalGas anticipates funding levels to increase year over year as the pilots ramp up and more customers enroll.

Table 1-10 lists budgets for each DR pilot by program year. This differs from the sections above which list the DR pilot budgets based on winter season. SoCalGas will not exceed the total DR pilot budget amount, but itemized budgets for the DR pilots may adjust within winter seasons and between pilots during SoCalGas' DR Program time period. This will allow SoCalGas to move funds from pilots that are performing poorly to pilots that are more successful and need additional funding.

Table 1-10: Annual Budgets by DR Pilot

Pilot ($000's)	2020	2021	2022	Total
SHLC Pilot	$5,786	$6,575	$7,406	$19,767
WHLC Pilot	$1,445	$2,049	$2,643	$6,137
LRP	$926	$1,437	$1,950	$4,313
Behavioral Messaging Pilot	$0	$594	$716	$1,310
Gas DR Emerging Technologies Program	$843	$850	$859	$2,552
Evaluation, Measurement, & Verification	$538	$691	$815	$2,044
Total	$9,538	$12,196	$14,389	$36,123

A. Winter Demand Response Memorandum Account (WDRMA)

On September 15, 2016, SoCalGas established the WDRMA pursuant to the direction from the Commission's Energy Division to establish a 2016-2017 winter demand response (WDR) program.[23] The WDRMA was used to track all costs associated with the 2016-2017 WDR Programs. On November 28, 2017, pursuant to the direction of the Commission's Energy Division, SoCalGas revised the WDRMA to establish the 2017-2018 and 2018-2019 WDR Program subaccounts of the WDRMA to track all costs associated with the WDR Programs

[23] SoCalGas submitted AL 5027 on September 15, 2016 requesting approval for the establishment of the WDRMA. On September 30, 2016, Energy Division issued a disposition letter approving AL 5027.

during those two winter seasons. In the September 30, 2016 Energy Division disposition letter on AL 5027, Energy Division noted that it could not determine the cost allocation or recovery of the 2016-2017 DR Program at that time because Energy Division had not approved a winter DR Program, nor determined the cost responsibility of the program. Therefore, Energy Division noted that cost recovery and allocation of the balance of the WDRMA would be determined in a future proceeding.

As discussed in the Direct Testimony of Reginald M. Austria and Michael Foster, SoCalGas proposes to incorporate the balance of the WDRMA, which includes costs associated with the 2016-2017, 2017-2018, and 2018-2019 winter seasons, in the Public Purpose Program surcharge rate. SoCalGas believes this application is the appropriate venue to seek cost recovery of the WDR Program costs incurred during the 2016-2017 and 2017-2018 winter seasons and that will be incurred in the 2018-2019 winter season. The 2016-2017 and 2017-2018 WDR Programs have been fully reviewed and approved by Energy Division. The 2018-2019 WDR Program has been developed similarly to the previous WDR Program implemented in 2017-2018. The 2018-2019 DR Program and its total budget of $5.87 million was recently approved by the Commission in Res. G-3541.[24]

SoCalGas will implement the 2018-2019 winter DR Program on December 1, 2018 through March 31, 2019. The costs associated with the program during this winter season will conclude in 2019 after SoCalGas conducts the impact evaluation of the program's performance. SoCalGas is also awaiting Commission approval to record costs related to its winter notification

[24] The Commission approved Res. G-3541 on October 25, 2018.

marketing campaign for the 2018-2019 winter season[25] in the MEOMA and is also seeking recovery for those costs through this Application. Further detail is provided in Chapter 4.

This concludes my prepared direct testimony.

VI. QUALIFICATIONS

My name is Darren M. Hanway. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by SoCalGas as the Energy Efficiency Program Operations Manager in the Customer Programs and Assistance Department.

I joined SoCalGas in October of 2012 to lead the energy efficiency policy support team. In December 2015, I assumed my current position. My current responsibilities include the management of the company's energy efficiency programs, including residential, commercial, industrial, agricultural, workforce education and training, and codes and standards offerings. I also oversee the company's demand response and solar thermal programs.

Prior to joining SoCalGas, I held positions of increasing responsibility at Southern California Edison working on their demand-side program offerings. I received a Bachelor of Science degree in Business Administration and a Bachelor of Arts degree in International Relations from the University of Southern California in 2003.

[25] On October 29, 2018 in advice letter 5369-A, SoCalGas requests $2 million to implement a Dial It Down Alert wintertime messaging campaign that will run from December 1, 2018 to March 31, 2019.

APPENDIX A

REPORT

SoCalGas® 2016-2017 Winter Demand Response Load Impact Evaluation

September 1, 2017

Prepared for
Southern California Gas Company

Prepared by
Josh Schellenberg
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1 Executive Summary

California Public Utilities Commission Resolution G-3522 approved SoCalGas' proposed winter demand response programs (AL 5035-G) with modifications and directed SoCalGas to undertake evaluation efforts of the ex post load reductions provided. These pilot programs were implemented during the 2016-2017 winter. All three programs utilized the messaging "SoCalGas Advisory – A Call to Conserve Natural Gas" to execute and communicate natural gas demand response events called Advisory days. The pilots were:

- **SoCalGas Advisory Pilot Rebate Program:** An offering that includes incentives for gas usage below a customer-specific 10/10 baseline on Advisory days;
- **Core Notification Campaign:** Mass media campaign promoting customer reduction in gas usage on SoCalGas Advisory days; and
- **Noncore Notification Campaign:** Similar to the Core Notification Campaign, but specifically for large noncore customers.

During the SoCalGas Advisory program, SoCalGas called two Advisories, the first from December 18 through 20, 2016 and the second from January 23 through 26, 2017, totaling seven days.

1.1 Load Impact Evaluation Results

Gas impacts on Advisory days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. As in the annual electric DR evaluations, the SoCalGas Advisory load impact estimates leverage the wide availability of interval data from advanced meters to estimate the usage reductions. Applying these best practices, Nexant estimated the load impact results, as summarized in this report. **The key finding is that the three SoCalGas Advisory programs generally did not produce statistically significant reductions in gas usage. The one exception is that the My Account customer segment of the Pilot Rebate Program delivered a 3.7% reduction in total gas usage during three days of the second Advisory (January 23 through 25, 2017).** The total amount of gas usage reduced was 792 therms.

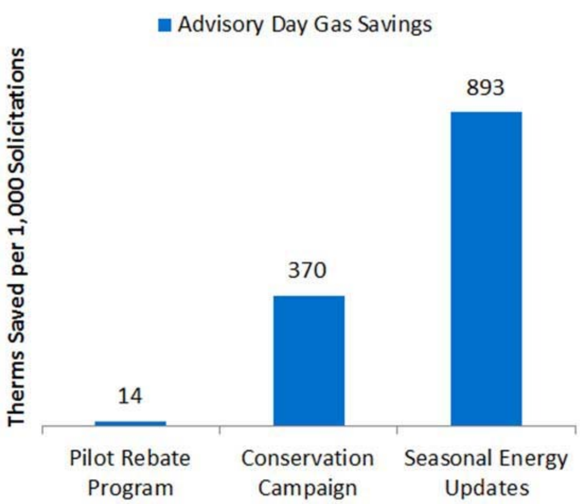
These load impact results are consistent with those outlined in Nexant's memo "2016-2017 SoCalGas Winter Demand Response Programs Preliminary Load Impact Results" sent to CPUC staff by SoCalGas on June 23, 2017.

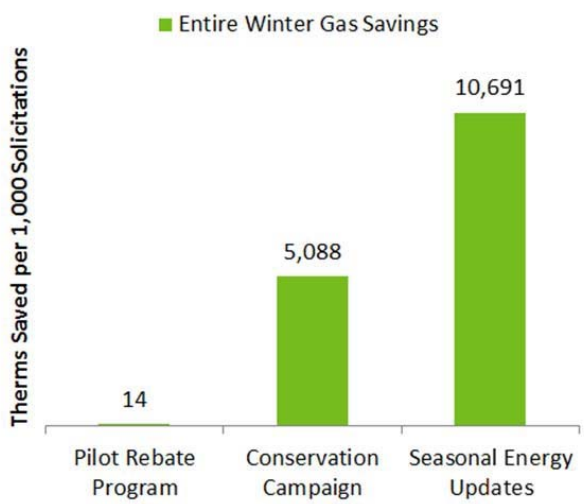
1.2 Comparison to SoCalGas Advanced Meter Conservation Campaign Treatments

In accordance with the criteria outlined in SoCalGas' AL 5035, the solicitation lists of nearly 55,000 residential My Account and Non-My Account SoCalGas Advisory Pilot Rebate Program customers were randomly selected from the control groups of the SoCalGas Advanced Meter 2016-2017 Conservation Campaign, which launched at the same time as the winter gas demand response programs. Therefore, the Pilot Rebate Program results can be directly compared to those of several behavioral program interventions from the Conservation Campaign that involved over 245,000 solicited residential customers. While the behavioral treatments from the Conservation Campaign did not ask customers to conserve on any particular day, the gas savings for Conservation Campaign pilot programs were estimated for the Advisory days as well as for the entire winter from December 2016 through March 2017.

For My Account and Non-My Account customers, Figure 1-1 scales the total therms saved by the number of customers solicited for the Pilot Rebate Program, Conservation Campaign overall and the Seasonal Energy Update (SEU) monthly energy reports treatment, which was the highest performing of the Conservation Campaign. In total, the Conservation Campaign treatments produced nearly 91,000 therms saved across the two Advisories, which equates to 370 therms saved per 1,000 solicited customers. Even though reducing usage on specific days was not a focus of the Advanced Meter Conservation Campaign, these treatments produced nearly *26 times* more gas savings per solicited customer than the Pilot Rebate Program. The most effective Conservation Campaign treatment, "Seasonal Energy Update" monthly energy reports, produced more gas savings per 1,000 solicited customers on Advisory days than the entire Pilot Rebate Program produced with nearly 55,000 total solicited customers. Importantly, these Conservation Campaign treatments have the significant additional benefit of producing gas savings on non-Advisory days, which brings in an additional 1.16 million therms saved throughout the winter (around 4,700 therms saved per 1,000 solicited customers).

Table 3-4: Comparison of Pilot Rebate Program and Conservation Campaign





1.3 Nexant Observations and Recommendations

The SoCalGas Advisory had a variety of significant challenges, some of which were likely due to the short lead time for designing and launching the pilots. If a similar need for conservation arises in the future, SoCalGas may be able to address some of these challenges to improve the impacts for these types of pilots, but many of the issues are likely to persist, including:

- Long, multi-day events lead to relatively low impacts (or no impacts)

- Typical, relatively low enrollment rates in the opt-in Pilot Rebate Program for most segments (4.5% overall enrollment rate, ranging from 0.5% for the CTA-served customer segment to 8.6% for the My Account segment)[1]
- Settlement baseline error for the Pilot Rebate Program, as summarized in Section 6
- As in the most recent CPUC-filed Statewide Flex Alert evaluation of electricity impacts,[2] mass market calls for energy conservation do not produce measurable impacts

Therefore, if a similar need for conservation arises in the future, Nexant recommends scaling up the many successful behavioral interventions from the Advanced Meter Conservation Campaign, most notably Seasonal Energy Update energy reports. These interventions have the dual benefit of providing significant gas savings on both Advisory days and non-Advisory days throughout the winter.

1.4 Baseline Accuracy Assessment

Nexant evaluated 22 different potential baseline methodologies as alternate methods for the SoCalGas winter demand response programs. These included the 10/10 baseline methodology specified in CPUC Resolution G-3522, as well as regression-based approaches, such as that proposed in the draft CPUC resolution. The key finding of this analysis was that "day matching" baseline methods performed best, especially those with short look-back periods such as the top 3/5 and top 4/4. While "weather matching" results performed well, their results were never best overall.

[1] As SoCalGas stated in its response to the Energy Division "Data Request for Estimated therms savings for Winter Demand Response Proposed Programs in Advice Letter No. 5035-G," requested on September 30, 2016, submitted on October 7, 2016, "Best case and worst case scenario [therms savings] assumptions are derived from several studies and analyses performed over the last five years of electric "Peak Time Rebate" and "Critical Peak Pricing" pilots and programs offered across the country. Upper bounds on "opt-in" rates for the most successful programs appear to be roughly 20 to 25%. The lower end on "opt-in" rates in these same studies is around 5%, however average response rates for direct response solicitations across all industries and marketing solicitation types more broadly can be as low as 1 to 2%."

[2] Christensen Associates. "2013 Impact Evaluation of California's Flex Alert Demand Response Program." February 28, 2014. CALMAC Study ID: SCE0343.01.

2 Introduction

California Public Utilities Commission Resolution G-3522 approved SoCalGas' proposed winter demand response programs (AL 5035-G) with modifications and directed SoCalGas to undertake evaluation efforts of the ex post load reductions provided.[3] Pursuant to this directive, SoCalGas worked with Nexant to conduct a load impact analysis to estimate the therm reductions for all three "Natural Gas Conservation" pilot programs included in the Resolution.

These pilot programs were implemented during the 2016-2017 winter, from December 1, 2016 through March 31, 2017. All three programs utilized the messaging "SoCalGas Advisory – A Call to Conserve Natural Gas" to execute and communicate natural gas demand response events called Advisory days. The pilots were:

- **SoCalGas Advisory Pilot Rebate Program:** An offering that includes incentives for gas usage below a customer-specific 10/10[4] baseline on Advisory days;
- **Core Notification Campaign:** Mass media campaign promoting customer reduction in gas usage on SoCalGas Advisory days; and
- **Noncore Notification Campaign:** Similar to the Core Notification Campaign, but specifically for large noncore customers.

In addition, as another element of the Pilot Rebate Program, SoCalGas implemented a Smart Thermostat direct control demand response pilot, called the "SoCalGas Advisory Thermostat Program." Appendix D provides an overview of this pilot.

During the SoCalGas Advisory program, SoCalGas called two Advisories, the first from December 18 through 20, 2016 and the second from January 23 through 26, 2017, totaling seven days. Pilot Rebate Program participants were eligible to receive rebates if they reduced usage below their customer-specific 10/10 baseline on those days. This report summarizes the impact estimates and impact estimation methodology for each pilot. For the Pilot Rebate Program specifically, this report also provides a summary of enrollment and rebates by customer segment and a baseline accuracy assessment.

Gas impacts on Advisory days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. In 2008, the California Public Utilities Commission (CPUC) and joint electric Investor-Owned Utilities (IOUs) developed California's Load Impact Protocols, which required the electric utilities to conduct annual evaluations of all DR programs in the state. As in the annual electric DR evaluations, the SoCalGas Advisory load impact estimates leverage the wide availability of

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[3] Paragraph 7 of the Resolution "Findings" directed SoCalGas as follows: "It is reasonable to authorize SoCalGas an additional $800,000 to undertake evaluation efforts of the ex post load reductions provided by all three proposed programs, including the modifications to the Natural Gas Conservation Rebate Pilot adopted in this resolution. The evaluations should also include an analysis of the accuracy of the baseline method for the Natural Gas Conservation Rebate Pilot and those that were proposed in the draft resolution."

[4] Also referred to as a "10-10 baseline." Paragraph 4 on page 2 of the Resolution directed SoCalGas as follows: "SoCalGas shall use a 10-10 baseline methodology to calculate the load drops for purposes of determining the incentive payment for all participants in the program." On page 13, the methodology is further defined as: "using the participant's gas load profile for the past 10 days, a simple daily use average is calculated to determine the customer's gas load for the day in which the DR event occurred. Weekends, holidays and days when a DR event occurred are all removed from the 10 day calculation and replaced with the next available day in the calendar."

interval data from advanced meters to estimate the usage reductions. The Pilot Rebate Program methodology that uses a matched control group is similar to how most electric DR programs have been evaluated for several years, including Southern California Edison's Save Power Days Program,[5] which is also a peak-time rebate program. In addition, the core and noncore Notification Campaign methodologies draw from the most recent CPUC-filed Statewide Flex Alert evaluation,[6] which also used a regression approach to model aggregate load and estimate load impacts.

The remainder of this report proceeds as follows:

- **Section 3:** Pilot Rebate Program background, impact evaluation methodology and daily impact estimates, including comparisons to experimental design results and to the gas savings from the SoCalGas Advanced Meter 2016-2017 Conservation Campaign treatments.
- **Section 4:** Core Notification Campaign background, impact evaluation methodology and daily impact estimates.
- **Section 5:** Noncore Notification Campaign background, impact evaluation methodology and daily impact estimates.
- **Section 6:** Pilot Rebate Program baseline accuracy assessment, including alternative baselines tested and Nexant recommendations.

In addition, the appendices provide various supporting tables for the Pilot Rebate Program impact analysis and baseline accuracy assessment.

[5] Nexant. "2016 Load Impact Evaluation of Southern California Edison's Save Power Days Program." April 1, 2017. CALMAC Study ID: SCE0409.

[6] Christensen Associates. "2013 Impact Evaluation of California's Flex Alert Demand Response Program." February 28, 2014. CALMAC Study ID: SCE0343.01.

3 Pilot Rebate Program

This section summarizes the Pilot Rebate Program background, impact evaluation methodology and daily impact estimates. It also provides comparisons to experimental design results and to the gas savings from the SoCalGas Advanced Meter 2016-2017 Conservation Campaign treatments for residential My Account and Non-My Account customers.

3.1 Background

Figure 3-1 shows the cumulative enrollments in the Pilot Rebate Program by day from December 2016 through March 2017. The two SoCalGas Advisories are highlighted by the gray bars. Customers were eligible to receive rebates on a given Advisory day if it was on or after their enrollment date. About 48% of customers were enrolled in the program by the first Advisory day, and 76% were enrolled by the last. Ultimately, 3,408 customers enrolled in the program, but about 24% enrolled too late to be eligible to receive rebates on an Advisory day.

Figure 3-1: Cumulative Enrollment in the SoCalGas Advisory Pilot Rebate Program by Date (December 1, 2016 through March 31, 2017)

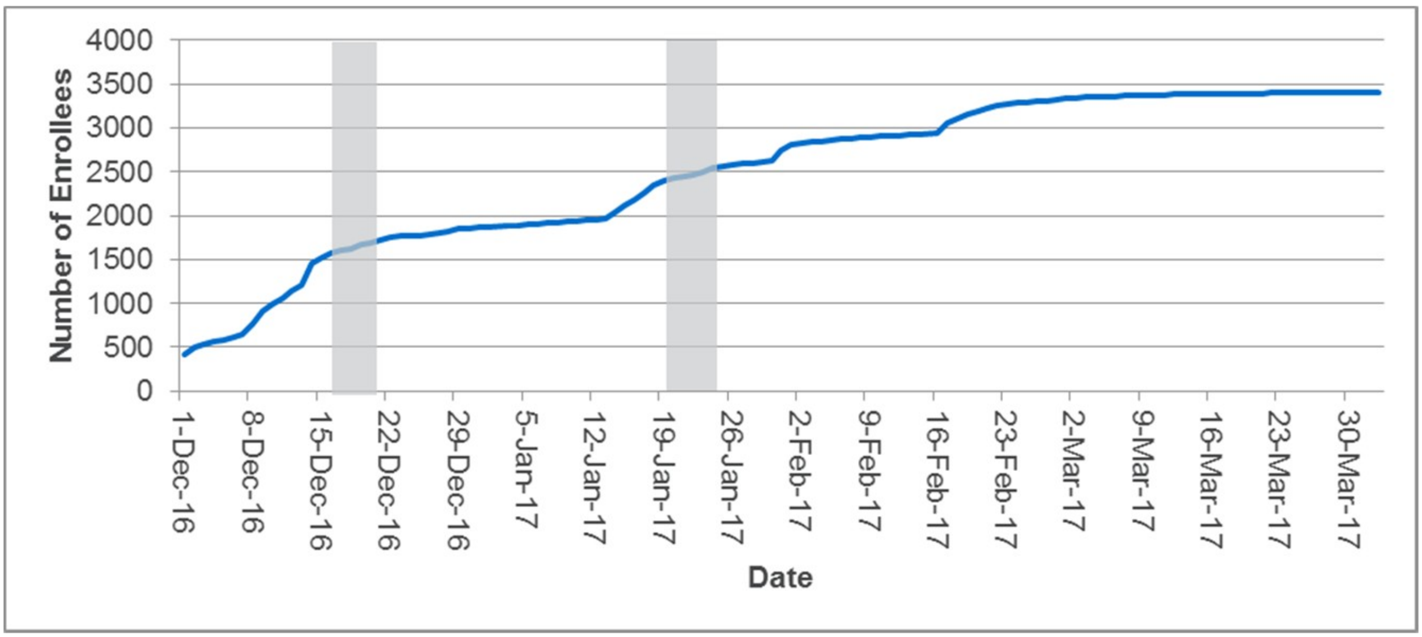


Table 3-1 presents the total customers solicited/eligible and enrolled in the Pilot Rebate Program in each segment, including Core Transport Agent (CTA)-served customers, Highest Winter Load (HWL), My Account and Non-My Account customers. The table also shows the number of customers eligible to receive rebates, the number of customers who earned rebates, and the average rebates they earned. Using the 10/10 baseline methodology as described in Resolution G-3522, Nexant calculated rebates for the 2,556 customers who were enrolled during at least one Advisory day. Rebates were calculated for each customer by adding up the therms the customer reduced below their baseline on each Advisory day and multiplying that total by $2.50 per therm. The final two columns show the total rebates that were paid to each customer segment and total usage below the baseline.

Table 3-1: Summary of Enrollment and Rebates by Customer Segment

Customer Segment	Total Solicited/ Eligible	Enrolled as of March 31, 2017	Percent Enrolled	Eligible to Receive Rebate*	Earned Rebate (saved 1 therm or more)	Average Rebate (for those who earned a rebate)**	Total Rebates	Total Usage (therms) below Baseline
CTA	10,439	54	0.5%	37	12	$7.50	$90.00	36
HWL	10,465	189	1.8%	141	65	$235.96	$15,337.50	6,135
My Account	27,499	2,353	8.6%	1,768	417	$6.26	$2,610.00	1,044
Non-My Account	27,388	812	3.0%	610	116	$7.00	$812.50	325
Total	**75,791**	**3,408**	**4.5%**	**2,556**	**610**	**$30.90**	**$18,850**	**7,540**

* Enrolled during at least one Advisory day and met eligibility criteria. Note: As of June 23, calculation of potential rebates earned was still underway for 19 enrolled customers across the four customer segments, due to exceptions in the data for these accounts that required further assessment. These customer accounts are not reflected above. Three of the accounts were determined to be ineligible for the program, four did not earn a rebate, one earned a rebate, and an alternative calculation method was used to determine rebate amounts for eleven residential accounts with some missing advanced meter usage data.

** Does not include additional $5 participation credit provided to Non-My Account customers

Importantly, while many customers received rebates, they may not have actually reduced usage on the Advisory days. The 10/10 baseline can be biased upward for individual customers on individual days, leading to rebates even if the customer did not respond. Nexant's load impact evaluation summarized below provides a much more reliable estimate of program-level usage reductions for the Pilot Rebate Program participants by leveraging data throughout the winter, including hourly usage data for a control group of non-participants that was developed. In addition, Section 6 provides a detailed assessment of baseline accuracy.

3.2 Impact Evaluation Methodology

Nexant developed several control groups of carefully selected non-participants in order to estimate reductions in gas consumption on Advisory days. The methods used to assemble the control groups are designed to ensure that the control group load on Advisory days is an accurate estimate of what load would have been among Pilot Rebate Program participants on Advisory days if they had not participated. The fundamental idea behind the matching process is to find customers who did not participate in the pilot with similar characteristics to those who did.

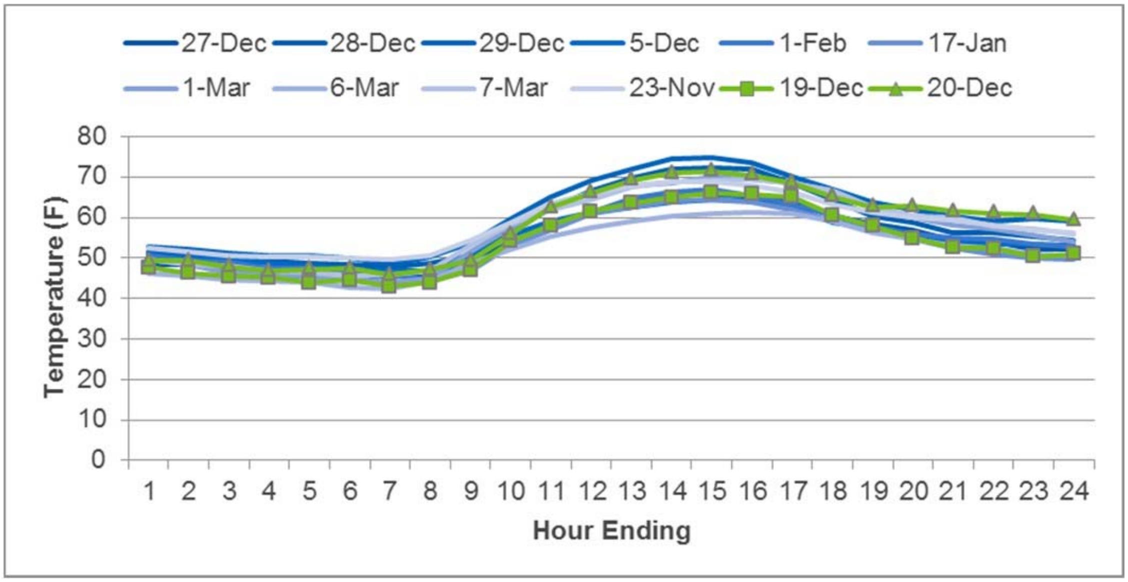
The control groups were selected using a propensity score match to find customers who, on non-Advisory days, had hourly gas usage most similar to pilot participants. In this procedure, a probit model is used to estimate a propensity score for each customer based on a set of observable variables. A probit model is a regression model designed to estimate the propensity score and each customer in the control group is matched to a pilot participant with a similar estimate score given the observed variables.

The first step in the matching process was to select non-Advisory days on which participants and non-participants will be matched; these are called *proxy days*.[7] A separate set of proxy days

[7] Depending on the available data and objectives for each analysis and customer group, the number and mix of proxy days varies between each analysis described in this report.

was selected for each customer segment and three groups of Advisory days: December 18 (a Sunday), December 19 and 20, and January 23 through 26. The weather on the proxy days was similar to the weather on the corresponding Advisory days. Figure 3-2 shows hourly temperature profiles for the December 19 and 20 advisory days and their corresponding proxy days.

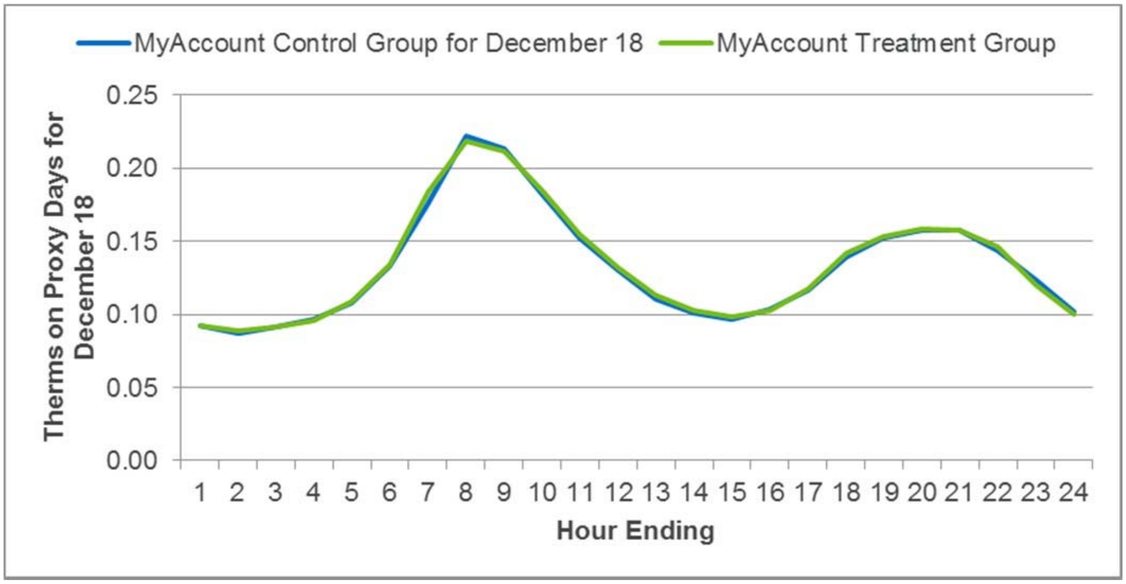
Figure 3-2: Proxy Day Weather Profiles



Next, the propensity score model was used to match each participant to a non-participant with similar hourly gas usage on proxy days. A participant could have up to three different matches (one for each set of Advisory days) or they could be matched to the same non-participant multiple times. Customers were guaranteed to be matched to customers within their geographic location and customer segment (for CTA and HWL customers, matched control group customers also had to be on the initial eligibility lists). Each control group customer is only matched to one participant per set of Advisory days.

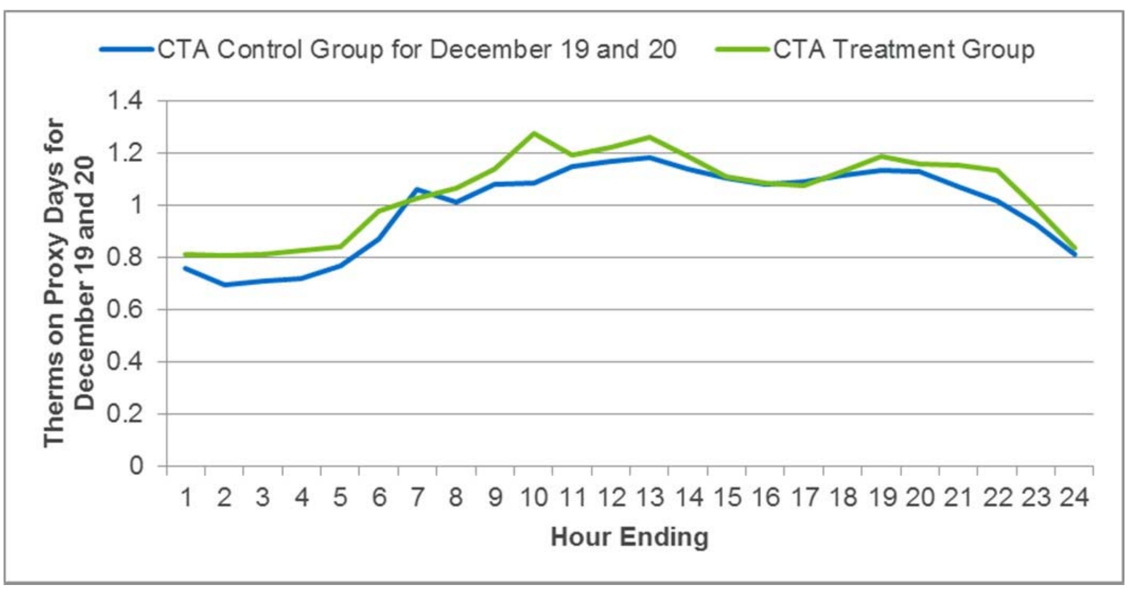
To summarize, any particular participant has a corresponding control customer for December 18 (a Sunday), another for December 19 and 20, and another for the January Advisory days, given that load patterns on these three sets of days are different. The control customer for December 18 has similar hourly gas consumption during corresponding proxy days, and so on. Figure 3-3 presents the average hourly gas usage on proxy days corresponding to the December 18 Advisory day. The customers presented in this figure are all My Account customers. This figure shows that the treatment group and their corresponding control group have very similar usage patterns on non-Advisory days. It is reasonable to assume that these two groups would have similar usage patterns on Advisory days if not for the effect of the Pilot Rebate Program that is estimated.

Figure 3-3: My Account Control and Treatment Groups on December 18 Proxy Days



Unfortunately, when enrollment is lower than 100 customers as in the CTA customer segment, it is often difficult to find control groups as well-matched as the one above. Average gas usage for this group is rather noisy, as shown in Figure 3-4 below. Because of this, there are small differences between the control group and treatment group on proxy days.

Figure 3-4: CTA Control and Treatment Groups on December 19 and 20 Proxy Days



While this may be concerning, the method used to estimate load impacts accounts for differences between treatment and control groups on non-Advisory days. The analysis method used is referred to as difference-in-differences (DiD) analysis. This method estimates impacts by subtracting non-Advisory day differences between treatment and control groups from Advisory day differences between the two groups. Table 3-2 presents an example in which the non-Advisory day difference in consumption between the two groups is 1.0 therm. The difference on the Advisory day is 3.0. Therefore, the estimated gas consumption impact is 3.0 minus 1.0, or 2.0 therms.

Table 3-2: Difference-in-Differences Example

Group	Non-Advisory Day Usage (Therms)	Advisory Day Usage (Therms)	Total Impact (Therms)
Control	3.0	6.0	3.0 - 1.0 =
Treatment	2.0	3.0	
Difference	**1.0**	**3.0**	**2.0**

The DiD analysis can be done with simple calculations using averages, as in Table 3-2, but regression analysis is required to produce accurate standard errors for assessing statistical significance. Customer fixed effects regression analysis allows each customer's mean usage to be modeled separately, which reduces the standard error of the impact estimates without changing their magnitude. Additionally, standard regression software allows for the calculation of standard errors, confidence intervals, and significance tests for load impact estimates that correctly account for the correlation in customer loads over time. A typical regression specification for estimating impacts is shown in this equation:

$$\mathrm{therms}_{i,t} = \mathrm{a}_i + \mathrm{yadvisory}_t + \mathrm{P}(\mathrm{treatmentXadvisory})_{i,t} + \mathrm{v}_i + \mathrm{E}_{i,t}$$

In this equation, the variable $therms_{i,t}$ equals gas usage during the time period of interest, which in this case is the Advisory day. The index *i* refers to customers and the index *t* refers to the Advisory day of interest. The analysis dataset contains gas usage data during both the non-Advisory proxy days and Advisory days for both treatment and matched control group customers. The variable *advisory* is equal to 1 during a specific advisory day and 0 on proxy days. The *treatmentXadvisory* term is the interaction of *treatment* and *advisory* and its coefficient β is a difference-in-differences estimator of the treatment effect that makes use of the proxy day data. The primary parameter of interest is β, which provides the estimated gas usage impact of the pilot during the relevant period. The parameter a_i is equal to mean usage for each customer for the relevant time period (e.g., daily). The v_i term is the customer fixed effects variable that controls for unobserved factors that are time-invariant and unique to each customer. This model is estimated separately for each customer segment and Advisory day.

3.3 Daily Impact Estimates

Table 3-3 presents gas usage impacts for each customer segment and each Advisory day. The number of customers for each day is based on the number of customers who were enrolled on a particular Advisory day. The Reference Therms column presents what we expect pilot participants would have used if not for the Advisory day. The Observed Therms column presents the average gas consumption for that group of customers on the Advisory day. The estimated impact is the difference between Reference Therms and Observed Therms. A positive value indicates that customers reduced their consumption, while a negative value indicates that they have increased it. The three rows with gas usage reductions that are statistically significant (p-value less than 0.05) are highlighted in light blue.

My Account customers showed statistically significant gas consumption reductions on January 23, 24, and 25. Across the three days, each customer saved 0.45 therms on average (3.7% of total gas usage), which totals nearly 800 therms in aggregate. CTA, HWL, and Non-My Account customers did not provide statistically significant gas usage reductions. In some cases, these customers show negative gas impacts, but these estimated increases in usage were also not statistically significant.

Table 3-3: Pilot Rebate Program Gas Consumption Daily Impacts by Customer Segment

Pilot Rebate Program - Customer Segment	Number of Customers	Date	Reference (Therms)	Observed (Therms)	Impact (Therms)	Impact (%)	95% Confidence Interval		P-Value
CTA	5	December 18, 2016	17.6	16.8	0.78	4.5%	-28%	37%	0.79
	5	December 19, 2016	15.6	15.9	-0.30	-1.9%	-14%	10%	0.75
	5	December 20, 2016	14.5	15.2	-0.73	-5.1%	-17%	7%	0.39
	10	January 23, 2017	31.1	33.1	-1.99	-6.4%	-18%	5%	0.27
	24	January 24, 2017	25.3	25.3	-0.04	-0.2%	-7%	7%	0.97
	33	January 25, 2017	25.1	26.2	-1.14	-4.6%	-11%	2%	0.16
	33	January 26, 2017	25.6	25.9	-0.25	-1.0%	-7%	5%	0.76
HWL	59	December 18, 2016	87.4	86.4	1.01	1.2%	-20%	22%	0.91
	58	December 19, 2016	101.8	117.3	-15.52	-15.2%	-42%	12%	0.27
	61	December 20, 2016	94.3	105.9	-11.56	-12.3%	-39%	14%	0.36
	135	January 23, 2017	116.1	112.4	3.75	3.2%	-6%	12%	0.49
	138	January 24, 2017	117.6	118.7	-1.10	-0.9%	-10%	8%	0.84
	140	January 25, 2017	121.3	118.6	2.70	2.2%	-8%	13%	0.67
	141	January 26, 2017	120.4	118.8	1.55	1.3%	-6%	8%	0.73
My Account	1,307	December 18, 2016	4.1	4.0	0.09	2.1%	-1%	6%	0.23
	1,335	December 19, 2016	3.1	3.2	-0.11	-3.5%	-7%	0%	0.05
	1,348	December 20, 2016	2.5	2.6	-0.05	-1.9%	-5%	1%	0.27
	1,748	January 23, 2017	3.9	3.6	0.24	6.1%	4%	8%	0.00
	1,764	January 24, 2017	4.3	4.2	0.09	2.1%	0%	4%	0.04
	1,769	January 25, 2017	4.0	3.9	0.13	3.2%	1%	5%	0.00
	1,775	January 26, 2017	3.8	3.8	0.07	1.8%	0%	4%	0.08
Non-My Account	248	December 18, 2016	3.9	3.9	0.04	0.9%	-6%	8%	0.79
	259	December 19, 2016	3.2	3.2	0.07	2.1%	-4%	9%	0.52
	269	December 20, 2016	2.5	2.6	-0.09	-3.4%	-11%	4%	0.39
	585	January 23, 2017	3.9	3.8	0.11	2.9%	-1%	6%	0.10
	595	January 24, 2017	4.4	4.4	0.02	0.6%	-3%	4%	0.75
	605	January 25, 2017	4.1	4.1	0.03	0.7%	-3%	4%	0.69
	612	January 26, 2017	4.0	4.0	-0.04	-1.1%	-5%	3%	0.55

3.4 Comparison to Experimental Design Results

In accordance with the criteria outlined in SoCalGas' AL 5035, the solicitation lists for residential My Account and Non-My Account SoCalGas Advisory Pilot Rebate Program customers were randomly selected from the control groups of the SoCalGas Advanced Meter 2016-2017 Conservation Campaign. Therefore, for comparison purposes, Nexant leveraged these randomized groups to estimate the impacts using an experimental design, which is the CPUC's preferred method for evaluating energy savings, especially for behavioral interventions. Given that not all solicited customers enrolled in the Pilot Rebate Program, Nexant estimated the impacts using a Randomized Encouragement Design (RED). If the RED results showed that there were statistically significant impacts among customers in the *encouraged* group (solicited My Account and Non-My Account customers), the impacts for enrolled customers could then be deduced. However, if the RED results were not statistically significant, the impacts for enrolled customers would not be measurable, given the effect size and percent of customers enrolled on each Advisory day (around 1% to 7%, depending on date and customer segment).

Figure 3-5 and Figure 3-6 provide the results of the Pilot Rebate Program impacts based on the experimental design. The figures show the daily impacts for each encouraged group relative to its respective control group for My Account and Non-My Account customers. Advisory days and non-Advisory days are included to check that the randomization is valid and determine whether there is a change in the pattern when SoCalGas called the Advisories. From December 1, 2016 through February 1, 2017, the estimated change in daily usage for the encouraged groups relative to their respective control groups is not statistically significant. The estimated impacts on both Advisory and non-Advisory days fall within a remarkably narrow range of -1% to 1% of daily usage throughout the winter, even as Pilot Rebate Program enrollment increases. These results confirm that the randomization was valid and corroborate the finding that the Pilot Rebate Program generally did not produce statistically significant reductions in gas usage.

Figure 3-5: Pilot Rebate Program Experimental Design Results for My Account (Impacts for Encouraged Group Relative to Control Group)

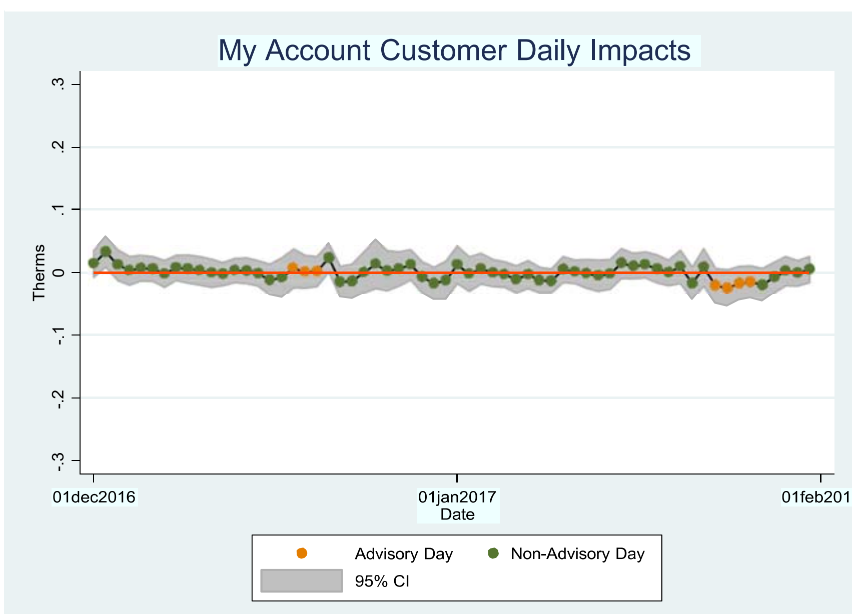
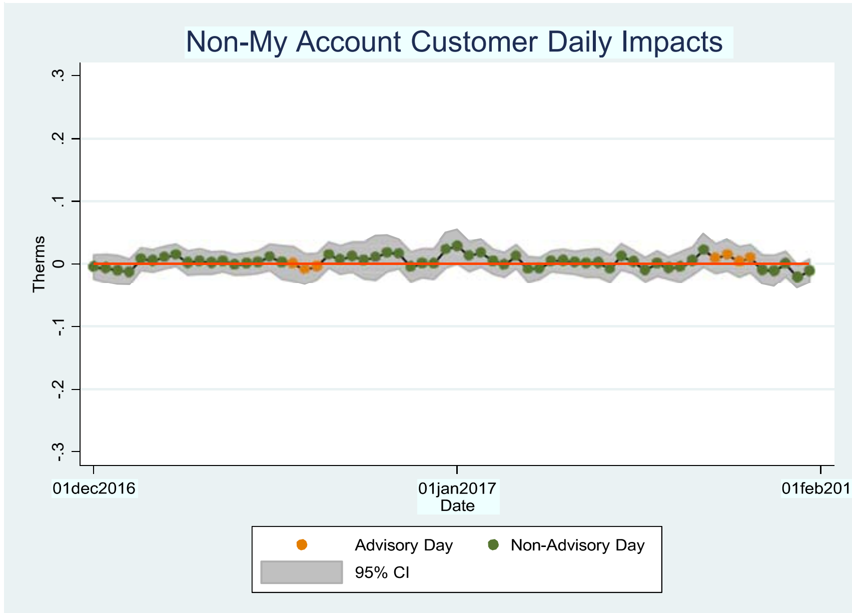


Figure 3-6: Pilot Rebate Program Experimental Results for Non-My Account (Impacts for Encouraged Group Relative to Control Group)



3.5 Comparison to SoCalGas Conservation Campaign Treatments

Given that the solicitation lists for My Account and Non-My Account customers were randomly selected from the control groups of the SoCalGas Advanced Meter Conservation Campaign, the results of several behavioral interventions that SoCalGas launched at the same time can be directly compared. While the behavioral treatments from the Conservation Campaign did not ask customers to conserve on any particular day, the gas savings can be estimated for the Advisory days as well as for the entire winter from December 2016 through March 2017. Table 3-4 summarizes the results for My Account and Non-My Account treatments as compared to the Pilot Rebate Program. The gas savings on Advisory days were positive and statistically significant for every Conservation Campaign treatment during the January Advisory. In total, these Conservation Campaign treatments produced nearly 91,000 therms saved across the two Advisories. Even though reducing usage on specific days was not a focus of the Advanced Meter (AM) Conservation Campaign, these treatments produced nearly 26 times more gas savings per solicited customer than the Pilot Rebate Program (370 therms saved per 1,000 solicited customers as compared to 14 therms saved). The most effective Conservation Campaign treatment, “Seasonal Energy Update” monthly energy reports (SEU), produced more gas savings per 1,000 solicited customers on Advisory days than the entire Pilot Rebate Program produced with nearly 55,000 total solicited customers. Importantly, these Conservation Campaign treatments have the significant additional benefit of producing gas savings on non-Advisory days, which brings in an additional 1.16 million therms saved throughout the winter (around 4,700 therms saved per 1,000 solicited customers).

Table 3-4: Comparison of SoCalGas Advisory Pilot Rebate Program and 2016-2017 AM Conservation Campaign Gas Savings by Customer Segment

Customer Segment	Treatment	Total Customers Solicited	Advisory Day Gas Savings		Entire Winter Gas Savings	
			Total (Therms)	Per 1,000 Solicited Customers	Total (Therms)	Per 1,000 Solicited Customers
My Account	SoCalGas Advisory Pilot Rebate Program	27,499	792	29	792	29
	Bill Tracker Alert (BTA) w/Tips + Paper Opower HER	40,554	17,722	437	255,322	6,296
	BTA w/o Tips	32,322	5,564	172	70,435	2,179
	BTA w/ Tips	32,022	6,747	211	83,103	2,595
Non-My Account	SoCalGas Advisory Pilot Rebate Program	27,388	0	0	0	0
	Paper Opower HER	53,500	9,032	169	209,944	3,924
	Paper Aclara HER	33,000	12,158	368	143,375	4,345
	Paper In-House HER	13,750	3,338	243	53,596	3,898
	SEU	20,350	18,644	916	211,926	10,414
	SEU (Weatherization version)	20,350	17,687	869	223,203	10,968
Total	**Pilot Rebate Program**	**54,887**	**792**	**14**	**792**	**14**
	AM Conservation Campaign	**245,848**	**90,892**	**370**	**1,250,904**	**5,088**

4 Core Notification Campaign

This section summarizes the Core Notification Campaign background, impact evaluation methodology and daily impact estimates.

4.1 Background

The SoCalGas Advisory Notification Campaign encourages voluntary reduction in gas usage on Advisory days by issuing public notifications through mass media marketing channels. These notifications were provided on the same seven Advisory days as for the Pilot Rebate Program.

Each Advisory included the following level of outreach:

- Traditional radio: 24 stations with an average of 10 spots per day (6.8 million total impressions)
- Digital radio: Pandora delivered 800,000 impressions (first Advisory) and 650,000 impressions (second Advisory)
- SoCalGas e-mail notifications: Approximately 3.2 million per deployment
- SoCalGas SMS notifications: 3,200 text messages deployed (first Advisory) and 14,200 (second Advisory) text messages deployed
- Social media: Over 1.8 million impressions (first Advisory) and 1.6 million impressions (second Advisory)

4.2 Impact Evaluation Methodology

In order to estimate gas consumption impacts, hourly gas consumption data was collected for a sample of SoCalGas core customers. The random sample had approximately 5,000 residential and 5,000 non-residential customers, each with at least 18 months of historical hourly gas consumption data. The sample was designed to contain a representative group among several levels of gas consumption, with oversampling among higher usage customers to maximize precision (following standard load research sampling techniques). Pilot Rebate Program customers were not included in the sample.

The first step in estimating Advisory day impacts is developing reference loads for the customers in the residential and non-residential samples. Reference loads indicate how customers would have behaved in the absence of the Notification Campaign. They are estimated using regression analysis of customer usage on non-Advisory days. Given that any customer could have received the mass media notifications, a matched control group of non- participants could not be used in this case. The observed loads on Advisory days are then subtracted from the predicted reference loads to estimate impacts. Generally speaking, customer gas consumption is a function of weather and day type. Figure 4-1 and Figure 4-2 illustrate this relationship. As temperatures decrease, gas consumption increases. Above a certain temperature, around 75 degrees Fahrenheit, gas consumption is relatively constant. While this figure presents 18 months of daily data, Nexant tested many model specifications and determined that it is best if the final analysis dataset only includes days less than 60 degrees Fahrenheit, given that the Advisory days were all less than that threshold.

Figure 4-1: Residential Core Gas Consumption vs. Temperature

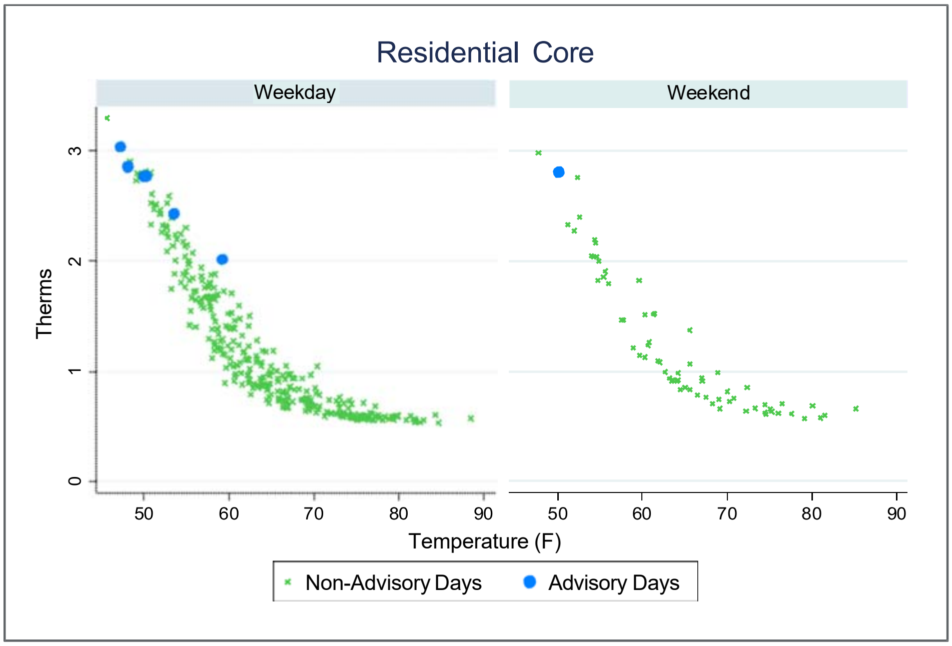
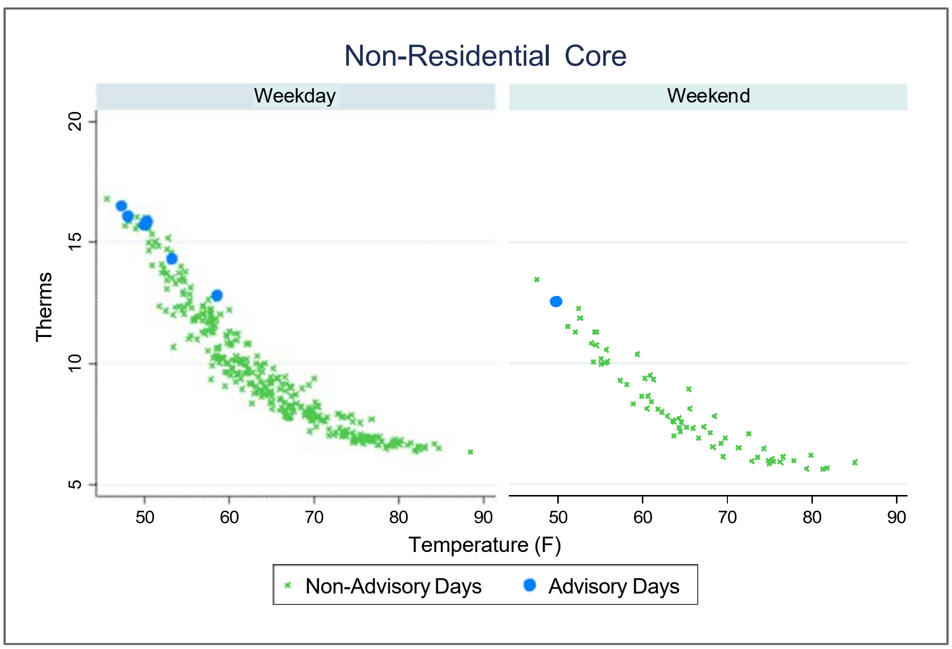


Figure 4-2: Non-Residential Core Gas Consumption vs. Temperature



Below 60 degrees Fahrenheit, the relationship between temperature and gas consumption for residential and non-residential customers is somewhat linear. Therefore, a simple temperature variable was included in the regression model along with day of week and time variables as follows:

$$\text{therms}_t = a + y(\text{temperature})_t + A(\text{day\_of\_week})_t + o(\text{year\_month})_t + P(\text{advisory})_t + E_t$$

In this equation, the *day_of_week* variable is a binary variable for each weekday. The variable *year_month* refers to the year and month of a particular day. Essentially, gas consumption for residential customers is a function of average daily temperature, the day of the week, and the year and month of the day. The primary parameter of interest is β, which provides the estimated gas usage impact of the campaign during the relevant period. This regression model was run separately for residential and non-residential customers.

4.3 Daily Impact Estimates

Table 4-1 presents daily impact estimates for core customers on each Advisory day. Values have been scaled up from a per-customer level to a population level. In other words, estimates have been multiplied by the number of customers that met the sampling criteria, most notably that 18 months of advanced meter data was available.

The Reference Therms column presents the predicted load on each day (in other words, the gas consumption estimated if it were not an Advisory day). The Observed Therms column is the average consumption among customers in the sample on those days. The Impact column is the difference between the two, where a positive value indicates a reduction in gas consumption. On nearly every Advisory day, these results suggest that residential and non-residential customers increased their gas consumption.

Table 4-1: Core Gas Consumption Impacts by Customer Segment and Advisory Day

Population	Number of Customers	Date	Reference (Therms)	Observed (Therms)	Impact (Therms)	Impact (%)	95% Confidence Interval		P-Value
Core - Non-Residential	131,635	December 18, 2016	1,646,834	1,654,432	-7,599	0%	-10%	9%	0.93
		December 19, 2016	1,726,845	1,883,828	-156,983	-9%	-18%	0%	0.06
		December 20, 2016	1,458,674	1,685,587	-226,912	-16%	-27%	-5%	0.01
		January 23, 2017	1,945,835	2,086,727	-140,892	-7%	-15%	1%	0.09
		January 24, 2017	2,121,236	2,172,737	-51,501	-2%	-10%	5%	0.54
		January 25, 2017	2,076,012	2,117,467	-41,455	-2%	-10%	6%	0.62
		January 26, 2017	1,956,733	2,066,099	-109,366	-6%	-14%	3%	0.19
Core - Residential	3,212,437	December 18, 2016	8,336,045	9,017,107	-681,062	-8%	-20%	4%	0.19
		December 19, 2016	6,833,277	7,806,352	-973,075	-14%	-29%	0%	0.06
		December 20, 2016	4,486,703	6,464,019	-1,977,315	-44%	-66%	-22%	0.00
		January 23, 2017	8,568,014	8,889,288	-321,274	-4%	-15%	8%	0.53
		January 24, 2017	9,837,362	9,744,646	92,716	1%	-9%	11%	0.86
		January 25, 2017	9,501,260	9,169,643	331,616	3%	-7%	14%	0.52
		January 26, 2017	8,650,882	8,896,350	-245,467	-3%	-14%	9%	0.63

To explore why these negative impacts were estimated, Figure 4-3 and Figure 4-4 add the predicted reference usage on Advisory days to the two figures above. In every case, the predicted usage on Advisory days falls within the range of usage that has been observed at a given temperature, which suggests that the predictions are reasonable. However, the Advisory days exhibit usage that is higher than the average usage that is typically observed at a given temperature in many cases. Most notably, the Advisory day that had average temperatures of nearly 60 degrees – December 20 – had average usage for both residential and non-residential core customers that is similar to the level of usage that is typically observed when it is several degrees colder. As a result, the estimates for this day show large negative impacts, even though the usage prediction seems reasonable. Appendix A includes further information on the accuracy testing of the regression models for the Core Notification Campaign to show that the available variables cannot explain this unusually high usage.

Figure 4-3: Residential Core Gas Consumption and Predicted Usage vs. Temperature

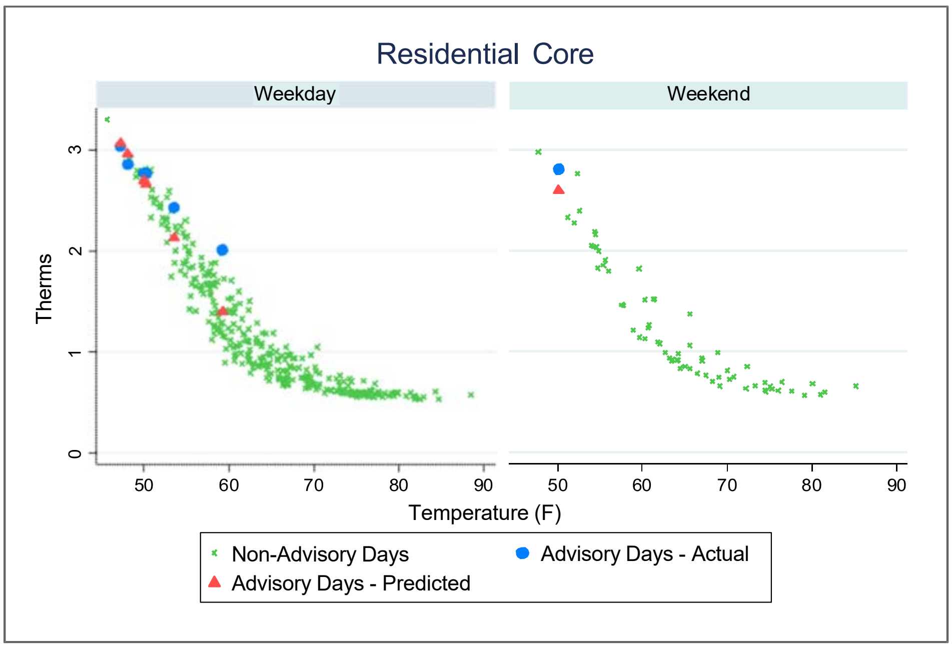
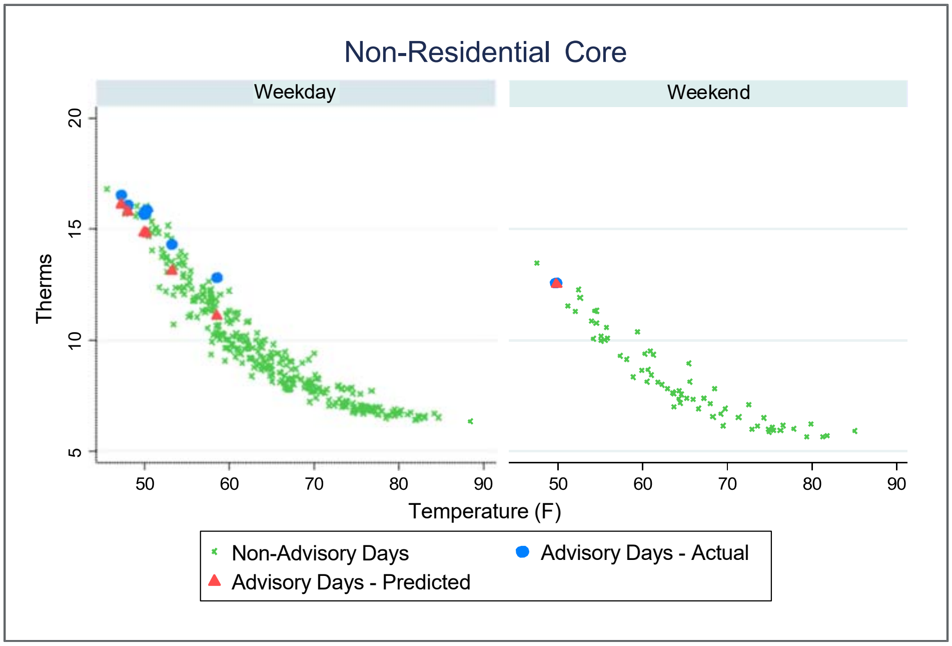


Figure 4-4: Non-Residential Core Gas Consumption and Predicted Usage vs. Temperature



5 Noncore Notification Campaign

This section summarizes the Noncore Notification Campaign background, impact evaluation methodology and daily impact estimates.

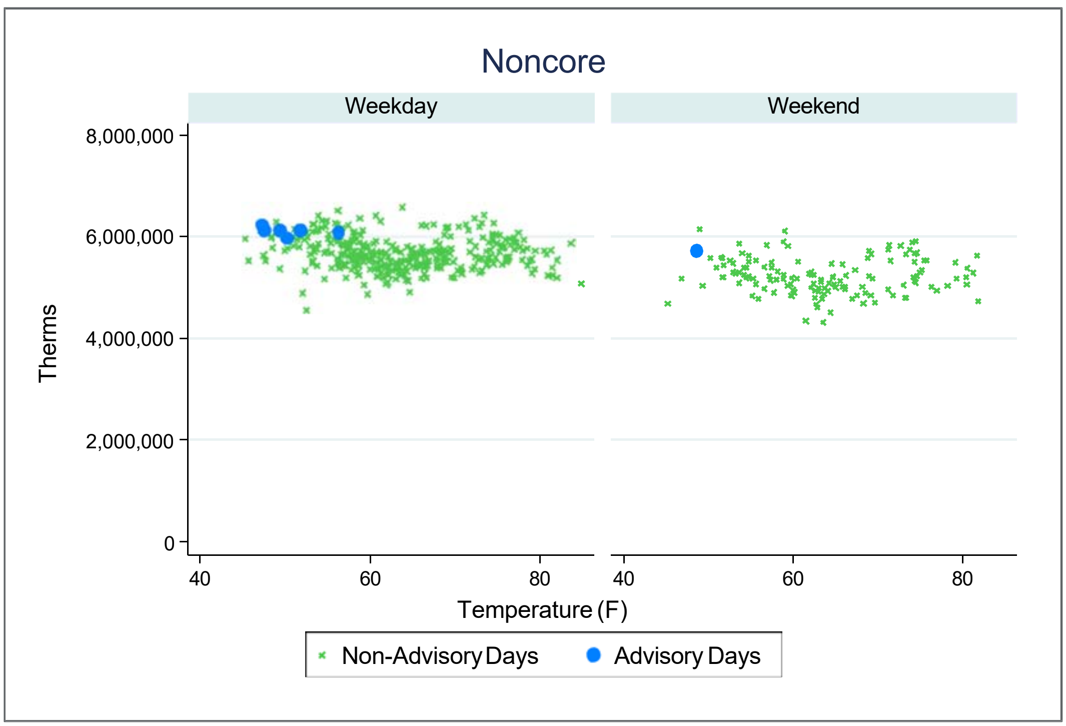
5.1 Background

The Noncore Notification Campaign is similar to the pilot described in the previous section, but it is specific to large, noncore customers and included direct email communications to noncore, non-electric generation customers, in addition to the radio and social media announcements summarized in Section 4.1 for core customers.

5.2 Impact Evaluation Methodology

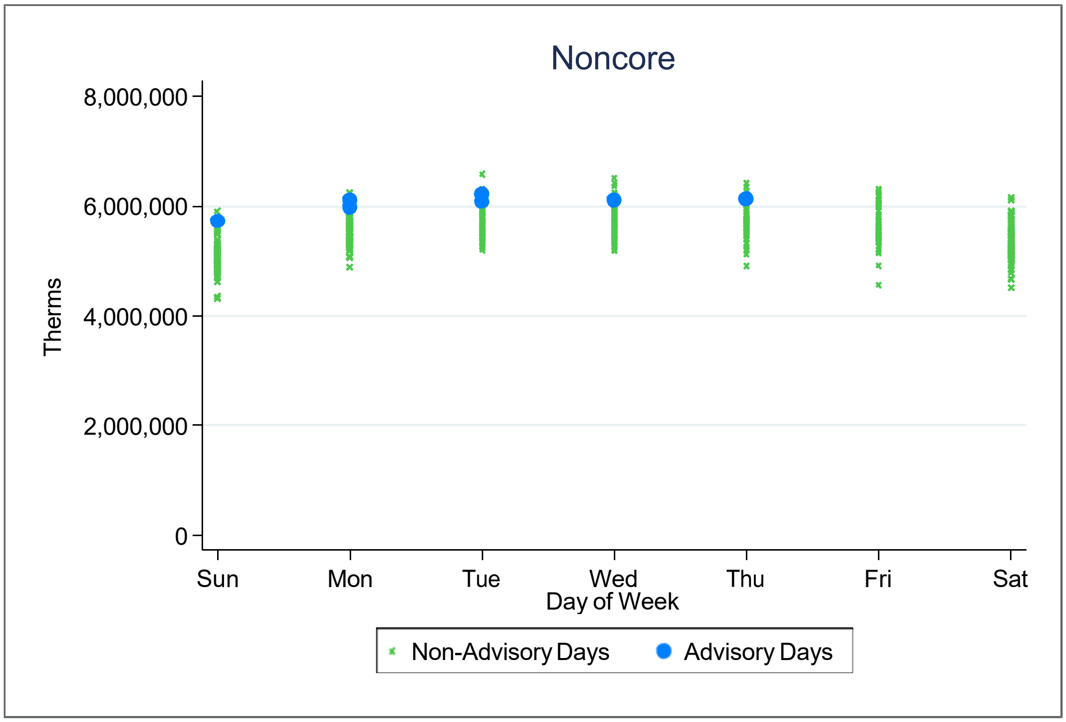
The method for estimating load impacts for the Noncore Notification Campaign is very similar to that used for the core campaign. The analysis dataset was limited to 601 noncore customers with 18 months of hourly gas consumption data. A major difference between core and noncore customers is that noncore customer consumption is not as closely correlated with weather, as shown in Figure 5-1. Note that this figure presents total noncore therms, not therms per customer.

Figure 5-1: Noncore Gas Consumption vs. Temperature



In fact, gas consumption for noncore customers is more closely tied to the day of week. This relationship is shown in Figure 5-2. The time of year plays a large part as well.

Figure 5-2: Noncore Gas Consumption vs. Day of Week



After testing over 30 models with different combinations of weather and day type variables, a final specification was selected, as shown in this equation:

$$\text{therms}_t = a + y(\text{HDD\_65})_t + o(\text{HDD\_65})\text{^}2_t + K(\text{day\_of\_week})_t + A(\text{year\_month})_t + P(\text{advisory})_t + E_t$$

The variable *HDD_65* is the heating degree days with a base of 65 degrees Fahrenheit. This is estimated by determining the maximum of 65 minus average daily temperature, and 0. For example, a day with an average temperature of 60 degrees has a *HDD_65* value of 5, while a day with an average temperature of 70 degrees has a *HDD_65* value of 0. The model for noncore customers includes a squared HDD term as well. As before, the coefficient β provides the estimated gas usage impact of the campaign during the relevant period.

5.3 Daily Impact Estimates

Table 5-1 presents the aggregate therm impact estimates for noncore customers for each Advisory day. Impacts were not statistically significant on any day.

Table 5-1: Noncore Gas Consumption Impacts by Customer Segment and Advisory Day

Population	Number of Customers	Date	Reference (Therms)	Observed (Therms)	Impact (Therms)	Impact (%)	95% Confidence Interval		P-Value
Noncore	601	December 18, 2016	5,736,235	5,720,791	15,444	0.3%	-5.8%	6.3%	0.93
		December 19, 2016	6,148,670	6,118,975	29,695	0.5%	-5.1%	6.1%	0.87
		December 20, 2016	6,181,585	6,073,865	107,720	1.7%	-3.8%	7.3%	0.54
		January 23, 2017	5,910,559	5,972,285	-61,726	-1.0%	-6.9%	4.8%	0.72
		January 24, 2017	6,044,072	6,219,816	-175,744	-2.9%	-8.7%	2.9%	0.33
		January 25, 2017	6,085,918	6,118,554	-32,637	-0.5%	-6.3%	5.2%	0.85
		January 26, 2017	6,068,712	6,128,313	-59,602	-1.0%	-6.7%	4.7%	0.73

6 Pilot Rebate Program Baseline Accuracy Assessment

This section summarizes the alternative baseline accuracy assessment for the Pilot Rebate Program. It summarizes the results, reviews the baseline methodology, the advantages and disadvantages of each type of baseline method, and then explores baseline accuracy on proxy days and rebates on Advisory days. The full proxy day and Advisory day results are located in Appendix B and Appendix C.

6.1 Summary of Results

Nexant tested 22 different baselines, including the 10/10 and regression-based approaches. In addition, both day-matching and weather-matching baselines were tested. Nexant found that:

1. The regression-based method performed the worst of all methods tested across all customer segments, including among customers with relatively high weather sensitivity.
2. Both the 10/10 and regression-based models were highly biased when compared to observed proxy day gas consumption. These models were downward biased, which indicates that impacts calculated using these methods were lower than their true values.
3. Day matching methods performed best, especially those with short look-back periods such as the top 3/5 and top 4/4. While weather matching results performed well, their results were never best overall.
4. Baseline choice has some implications for total rebates paid out. The best-performing baselines resulted in higher estimated rebates; however some of this is likely due to the upward bias of that baseline in general, and is not necessarily because customers responded that aggressively to the program.

6.2 Baselines Tested

For this analysis, Nexant leveraged the methodology developed for electricity baselines in the California ISO's Baseline Accuracy Working Group (BAWG), which informed the baselines that would be used for all electric DR programs that are settled in California's wholesale electricity market. The group was tasked with developing alternative baselines compared to the existing 10/10 day matching method on the basis of accuracy (baselines showing little bias) and precision (baseline accuracy not varying over event days and populations). The final BAWG-recommended baselines are shown in Table 6-1. For more information regarding the methods and process used to test, develop, and evaluate these baselines, refer to the 2017 Baseline Accuracy Working Group Proposal that was adopted by the California ISO.[8]

8 https://www.caiso.com/Documents/2017BaselineAccuracyWorkGroupProposal-Nexant.pdf

Table 6-1: CAISO BAWG Recommended Baselines

Customer Segment	Weekday	Baselines Recommended
Residential	Weekday	Control group
		4 day weather matching using maximum temperature
		Highest 5/10 day matching
	Weekend	Control group
		4 day weather matching using maximum temperature
		Highest 3/5 weighted day matching
Non-residential	Weekday	Control Group
		4 day weather matching using maximum temperature
		10/10 day matching
	Weekend	Control group
		4 day weather matching using maximum temperature
		4 eligible days immediately prior (4/4)

In addition to the recommended BAWG baselines, Nexant incorporated several other baselines evaluated in the BAWG, as well as the current 10/10 day matching baseline for the Pilot Rebate Program and the regression-based approach described in the draft CPUC resolution for the SoCalGas winter demand response programs. The full summary of baselines tested is shown in Table 6-2 and comprise both weather matching and day matching options.

Table 6-2: Tested Baselines for Pilot Rebate Program

Baseline Method	Baseline Type	Notes
Weather Matching	Matching on top X closest weather days based on average temp	Top 3, 4, 5, 10 and 20 days were tested. Method picks the top X days out of last 90
	Matching on top X closest weather days based on HDD(60)	
	Matching on top X closest weather days based on min temp	
Day Matching	Matching the top 4 of the past 4 days	
	Matching the top 3 of the past 5 days	
	Matching the top 3 of the past 5, weighted so that the days closest to the Advisory matter more	
	Matching the top 5 of the past 10 days	
	Matching the top 10 of the past 10 days	
Regression Methods	Regression	
	Regression with Month/DOW	

6.3 Baseline Calculation Process

The baselines shown above were constructed at the individual customer level, and while the baselines developed for modeling electricity consumption also involved a same-day adjustment, Nexant did not include the adjustment as part of this analysis. Same-day adjustments improve accuracy for hourly baselines of relatively short electric demand response events with sufficient pre-event hourly data. This data is used on the day of the event to provide a calibration of the baseline to the observed pre-event unperturbed load. As the SoCalGas Advisory days were multi-day events, there was not a comparable pre-event period that would be able to meaningfully improve accuracy. It is also unlikely that such a pre-event adjustment would perform well for a demand response event that lasts multiple days, as in the Advisories. The next two sections cover the general methods used to construct day and weather matching baselines. While only two specific baselines are shown, the process can easily be generalized to create other baselines.

Day Matching Baselines

Table 6-3 summarizes the methodology for day matching baselines, which are constructed by picking days with high system loads from within eligible days directly preceding the Advisory. Their viability relies on the assumption that customers on days that have similar system-level loads to the Advisory day will perform similarly on Advisory days. Because these baselines often do not have a look-back period longer than 3 weeks, any seasonal effects of customer behavior can effectively be ignored, as loads are not expected to change significantly over that horizon. However, if weather on the Advisory day is significantly different than the days that comprise the baseline, it's possible that day-matching methods will result in biased baselines for highly weather-sensitive customers.

Table 6-3: Day Matching Baseline Methodology

Step	Top 3/5 Days, Weighted
Baseline calculation process	1. Identify the past 5 eligible baseline days that occurred prior to an Advisory 2. Identify the hourly participant gas consumption on the Advisory day and on each eligible baseline day during the Advisory period hour. Sum to get daily consumption. 3. Identify the top 3 days of the eligible days based on aggregate demand
Eligible baseline days	Weekdays, excluding Advisory days and federal holidays
Baseline day selection criteria	Aggregate load (total population gas consumption)
Number of days selected to develop baseline	Top 3 based on system load
Calculation of temperatures	N/A
Advisory	The Advisory is defined as the entire day that the SoCalGas Advisory notification program is activated
Baseline	The day closest in time to the baseline day is weighted 50%, the second closest is weighted 30% and the third day is weighted 20%. The three days are averaged with weights to construct the baseline.

Weather Matching Baselines

Table 6-4 summarizes the methodology for weather matching baselines, which directly address the question of bias for customers with weather-sensitive loads. These methods involve finding days with similar weather profiles to the Advisory day, based on average temperature, minimum temperature, maximum temperature, or other weather metrics. Because finding a good weather matching day requires more data, considerations of having sufficient data must be balanced against seasonal patterns in gas consumption. For both the BAWG-recommended baselines and the baselines evaluated in this analysis, the look-back period for weather matching baselines was capped at 90 days. While most customers are likely to have 90 days of prior data from which to construct a baseline, customer account changes could impact the number of days available for new customers, reducing the accuracy of the baseline.

Table 6-4: Weather Matching Baseline Methodology

Step	Weekday Baseline 4 Day Matching Using Daily Minimum Temperature
Baseline calculation process	1. Identifying eligible baseline days that occurred prior to an Advisory 2. Identify the hourly participant gas consumption on the Advisory day and on each eligible baseline day during the Advisory period hour. Sum to get daily consumption. 3. Identify the participant-experienced temperatures for each hour of each Advisory day and eligible baseline day
Eligible baseline days	Weekdays, excluding Advisory days and federal holidays, in the 90 days immediately prior to the Advisory.
Baseline day selection criteria	Rank eligible days based on how similar daily minimum temperature is to the Advisory day
Number of days selected to develop baseline	4 days with the closest daily minimum temperature
Calculation of temperatures	Calculate the average temperature, HDD60 or daily minimum temperatures across all 24 hours in both the Advisory day and eligible baseline days.
Advisory	The Advisory is defined as the entire day that the SoCalGas Advisory notification program is activated
Baseline	The daily total average of the customer's gas consumption during baseline days. The baseline includes all 24 hours in day.

Regression-based Baselines

Regression-based baselines were not tested in the BAWG, but were proposed in the draft CPUC resolution for the SoCalGas winter demand response programs as an alternative method to develop baselines. The procedure for regression baselines is to fit a model that will explain daily therm consumption from the Heating Degree Day (HDD) that a customer experiences.
HDD is meant to approximate the heating needs of a customer and is calculated by computing the maximum of either the difference between a base temperature, 60°F in this case, and the day's average temperature and zero. So a day with an average daily temperature of 45°F would have an HDD (base 60°F) of 15. A day with an average daily temperature of 70°F would have an HDD of 0.

For this method, all weekend, holiday and Advisory days were excluded before Nexant fit a regression that related daily total load for each customer to their daily HDD values using a full year of pre-Advisory data. This method is intended to work similarly to a weather-matching baseline by making the assumption that weather conditions are the primary driver of gas consumption. However, by imposing the requirement of including a full year of data, this approach is not be able to control for seasonal effects without the inclusion of additional modeling variables. In addition, customer account churn and a lack of Advanced Meter data going back a year limit the availability of a full year of interval data for a subset of customers. This implies that fewer customers will have accurate results because they will not have data available for the prior winter; the period in which most of the information about HDD and load is available.

The draft CPUC resolution also stipulated that this method be used only for customers with a correlation between gas consumption and HDD that is greater than 0.8. Statistical correlation, most commonly calculated using Pearson's correlation coefficient, is a measurement of how two variables move together. It has a range of -1 to 1, where values closer to either -1 or 1 indicate that the variables highly correlated. A correlation coefficient of 0 indicates that there is no measurable correlation between the two variables. By limiting this regression model to be applied to only customers with a correlation coefficient of 0.8 or greater, the modeling is done on customers that experience high degrees of positive correlation between temperature and load. In this case, it can be interpreted that the cooler the conditions (i.e., the higher the HDD value), the higher the customer's gas consumption will be.

Nexant found that approximately 25% of customers enrolled in the Pilot Rebate Program met this correlation threshold requirement. The average customer had a correlation coefficient of 0.65, while the median customer had a correlation coefficient of 0.72. This indicates that, while these customers are generally weather-sensitive, 75% are not sufficiently so such that they would qualify for the proposed regression-based baseline. After factoring in the requirement to also have a full year of available interval data, only 389 out of the 3,408 Pilot Rebate Program participants (11.4%) met both regression-based baseline criteria.

6.4 Recommended Baseline Results on Proxy Days

To identify the best baselines for this analysis, Nexant assessed baseline performance on proxy days. A proxy day is a day with similar characteristics to the Advisory day in terms of weather conditions, but on which an Advisory was not actually called. Using a proxy day is useful for baseline accuracy analysis because, since no Advisory was called, the baseline can be compared to the observed load and any difference between the baseline and the observed load must be attributable to error. Two metrics of interest were used to identify the best baselines:

1. Mean Percent Error is a measure of bias, or how different the average baseline result is to the true value
2. Normalized Root Mean Squared Error, a measure of precision, or how variable individual baseline estimates are from each other.

For more information on how these metrics are calculated, refer back to the 2017 BAWG Proposal. For this analysis, we report the average customer mean percent error a well as the aggregate percent difference. The best baseline is in the top three of absolute mean percent error, meaning that it is not substantially biased upward or downward. Of the top three baseline methods for each program, the best baseline is the one that minimized the normalized root mean squared error. Basically, the best baseline is the one that is the least noisy from day to day and customer to customer.

Best Baselines for Each Segment

Table 6-5 shows the results of the best baseline by customer segment in comparison to the original 10/10 baseline method and the regression-based method. In all cases, day matching methods perform best. The 3/5 baseline, either weighted or unweighted, perform best for three of the four customer groups, in addition to the program overall. The 4/4 baseline performs best for CTA customers. In general, the 3/5 baseline demonstrated a slight upward bias overall, meaning that it tends to overestimate the reference load, causing higher impacts. The regression and 10/10 methods tend to significantly underestimate reference loads, leading to smaller impacts.

Shown in the farthest column on the right is the rank of the baselines' overall bias compared to other baseline methods for that customer segment. This should be interpreted as a value of 1 being the least biased, and a value of 2 being the second-least biased, and so on. There were 22 baselines methods tested for each customer segment, and in each case, the regression-based method performed the worst of all methods tested.

Table 6-5: Best Baseline Performance Compared to Original Baseline Methods

Program (Population)	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias Compared to Other Baselines Tested
All (3,403)	3/5	8.8	9.1	4%	9%	1
	10/10	8.8	7.5	-14%	-18%	17
	Regression	8.8	6.3	-28%	-39%	22
CTA (52)	4/4	26.2	25.5	-3%	-2%	3
	10/10	26.2	24.5	-7%	-5%	19
	Regression	26.2	23.5	-10%	-8%	22
HWL (188)	3/5	104.4	107.9	3%	6%	1
	10/10	104.4	93.0	-11%	-8%	9
	Regression	104.4	82.2	-21%	-19%	22
MA (2,351)	3/5	2.7	2.9	4%	9%	2
	10/10	2.7	2.2	-22%	-18%	18
	Regression	2.7	1.5	-47%	-40%	22
Non-My Account (812)	3/5, Weighted	2.9	3.1	6%	9%	3
	10/10	2.9	2.3	-22%	-19%	18
	Regression	2.9	1.5	-49%	-45%	22

Table 6-6 shows the results for the small subset of 389 highly weather-sensitive customers with a correlation coefficient above 0.8 and a full year of Advanced Meter data from which to fit a regression. Among this select group of customers, the best performing baselines are still day-matching methods. In general, these results are similar to that of the full population. The customers that meet the weather correlation and data criteria are more likely to be part of the CTA or Non-My Account customer segments. For these segments, however, there is still no benefit to the regression models as they continue to exhibit the highest bias in each customer group.

Table 6-6: Best Baseline Performance Compared to Original Baseline Methods for Weather-Sensitive Customers with a Full Year of Data

Program (Population)	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
All (389)	3/5	7.7	7.3	-6%	1%	1
	10/10	7.7	5.5	-28%	-26%	20
	Regression	7.7	4.4	-43%	-48%	22
CTA (52)	4/4	37.3	36.2	-3%	-3%	1
	10/10	37.3	30.5	-18%	-18%	22
	Regression	37.3	31.6	-15%	-15%	17
HWL (16)	3/5	93.1	82.6	-11%	-12%	1
	10/10	93.1	62.6	-33%	-33%	20
	Regression	93.1	50.8	-45%	-46%	22
My Account (245)	3/5	3.1	3.1	-1%	1%	1
	10/10	3.1	2.3	-26%	-25%	19
	Regression	3.1	1.6	-48%	-48%	22
Non-My Account (118)	3/5, Weighted	3.2	3.1	-4%	-3%	2
	10/10	3.2	2.3	-28%	-28%	19
	Regression	3.2	1.6	-51%	-50%	22

6.5 Recommended Baseline Results on Advisory Days

Nexant then performed the baseline modeling procedure on Advisory days to assess the degree to which modeling choices influence the resulting aggregate rebate values. The results of this exercise are shown in Table 6-7. The method used to calculate rebates in the table below assign a value of $2.50 per therm saved, but did not round to the nearest therm, meaning that the total rebate values may be slightly different than those reported in Section 3.1. For this analysis, the comparative results are of more interest than the exact dollar values.

In general, the methods identified as having the best performance on proxy days tend to result in higher aggregate rebates to customers. This is especially pronounced in the HWL customer segment, where there is a $10,000 difference in total rebates. While this difference is significant, it is important to note that while the recommended baselines were the least biased of the available options, they all demonstrated slight upward bias, while the 10/10 and regression-based methods demonstrated significant downward bias. The 3/5, 4/4 and 3/5 weighted methods are likely to overstate the impacts of the program and increase the amount of rebates, while the 10/10 and regression methods understate the program impacts, leading to lower aggregate rebates. A full set of results can be found in Appendix C.

Table 6-7: Rebates Calculated on Advisory Days for Different Baseline Methods

Customer Segment	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Average Percent Difference	Total Rebate
CTA	4/4	26.2	24.6	-6%	$115
	10/10	26.2	23.9	-8%	$92
	Regression	26.2	22.0	-16%	$91
HWL	3/5	114.8	114.5	0%	$25,796
	10/10	114.8	100.7	-12%	$15,287
	Regression	114.8	81.6	-29%	$15,215
My Account	3/5	3.6	2.9	-20%	$5,250
	10/10	3.6	2.4	-33%	$2,638
	Regression	3.6	1.5	-59%	$1,456
Non-My Account	3/5, Weighted	3.9	3.3	-16%	$1,930
	10/10	3.9	2.6	-32%	$841
	Regression	3.9	1.5	-61%	$367
All	**Best Baseline for Each Segment**				$33,091
	10/10				$18,858
	Regression				$17,129

Appendix A Accuracy Testing of Core Regression Models

This appendix includes further information on the accuracy testing of the regression models for the Core Notification Campaign to show that the available variables cannot explain the unusually high usage on December 19 and 20 that has led to negative estimated impacts. Nexant tested over 60 different models to find the one that best predicted core customer gas consumption on a set of proxy days that were most similar to the Advisory days, as described in Section 3.2. The independent variables tested included weather variables such as average daily temperature and heating degree days, as well as variables such as calendar month and day of the week. A list of the independent variables is presented below in Table A-1.

Table A-1: Core Gas Consumption Modeling – Independent Variables

Variable	Description
dow	day of week
event	binary indicator for Advisory day of interest
HDD_58	heating degree days (base 58)
HDD_65	heating degree days (base 65)
HDD_65_0	heating degree days (base 65), equal to 0 if average temperature is below 58 degrees
HDD65_2	heating degree days (base 65), squared
mean7	average temperature over first 7 hours in the day
month	calendar month
prev_day_temp	average temperature over previous 24 hour day
temp2	average temperature over 24 hour day, squared
temperature	average temperature over 24 hour day
temperatureXym	temperature and ym interaction
weekday	binary weekday indicator
ym	year and month

Table A-2 each combination of independent variables and conditions tested for modeling gas consumption on proxy days. To measure each model's performance, Nexant calculated the sum of the squared errors for each model. Using this metric, Nexant determined that model 51 performed the best in terms of predicting proxy day gas consumption for residential and non-residential customers.

As reported in Section 4-3, model 51 predicted an increase in gas consumption, with the largest increases on December 19 and 20. Each model's prediction of gas consumption on these days is included in the table to show that this is true for every model Nexant tested. Therefore, the available variables cannot explain the unusually high usage on December 19 and 20 that has led to negative estimated impacts.

Table A-2: Core Gas Consumption Models

Model Number	Independent Variables	Conditions	Non-Residential				Residential			
			19-Dec-16		20-Dec-16		19-Dec-16		20-Dec-16	
			% Impact	p-value	% Impact	p-value	% Impact	p-value	% Impact	p-value
1	HDD65_2, HDD_65, dow, event	-	-10.1%	0.138	-16%	0.043	-14%	0.086	-45%	0.000
2	HDD65_2, HDD_65, dow, ym, event	-	-12.5%	0.009	-16%	0.004	-16%	0.004	-38%	0.000
3	HDD65_2, HDD_65, event	-	-11.9%	0.142	-20%	0.039	-13%	0.097	-43%	0.000
4	HDD65_2, HDD_65, weekday, event	-	-8.3%	0.201	-16%	0.040	-14%	0.085	-44%	0.000
5	HDD65_2, HDD_65, weekday, ym, event	-	-11.1%	0.014	-16%	0.003	-17%	0.003	-38%	0.000
6	HDD65_2, HDD_65, ym, event	-	-14.2%	0.033	-19%	0.014	-16%	0.004	-37%	0.000
7	HDD_65, HDD_58, weekday, month, event	-	-8.9%	0.048	-15%	0.006	-12%	0.022	-36%	0.000
8	HDD_65, HDD_58, weekday, ym, event	-	-10.8%	0.018	-16%	0.002	-15%	0.008	-39%	0.000
9	HDD_65, dow, event	-	-10.0%	0.144	-18%	0.027	-14%	0.090	-42%	0.001
10	HDD_65, dow, ym, event	-	-13.2%	0.007	-15%	0.005	-18%	0.005	-37%	0.000
11	HDD_65, event	-	-11.8%	0.150	-22%	0.025	-13%	0.100	-40%	0.001
12	HDD_65, weekday, event	-	-8.2%	0.213	-18%	0.025	-14%	0.088	-41%	0.001
13	HDD_65, weekday, ym, event	-	-11.8%	0.011	-16%	0.004	-19%	0.004	-36%	0.000
14	HDD_65, ym, event	-	-14.9%	0.028	-19%	0.017	-18%	0.005	-36%	0.000
15	HDD_65_0, HDD_58, event	-	-17.5%	0.135	-21%	0.116	-22%	0.128	-48%	0.024
16	HDD_65_0, HDD_58, weekday, ym, event	-	-9.6%	0.078	-14%	0.032	-14%	0.055	-32%	0.002
17	HDD_65_0, HDD_58, ym, event	-	-12.8%	0.083	-17%	0.047	-14%	0.062	-32%	0.002
18	dow, month, event	-	-15.2%	0.110	-3%	0.780	-21%	0.211	-2%	0.889
19	dow, ym, event	-	-22.5%	0.022	-9%	0.342	-38%	0.046	-16%	0.391
20	mean7, dow, event	-	-7.7%	0.310	-3%	0.739	-12%	0.409	-9%	0.610
21	mean7, dow, ym, event	-	-6.8%	0.247	-1%	0.907	-7%	0.476	-2%	0.844
22	mean7, weekday, event	-	-7.8%	0.293	-2%	0.753	-15%	0.302	-9%	0.607
23	mean7, weekday, ym, event	-	-7.1%	0.216	-1%	0.910	-11%	0.297	-2%	0.837
24	temp2, dow, event	-	-17.5%	0.040	-14%	0.120	-31%	0.082	-32%	0.143
25	temp2, dow, ym, event	-	-17.3%	0.011	-12%	0.097	-28%	0.035	-24%	0.119
26	temp2, event	-	-20.8%	0.035	-19%	0.082	-32%	0.069	-31%	0.144
27	temp2, month, event	-	-14.9%	0.063	-10%	0.231	-18%	0.136	-12%	0.404

Model Number	Independent Variables	Conditions	Non-Residential				Residential			
			19-Dec-16		20-Dec-16		19-Dec-16		20-Dec-16	
			% Impact	p-value	% Impact	p-value	% Impact	p-value	% Impact	p-value
28	temp2, temperature, dow, ym, , event	-	-13.4%	0.005	-15%	0.004	-19%	0.004	-36%	0.000
29	temp2, temperature, weekday, ym, event	-	-12.0%	0.008	-15%	0.003	-19%	0.004	-36%	0.000
30	temp2, weekday, event	-	-16.7%	0.043	-15%	0.108	-33%	0.063	-32%	0.134
31	temp2, weekday, ym, event	-	-16.9%	0.011	-12%	0.083	-31%	0.022	-24%	0.111
32	temperature, HDD65_2, HDD_65, ym, event	-	-14.3%	0.029	-19%	0.013	-16%	0.004	-37%	0.000
33	temperature, HDD_58, dow, ym, event	-	-11.2%	0.021	-17%	0.003	-13%	0.038	-38%	0.000
34	temperature, HDD_58, weekday, ym, event	-	-10.1%	0.029	-17%	0.002	-14%	0.031	-38%	0.000
35	temperature, HDD_58, ym, event	-	-13.3%	0.049	-20%	0.012	-13%	0.037	-38%	0.000
36	temperature, HDD_65, dow, ym, event	-	-13.3%	0.005	-15%	0.005	-19%	0.005	-37%	0.000
37	temperature, HDD_65, weekday, ym, event	-	-12.0%	0.007	-15%	0.003	-19%	0.004	-36%	0.000
38	temperature, HDD_65, ym, event	-	-15.1%	0.024	-19%	0.016	-18%	0.005	-35%	0.000
39	temperature, dow, event	-	-15.7%	0.036	-15%	0.079	-27%	0.079	-32%	0.100
40	temperature, dow, ym, event	-	-16.2%	0.009	-13%	0.055	-26%	0.029	-26%	0.064
41	temperature, event	-	-18.7%	0.036	-19%	0.058	-28%	0.067	-31%	0.101
42	temperature, weekday, event	-	-14.8%	0.042	-15%	0.070	-29%	0.061	-32%	0.093
43	temperature, weekday, ym, event	-	-15.6%	0.009	-13%	0.045	-28%	0.018	-27%	0.059
44	temperature, ym, event	-	-18.7%	0.017	-16%	0.060	-27%	0.022	-26%	0.066
45	temperatureXym, event	-	-18.7%	0.019	-16%	0.063	-27%	0.026	-27%	0.066
46	temperatureXym, weekday, event	-	-15.5%	0.012	-13%	0.048	-28%	0.022	-28%	0.059
47	weekday, month, event	-	-15.0%	0.110	-3%	0.755	-24%	0.160	-3%	0.865
48	HDD_65_0, HDD_58, event	temperature<60	-12.5%	0.185	-25%	0.036	-13%	0.168	-43%	0.002
49	HDD_65_0, HDD_58, weekday, ym, event	temperature<60	-9.8%	0.069	-18%	0.007	-15%	0.043	-39%	0.000
50	HDD_65_0, HDD_58, ym, event	temperature<60	-14.2%	0.108	-23%	0.033	-14%	0.046	-39%	0.000
51	**temperature, dow, ym, event**	**temperature<60**	**-9.1%**	**0.058**	**-16%**	**0.006**	**-14%**	**0.058**	**-44%**	**0.000**
52	temperature, prev_day_temp, dow, event	temperature<60	-3.2%	0.604	-7%	0.336	-5%	0.486	-30%	0.007
53	temperature, prev_day_temp, dow, ym, event	temperature<60	-6.4%	0.245	-9%	0.147	-8%	0.170	-32%	0.000
54	temperature, prev_day_temp, ym, event	temperature<60	-10.4%	0.219	-14%	0.165	-9%	0.138	-30%	0.000
55	temperature, weekday, event	temperature<60	-7.3%	0.245	-15%	0.045	-13%	0.147	-49%	0.001

Model Number	Independent Variables	Conditions	Non-Residential				Residential			
			19-Dec-16		20-Dec-16		19-Dec-16		20-Dec-16	
			% Impact	p-value	% Impact	p-value	% Impact	p-value	% Impact	p-value
56	temperature, weekday, ym, event	temperature<60	-9.6%	0.068	-15%	0.013	-15%	0.035	-45%	0.000
57	temperature, ym, event	temperature<60	-14.1%	0.112	-19%	0.066	-15%	0.038	-44%	0.000
58	temperature, dow, ym, event	temperature<=65	-11.0%	0.047	-14%	0.032	-17%	0.034	-37%	0.001
59	temperature, weekday, event	temperature<=65	-8.2%	0.162	-14%	0.037	-14%	0.131	-40%	0.004
60	temperature, weekday, ym, event	temperature<=65	-10.6%	0.040	-15%	0.014	-18%	0.027	-37%	0.001
61	temperature, ym, event	temperature<=65	-14.7%	0.074	-19%	0.049	-17%	0.030	-37%	0.001

Appendix B Pilot Rebate Program Baseline Proxy Day Results

Table B-1: Full Proxy Day Results

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
All	3403	3/5	8.8	9.1	3.6%	8.5%	1
		5/10	8.8	9.1	4.0%	7.0%	2
		3/5 Weighted	8.8	9.2	4.9%	10.6%	3
		4/4	8.8	7.9	-9.5%	-8.5%	4
		Top 3 Day Match on Avg Temp	8.8	7.8	-10.5%	-6.7%	5
		Top 5 Day Match on Avg Temp	8.8	7.8	-10.6%	-7.4%	6
		Top 4 Day Match on Avg Temp	8.8	7.8	-10.7%	-6.8%	7
		Top 10 Day Match on Avg Temp	8.8	7.8	-11.1%	-9.4%	8
		Top 3 Day Match on HDD60	8.8	7.6	-12.8%	-7.8%	9
		Top 3 Day Match on Min Temp	8.8	7.6	-13.0%	-12.3%	10
		Top 5 Day Match on HDD60	8.8	7.6	-13.1%	-8.4%	11
		Base Reg. w/Month & Day of Week Vars	8.8	7.6	-13.2%	-16.4%	12
		Top 4 Day Match on HDD60	8.8	7.6	-13.2%	-7.7%	13
		Top 4 Day Match on Min Temp	8.8	7.6	-13.4%	-12.9%	14
		Top 5 Day Match on Min Temp	8.8	7.6	-13.4%	-12.8%	15
		Top 20 Day Match on Avg Temp	8.8	7.6	-13.6%	-14.9%	16
		10/10	8.8	7.5	-13.9%	-17.6%	17
		Top 10 Day Match on Min Temp	8.8	7.5	-14.3%	-14.7%	18
		Top 10 Day Match on HDD60	8.8	7.5	-14.3%	-11.7%	19
		Top 20 Day Match on Min Temp	8.8	7.4	-16.0%	-18.6%	20
		Top 20 Day Match on HDD60	8.8	7.2	-17.9%	-18.1%	21
		Regression vs HDD60	8.8	6.3	-28.4%	-39.3%	22
CTA	52	5/10	26.2	26.4	0.9%	2.5%	1
		3/5	26.2	26.7	1.9%	3.1%	2
		4/4	26.2	25.5	-2.8%	-1.5%	3
		3/5 Weighted	26.2	26.9	2.9%	4.1%	4
		Top 3 Day Match on Min Temp	26.2	24.9	-4.8%	-3.6%	5
		Top 4 Day Match on Min Temp	26.2	24.9	-4.9%	-3.9%	6
		Top 5 Day Match on Min Temp	26.2	24.8	-5.1%	-4.3%	7
		Top 10 Day Match on Avg Temp	26.2	24.7	-5.5%	-4.6%	8
		Base Reg. w/Month & Day of Week Vars	26.2	24.7	-5.6%	-4.0%	9
		Top 5 Day Match on Avg Temp	26.2	24.7	-5.7%	-4.6%	10
		Top 4 Day Match on Avg Temp	26.2	24.6	-5.9%	-4.7%	11
		Top 10 Day Match on HDD60	26.2	24.6	-6.0%	-5.3%	12
		Top 10 Day Match on Min Temp	26.2	24.6	-6.0%	-5.0%	13

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 5 Day Match on HDD60	26.2	24.6	-6.0%	-4.9%	14
		Top 3 Day Match on Avg Temp	26.2	24.6	-6.1%	-5.1%	15
		Top 4 Day Match on HDD60	26.2	24.6	-6.1%	-4.9%	16
		Top 3 Day Match on HDD60	26.2	24.5	-6.4%	-5.4%	17
		Top 20 Day Match on Avg Temp	26.2	24.5	-6.5%	-5.4%	18
		10/10	26.2	24.5	-6.6%	-5.1%	19
		Top 20 Day Match on HDD60	26.2	24.3	-7.2%	-6.3%	20
		Top 20 Day Match on Min Temp	26.2	24.1	-7.7%	-6.5%	21
		Regression vs HDD60	26.2	23.5	-10.3%	-8.1%	22
HWL	188	3/5	104.4	107.9	3.4%	6.4%	1
		3/5 Weighted	104.4	108.9	4.3%	7.4%	2
		5/10	104.4	109.8	5.2%	8.1%	3
		4/4	104.4	95.1	-8.9%	-5.2%	4
		Base Reg. w/Month & Day of Week Vars	104.4	94.9	-9.1%	-6.6%	5
		Top 10 Day Match on Avg Temp	104.4	93.6	-10.3%	-7.5%	6
		Top 5 Day Match on Avg Temp	104.4	93.3	-10.6%	-7.4%	7
		Top 3 Day Match on Avg Temp	104.4	93.2	-10.7%	-7.6%	8
		10/10	104.4	93.0	-10.9%	-8.1%	9
		Top 4 Day Match on Avg Temp	104.4	92.9	-11.0%	-7.8%	10
		Top 20 Day Match on Avg Temp	104.4	92.4	-11.5%	-8.8%	11
		Top 3 Day Match on Min Temp	104.4	92.2	-11.7%	-8.0%	12
		Top 4 Day Match on Min Temp	104.4	91.7	-12.1%	-9.0%	13
		Top 5 Day Match on Min Temp	104.4	91.7	-12.2%	-8.7%	14
		Top 10 Day Match on Min Temp	104.4	91.2	-12.6%	-9.3%	15
		Top 20 Day Match on Min Temp	104.4	90.4	-13.4%	-10.5%	16
		Top 3 Day Match on HDD60	104.4	90.1	-13.7%	-10.3%	17
		Top 5 Day Match on HDD60	104.4	89.8	-13.9%	-10.1%	18
		Top 4 Day Match on HDD60	104.4	89.4	-14.3%	-10.4%	19
		Top 10 Day Match on HDD60	104.4	89.4	-14.4%	-11.4%	20
		Top 20 Day Match on HDD60	104.4	87.0	-16.6%	-13.3%	21
		Regression vs HDD60	104.4	82.2	-21.3%	-18.8%	22
My Account	2351	5/10	2.7	2.8	2.3%	7.5%	1
		3/5	2.7	2.9	4.5%	9.1%	2
		3/5 Weighted	2.7	2.9	6.8%	11.5%	3
		Top 4 Day Match on Avg Temp	2.7	2.5	-10.4%	-6.0%	4
		Top 3 Day Match on Avg Temp	2.7	2.5	-10.5%	-5.8%	5
		Top 5 Day Match on Avg Temp	2.7	2.4	-11.0%	-6.8%	6
		Top 4 Day Match on HDD60	2.7	2.4	-11.3%	-6.7%	7

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 3 Day Match on HDD60	2.7	2.4	-11.3%	-6.9%	8
		4/4	2.7	2.4	-11.7%	-8.5%	9
		Top 5 Day Match on HDD60	2.7	2.4	-12.0%	-7.6%	10
		Top 10 Day Match on Avg Temp	2.7	2.4	-13.3%	-8.9%	11
		Top 10 Day Match on HDD60	2.7	2.3	-15.2%	-11.2%	12
		Top 3 Day Match on Min Temp	2.7	2.3	-16.8%	-11.7%	13
		Top 5 Day Match on Min Temp	2.7	2.3	-17.0%	-12.1%	14
		Top 4 Day Match on Min Temp	2.7	2.3	-17.1%	-12.3%	15
		Top 10 Day Match on Min Temp	2.7	2.2	-18.8%	-14.3%	16
		Top 20 Day Match on Avg Temp	2.7	2.2	-19.0%	-14.7%	17
		10/10	2.7	2.2	-21.6%	-18.0%	18
		Top 20 Day Match on HDD60	2.7	2.1	-21.8%	-17.9%	19
		Top 20 Day Match on Min Temp	2.7	2.1	-22.9%	-18.5%	20
		Base Reg. w/Month & Day of Week Vars	2.7	2.1	-23.1%	-16.0%	21
		Regression vs HDD60	2.7	1.5	-46.6%	-39.7%	22
Non-My Account	812	5/10	2.9	2.9	1.5%	5.6%	1
		3/5	2.9	3.0	3.8%	7.5%	2
		3/5 Weighted	2.9	3.1	5.8%	9.4%	3
		Top 3 Day Match on Avg Temp	2.9	2.5	-12.1%	-9.1%	4
		Top 4 Day Match on Avg Temp	2.9	2.5	-12.1%	-9.0%	5
		4/4	2.9	2.5	-12.2%	-9.5%	6
		Top 5 Day Match on Avg Temp	2.9	2.5	-12.7%	-9.6%	7
		Top 3 Day Match on HDD60	2.9	2.5	-13.1%	-10.0%	8
		Top 4 Day Match on HDD60	2.9	2.5	-13.2%	-10.0%	9
		Top 5 Day Match on HDD60	2.9	2.5	-13.9%	-10.7%	10
		Top 10 Day Match on Avg Temp	2.9	2.5	-14.3%	-11.6%	11
		Top 10 Day Match on HDD60	2.9	2.4	-16.3%	-13.6%	12
		Top 3 Day Match on Min Temp	2.9	2.4	-18.2%	-15.6%	13
		Top 4 Day Match on Min Temp	2.9	2.4	-18.5%	-16.0%	14
		Top 5 Day Match on Min Temp	2.9	2.3	-18.8%	-16.3%	15
		Top 20 Day Match on Avg Temp	2.9	2.3	-20.1%	-17.4%	16
		Top 10 Day Match on Min Temp	2.9	2.3	-20.2%	-17.9%	17
		10/10	2.9	2.3	-22.2%	-19.5%	18
		Top 20 Day Match on HDD60	2.9	2.2	-23.4%	-20.8%	19
		Top 20 Day Match on Min Temp	2.9	2.2	-23.9%	-21.5%	20
		Base Reg. w/Month & Day of Week Vars	2.9	2.2	-24.1%	-20.4%	21
		Regression vs HDD60	2.9	1.5	-48.5%	-44.7%	22

Table B-2: Full Proxy Day Results for Customers with a Full Panel of Data

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
All	1817	3/5	13.5	14.0	3.6%	9.1%	1
		5/10	13.5	14.1	4.5%	7.8%	2
		3/5 Weighted	13.5	14.2	4.7%	11.4%	3
		4/4	13.5	12.3	-9.1%	-8.0%	4
		Top 5 Day Match on Avg Temp	13.5	12.1	-10.7%	-8.2%	5
		Top 3 Day Match on Avg Temp	13.5	12.1	-10.8%	-7.2%	6
		Top 10 Day Match on Avg Temp	13.5	12.1	-10.8%	-9.6%	7
		Top 4 Day Match on Avg Temp	13.5	12.1	-11.0%	-7.7%	8
		Base Reg. w/Month & Day of Week Vars	13.5	12.0	-11.3%	-12.6%	9
		Top 3 Day Match on Min Temp	13.5	11.9	-12.4%	-11.7%	10
		Top 20 Day Match on Avg Temp	13.5	11.8	-12.6%	-14.4%	11
		10/10	13.5	11.8	-12.7%	-17.1%	12
		Top 5 Day Match on Min Temp	13.5	11.8	-12.8%	-12.5%	13
		Top 4 Day Match on Min Temp	13.5	11.8	-12.8%	-12.6%	14
		Top 3 Day Match on HDD60	13.5	11.7	-13.3%	-8.9%	15
		Top 10 Day Match on Min Temp	13.5	11.7	-13.5%	-14.3%	16
		Top 5 Day Match on HDD60	13.5	11.7	-13.6%	-9.4%	17
		Top 4 Day Match on HDD60	13.5	11.7	-13.8%	-8.9%	18
		Top 10 Day Match on HDD60	13.5	11.6	-14.4%	-12.6%	19
		Top 20 Day Match on Min Temp	13.5	11.5	-14.9%	-18.1%	20
		Top 20 Day Match on HDD60	13.5	11.2	-17.3%	-18.3%	21
		Regression vs HDD60	13.5	10.2	-24.7%	-34.0%	22
CTA	42	5/10	25.8	25.9	0.3%	2.1%	1
		3/5	25.8	26.1	1.1%	2.5%	2
		3/5 Weighted	25.8	26.3	2.2%	3.5%	3
		4/4	25.8	24.9	-3.4%	-2.0%	4
		Top 3 Day Match on Min Temp	25.8	24.4	-5.3%	-4.0%	5
		Top 4 Day Match on Min Temp	25.8	24.4	-5.4%	-4.5%	6
		Top 5 Day Match on Min Temp	25.8	24.3	-5.6%	-4.8%	7
		Base Reg. w/Month & Day of Week Vars	25.8	24.3	-5.8%	-3.8%	8
		Top 10 Day Match on Avg Temp	25.8	24.2	-6.2%	-5.2%	9
		Top 5 Day Match on Avg Temp	25.8	24.0	-6.7%	-5.5%	10
		Top 10 Day Match on Min Temp	25.8	24.0	-6.8%	-5.8%	11
		Top 10 Day Match on HDD60	25.8	24.0	-6.8%	-6.0%	12
		Top 20 Day Match on Avg Temp	25.8	24.0	-7.1%	-6.0%	13
		Top 4 Day Match on Avg Temp	25.8	23.9	-7.2%	-5.6%	14

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 5 Day Match on HDD60	25.8	23.9	-7.2%	-6.0%	15
		10/10	25.8	23.9	-7.2%	-5.4%	16
		Top 4 Day Match on HDD60	25.8	23.9	-7.4%	-5.9%	17
		Top 3 Day Match on Avg Temp	25.8	23.8	-7.5%	-6.3%	18
		Top 3 Day Match on HDD60	25.8	23.8	-7.9%	-6.7%	19
		Top 20 Day Match on HDD60	25.8	23.8	-7.9%	-6.9%	20
		Top 20 Day Match on Min Temp	25.8	23.5	-8.7%	-7.4%	21
		Regression vs HDD60	25.8	23.2	-10.1%	-7.7%	22
HWL	184	3/5	104.3	108.0	3.5%	6.7%	1
		3/5 Weighted	104.3	109.0	4.4%	7.6%	2
		5/10	104.3	109.9	5.3%	8.3%	3
		4/4	104.3	95.2	-8.8%	-5.0%	4
		Base Reg. w/Month & Day of Week Vars	104.3	94.9	-9.1%	-6.5%	5
		Top 10 Day Match on Avg Temp	104.3	93.7	-10.2%	-7.3%	6
		Top 5 Day Match on Avg Temp	104.3	93.5	-10.4%	-7.2%	7
		Top 3 Day Match on Avg Temp	104.3	93.3	-10.6%	-7.4%	8
		10/10	104.3	93.1	-10.8%	-7.9%	9
		Top 4 Day Match on Avg Temp	104.3	93.0	-10.9%	-7.6%	10
		Top 20 Day Match on Avg Temp	104.3	92.5	-11.3%	-8.6%	11
		Top 3 Day Match on Min Temp	104.3	92.2	-11.6%	-7.9%	12
		Top 5 Day Match on Min Temp	104.3	91.8	-12.0%	-8.5%	13
		Top 4 Day Match on Min Temp	104.3	91.8	-12.1%	-8.9%	14
		Top 10 Day Match on Min Temp	104.3	91.3	-12.5%	-9.2%	15
		Top 20 Day Match on Min Temp	104.3	90.5	-13.3%	-10.3%	16
		Top 3 Day Match on HDD60	104.3	90.2	-13.6%	-10.1%	17
		Top 5 Day Match on HDD60	104.3	89.9	-13.8%	-9.9%	18
		Top 4 Day Match on HDD60	104.3	89.5	-14.2%	-10.2%	19
		Top 10 Day Match on HDD60	104.3	89.5	-14.3%	-11.1%	20
		Top 20 Day Match on HDD60	104.3	87.1	-16.5%	-13.1%	21
		Regression vs HDD60	104.3	82.2	-21.2%	-18.6%	22
My Account	1087	5/10	2.7	2.7	2.2%	9.1%	1
		3/5	2.7	2.8	4.7%	10.5%	2
		3/5 Weighted	2.7	2.9	7.2%	13.3%	3
		4/4	2.7	2.3	-11.8%	-7.9%	4
		Top 3 Day Match on Avg Temp	2.7	2.3	-12.2%	-6.0%	5
		Top 4 Day Match on Avg Temp	2.7	2.3	-12.4%	-6.7%	6
		Top 5 Day Match on Avg Temp	2.7	2.3	-12.7%	-7.5%	7
		Top 3 Day Match on HDD60	2.7	2.3	-13.5%	-7.8%	8

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 4 Day Match on HDD60	2.7	2.3	-13.7%	-7.6%	9
		Top 5 Day Match on HDD60	2.7	2.3	-14.1%	-8.4%	10
		Top 10 Day Match on Avg Temp	2.7	2.3	-14.5%	-8.9%	11
		Top 10 Day Match on HDD60	2.7	2.2	-17.0%	-12.2%	12
		Top 3 Day Match on Min Temp	2.7	2.2	-17.0%	-10.7%	13
		Top 5 Day Match on Min Temp	2.7	2.2	-17.3%	-11.5%	14
		Top 4 Day Match on Min Temp	2.7	2.2	-17.4%	-11.7%	15
		Top 10 Day Match on Min Temp	2.7	2.1	-19.2%	-13.8%	16
		Top 20 Day Match on Avg Temp	2.7	2.1	-19.5%	-14.1%	17
		Base Reg. w/Month & Day of Week Vars	2.7	2.1	-21.8%	-10.8%	18
		10/10	2.7	2.1	-22.0%	-17.6%	19
		Top 20 Day Match on HDD60	2.7	2.0	-22.9%	-18.1%	20
		Top 20 Day Match on Min Temp	2.7	2.0	-23.4%	-18.1%	21
		Regression vs HDD60	2.7	1.5	-43.3%	-33.7%	22
Non-My Account	504	5/10	2.8	2.9	1.1%	5.2%	1
		3/5	2.8	2.9	3.7%	7.4%	2
		3/5 Weighted	2.8	3.0	5.8%	9.4%	3
		Top 3 Day Match on Avg Temp	2.8	2.5	-12.2%	-9.7%	4
		4/4	2.8	2.5	-12.4%	-9.8%	5
		Top 4 Day Match on Avg Temp	2.8	2.5	-12.7%	-10.0%	6
		Top 5 Day Match on Avg Temp	2.8	2.5	-13.1%	-10.5%	7
		Top 3 Day Match on HDD60	2.8	2.4	-13.7%	-10.9%	8
		Top 4 Day Match on HDD60	2.8	2.4	-14.2%	-11.4%	9
		Top 5 Day Match on HDD60	2.8	2.4	-14.6%	-11.9%	10
		Top 10 Day Match on Avg Temp	2.8	2.4	-14.7%	-12.3%	11
		Top 10 Day Match on HDD60	2.8	2.4	-17.1%	-14.7%	12
		Top 3 Day Match on Min Temp	2.8	2.3	-18.2%	-15.9%	13
		Top 4 Day Match on Min Temp	2.8	2.3	-18.5%	-16.3%	14
		Top 5 Day Match on Min Temp	2.8	2.3	-18.9%	-16.5%	15
		Top 10 Day Match on Min Temp	2.8	2.3	-20.1%	-18.1%	16
		Top 20 Day Match on Avg Temp	2.8	2.3	-20.2%	-18.0%	17
		10/10	2.8	2.2	-22.7%	-20.2%	18
		Base Reg. w/Month & Day of Week Vars	2.8	2.2	-23.5%	-19.6%	19
		Top 20 Day Match on Min Temp	2.8	2.2	-23.9%	-21.8%	20
		Top 20 Day Match on HDD60	2.8	2.2	-24.0%	-21.7%	21
		Regression vs HDD60	2.8	1.5	-45.9%	-42.5%	22

Table B-3: Full Proxy Day Results for Customers with a Full Panel of Data & HDD60 Correlation Greater than 0.8

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
All	389	3/5 Weighted	7.7	7.3	-5.7%	1.4%	1
		3/5	7.7	7.1	-8.2%	-1.3%	2
		5/10	7.7	6.8	-12.2%	-5.7%	3
		4/4	7.7	6.4	-17.2%	-14.6%	4
		Top 5 Day Match on Avg Temp	7.7	6.0	-22.1%	-17.9%	5
		Top 5 Day Match on HDD60	7.7	6.0	-22.4%	-18.6%	6
		Top 10 Day Match on Avg Temp	7.7	6.0	-22.4%	-18.8%	7
		Top 10 Day Match on HDD60	7.7	5.9	-23.0%	-19.8%	8
		Top 4 Day Match on Avg Temp	7.7	5.9	-23.1%	-18.4%	9
		Top 4 Day Match on HDD60	7.7	5.9	-23.4%	-18.9%	10
		Top 3 Day Match on Avg Temp	7.7	5.9	-23.4%	-18.2%	11
		Top 3 Day Match on Min Temp	7.7	5.9	-23.4%	-21.8%	12
		Top 3 Day Match on HDD60	7.7	5.9	-23.6%	-18.7%	13
		Top 5 Day Match on Min Temp	7.7	5.9	-23.9%	-21.9%	14
		Top 4 Day Match on Min Temp	7.7	5.8	-24.4%	-21.9%	15
		Base Reg. w/Month & Day of Week Vars	7.7	5.8	-25.5%	-25.9%	16
		Top 20 Day Match on Avg Temp	7.7	5.7	-25.7%	-23.7%	17
		Top 10 Day Match on Min Temp	7.7	5.7	-26.0%	-23.9%	18
		Top 20 Day Match on HDD60	7.7	5.7	-26.7%	-25.6%	19
		10/10	7.7	5.5	-28.3%	-26.2%	20
		Top 20 Day Match on Min Temp	7.7	5.4	-30.2%	-28.4%	21
		Regression vs HDD60	7.7	4.4	-43.4%	-47.6%	22
CTA	10	3/5 Weighted	37.3	36.2	-2.9%	-2.6%	1
		3/5	37.3	35.6	-4.5%	-4.2%	2
		5/10	37.3	35.0	-6.1%	-5.9%	3
		4/4	37.3	34.0	-9.0%	-8.8%	4
		Base Reg. w/Month & Day of Week Vars	37.3	33.3	-10.7%	-10.5%	5
		Top 4 Day Match on Min Temp	37.3	32.7	-12.3%	-12.0%	6
		Top 5 Day Match on Min Temp	37.3	32.7	-12.5%	-12.1%	7
		Top 3 Day Match on Min Temp	37.3	32.4	-13.1%	-12.7%	8
		Top 10 Day Match on Avg Temp	37.3	32.4	-13.3%	-13.2%	9
		Top 10 Day Match on HDD60	37.3	32.2	-13.6%	-13.6%	10
		Top 10 Day Match on Min Temp	37.3	32.1	-13.9%	-13.6%	11
		Top 20 Day Match on Avg Temp	37.3	32.1	-14.0%	-13.9%	12
		Top 20 Day Match on HDD60	37.3	32.0	-14.4%	-14.4%	13
		Top 5 Day Match on Avg Temp	37.3	31.8	-14.7%	-14.7%	14

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 5 Day Match on HDD60	37.3	31.7	-15.0%	-15.1%	15
		Top 3 Day Match on Avg Temp	37.3	31.6	-15.2%	-15.0%	16
		10/10	37.3	31.6	-15.4%	-15.2%	17
		Top 3 Day Match on HDD60	37.3	31.6	-15.4%	-15.3%	18
		Top 4 Day Match on Avg Temp	37.3	31.4	-15.8%	-15.7%	19
		Top 4 Day Match on HDD60	37.3	31.3	-16.1%	-16.1%	20
		Top 20 Day Match on Min Temp	37.3	31.2	-16.5%	-16.1%	21
		Regression vs HDD60	37.3	30.5	-18.4%	-18.3%	22
HWL	16	3/5 Weighted	93.1	82.6	-11.3%	-11.6%	1
		3/5	93.1	80.0	-14.0%	-14.4%	2
		5/10	93.1	76.2	-18.2%	-18.3%	3
		4/4	93.1	73.5	-21.0%	-21.5%	4
		Top 3 Day Match on Min Temp	93.1	68.8	-26.1%	-26.7%	5
		Top 5 Day Match on Avg Temp	93.1	68.4	-26.5%	-27.2%	6
		Top 5 Day Match on HDD60	93.1	68.3	-26.6%	-27.2%	7
		Top 10 Day Match on Avg Temp	93.1	68.0	-26.9%	-27.4%	8
		Top 10 Day Match on HDD60	93.1	67.8	-27.2%	-27.6%	9
		Top 5 Day Match on Min Temp	93.1	67.5	-27.5%	-27.6%	10
		Top 4 Day Match on HDD60	93.1	67.0	-28.0%	-28.5%	11.5
		Top 4 Day Match on Avg Temp	93.1	67.0	-28.0%	-28.5%	11.5
		Base Reg. w/Month & Day of Week Vars	93.1	67.0	-28.0%	-28.3%	13
		Top 4 Day Match on Min Temp	93.1	66.6	-28.4%	-28.6%	14
		Top 3 Day Match on Avg Temp	93.1	66.3	-28.8%	-29.3%	15.5
		Top 3 Day Match on HDD60	93.1	66.3	-28.8%	-29.3%	15.5
		Top 20 Day Match on Avg Temp	93.1	65.5	-29.7%	-30.2%	17
		Top 10 Day Match on Min Temp	93.1	65.1	-30.0%	-30.3%	18
		Top 20 Day Match on HDD60	93.1	65.1	-30.1%	-30.6%	19
		10/10	93.1	62.6	-32.7%	-33.3%	20
		Top 20 Day Match on Min Temp	93.1	61.0	-34.4%	-34.8%	21
		Regression vs HDD60	93.1	50.8	-45.4%	-46.1%	22
My Account	245	3/5	3.1	3.1	-0.7%	0.7%	1
		3/5 Weighted	3.1	3.2	1.9%	3.6%	2
		5/10	3.1	2.9	-5.4%	-4.0%	3
		4/4	3.1	2.7	-14.1%	-13.6%	4
		Top 5 Day Match on Avg Temp	3.1	2.6	-17.8%	-16.7%	5
		Top 5 Day Match on HDD60	3.1	2.5	-18.4%	-17.3%	6
		Top 3 Day Match on Avg Temp	3.1	2.5	-18.5%	-17.2%	7
		Top 4 Day Match on Avg Temp	3.1	2.5	-18.5%	-17.2%	8

Customer Segment	Population	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Percent Difference	Average Customer Day Bias	Rank of Bias compared to Other Baselines Tested
		Top 10 Day Match on Avg Temp	3.1	2.5	-18.7%	-17.7%	9
		Top 3 Day Match on HDD60	3.1	2.5	-18.9%	-17.7%	10
		Top 4 Day Match on HDD60	3.1	2.5	-19.0%	-17.6%	11
		Top 10 Day Match on HDD60	3.1	2.5	-19.7%	-18.8%	12
		Top 4 Day Match on Min Temp	3.1	2.4	-22.1%	-20.7%	13
		Top 3 Day Match on Min Temp	3.1	2.4	-22.1%	-20.6%	14
		Top 5 Day Match on Min Temp	3.1	2.4	-22.3%	-21.1%	15
		Top 20 Day Match on Avg Temp	3.1	2.4	-23.5%	-22.7%	16
		Top 10 Day Match on Min Temp	3.1	2.4	-24.2%	-23.1%	17
		Top 20 Day Match on HDD60	3.1	2.3	-25.2%	-24.6%	18
		10/10	3.1	2.3	-25.9%	-25.3%	19
		Base Reg. w/Month & Day of Week Vars	3.1	2.3	-26.3%	-25.4%	20
		Top 20 Day Match on Min Temp	3.1	2.2	-28.6%	-27.7%	21
		Regression vs HDD60	3.1	1.6	-48.0%	-47.5%	22
Non-My Account	118	3/5 Weighted	3.2	3.2	-1.8%	-0.9%	1
		3/5	3.2	3.1	-4.2%	-3.4%	2
		5/10	3.2	3.0	-8.4%	-7.6%	3
		4/4	3.2	2.7	-16.4%	-16.1%	4
		Top 3 Day Match on Avg Temp	3.2	2.6	-20.0%	-19.1%	5
		Top 5 Day Match on Avg Temp	3.2	2.6	-20.3%	-19.6%	6
		Top 3 Day Match on HDD60	3.2	2.6	-20.6%	-19.8%	7
		Top 4 Day Match on Avg Temp	3.2	2.6	-20.6%	-19.7%	8
		Top 5 Day Match on HDD60	3.2	2.5	-21.0%	-20.3%	9
		Top 10 Day Match on Avg Temp	3.2	2.5	-21.0%	-20.3%	10
		Top 4 Day Match on HDD60	3.2	2.5	-21.2%	-20.4%	11
		Top 10 Day Match on HDD60	3.2	2.5	-22.1%	-21.5%	12
		Top 5 Day Match on Min Temp	3.2	2.4	-24.6%	-23.8%	13
		Top 4 Day Match on Min Temp	3.2	2.4	-25.0%	-24.4%	14
		Top 3 Day Match on Min Temp	3.2	2.4	-25.3%	-24.4%	15
		Top 10 Day Match on Min Temp	3.2	2.4	-26.2%	-25.7%	16
		Top 20 Day Match on Avg Temp	3.2	2.4	-26.3%	-25.8%	17
		Top 20 Day Match on HDD60	3.2	2.3	-28.3%	-27.9%	18
		10/10	3.2	2.3	-28.3%	-28.0%	19
		Base Reg. w/Month & Day of Week Vars	3.2	2.3	-28.6%	-27.8%	20
		Top 20 Day Match on Min Temp	3.2	2.2	-30.3%	-30.0%	21
		Regression vs HDD60	3.2	1.6	-50.8%	-50.4%	22

Appendix C Pilot Rebate Program Baseline Advisory Day Results

Table C-1: Full Advisory Day Results

Customer Segment	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Average Percent Difference	Total Rebate
CTA	Top 10 Day Match on Avg Temp	26.2	24.1	-7.8%	$ 121
	Top 20 Day Match on Avg Temp	26.2	23.7	-9.2%	$ 110
	Top 3 Day Match on Avg Temp	26.2	24.3	-6.9%	$ 225
	Top 4 Day Match on Avg Temp	26.2	24.3	-7.2%	$ 174
	Top 5 Day Match on Avg Temp	26.2	24.3	-7.1%	$ 170
	5/10	26.2	25.8	-1.5%	$ 288
	4/4	26.2	24.6	-5.9%	$ 115
	Top 10 Day Match on HDD60	26.2	24.1	-7.9%	$ 122
	Top 20 Day Match on HDD60	26.2	23.7	-9.5%	$ 109
	Top 3 Day Match on HDD60	26.2	24.4	-6.8%	$ 229
	Top 4 Day Match on HDD60	26.2	24.3	-7.2%	$ 174
	Top 5 Day Match on HDD60	26.2	24.2	-7.3%	$ 170
	Top 10 Day Match on Min Temp	26.2	23.7	-9.3%	$ 142
	Top 20 Day Match on Min Temp	26.2	23.4	-10.5%	$ 128
	Top 3 Day Match on Min Temp	26.2	24.2	-7.5%	$ 200
	Top 4 Day Match on Min Temp	26.2	24.1	-7.8%	$ 168
	Top 5 Day Match on Min Temp	26.2	23.9	-8.6%	$ 151
	Regression vs HDD60	26.2	22.0	-15.7%	$ 91
	Base Reg. w/Month & Day of Week Vars	26.2	24.0	-8.1%	$ 159
	10/10	26.2	23.9	-8.5%	$ 92
	3/5	26.2	25.6	-2.0%	$ 238
	3/5 Weighted	26.2	26.0	-0.7%	$ 280
HWL	Top 10 Day Match on Avg Temp	114.8	96.9	-15.6%	$ 13,619
	Top 20 Day Match on Avg Temp	114.8	97.0	-15.5%	$ 13,829
	Top 3 Day Match on Avg Temp	114.8	94.9	-17.3%	$ 15,107
	Top 4 Day Match on Avg Temp	114.8	95.1	-17.1%	$ 13,860
	Top 5 Day Match on Avg Temp	114.8	95.2	-17.0%	$ 12,908
	5/10	114.8	117.1	2.0%	$ 27,668
	4/4	114.8	103.1	-10.2%	$ 15,881
	Top 10 Day Match on HDD60	114.8	95.4	-16.9%	$ 13,628
	Top 20 Day Match on HDD60	114.8	94.8	-17.4%	$ 13,868
	Top 3 Day Match on HDD60	114.8	94.7	-17.5%	$ 15,362
	Top 4 Day Match on HDD60	114.8	94.9	-17.3%	$ 13,785
	Top 5 Day Match on HDD60	114.8	94.8	-17.4%	$ 13,486
	Top 10 Day Match on Min Temp	114.8	96.1	-16.3%	$ 14,173
	Top 20 Day Match on Min Temp	114.8	94.6	-17.6%	$ 13,404

Customer Segment	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Average Percent Difference	Total Rebate
	Top 3 Day Match on Min Temp	114.8	96.9	-15.6%	$ 17,072
	Top 4 Day Match on Min Temp	114.8	97.8	-14.8%	$ 16,453
	Top 5 Day Match on Min Temp	114.8	97.6	-15.0%	$ 16,254
	Regression vs HDD60	114.8	81.6	-28.9%	$ 15,215
	Base Reg. w/Month & Day of Week Vars	114.8	102.7	-10.5%	$ 18,913
	10/10	114.8	100.7	-12.2%	$ 15,287
	3/5	114.8	114.5	-0.2%	$ 25,796
	3/5 Weighted	114.8	115.6	0.7%	$ 26,747
My Account	Top 10 Day Match on Avg Temp	3.6	2.5	-31.2%	$ 3,352
	Top 20 Day Match on Avg Temp	3.6	2.3	-35.7%	$ 2,644
	Top 3 Day Match on Avg Temp	3.6	2.4	-35.5%	$ 4,172
	Top 4 Day Match on Avg Temp	3.6	2.5	-32.7%	$ 3,986
	Top 5 Day Match on Avg Temp	3.6	2.5	-31.6%	$ 3,869
	5/10	3.6	3.0	-16.7%	$ 6,235
	4/4	3.6	2.6	-28.7%	$ 3,116
	Top 10 Day Match on HDD60	3.6	2.5	-32.2%	$ 3,299
	Top 20 Day Match on HDD60	3.6	2.3	-37.5%	$ 2,567
	Top 3 Day Match on HDD60	3.6	2.3	-36.1%	$ 4,188
	Top 4 Day Match on HDD60	3.6	2.4	-33.4%	$ 3,992
	Top 5 Day Match on HDD60	3.6	2.5	-32.4%	$ 3,866
	Top 10 Day Match on Min Temp	3.6	2.5	-32.5%	$ 3,247
	Top 20 Day Match on Min Temp	3.6	2.3	-37.9%	$ 2,573
	Top 3 Day Match on Min Temp	3.6	2.6	-29.3%	$ 4,521
	Top 4 Day Match on Min Temp	3.6	2.6	-29.9%	$ 4,004
	Top 5 Day Match on Min Temp	3.6	2.5	-30.2%	$ 3,823
	Regression vs HDD60	3.6	1.5	-59.3%	$ 1,456
	Base Reg. w/Month & Day of Week Vars	3.6	2.6	-28.1%	$ 3,867
	10/10	3.6	2.4	-32.9%	$ 2,638
	3/5	3.6	2.9	-20.5%	$ 5,250
	3/5 Weighted	3.6	3.0	-18.3%	$ 5,932
Non-My Account	Top 10 Day Match on Avg Temp	3.9	2.7	-29.7%	$ 1,084
	Top 20 Day Match on Avg Temp	3.9	2.6	-33.5%	$ 866
	Top 3 Day Match on Avg Temp	3.9	2.6	-33.2%	$ 1,482
	Top 4 Day Match on Avg Temp	3.9	2.7	-30.8%	$ 1,352
	Top 5 Day Match on Avg Temp	3.9	2.7	-29.8%	$ 1,312
	5/10	3.9	3.3	-15.2%	$ 1,869
	4/4	3.9	2.8	-26.5%	$ 992
	Top 10 Day Match on HDD60	3.9	2.7	-30.4%	$ 1,059

Customer Segment	Baseline Type	Average Daily Use	Average Baseline Predicted Use	Average Percent Difference	Total Rebate
	Top 20 Day Match on HDD60	3.9	2.5	-34.8%	$ 817
	Top 3 Day Match on HDD60	3.9	2.6	-33.7%	$ 1,446
	Top 4 Day Match on HDD60	3.9	2.6	-31.3%	$ 1,325
	Top 5 Day Match on HDD60	3.9	2.7	-30.2%	$ 1,288
	Top 10 Day Match on Min Temp	3.9	2.6	-31.6%	$ 1,004
	Top 20 Day Match on Min Temp	3.9	2.5	-36.3%	$ 822
	Top 3 Day Match on Min Temp	3.9	2.8	-28.2%	$ 1,456
	Top 4 Day Match on Min Temp	3.9	2.7	-29.0%	$ 1,311
	Top 5 Day Match on Min Temp	3.9	2.7	-29.6%	$ 1,194
	Regression vs HDD60	3.9	1.5	-60.8%	$ 367
	Base Reg. w/Month & Day of Week Vars	3.9	2.7	-29.2%	$ 1,004
	10/10	3.9	2.6	-31.6%	$ 841
	3/5	3.9	3.2	-17.5%	$ 1,748
	3/5 Weighted	3.9	3.3	-15.5%	$ 1,930

Appendix D Overview of “SoCalGas Advisory Thermostat Program”

June 2017

OVERVIEW OF SOCALGAS(R) WINTER THERMOSTAT DEMAND RESPONSE PILOT

Summary and Key Outcomes

In the winter of 2017 Southern California Gas Company (SoCalGas) partnered with ecobee and EnergyHub to implement the "SoCalGas Advisory Thermostat Program." This pilot program was an element of the "Natural Gas Conservation Pilot Rebate Program" as described in SoCalGas Advice Letter 5035. The pilot was an innovative gas demand response program intended to reduce gas demand by direct control of customer thermostats. The pilot used the Bring Your Own Thermostat™ (BYOT) model to recruit existing customers with ecobee thermostats into the program by offering up to $50 of incentives. The following are the pilot's key stats and outcomes:

- 2,488 eligible ecobee thermostats within SoCalGas territory
- 411 thermostats applied
- 396 thermostats successfully enrolled
- 16% enrollment rate (above the industry average for first year)

Program Design

Season	January 19, 2017-March 31, 2017
Control Parameters	Up to 4-degree offset; Events from 5am-9am and/or 5pm-9pm; Opt-out allowed
Number of events per season	No more than 5
Customer eligibility criteria	Must be an ecobee owner within SoCalGas territory with active SoCalGas account and an activated Advanced Meter, but outside of SCE territory. Ecobee thermostat must control heat.
Program Name and messaging	"SoCalGas Advisory Thermostat Program"
Customer rebate (upfront and ongoing)	$25 for signing up, $25 end of season for staying in the program. Incentive paid to customers via check.

Engagement Strategy

EnergyHub and ecobee implemented a digital engagement campaign to recruit SoCalGas customers from the existing base of 2,488 ecobee thermostats. The campaign included

EnergyHub

www.energyhub.com

ecobee

www.ecobee.com

advertisements and rebate information on ecobee's webpage, outbound emails, and a SoCalGas branded enrollment site. Eligible SoCalGas customers began enrolling after January 19th, with the first enrollments processed and available for direct thermostat control on January 30th. Examples of some of the materials are provided below.

Cobranded Enrollment Page

Outbound Email

The email campaigns had higher than typical engagement levels experienced in similar ecobee promotional campaigns with 55% of recipients opening the email and 16% clicking through to the enrollment page. In total, 396 thermostats were successfully enrolled representing a 16% total enrollment rate which is high considering the limited recruitment time. A total of 14 thermostats were rejected from enrollment. Reasons for rejection include no SoCalGas account found (7), outside the service territory (6), or name of the application did not match account (1).

Demand Response Results

Because there were no further SoCalGas Advisory days called after the point at which customers were enrolled in the pilot, SoCalGas did not have a need to call any control events using the EnergyHub Demand Response Management System (DRMS). It is not uncommon for utilities to not run control events given weather conditions or other factors.

www.energyhub.com

www.ecobee.com

APPENDIX B

REPORT

SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation

August 14, 2018

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Southern California Gas Company

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1 Executive Summary

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Thermostat Program in response to the potential need for demand reductions during the 2017-2018 winter and future winters. The Smart Thermostat Program for 2018 was an offering where two vendors (Vendor 1 and Vendor 2) recruited from their installed smart thermostat customer base, and offered incentives for customers to enroll. The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. All activations took place either between the hours of 5 AM to 9 AM or 5 PM to 9 PM.

Gas load impacts (usage reductions) on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. As in the annual electric DR evaluations, the SoCalGas Smart Thermostat Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate the usage reductions.

Table 1-1 provides a summary of the 2017-2018 winter SoCalGas Smart Thermostat Program hourly event impacts for each event and for the average morning and evening event by vendor. The average load reduction for a Vendor 1 morning event was 0.031 thm per participant leading to an aggregate reduction of 217.152 thm, or 16.0%. The average load reduction for a Vendor 1 evening event was 0.012 thm, leading to an aggregate reduction of 81.795 thm, or 10.7%. The average load reduction for a Vendor 2 morning event was 0.050 thm, leading to an aggregate reduction of 102.308 thm, or 25.0%. The average load reduction for a Vendor 2 evening event was 0.014 thm, leading to an aggregate reduction of 37.768 thm, or 15.6%. Vendor 2 event impacts were consistently larger than Vendor 1 event impacts, and both vendors saw morning event impacts that were larger than evening event impacts.

Table 1-1: Winter 2017-2018 Load Impact Estimates

Date	Event Window	Vendor 1 Number of Participants	Vendor 1 Average Impact (thm)	Vendor 1 Aggregate Impact (thm)	Vendor 1 Impact (%)	Vendor 2 Number of Participants	Vendor 2 Average Impact (thm)	Vendor 2 Aggregate Impact (thm)	Vendor 2 Impact (%)	Avg. Event Temp. (°F)
20-Feb	AM	6,976	0.029	201.36	12.5%	2,029	0.052	105.14	21.2%	44.8
20-Feb	PM	-	-	-	-	2,029	0.031	63.70	22.0%	51.8
21-Feb	AM	6,976	0.032	224.78	15.5%	2,029	0.052	104.96	23.7%	50.2
21-Feb	PM	-	-	-	-	2,029	0.023	46.84	18.0%	53.2
22-Feb	AM	6,976	0.031	214.12	14.1%	2,029	0.048	96.41	21.2%	48.7
22-Feb	PM	-	-	-	-	2,029	0.016	32.47	13.3%	53.5
23-Feb	AM	6,976	0.030	211.73	15.3%	-	-	-	-	48.3
26-Feb	PM	6,976	0.012	85.01	11.4%	2,029	0.017	34.29	16.4%	55.5
27-Feb	AM	6,976	0.031	214.71	16.5%	2,029	0.050	101.86	25.9%	46.8
28-Feb	PM	6,976	0.015	105.33	12.7%	2,029	0.010	20.76	9.6%	54.2
1-Mar	AM	6,976	0.032	222.01	16.4%	2,029	0.058	116.67	28.7%	51.0
1-Mar	PM	6,976	0.008	55.05	8.0%	2,029	0.014	28.55	14.3%	54.7
2-Mar	AM	6,976	0.033	231.36	21.6%	2,029	0.044	88.81	29.1%	52.3
All Events										
Avg.	**AM**	6,976	0.031	217.15	16.0%	2,029	0.050	102.31	25.0%	48.9
Avg.	**PM**	6,976	0.012	81.80	10.7%	2,029	0.019	37.77	15.6%	53.8
Common Events across both vendors										
Avg.	**AM**	6,976	0.031	218.01	16.1%	2,029	0.050	102.31	25.0%	49.0
Avg.	**PM**	6,976	0.012	81.80	10.7%	2,029	0.014	27.87	13.4%	54.8

The SoCalGas Thermostat program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and evening. However, the thermostat setback strategy was also shown to be important, and can significantly affect the size of the load reductions and the post-event "snap back", as shown by the different vendor performance. The snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and generally erases any net daily therm savings.

From a technical perspective, it's clear the program met the objectives of reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, there were no statistically significant net daily therm savings that resulted from this program. Without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective. While on the electric grid blackouts can be caused by an immediate supply/demand imbalance, gas supply shortages causing low gas system pressure and deliverability issues are typically a more protracted event due to the slow speed of how gas travels. It's unclear how much of a supply shortage may exist for only a few hours in Southern California. If there aren't supply shortages lasting only a few hours, it's possible that traditional energy efficiency and behavioral conservation based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage. These interventions have the dual benefit of providing significant gas savings on both DR event days and non-DR days throughout the winter.

2 Overview

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Thermostat Program in response to the potential need for demand reductions during the 2017-2018 winter and future winters. The Smart Thermostat Program for 2018 was an offering where two vendors (Vendor 1 and Vendor 2) recruited from their installed smart thermostat customer base, and offered incentives for customers to enroll. The program was event-based, meaning that it targeted relatively few hours on days of peak demand. Load reductions were attained on event days from temporary degree setbacks on thermostats, which led to a reduction in demand for heating. Further details regarding the implementation of the pilot are contained in Section 2.1.

Gas load impacts on event days were estimated by applying the best practices that have been developed for electric Demand Response (DR) program measurement and evaluation in California. In 2008, the California Public Utilities Commission (CPUC) and joint electric Investor-Owned Utilities (IOUs) developed California's Load Impact Protocols, which required the electric utilities to conduct annual evaluations of all DR programs in the state. As in the annual electric DR evaluations, the SoCalGas Smart Thermostat Program load impact estimates leverage the wide availability of interval data from advanced meters to estimate usage reductions. The program evaluation methodology that uses a matched control group is similar to how most electric DR programs have been evaluated for several years, including Southern California Edison's (SCE's)® Save Power Days (also known as Peak Time Rebate) Program,[1] which is also a smart thermostat program.

Throughout this report, Nexant will define event, program, and load as follows:

- Event – refers to the four-hour period during which SoCalGas adjusted a customer's thermostat in order to reduce heating demand during that period (an "activation"). There can be multiple events in a single day.
- Program – refers to the SoCalGas Smart Thermostat Program, which is a combination of the Vendor 1 Program and the Vendor 2 Program
- Load – refers to customer gas usage, measured in therms (thm)

2.1 Program Design and Implementation

The SoCalGas Smart Thermostat program used the Bring Your Own Thermostat (BYOT) model to recruit existing customers with Vendor 1 and Vendor 2 thermostats into the program by offering up to $75 of incentives. Customers who enrolled in the program received a $50 enrollment incentive, as well as a $25 participation incentive after the winter season for remaining in the program. To recruit customers into the program, SoCalGas promoted the program using social media and radio advertising, and the vendors reached out to customers who had already adopted smart thermostat technologies. SoCalGas additionally sent out bill inserts to customers and had an email campaign for the program. Before the start of the program, customers were told that if an event was called, customer thermostats could be

[1] Nexant. "2017 Load Impact Evaluation of Southern California Edison's Peak Time Rebate Program." April 1, 2018. CALMAC Study ID: SCE0420.

adjusted remotely by SoCalGas by a few degrees, and there would be no “penalty of non-participation” for overriding a smart thermostat during a Natural Gas Conservation event. As shown in Table 2-1, at the end of recruitment, Vendor 1 had a little over 7,000 customers enroll in the Vendor 1 program and Vendor 2 had almost 2,000 customers enroll in the Vendor 2 program, for a total of approximately 9,000 customers enrolled in the SoCalGas Smart Thermostat Program.

Table 2-1: Vendors and Respective Pilot Program Enrollment

Contracted Vendor	Smart Thermostat Program	Enrolled Customers
Vendor 1	Vendor 1 Program	7,132
Vendor 2	Vendor 2 Program	1,842

Table 2-2 provides a summary of eligibility screens that each vendor applied to customers who had agreed to participate. Customers needed to own a thermostat from the respective vendor and needed to be a current SoCalGas residential gas service account holder. Vendor 2 additionally required that participants could not currently be enrolled in the SCE Save Power Days Program or the "SoCalGas Advanced Meter Opt-Out Program".

Table 2-2: Smart Thermostat Program Vendor Eligibility Requirements

Vendor 1 Criteria	Vendor 2 Criteria
Own Vendor 1 Thermostat with an active account	Own Vendor 2 Thermostat with active account
Have a wireless network installed at service address	Have a wireless network installed at service address
Active SoCalGas Account	Active SoCalGas Account
	Not enrolled in SCE Save Power Days
	Installed Advanced Meter at service address
	Natural gas furnace
	Not enrolled in “SoCalGas Meter Opt-Out Program”

Natural Gas Conservation events took place during periods of system constraint by adjusting thermostats to a lower temperature by no more than four degrees. Once the activations came to an end, thermostats were returned to their original set points.[2] All activations took place either between the hours of 5 AM to 9 AM or 5 PM to 9 PM, and customers who participated in the program received a notice at least two hours before the event.[3]

[2] Vendor 1 limits its thermostat adjustment to three degrees. Vendor 1 thermostats additionally will pre-adjust the temperature in the home before the event to maximize comfort. However, in the case of a morning event the thermostat will not pre-adjust the temperature unless the customer has a specific setting enabled. This is to ensure noise comfort for the customer.

[3] With the exception of Vendor 1’s second event in a day, which notifies the customer at the time of the activation.

In May 2018, SoCalGas conducted a focus group in order to evaluate overall customer satisfaction with the DR program. In the focus group, customers did not report any pain points for enrollment in either program, and they found enrollment in the program to be “fast and easy”. The focus group also found that both Vendor 1 and Vendor 2 customers were very satisfied with the program, and were likely to recommend the program to a friend and participate in the program again.[4]

2.2 Program Participants

Customers who signed up to participate in the SoCalGas Smart Thermostat Program are inherently different from customers who did not sign up to participate in the program or customers who were not targeted by SoCalGas marketing or thermostat vendors. Before the evaluation, specific customer segments were examined to observe how program participants differed from the overall population. Table 2-3 compares the portion of CARE customers who enrolled in the pilot to the overall population. Program participants were less likely to be CARE customers compared to the general residential population.

Table 2-3: Comparison of Program and Participation CARE Customers

CARE	% of Program Participants	% of SoCalGas Residential Customers
Yes	9%	28%
No	91%	72%
All	100%	100%

Table 2-4 compares the breakout of SoCalGas program participant housing type to the SoCalGas residential customer population. Program participants were more likely to reside in a single family home compared to the general population.

Table 2-4: Comparison of Program and Population Housing Types

Housing Type	% of Program Participants	% of SoCalGas Residential Customers
Single Unit	84%	65%
2 or More Separate Units	2%	3%
2-4 Connected Units	4%	10%
5 or More Connected Units	10%	22%
Mobile Home Park	0%	0%
All	100%	100%

[4] From Vendor 1 program and Vendor 2 progam Focus Group Report.

Figure 2-1 shows a heat map of the locations of pilot participants throughout the SoCalGas service territory. The largest concentrations of customers are in the LA Basin and Orange County areas. The next largest concentration is in the Riverside, Palm Springs and Bakersfield areas.

Figure 2-1: Heat Map of Pilot Participant Location

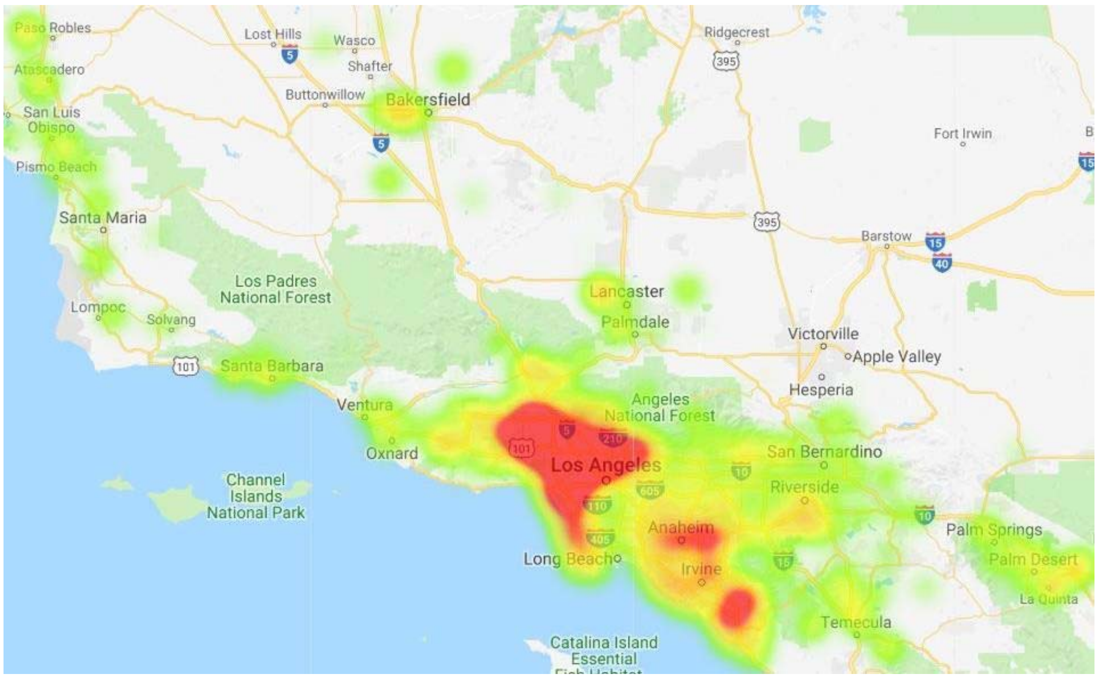
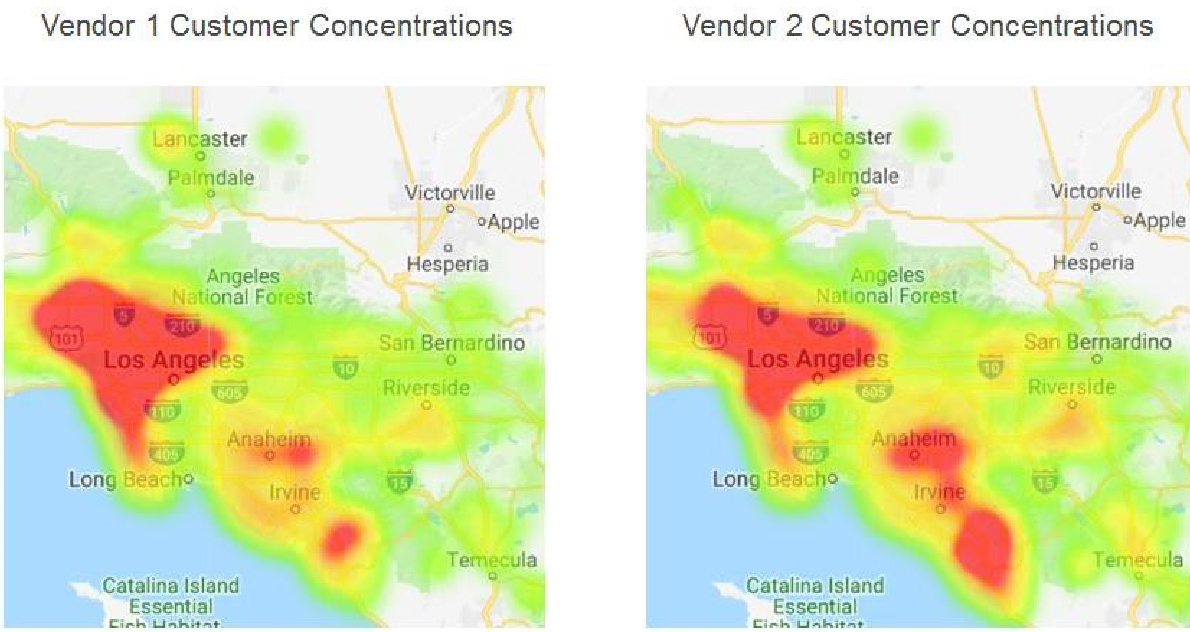


Figure 2-2 shows a heat map of pilot participants broken out by vendor. Vendor 2 has greater concentrations of customers in the Orange County region than Vendor 1, but the two vendors have similar customer concentrations in the LA Basin.

Figure 2-2: Heat Map of Pilot Participant Location By Vendor



2.3 Event Summary

Events were four hours long and took place either in the morning from 5 AM to 9 AM or in the evening from 5 PM to 9 PM. All of the events took place between February 20, 2018 and March 2, 2018. There were a total of thirteen events on nine different days, with seven morning events and six evening events. On four of the nine days, both morning and evening events were called.

Table 2-5 provides a summary of the events called during the 2017/2018 season. The thermostat vendor identifies which vendor(s) was called for each event, and the devices targeted column refers to the number of devices that were activated for an event. The last four columns record the participation status of the activated devices. Full participation refers to devices that were successfully accessed and the DR settings were in place for the entire event. An opt-out refers to customers that overrode the DR event settings. Vendor 1 kept track of which customers opted out before or during events. Vendor 2 did not, and so all opt-outs are counted as opting out before an event for Vendor 2 customers. Other refers to devices that were either "off", in an incompatible mode, or were not accessible due to technical issues. On average, 57% of devices targeted participated in the entire event, 22% of devices targeted opted out before the event, 13% of devices targeted opted out during the event, and 8% did not participate in the event due to technical issues.

Table 2-5: Overall Event Summary

Date	Event Window	Thermostat Vendor	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	Vendor 1 and Vendor 2	9,384	51%	25%	19%	5%
2/20/2018	PM	Vendor 2 only	1,564	59%	17%	0%	24%
2/21/2018	AM	Vendor 1 and Vendor 2	9,374	55%	24%	17%	4%
2/21/2018	PM	Vendor 2 only	1,550	59%	19%	0%	22%
2/22/2018	AM	Vendor 1 and Vendor 2	9,354	55%	23%	17%	4%
2/22/2018	PM	Vendor 2 only	1,541	60%	19%	0%	21%
2/23/2018	AM	Vendor 1 only	7,801	56%	23%	20%	1%
2/26/2018	PM	Vendor 1 and Vendor 2	9,317	57%	23%	15%	5%
2/27/2018	AM	Vendor 1 and Vendor 2	9,317	55%	24%	17%	4%
2/28/2018	PM	Vendor 1 and Vendor 2	9,313	55%	23%	17%	4%
3/1/2018	AM	Vendor 1 and Vendor 2	9,575	56%	23%	17%	5%
3/1/2018	PM	Vendor 1 and Vendor 2	9,814	59%	22%	14%	5%
3/2/2018	AM	Vendor 1 and Vendor 2	9,807	59%	20%	16%	4%
Average	-	-	-	57%	22%	13%	8%

Each vendor was called for a different number of events. Vendor 1 customers were called for ten of the thirteen events and Vendor 2 customers were called for twelve of the thirteen events. Vendor 1 customers did not participate in the first three evening events due to technical difficulties, but participated in the remaining events. Vendor 2 customers were not called for a morning event on February 23, but participated in the remaining events. Both vendors were called for nine of the thirteen events, and there was one day where both vendors were called for both a morning and an evening event.

Tables 2-6 and 2-7 give the event summaries for each vendor. Vendor 2 had a higher participation rate on average than Vendor 1, with an average of 59% of Vendor 2 customers participating in events compared to 55% of Vendor 1 customers participating in events. Vendor 2 also had a higher percent of customers that did not participate due to technical issues, with 22% of customers characterized with a participation status of other, while Vendor 1 had only 1% of participants categorized as other. These differences could be due to different methods of recording participation between the two vendors, as Vendor 2 did not record different opt-out times in the same way that Vendor 1 did. Vendor 1 broke out its opt-outs into customers that opted-out before an event and customers that opted-out during an event. On average, 24% of

Vendor 1 customers opted-out before an event and 20% of Vendor 1 customers opted-out during an event. This distribution did not change significantly between morning and evening events. On average, about 19% of Vendor 2 customers opted out either before or during an event.

Table 2-6: Vendor 1 Event Summary

Date	Time	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	7,816	51%	26%	22%	1%
2/20/2018	PM					
2/21/2018	AM	7,812	55%	24%	20%	1%
2/21/2018	PM					
2/22/2018	AM	7,806	55%	24%	21%	1%
2/22/2018	PM					
2/23/2018	AM	7,801	56%	23%	20%	1%
2/26/2018	PM	7,792	56%	25%	18%	1%
2/27/2018	AM	7,792	55%	24%	20%	1%
2/28/2018	PM	7,792	54%	24%	21%	1%
3/1/2018	AM	7,793	56%	23%	21%	1%
3/1/2018	PM	8,034	58%	23%	18%	1%
3/2/2018	AM	8,029	59%	21%	19%	1%
Average	-	7,847	55%	24%	20%	1%

Table 2-7: Vendor 2 Event Summary

Date	Event Window	Devices Targeted	Full Participation	Opt-out Before	Opt-out During	Other
2/20/2018	AM	1,568	54%	22%		24%
2/20/2018	PM	1,564	59%	17%		24%
2/21/2018	AM	1,562	57%	23%		20%
2/21/2018	PM	1,550	59%	19%		22%
2/22/2018	AM	1,548	57%	22%		21%
2/22/2018	PM	1,541	60%	19%		21%
2/23/2018	AM					
2/26/2018	PM	1,525	64%	12%		24%
2/27/2018	AM	1,525	57%	23%		20%
2/28/2018	PM	1,521	61%	17%		22%
3/1/2018	AM	1,782	57%	22%		20%
3/1/2018	PM	1,780	61%	15%		23%
3/2/2018	AM	1,778	60%	20%		21%
Average	-	1,604	59%	19%		22%

3 Load Impact Estimation Methodology

The primary challenge in estimating load impacts for DR programs such as the Smart Thermostat Program is estimating how much gas participants would have used during an event in the absence of SoCalGas dispatching the program. The estimated participants' usage in the absence of the event is referred to as the counterfactual or the reference load. This was not a randomized control trial, so the primary source of data used to develop reference loads is a matched control group. Control customers were selected from a pool of non-participant customers that passed several filters that were also applied to the program participants, and were statistically matched to program participants. The fundamental idea behind the matching process is to find customers who were not subject to DR events that have similar observable characteristics to those who were subject to DR events.

Once a suitable control group was created from a group of non-participants, the next step was to use a "difference-in-differences" analysis to estimate load impacts. Difference-in-differences helps to yield more precise estimates and can correct for observable differences in load not accounted for through matching. This calculation was done using a fixed-effects regression methodology, which reduces the standard error of the estimates. The underlying approach for difference-in-differences is comprised of the following:

- Measure gas demand for both treatment and control customers on proxy (similar non-event) days;
- Measure gas demand for both treatment and control customers on event days;
- Treatment effects are calculated by taking the difference between the treatment and matched control group in the event hours and subtracting any difference between the two groups in the event period hours on proxy days.

Additional details on the load impact estimation methodology including the selection of the matched control group and difference-in-differences regression model can be found in Appendix A.

4 Load Impacts

During the 2017-2018 winter, thirteen events were called on nine different days. All thirteen events ran for four hours and were called either from 5 AM to 9 AM or from 5 PM to 9 PM. Load impacts were evaluated separately for each vendor due to differences in when vendor customers were called for events and the ways in which events were implemented for each vendor. The remainder of this section presents the load impacts for each vendor for each event the vendor participated in.

4.1 Load Impacts for Vendor 1

Table 4-1 summarizes the average and aggregate impacts for each Vendor 1 event as well as the event temperature. Vendor 1 customers participated in eight morning events and two evening events for a total of 10 events. The average hourly impact during a morning event was 0.031 thm per participant, representing a 16% load reduction from an average reference load of 0.204 thm. The average hourly aggregate impact during a morning event was a 217.152 thm load reduction from a reference load of 1,423.104 thm. The average hourly per-customer impact during an evening event was 0.012 thm, an 11% load reduction from an average reference load of 0.114 thm. The average hourly aggregate impact was a 81.795 thm load reduction from a reference load of 711.552 thm.

Time of day and corresponding levels of consumption, which are at least partially driven by temperature, were large drivers of impact differences. Morning event impacts and reference loads were consistently higher than evening event impacts and reference loads, with higher reference loads generally associated with larger event impacts. On average, there was a 5 degree temperature difference between the average morning event hour and the average evening event hour. The afternoon events also likely had reduced heating load due to the heat buildup in the home during the day as well as warmer event period temperatures.

Table 4-1: Vendor 1 Event Summary for Average Customer

Date	Event Window	Vendor 1 Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Avg. Event Temp. (°F)
20-Feb	AM	0.241	0.213	0.029	201.36	12.5%	44.8
21-Feb	AM	0.214	0.182	0.032	224.78	15.5%	50.2
22-Feb	AM	0.222	0.192	0.031	214.12	14.1%	48.7
23-Feb	AM	0.206	0.176	0.030	211.73	15.3%	48.3
26-Feb	PM	0.109	0.097	0.012	85.01	11.4%	55.5
27-Feb	AM	0.192	0.161	0.031	214.71	16.5%	46.8
28-Feb	PM	0.123	0.108	0.015	105.33	12.7%	54.2
1-Mar	AM	0.195	0.163	0.032	222.01	16.4%	51.0
1-Mar	PM	0.109	0.101	0.008	55.05	8.0%	54.7
2-Mar	AM	0.154	0.121	0.033	231.36	21.6%	52.3
All Events							
Avg.	**AM**	0.204	0.172	0.031	217.15	16.0%	48.9
Avg.	**PM**	0.114	0.102	0.012	81.80	10.7%	54.8

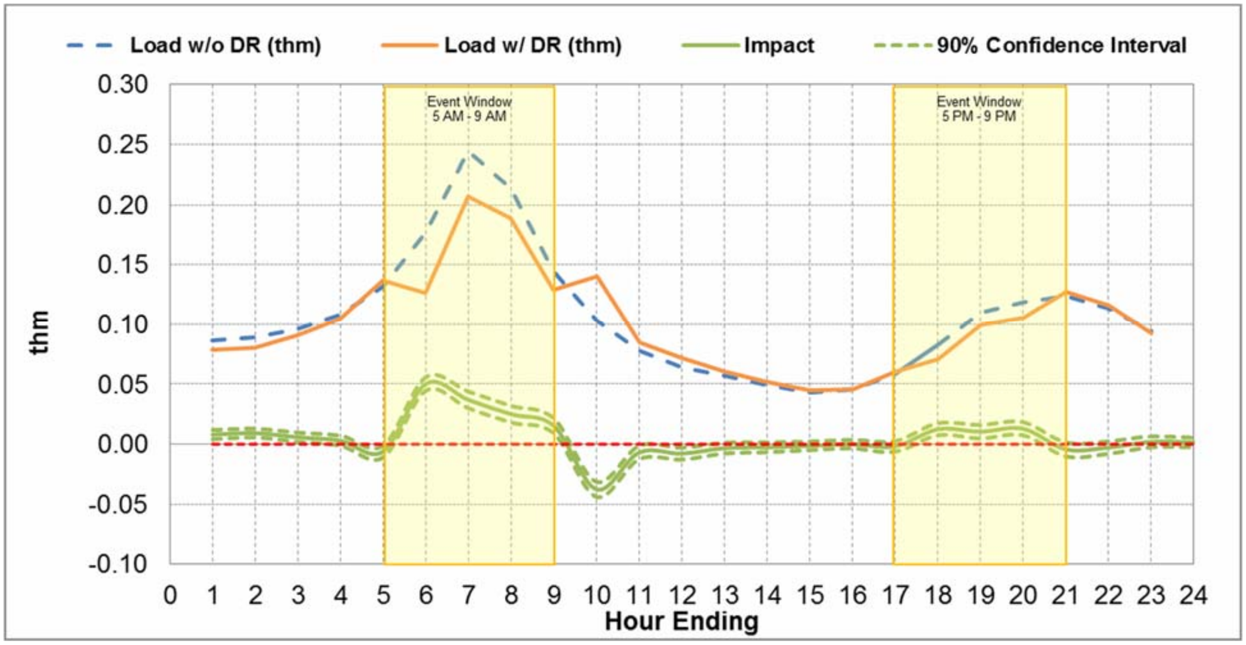
Vendor 1 customers experienced three different event day types: days with only morning activations, days with only evening activations, and days with both morning and evening activations. There was one day (March 1) where both a morning and evening event were called. Figure 4-1 provides the average per customer load with DR, load without DR (reference load), and load impact for that day. The load shape and usage patterns for the morning event window in Figure 4-1 are illustrative of customer behavior during all morning events, and the load shapes and usage patterns during the evening event window in Figure 4-1 are illustrative of the customer load shapes during all evening events.[5] Morning event windows had the highest overall reference load and highest overall impacts, with the largest impact occurring in the first hour of the morning event. Evening events had a much lower reference load and lower impacts.

In the hour following both morning and evening events, there is what is referred to as "snap back", which is when customer gas usage is higher after an event than would be expected if an event had not taken place. This is because during an event, the Vendor 1 thermostat temperature is lowered by up to 3°F. After the event, the thermostat temperature is returned to its pre-event temperature. In order to increase the temperature in the home to the non-event temperature, the HVAC system has to run more consistently for up to the first hour following the event (or longer). This can result in increased consumption in the hours following an event compared to what would typically be expected on a similar non-event day. The average snap back for Vendor 1 customers following morning events was 0.033 thms, with the load of the average participant 26% greater than customers that did not participate in the event. The

[5] This figure does not represent average morning event impacts across all morning events or average evening event impacts across all evening events. Its purpose is to illustrate what both events looked like, and shows exact impacts only for days where both morning and evening events were called.

average snap back for Vendor 1 customers following evening events was 0.015 therms, representing a 12% load increase compared to customers that did not participate in the event.

Figure 4-1: Vendor 1 Average Hourly Load Impact per Customer on Average Event Day with both Morning and Evening Events Called



4.2 Load Impacts for Vendor 2

Table 4-2 summarizes the average and aggregate impacts for each Vendor 2 event as well as the event temperature. Vendor 2 customers participated in six morning events and six evening events for a total of twelve events. The average impact during a morning event was 0.050 thm, representing a 25% reduction from an average reference load of 0.205 thm. The average hourly aggregate impact was a 102.308 thm reduction from a reference load of 415.905 thm. The average impact during an evening event was 0.019 thm, representing a 16% load reduction from an average reference load of 0.120 thm. The average aggregate impact was a 37.768 thm reduction from a reference load of 243.48 thm.

Similar to Vendor 1, all events Vendor 2 customers participated in were within approximately 10°F of each other. Time of day and corresponding levels of consumption, which are at least partially driven by temperature, were large drivers of impact differences. Morning event impacts and reference loads were also consistently higher than evening event impacts and reference loads, with higher reference loads generally associated with larger event impacts.

Table 4-2: Vendor 2 Event Summary for Average Customer

Date	Event Window	Vendor 2 Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Event Temp. (°F)
20-Feb	AM	0.244	0.192	0.052	105.141	21.2%	44.78
20-Feb	PM	0.147	0.116	0.031	63.701	22.0%	51.76
21-Feb	AM	0.218	0.166	0.052	104.957	23.7%	50.23
21-Feb	PM	0.133	0.110	0.023	46.844	18.0%	53.24
22-Feb	AM	0.224	0.176	0.048	96.413	21.2%	48.70
22-Feb	PM	0.127	0.111	0.016	32.466	13.3%	53.51
26-Feb	PM	0.104	0.087	0.017	34.285	16.4%	55.49
27-Feb	AM	0.195	0.145	0.050	101.858	25.9%	46.81
28-Feb	PM	0.111	0.101	0.010	20.764	9.6%	54.23
1-Mar	AM	0.198	0.140	0.058	116.673	28.7%	50.99
1-Mar	PM	0.099	0.085	0.014	28.552	14.3%	54.73
2-Mar	AM	0.152	0.108	0.044	88.805	29.1%	52.33
All Events							
Avg.	**AM**	0.205	0.155	0.050	102.308	25.0%	48.97
Avg.	**PM**	0.120	0.101	0.019	37.768	15.6%	53.83

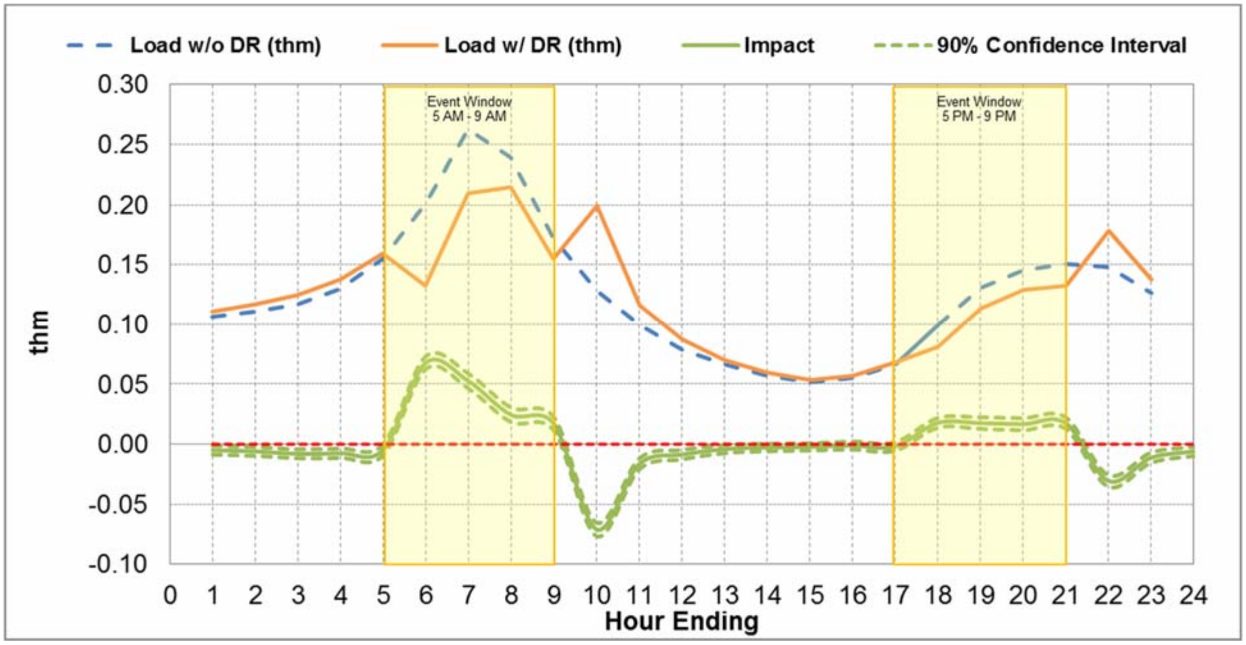
Vendor 2 customers experienced three different event day types: days with only morning events, days with only evening events, and days with both morning and evening events. There were four days where both a morning and evening event was called in the same day. Figure 4-1 provides the average per customer load with DR, load without DR (reference load), and load impact for the average event day for Vendor 2 customers where there were both morning and evening activations. The load shape and usage patterns for the morning event window in Figure 4-2 are illustrative of customer behavior during all morning events, and the load shapes and usage patterns during the evening event window in Figure 4-2 are illustrative of the customer load shapes during all evening events.[6] Morning event windows had the highest overall reference load and highest overall impacts, with the largest impact occurring in the first hour of the morning event. Evening events had a much lower reference load and lower impacts.

In the hour following the event, the snap back for the average Vendor 2 customer was larger than with Vendor 1 customers. The average snap back for Vendor 2 customers following morning events was 0.068 thm, with the load of the average participant 60% greater than customers that did not participate in the event. The average snap back for Vendor 2 customers following evening events was 0.028 thm, representing a 24% load increase compared to customers that did not participate in the event. In the evening, the post-event snap back

[6] This figure does not represent average morning event impacts across all morning events or average evening event impacts across all evening events. Its purpose is to illustrate what both events looked like, and shows exact impacts only for days where both morning and evening events were called.

increased the hourly consumption to a new higher hourly peak for Vendor 2 treatment customers between the hours of 9 PM and 10 PM.

Figure 4-2: Vendor 2 Average Hourly Load Impact per Customer on Average Event Day with both Morning and Evening Activations



4.3 Comparison of Vendor Load Impacts

Table 4-3 contains a summary of the average customer load impacts for each event for each vendor. The two vendors experienced a different mix of events during the 2017-2018 winter. Vendor 1 customers participated in seven morning events and three evening events, while Vendor 2 customers participated in six morning events and six evening events. Both vendors participated together in a total of nine events. In this section, we will use events where both vendors participated when comparing impacts since during these events customers experienced the same weather conditions. Each vendor took a different approach to the thermostat setback during the events, which is evident in the different load impacts and snap back patterns observed between the two vendors under similar weather conditions.

Vendor 2 and Vendor 1 customers both participated in a total of six morning events. During morning events, the average temperature was 48.97°F. Vendor 2 customers had a slightly higher baseline than Vendor 1 customers, with an average reference load of 0.205 thm compared to the Vendor 1 average reference load of 0.203 thm. Vendor 2 also had a much higher event impact than Vendor 1, with an average hourly impact of 0.050 thm during the event, 25% of the reference load. Vendor 1 customers had an average hourly impact of 0.031 thm, 16% of the reference load. However, as discussed above it should be noted that Vendor 2 customers also had a much larger snapback than Vendor 1 customers in the hour following an event, with Vendor 2 DR customers using 60% more load than would be expected in the absence of an event and Vendor 1 customers using 26% more load than would be expected in the absence of an event.

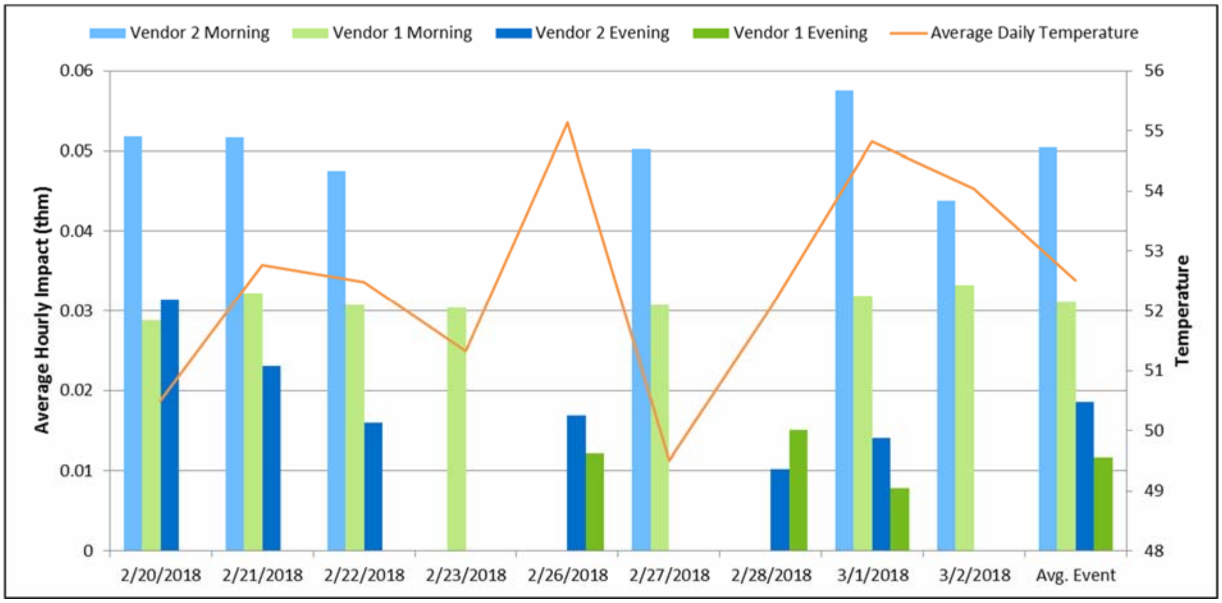
Vendor 2 and Vendor 1 customers both participated in a total of three evening events. During evening events, the average temperature was 54.82°F. Vendor 1 customers had a higher baseline than Vendor 2 customers, with an average reference load of 0.114 thm, compared to the Vendor 2 reference load of 0.104 thm. Similar to the morning impacts, Vendor 2 had a slightly higher event impact than Vendor 1, with an average hourly impact of 0.014 thm, 13% of the reference load. Vendor 1 customers had an average hourly impact of 0.012 thm, 10.7% of the reference load. Vendor 2 also again had a higher snapback after evening events than Vendor 1, seeing a 24% increase in load relative to the reference load in the hour following an event. Vendor 1 customers saw a 12% increase in load relative to the reference load in the hour following an event.

Table 4-3: Summary Load Impacts for Common Events Across Both Vendors

Vendor 1									
Date Event Temp. (°F)	Event Window	Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Impact (%)	Average Load w/o DR (thm)	Average Load w/ DR (thm)	Average Impact (thm)	Impact (%)
20-Feb	AM	0.241	0.213	0.029	12.5%	0.244	0.192	0.052	21.2%
21-Feb	AM	0.214	0.182	0.032	15.5%	0.218	0.166	0.052	23.7%
22-Feb	AM	0.222	0.192	0.031	14.1%	0.224	0.176	0.048	21.2%
26-Feb	PM	0.109	0.097	0.012	11.4%	0.104	0.087	0.017	16.4%
27-Feb	AM	0.192	0.161	0.031	16.5%	0.195	0.145	0.050	25.9%
28-Feb	PM	0.123	0.108	0.015	12.7%	0.111	0.101	0.010	9.6%
1-Mar	AM	0.195	0.163	0.032	16.4%	0.198	0.140	0.058	28.7%
1-Mar	PM	0.109	0.101	0.008	8.0%	0.099	0.085	0.014	14.3%
2-Mar	AM	0.154	0.121	0.033	21.6%	0.152	0.108	0.044	29.1%
Common									
Avg.	AM	0.203	0.172	0.031	16.1%	0.205	0.155	0.050	25.0%
Avg.	PM	0.114	0.102	0.012	10.7%	0.104	0.091	0.014	13.4%

Figure 4-3 illustrates the variation in impacts across events for each vendor for all events. Vendor 2 event impacts are blue and Vendor 1 event impacts are green. Vendor 2 consistently delivered larger impacts than Vendor 1 customers for morning events, and morning events consistently had larger impacts than evening events. Vendor 1 impacts varied very little across each event type, with all morning event impacts within 0.002 thm of the average morning event impact and all evening event impacts within 0.004 thm of the average evening event impact. Vendor 2 impacts varied more, with one morning event impact up to 0.008 thm greater than the average morning event impact and one evening event impact up to 0.011 thm greater than the average evening event impact.

Figure 4-3: Event Impact Summary by Vendor



4.4 Daily Therm Savings

Table 4-4 illustrates the average and aggregate daily savings for each event day type by vendor. It should be noted that neither vendor saw statistically significant daily savings for any event day type due to the snap-back in the hours following both morning and evening events. However, with a larger sample size it is possible that both vendors could see statistically significant daily savings in the future. Vendor 1 customers had a maximum daily saving of 4.9%[7] on March 1, when SoCalGas called both a morning and evening event. Vendor 2 customers had maximum average daily savings when only morning events were called, with an average daily impact of 2.5%. However, due to the small number of each event type, these numbers may not represent which event type would provide the largest daily savings on average.

Table 4-4: Estimated Daily Therm Savings by Vendor

Vendor	Event Day Type	Average Daily Impact (thm)	Aggregate Daily Impact (thm)	Aggregate Daily Impact (CCF)	Daily Impact (%)	Statistically Significant	Event Day Type Count
Vendor 1	AM Only	0.068	472.147	458.395	2.3%	No	6
	PM Only	0.047	328.490	318.923	1.8%	No	2
	AM & PM	0.118	826.482	802.410	4.9%	No	1
Vendor 2	AM Only	0.066	133.083	129.207	2.5%	No	2
	PM Only	0.016	31.463	30.546	0.6%	No	2
	AM & PM	0.045	91.226	88.569	1.6%	No	4

[7] Not statistically significant.

5 Conclusions and Recommendations

Table 5-1 provides a summary of the 2017-2018 winter SoCalGas Smart Thermostat Program hourly event impacts for each event and for the average morning and evening event by vendor. The average load reduction for a Vendor 1 morning event was 0.031 thm per participant leading to an aggregate reduction of 217.152 thm, or 16.0%. The average load reduction for a Vendor 1 evening event was 0.012 thm, leading to an aggregate reduction of 81.795 thm, or 10.7%. The average load reduction for a Vendor 2 morning event was 0.050 thm, leading to an aggregate reduction of 102.308 thm, or 25.0%. The average load reduction for a Vendor 2 evening event was 0.014 thm, leading to an aggregate reduction of 37.768 thm, or 15.6%. Overall, Vendor 2 customers consistently produced larger average event impacts relative to Vendor 1 customers. Across both vendors morning events provided larger impacts relative to evening events. Due to gas usage snap-backs after the event window, neither vendor had statistically significant daily therm savings, regardless of when an event was called or how many events were called.

Table 5-1: Winter 2017-2018 Load Impact Estimates

		Vendor 1				Vendor 2				
Date	Event Window	Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Number of Participants	Average Impact (thm)	Aggregate Impact (thm)	Impact (%)	Event Temp. (°F)
20-Feb	AM	6,976	0.029	201.355	12.5%	2,029	0.052	105.141	21.2%	44.78
20-Feb	PM	-	-	-	-	2,029	0.031	63.701	22.0%	51.76
21-Feb	AM	6,976	0.032	224.779	15.5%	2,029	0.052	104.957	23.7%	50.23
21-Feb	PM	-	-	-	-	2,029	0.023	46.844	18.0%	53.24
22-Feb	AM	6,976	0.031	214.118	14.1%	2,029	0.048	96.413	21.2%	48.70
22-Feb	PM	-	-	-	-	2,029	0.016	32.466	13.3%	53.51
23-Feb	AM	6,976	0.030	211.733	15.3%	-	-	-	-	48.25
26-Feb	PM	6,976	0.012	85.005	11.4%	2,029	0.017	34.285	16.4%	55.49
27-Feb	AM	6,976	0.031	214.712	16.5%	2,029	0.050	101.858	25.9%	46.81
28-Feb	PM	6,976	0.015	105.334	12.7%	2,029	0.010	20.764	9.6%	54.23
1-Mar	AM	6,976	0.032	222.013	16.4%	2,029	0.058	116.673	28.7%	50.99
1-Mar	PM	6,976	0.008	55.048	8.0%	2,029	0.014	28.552	14.3%	54.73
2-Mar	AM	6,976	0.033	231.357	21.6%	2,029	0.044	88.805	29.1%	52.33
All Events										
Avg.	**AM**	6,976	0.031	217.152	16.0%	2,029	0.050	102.308	25.0%	48.87
Avg.	**PM**	6,976	0.012	81.795	10.7%	2,029	0.019	37.768	15.6%	53.83
Common Events across both vendors										
Avg.	**AM**	6,976	0.031	218.055	16.1%	2,029	0.050	102.308	25.0%	48.97
Avg.	**PM**	6,976	0.012	81.795	10.7%	2,029	0.014	27.867	13.4%	54.82

The SoCalGas Thermostat program is one of the first, if not the first, natural gas based demand response programs in the US. It has proven that smart thermostats can be used to reduce demand for natural gas during targeted periods of time in the morning and the evening.

However, the snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and generally erase any net daily therm savings. Though, with larger sample sizes it may be possible to achieve statistically significant net daily therm savings. The thermostat setback strategy was also shown to be important, and can significantly affect the size of the load reductions and the post-event snap back, as shown by the different vendor performance. The performance differential actually provides a valuable data point, in that the setback strategy could be fine-tuned or adjusted to better meet a distribution system's specific need.

From a technical perspective, it's clear the program met the objectives of reducing gas consumption during specific windows of time. However, without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective. While on the electric grid blackouts can be caused by an immediate supply/demand imbalance, gas supply shortages causing low gas system pressure and deliverability issues are typically a more protracted event due to the slow speed of how gas travels. It's unclear how much of a supply shortage may exist for only a few hours in Southern California. If there aren't supply shortages lasting only a few hours, it's possible that traditional energy efficiency and behavioral conservation based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage. These interventions have the dual benefit of providing significant gas savings on both DR event days and non-DR days throughout the winter.

Appendix A Load Impact Methodology Details

A.1 Selection of Matched Control Group

Customers who signed up to participate in the Vendor 1 or Vendor 2 programs are inherently different from customers who did not sign up to participate in the SoCalGas DR programs or customers who were not targeted by the thermostat vendors. For this reason, a control group must be constructed using statistical matching. It is possible that the customers who enrolled in the SoCalGas DR programs had particular characteristics that made them more likely to enroll than customers who did not enroll or customers who were not targeted to enroll. This is particularly important when studying early adopters of a new technology such as smart thermostats who may have very different gas consumption patterns from those of the rest of the population. This type of behavior introduces selection bias because the difference in usage between the two groups caused by characteristics differences could be mistaken as the impact of treatment. A matched control group is the primary source for reference loads which are used to estimate impacts. The method used to assemble the matched control group is designed to ensure that the control group load on event days is an accurate estimate of what load would have been among SoCalGas DR customers on event days if an event hadn't taken place.

Nexant selected the control groups using propensity score matching to find residential SoCalGas customers who are non-DR program participants with load shapes most similar to those of SoCalGas DR participants. In this procedure, a probit model is used to estimate a score for each customer based on a set of observable variables that are assumed to affect the decision to join a SoCalGas DR program. A probit model is a regression model designed to estimate probabilities—in this case, the probability that a customer would enroll in a SoCalGas DR program. The score can be interpreted two different ways. First, the propensity score can be thought of as a summary variable that includes all the relevant information in the observable variables about whether a customer would choose to participate in a SoCalGas DR program. Each customer in the DR program population was matched with a customer in the non-DR population that has the closest propensity score. The second way to think of the propensity score is as the probability that a customer will join a SoCalGas DR program based on the included independent variables. Thinking of it this way, each customer in the control group was matched to a SoCalGas DR customer with a similar probability of joining a SoCalGas DR program given the observed variables. Nexant performed the match within four clusters that grouped customers based on their load shape similarity. In other words, the match was conducted separately for SoCalGas DR customers that had load shapes similar to one-another.

In order to select the probit model used to find the best match for each treatment customer, "out of sample" testing was performed to evaluate several different probit model specifications. Out of sample testing involves running each of the different model specifications using all but one of the proxy days, leaving the unused proxy day to test how well the model performed. By leaving a different proxy day out each time the matching selection is run, one is able to see how well the matches look on a day that was not used to select the match. During this process, sixteen different model specifications were tested using different observable variables including usage during event hours, average total daily usage, and usage from 12pm to 9pm. For each of the eleven models six different "calipers" were tested. Calipers set a maximum threshold of how large the difference in propensity scores can be for a matched pair. During the matching process, the treatment customers are matched to the control customer who has the most similar propensity score to them. Additionally, treatment customers can only be matched to a control customer in the same load shape cluster. If the difference between a treatment customer and control customer's propensity score is higher than the set caliper, the treatment customer will not be matched. Therefore, a caliper sets the standard for how close the matched pairs need to be. In order to find the closest control customer matches, the SoCalGas DR customers were split out by vendor to find the optimal probit model for each vendor. This provided much closer matches for each of the two thermostat vendor customers.

Figure A-1 and Figure A-2 show the results of the matched control group for the two thermostat vendors. The Vendor 1 customers match very well to their matched control group on proxy days. Vendor 2 also matches very well, although not quite as well as Vendor 1 customers do. This is in part due to the difference in sample size between the two vendors. Vendor 1 has over 7,000 customers while Vendor 2 has less than 2,000 customers. Both vendors also do not match perfectly during the daytime hours. This is because when selecting the model matching during event hours was given priority over non-event hours, since non-event hours are not as crucial for estimating event impacts.

Figure 5-1: Hourly Average Demand for Vendor 1 Customers on Proxy Days

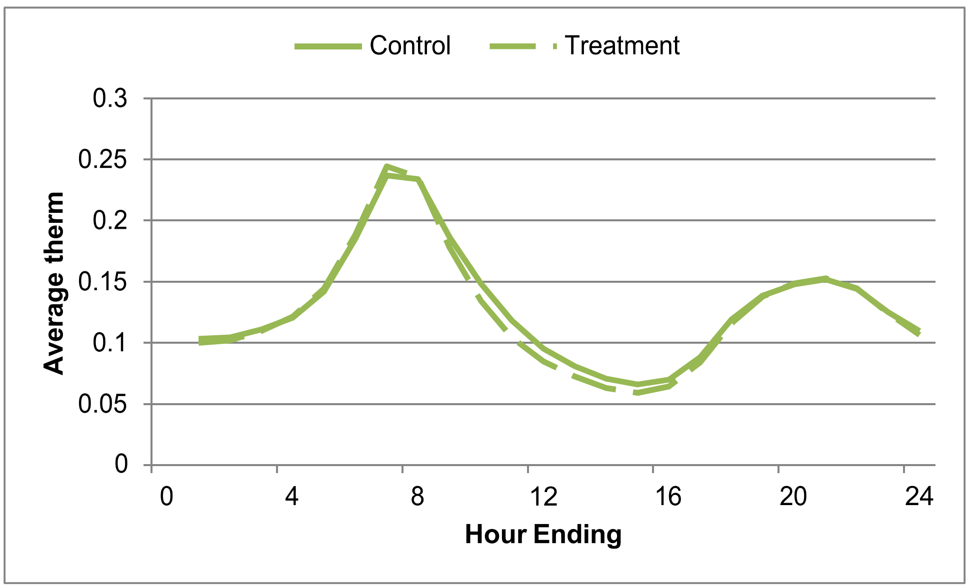
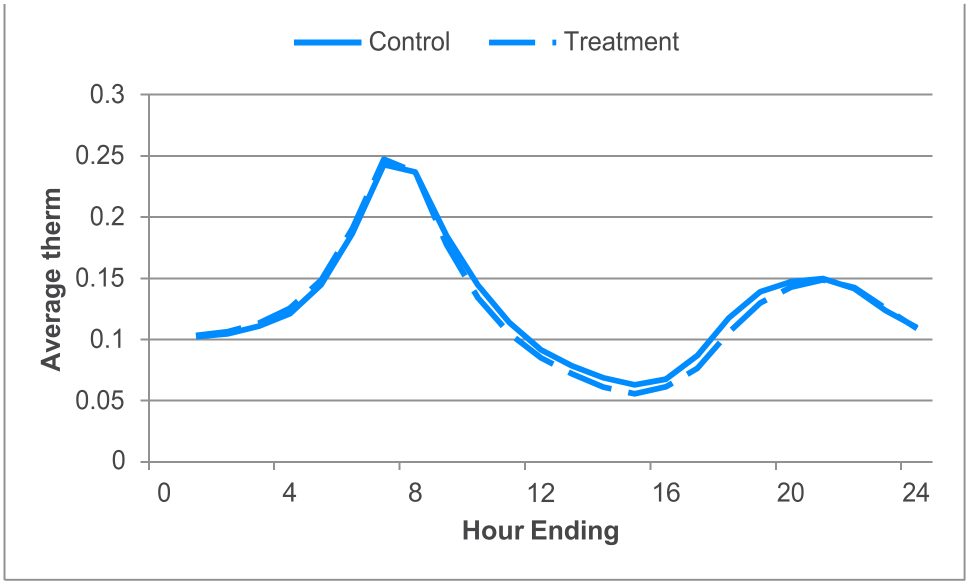


Figure 5-2: Hourly Average Demand for Vendor 2 Customers on Proxy Days



A.2 Difference-in-Differences Regression Models

After a matched control group was created, program impacts were estimated using a difference-in-differences regression model. This methodology is based on the assumption that the program impact is equal to the difference in usage between the treatment and the control groups during the event period, minus any pre-existing difference between the two groups. When using difference-in-differences, the matched control group does not need to perfectly match the treatment group on the proxy days. Any differences that may be due to observable differences in load not accounted for through matching will be netted out by the differencing. It is a reasonable assumption that any unobservable differences between the treatment and the control groups during the event period hours on proxy days stay the same during the DR event hours. Therefore any further difference between the groups in the DR event hours is assumed to be the impact of treatment. This regression model is shown in Equation A-1 below:

Equation A-1: Difference-in-Differences Models

Variable	Definition
i, t, n	Indicate observations for each individual i, date t and event number n
a	The model constant
b	Pre-existing difference between treatment and control customers
c	The difference between event and proxy days common to both treatment and control group members[8]
d	The net difference between treatment and control group customers during event days–this parameter represents the difference-in-differences
u	Time effects for each date that control for unobserved factors that are common to all treatment and control customers but unique to the time period
v	Customer fixed effects that control for unobserved factors that are time-invariant and unique to each customer; fixed effects do not control for fixed characteristics such as air conditioning that interact with time varying factors like weather
E	The error for each individual customer and time period
$Treatment$	A binary indicator or whether or not the customer is part of the treatment or control group
$Event$	A binary indicator of whether an event occurred that day–impacts are only observed if the customer is enrolled in DR ($Treatment$ = 1) and it was an event day

The model was estimated using both event days and proxy days, which are nonevent days with similar weather conditions and system load usage as days when events are called. The difference in loads between treatment and control customers for the event period hours on proxy days is subtracted from the differences on DR event hours to adjust for any differences between the treatment and control groups due to random chance.

As an extra validation, the simple difference in loads between treatment and control customers during event hours on event and proxy days was calculated to ensure that the regression model produces a similar output. The regression model also reduces the standard errors of the impact estimates compared to those that can be calculated from a simple difference in loads.

[8] In practice, this term is absorbed by the time effects, but it is useful for representing the model logic.

APPENDIX C

Project Test Report

Rheem Econet WiFi Water Heater Control Module Test

Prepared for:

SoCalGas'

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DISCLAIMER

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EXECUTIVE SUMMARY

Functionality testing was performed August 2018 to September 2018 on the Rheem Econet WiFi Module; a device meant to remotely control water heater (WH) temperature settings. In addition to functionality testing, simulations of Demand Response (DR) events were performed to gain an understanding of the effects of different DR event scenarios on customers' domestic hot water (DHW) which could lead to implementation of a DR program for SoCalGas customers.

The DR event scenarios tested were one-hour, two-hour, and three-hour events. The WH temperature was lowered to 110°F and 120°F from an initial (baseline) WH temperature set-point of 130°F. To simulate different household sizes, DHW draws of twelve, eighteen, twenty-four, thirty, and thirty-six gallons were performed for each DR event scenario.

Functionality testing of the Rheem EcoNet WiFi control module showed the ability of the module's application to run on two different operating systems. When performing DR event simulations, the Rheem module was able to control the WH temperature set-point when lowering the temperature from the initial 130°F to the two DR event temperature set-points of 110°F and 120°F. When returning the WH to the initial set-point from 110°F, the module was successful on fourteen out of fifteen simulations. The module was not successful in calling for burner cut-in at the end of all 120°F DR event simulations. An additional DHW draw of, on average, 2.4 gallons was necessary for the module to call for the burner to cut-in and return the WH temperature to 130°F from the 120°F DR event set-point.

From data obtained for DR event simulations run on the Rheem EcoNet module, the observation was made that the temperature change in DHW, at the WH outlet, over the duration of the water draw was no greater than 9.6°F in all but three of the DR event simulations. The average tank temperature over the duration of the DR event was also monitored. The change in average tank temperature was no greater than 14.5°F on forty-one out of forty-five DR event simulations.

INTRODUCTION

The California Public Utilities Commission Energy Division (ED) approved SoCalGas' Advice Letter (AL) 5223 with an effective date of December 21, 2017. AL 5223 proposed a device-based winter Demand Response (DR) program to help mitigate challenges to the reliability of natural gas service in SoCalGas territory.

In response to AL 5223, SoCalGas proposes to conduct a verification and demonstration project in collaboration with Rheem of a future WiFi-enabled WH technology that may be used in a natural gas demand response program. Phase I of this project will assess the technical and operational feasibility of the technology to perform a demand response function. The results gathered from phase I will be used in phase II which will help develop a natural gas demand response program for the 2018-2019 heating season.

OBJECTIVE

The Applied Technologies (AT) section at SoCalGas' Engineering Analysis Center (EAC) will demonstrate and evaluate the functionality of the Rheem EcoNet WiFi WH control module. The AT section will also look to help in the development of a strategy for a natural gas DR program for the 2018-2019 heating season by simulating DR events for various scenarios in a laboratory setting. In the case of a Natural Gas Conservation Event[1], the module would receive a signal via WiFi to adjust the WH temperature setting for the duration of the event.

PROJECT SETTING AND METHODOLOGY

TECHNOLOGY OVERVIEW

Rheem EcoNet WiFi WH Control Module

The Rheem WiFi control module is a hot water management device which allows the end user to control WH temperature setpoints remotely via the Rheem EcoNet application installed on a smart phone or tablet. The module also allows the end user to communicate to the WH when they are not home, away on vacation, or simply to change the temperature setting to help reduce energy consumption. In addition, the module can communicate with the Nest smart thermostat and Amazon's Alexa-enabled devices. The WiFi module is compatible with Rheem WH's which have powered dampers or are power vented.

The Rheem WiFi module connects directly in to the Rheem WH control module comm port which powers the WiFi module and allows it to communicate directly with the WH controller. The WiFi module

[1] A Natural Gas Conservation event is initiated to stimulate voluntary reductions in gas usage on forecasted gas system stressed days, similar to the statewide California Independent System Operator "Flex Alerts" campaign. SoCalGas Advice No. 5223 (U 904 G), November 28, 2017.

uses the WH's temperature sensor, located at the bottom of the WH tank directly behind the WH control module. An image of the Rheem WiFi module can be seen in Figure 1.

Figure 1. Rheem EcoNet WiFi Module

HOST SITE OVERVIEW

This study was conducted at SoCalGas' Engineering Analysis Center in Pico Rivera, California. The WH test rig was setup in the AT utilization lab and can be seen in Figure 3. A Rheem WH, model number XG50T12DU38U1, 50-gallon, 38,000 BTUH WH was used to provide DHW for the test. The WH was purchased by AT at a local Home Depot.

Figure 2. Project Test Rig

TEST PLAN OVERVIEW AND PROCEDURE

SCOPE

See Appendix A.

TEST PROCEDURE

See Appendix A.

MONITORING AND VERIFICATION EQUIPMENT

Table 1. List of Monitoring and Verification Equipment

Tag	Instrument	Manufacturer	Model	Instrument Range	Accuracy
T1	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T2	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T3	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T4	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T5	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T6	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
T7	Thermocouple	Omega Engineering	TQSS-18U	-270 to 400°C	0.75% from 0 to 350°C
P1	Differential Pressure Transducer	Setra	264	0 to 25 in. W.C	±1.0%
F1	Gas Meter	American Meter Company	DTM-200A	0 to 200 CFH	±1.0%
F2	Water Meter	Omega	FTB4700 Series	0.2-10 GPM	±1.0% FS

LIST OF CONTROLLED POINTS

Table 2. List of Controlled Points

List of Controlled Points	
Parameter Controlled	Controlled By
Water Heater Outlet Flow Rate	Needle Valve
Water Heater Temperature Settings	Water Heater Controller/Rheem WiFi Module
Water Heater Draw Volumes	Ball Valve
Natural Gas Pressure	Pressure Regulator

LIST OF PARAMETERS MONITORED

Table 3. List of Parameters Monitored

List of Parameters Monitored	
Parameter Recorded	Monitored By
Water Heater Tank Temperature-Top	Thermocouple (T2)
Water Heater Tank Temperature-Middle	Thermocouple (T3)
Water Heater Tank Temperature-Bottom	Thermocouple (T4)
Water Heater Inlet Temperature	Thermocouple (T1)
Water Heater Outlet Temperature	Thermocouple (T5)
Natural Gas Temperature	Thermocouple (T6)
Ambient Temperature	Thermocouple (T7)
Natural Gas Pressure at Gas Meter	Differential Pressure Transducer (P1)
Natural Gas Volume	Gas Meter (F1)
Water Heater Input Rate	Gas Meter (F1)
Water Heater Outlet Flow Rate	Water Meter (F2)
Water Heater Outlet Volume	Water Meter (F2)

PROJECT RESULTS AND DISCUSSION

THERMAL STRATIFICATION AND DEMAND RESPONSE PROGRAM DEVELOPMENT

A primary concern in all DR simulations was the temperature of the hot water coming out of the WH. The behavior of the hot water supplied by the WH was monitored over the duration of each hot water draw as well as the average internal WH tank temperature over the duration of the DR event simulation. The challenge in developing a test procedure that would provide accurate and realistic results is the thermal stratification that occurs in WHs with successive water draws. The temperature sensor for the WH's control module is located at the bottom of the tank. When a hot WH tank has a uniform temperature throughout and water is drawn, the cold water coming into the WH begins to replace the hot water drawn. The incoming cold water is forced to the bottom of the tank and therefore causes the temperature at the bottom of the tank to decrease rapidly; the WH controller senses this temperature drop and calls for the burner to cut-in to attempt to bring the temperature of the WH back to the temperature set-point even though the water at the top of the tank is still at the initial set-point. This leads to increasingly hotter water at the top of the tank while the bottom of the tank remains at the original temperature. This was most prevalent in small to intermediate water draws. Plots of hot water out of the WH versus draw time, and average WH tank temperature versus DR event duration, were generated to observe the DHW behavior and patterns that could potentially affect customers during a DR event. Special attention should be paid to changes in temperature of the hot water rather than initial and final temperatures since the thermal stratification of the WH tank can be misleading. It should be noted that all temperatures are taken at the WH outlet which is not always a true representation of the temperatures a customer would see at the end use fixture. Since heat is lost through pipe runs, the actual temperature at the end use fixture will depend on the length of the pipe run to the fixture, ambient temperatures, and pipe insulation among other things.

RHEEM ECONET WIFI MODULE

Functionality Testing

The Rheem Econet application was downloaded on to a smart phone and a tablet with different operating systems to verify the application's compatibility and the ability to control WH temperature set-points remotely with each. With respect to the application's ability to run on both operating systems, functionality was verified. To verify the ability of the module to remotely control the WH temperature settings, DR events were simulated. DR simulations where the WH temperature was lowered from 130°F to 120°F and from 130°F to 110°F showed that the module was able to successfully control the WH's temperature setting. When simulating the end of 110°F DR events, the WiFi module was successful in calling for burner cut-in to return the WH temperature to 130°F on fourteen out of fifteen simulations with an average response time of approximately four minutes. However, for all 120°F DR event simulations, the module was not successful in calling for burner cut-in to return the WH's temperature to the initial 130°F. To have the module call for burner cut-in at the end of the 120°F simulations, an average of 2.4 gallons of water had to be drawn.

Demand Response Event Scenario Results

Please refer to Table 5 below for a summary of all DR event scenarios performed with the Rheem EcoNet WiFi control module.

Table 4. DR Scenarios Run on the Rheem EcoNet Module

	1-Hour DR Event			2-Hour DR Event			3-Hour DR Event		
	110 °F	120 °F	130 °F	110 °F	120 °F	130 °F	110 °F	120 °F	130 °F
12 GAL	X	X	X	X	X	X	X	X	X
18 GAL	X	X	X	X	X	X	X	X	X
24 GAL	X	X	X	X	X	X	X	X	X
30 GAL	X	X	X	X	X	X	X	X	X
36 GAL	X	X	X	X	X	X	X	X	X

In forty out of forty-five simulations, the ***hot water out*** of the WH did not drop below the 130°F initial temperature set-point. All five instances where the temperature fell below 130°F occurred during the 36-gallon draws. Although the hot water for the 36-gallon 110°F 3-hour DR event simulation was below 130°F at the end of the draw, the temperature actually increased by 1°F from the beginning of the draw. In forty-one out of forty-five simulations, the ***temperature change in the hot water out*** of the WH did not exceed 10°F. The largest ***temperature change in the hot water out*** was 14.4°F which occurred during the 30-gallon 110°F 2-hour DR event.

The ***average WH tank temperature*** at the end of all DR event simulations was greater than 115°F and only fell below 120°F five times. The ***change in average WH tank temperature*** was at least 10.0°F in all but two DR event simulations at the 110°F set-point with the largest ***change in average WH tank temperature*** being observed for the 36-gallon 1-hour event which 18.8°F. The ***changes in average WH tank temperature*** for the 120°F DR scenarios exceeded 10°F only once during the 36-gallon 1-hour event.

A 2016 California Energy Commission study used to develop software (CBECC-Res) to demonstrate compliance with the California Residential Building Energy Efficiency Standards, used 105°F as the target temperature for showers. If it is believed that 105°F is the ideal shower temperature, and assuming a large percentage of the hot water used in a household is for showering, then it is important that the temperature of the customer's DHW stay well above 105°F during a DR event. The DR event simulations showed that, at the WH outlet, there were only three instances where the temperature drop in DHW exceeded 10°F; all three instances were for 110°F scenarios. This shows that the initial temperature setpoint on a customer's WH can significantly affect the DHW during a DR event if the WH tank is uniform and not stratified at the beginning of the DR event. The Rheem WiFi module instruction manual specifies to set the WH's gas valve to the "B" position which corresponds to a temperature of 140°F. Rather than use 140°F as the baseline temperature, 130°F was chosen as the baseline since this temperature poses less risk of scalding.

Table six shows the initial and final temperatures of the hot water out during the draw time interval and the average tank temperatures over the duration of the DR event. Figures four through nine show the plots generated for the 3-hour DR event simulation at 110°F, 120°F and the 130°F baseline. The tables and plots for all DR event simulations can be seen in Appendix D

Table 5. Rheem EcoNet 3-Hour DR Event Results

RHEEM ECONET WiFi MODULE 3 HOUR DEMAND RESPONSE EVENT						
	110°F WH TEMPERATURE SETPOINT					
	DHW_o (°F)	DHW_f (°F)	DHW ΔT (°F)	Avg Tank $Temp_o$ (°F)	Avg Tank $Temp_f$ (°F)	Avg Tank Temp ΔT (°F)
12GAL	145.5	141.1	4.4	139.3	129.3	10.0
18GAL	142.7	136.4	6.3	136.6	125.2	11.4
24GAL	143.0	133.5	9.5	134.7	121.4	13.3
30GAL	135.5	130.8	4.7	132.6	118.5	14.1
36GAL	126.8	127.8	-1.0	132.0	116.2	15.8
	120°F WH TEMPERATURE SETPOINT					
	DHW_o (°F)	DHW_f (°F)	DHW ΔT (°F)	Avg Tank $Temp_o$ (°F)	Avg Tank $Temp_f$ (°F)	Avg Tank Temp ΔT (°F)
12GAL	147.6	143.1	4.5	139.8	134.4	5.4
18GAL	146.3	139.4	6.9	137.6	131.5	6.1
24GAL	141.9	135.5	6.4	134.6	128.3	6.3
30GAL	137.7	132.5	5.2	133.1	126.4	6.7
36GAL	132.4	128.7	3.7	131.0	123.8	7.2
	130°F WH TEMPERATURE SETPOINT					
	DHW_o (°F)	DHW_f (°F)	DHW ΔT (°F)	Avg Tank $Temp_o$ (°F)	Avg Tank $Temp_f$ (°F)	Avg Tank Temp ΔT (°F)
12GAL	143.8	143.6	0.2	139.6	139.5	0.1
18GAL	140.9	139.6	1.3	137.2	136.7	0.5
24GAL	139.4	136.5	2.9	135.3	134.4	0.9
30GAL	134.2	132.7	1.5	132.5	132.4	0.1
36GAL	131.0	129.4	1.6	131.3	131.5	-0.2

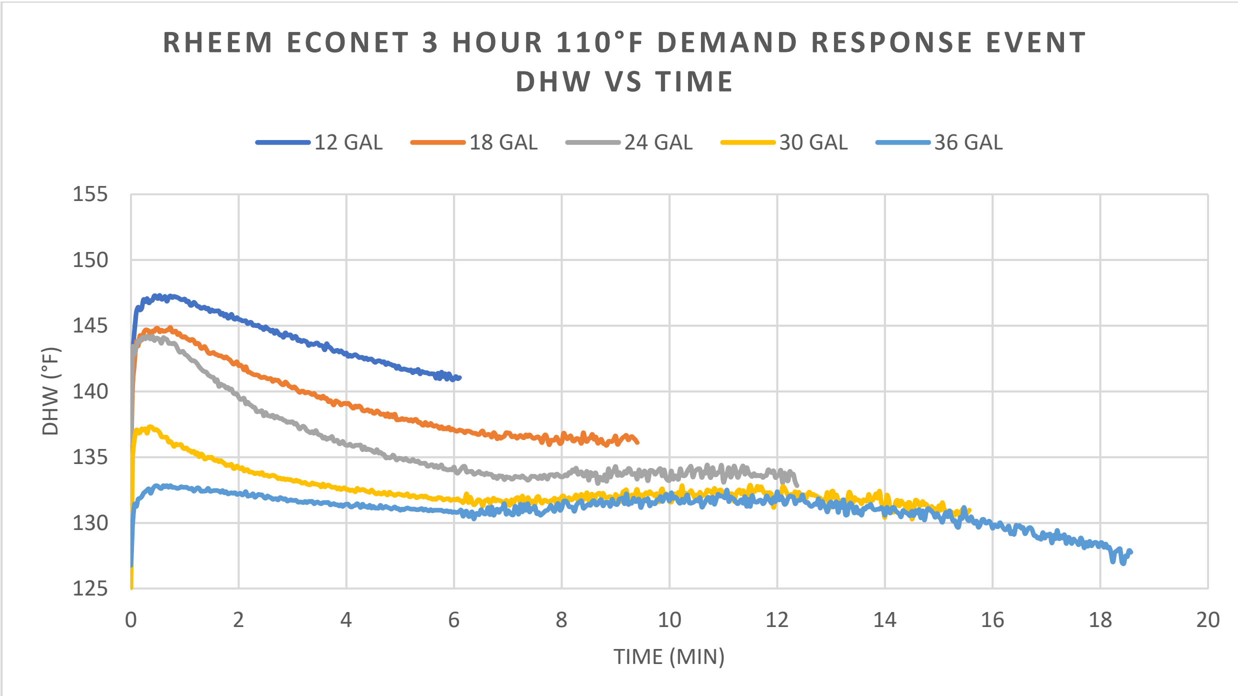

Figure 3. Rheem EcoNet 3-Hour 110°F DR Event DHW VS Draw Time

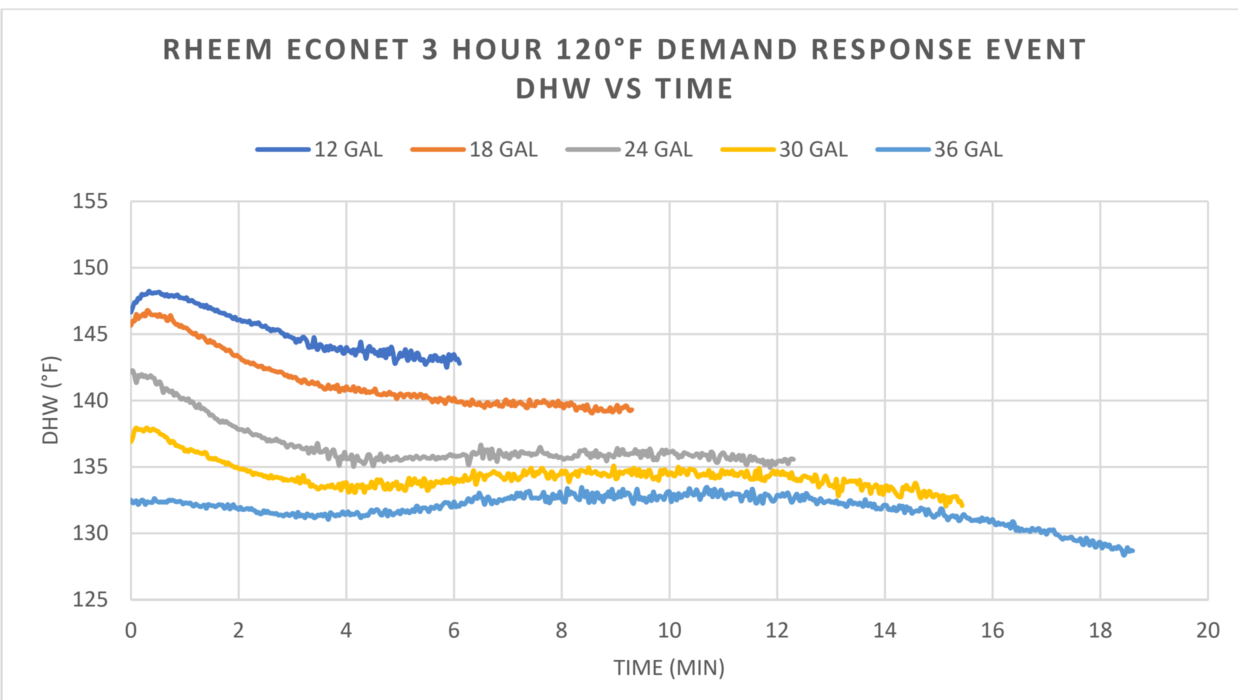

Figure 4. Rheem EcoNet 3-Hour 120°F DR Event DHW VS Draw Time

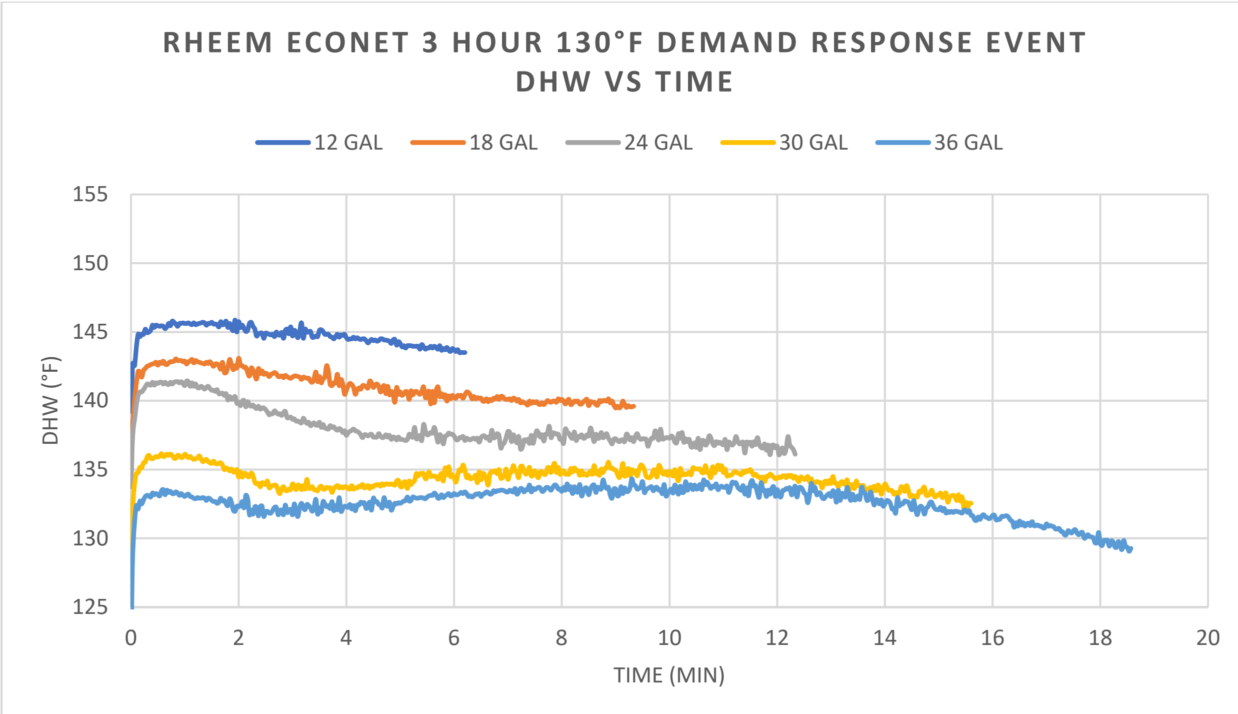

Figure 5. Rheem EcoNet 3-Hour 130°F DR Event DHW VS Draw Time

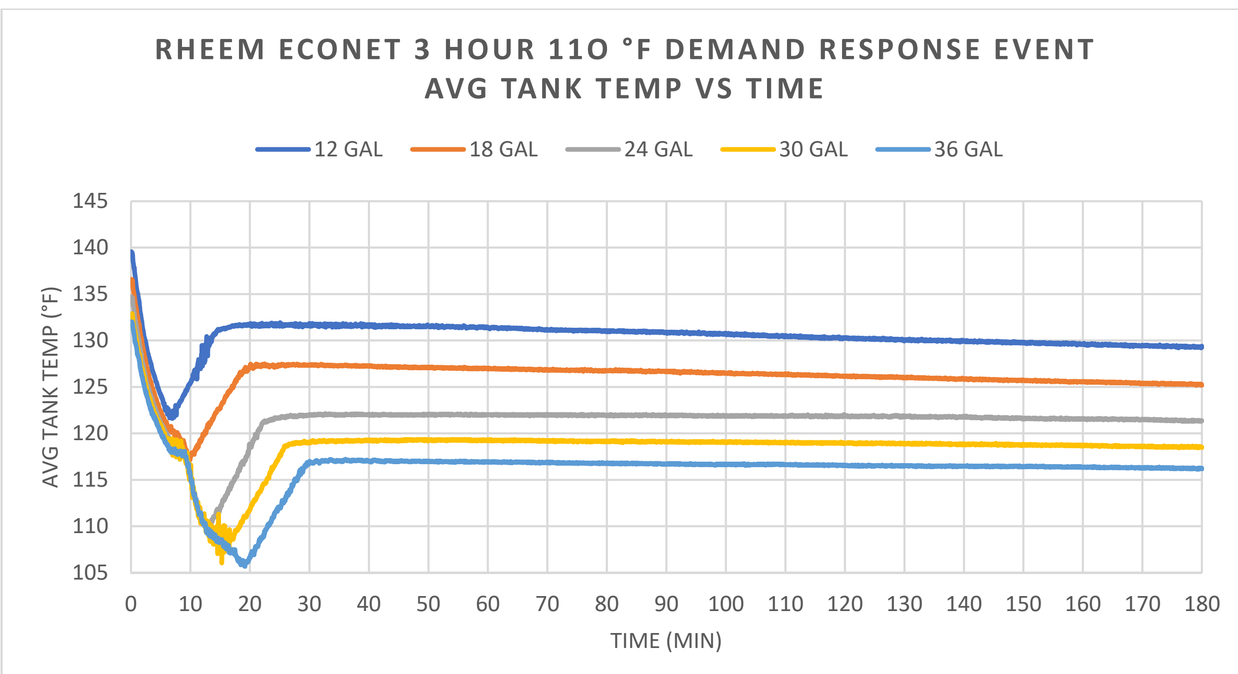

Figure 6. Rheem EcoNet 3-Hour 110°F DR Event Avg Tank Temp VS Event Time

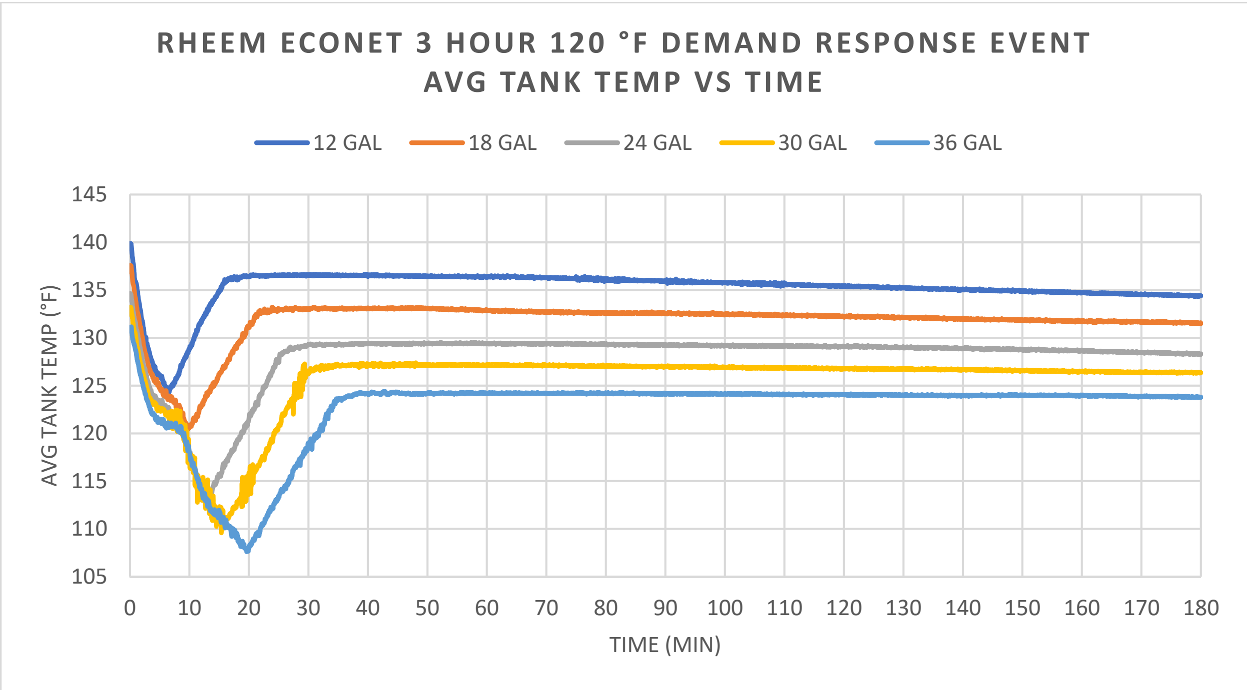

Figure 7. Rheem EcoNet 3-Hour 120°F DR Event Avg Tank Temp VS Event Time

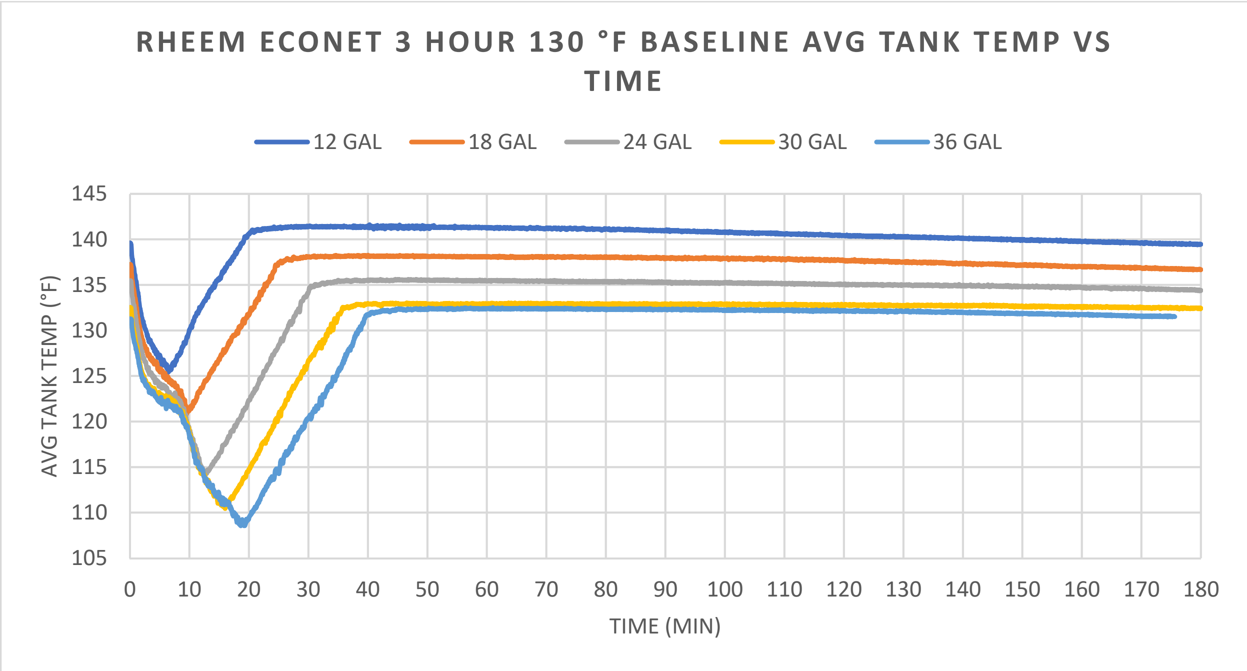

Figure 8. Rheem EcoNet 3-Hour 130°F DR Event Avg Tank Temp VS Event Time

CONCLUSION

GENERAL OBSERVATION

Functionality testing of the Rheem EcoNet WiFi module verified the module's ability to perform as intended by the manufacturer. The module's application performed equally as well on both operating systems. The module was also successful in controlling the WH's temperature settings while running DR event simulations. The most significant observation made was that the location of the WH's temperature sensor caused premature burner cut-in during the DHW draws in all DR events.

POSSIBLE DRAWBACKS AND RISKS OF EVALUATED TECHNOLOGY

It was found that an average of 2.4 gallons of water needed to be drawn in order to get the WH to call the burner to cut in to its initial set-point. This may be a result of the hysteresis of the WH's temperature sensor. The Rheem WiFi module instruction manual specifies to set the WH's gas valve to the "B" position which is 140°F. Rather than use this 140°F as the baseline temperature, it was chosen to use 130°F since this poses less risk of scalding. This is important to note because at lower initial WH temperature set-points/baselines, this hysteresis may be seen during 110°F DR events as well.

POTENTIAL FUTURE STUDY

This study was limited to testing of DR event scenarios at two temperatures: 110°F and 120°F. Possible future study may include studying various other temperature setpoints. Also, it was observed that the burner cut-in during the DHW draw in all DR event scenarios. Although the temperature set-point is lowered for a DR event, this shows that natural gas would still be consumed during a DR event. Data obtained from testing DR events using the vacation mode of the module, where the burner is not allowed to cut-in until vacation mode is deactivated, could be useful in further development of a DR program.