REPORT

2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program

CALMAC Study ID SCG0224

October 24, 2019

Principal authors:

Eric Bell, Principal

Stephanie Bieler, Consultant

Ty Lehman, Senior Analyst

Nicholas Cain, Senior Consultant

Contents

List of Tables

List of Figures

1 Executive Summary

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Smart Therm Program in response to the potential need for demand reductions during the 2018-2019 winter and future winters. The Smart Therm Program for 2019 was an offering where customers were recruited from an installed smart thermostat customer base of six vendors, and offered incentives 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 6 PM to 10 PM[1].

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 Therm 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 2018-2019 winter Smart Therm Program hourly event impacts for each event and for the average morning and evening event, along with the average number of customers that participated in an event. It should be noted that the number of customers called for morning and evening events differed, so the average and aggregate impacts for these events cannot be directly compared. The average load reduction for a morning event hour was 0.027 CCF/hr per participant leading to an aggregate reduction of 0.093 MMcf/hr, or 15.1%. The average load reduction per participant for an evening event hour was 0.020 CCF/hr, leading to an aggregate reduction of 0.019 MMcf/hr, or 15.5%.

Table 1-1: Winter 2018-2019 Hourly Load Impact Estimates[2]

Event Window	Number of Customers Called	Average Hourly Impact (CCF/hr)	Aggregate Hourly Impact (MMcf/hr)	Impact (%)
5am – 9am	33,895	0.027	0.093	15.10%
6pm – 10pm	9,208	0.020	0.019	15.50%

Table 1-2 provides a summary of 2018-2019 event savings for the average morning and evening event. These event savings are the sum of the hourly event impacts, and do not include the load lost after the event due to snap back. The average event savings for a morning event

[1] A small subset of customers were part of a testing strategy that involved an 8-hour event with a 2-degree setback. Testing strategy results are reported in Section 4.4.

[2] All impacts were originally calculated in therms and then divided by a conversion factor of 1.03 to get CCF.

was 0.110 CCF per participant leading to aggregate event savings of 0.372 MMcf. The average event savings for an evening event was 0.083 CCF per participant, leading to aggregate event savings of 0.076 MMcf.

Table 1-2: Winter 2018-2019 Event Savings Estimates

Event Window	Number of Customers Called	Average Event Savings (CCF)	Aggregate Event Savings (MMcf)	Savings (%)
5am – 9am	33,895	0.110	0.372	15.10%
6pm – 10pm	9,208	0.083	0.076	15.50%

Table 1-3 provides a summary of 2018-2019 net daily savings for the average morning and evening event. Daily savings include savings that occurred during the event as well as any pre- or post-event heating that may increase load relative to what would have occurred in the absence of an event. The average daily savings for a morning event was 0.061 CCF per participant leading to aggregate savings of 0.207 MMcf, or 2.24%. The average daily savings for an evening event was 0.034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.27%.

Table 1-3: Winter 2018-2019 Daily Savings Estimates

Event Window	Number of Customers Called	Average Daily Savings (CCF)	Aggregate Daily Savings (MMcf)	Savings (%)
5am – 9am	33,895	0.061	0.207	2.24%
6pm – 10pm	9,208	0.034	0.031	1.27%

The SoCalGas Smart Therm 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, as discussed in section 4.2, 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." The snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and greatly reduces net daily CCF savings compared to the event savings. Two new event implementation strategies were tested this year to determine if snap back could be reduced. While these efforts reduced snap back, they did not necessarily reduce daily consumption relative to current implementation strategies.

From a technical perspective, it's clear the program met the objectives of significantly reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, the net daily CCF savings that resulted from this program were only in the 1% to 2% range depending on the timing of the event.

2 Overview

SoCalGas was directed by the California Public Utilities Commission (CPUC) to continue and expand the SoCalGas Smart Therm Program in response to the potential need for demand reductions during the 2018-2019 winter and future winters. The Smart Therm Program for 2019 was an offering where six vendors (Nest, ecobee, Honeywell, Radio Thermostat, Lux, and Emerson/Sensi) participated. Customers were recruited from their installed smart thermostat customer bases, and offered incentives to enroll. Recruitment was conducted by the thermostat vendors or by SoCalGas.

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 program design and implementation 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 Therm 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)® Smart Energy Program (also known as Peak Time Rebate),[3] 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 Therm Program.
- Load – refers to customer gas usage, measured in hundred cubic feet (CCF) or million cubic feet (MMcf).

[3] Nexant. "2018 Load Impact Evaluation of Southern California Edison's Smart Energy Program." April 1, 2019. CALMAC Study ID: SCE0433.

2.1 Program Design and Implementation

The SoCalGas Smart Therm Program allows eligible residential customers[4] with a natural gas furnace and an approved smart thermostat to receive incentives for reducing gas use. This winter's program season ran from December 1, 2018 to April 1, 2019 and included a wider range of smart thermostats. Along with Nest and ecobee, who participated in the previous year's program, customers with smart thermostats from Honeywell, Lux, Radio Thermostat and Emerson/Sensi were able to participate.

The Smart Therm program is voluntary and only those customers who sign up for the program through their smart thermostat vendor can participate. SoCalGas offers various incentives to encourage customers to enroll and participate. Customers earn an initial $50 for enrolling in the program. Those who enrolled by March 1, 2019 and stay enrolled through April 1, 2019 were eligible to receive an additional $25 and customers receive this $25 credit for each winter season they remain enrolled. As such, customers who participated in the 2018 Demand Response season received a $25 credit for remaining in the program for the 2019 winter season.

Program events are four-hours in length and can result in up to a four-degree adjustment to a customer's thermostat.[5] Events may be called from 5:00 AM to 9:00 AM and from 6:00 PM to 10:00 PM on weekdays that are not Federal holidays. Customers receive a notification 10- to 12-hours before the event. Customers may override the setback, which opts the customer out of the event, without penalty. Once the activations came to an end, thermostats were returned to their original set points. Two aggregators, EnergyHub and Whisker Labs, provided dispatch related services for the thermostat vendors.

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 an email campaign for the program.

2.2 2019 Changes to the Smart Therm Program

SoCalGas introduced several program design changes this year. They changed the evening event window from 5 PM to 9 PM to 6 PM to 10 PM and eliminated the possibility for customers to participate in multiple events in a single day. The main reason for limiting customers to only one event per day was to prevent customer fatigue and to see if that would increase participation in events. Additionally, during the 2019 season SoCalGas tested two new event implementation strategies on a subset of customers to determine if the new strategies were able to reduce gas consumption, reduce post event snap back, and increase customer satisfaction. These strategies were tested from February 19 through February 21. Table 2-1 depicts the details of the two strategies that were implemented as well as the standard implementation

[4] Eligible customers must have an active SoCalGas account with an Advanced Meter and have a participating smart thermostat controlling a natural-gas-fired furnace in their residence. Additional information is online: https://www.socalgas.com/save-money-and-energy/rebates-and-incentives/smart-therm/smart-therm-faq

[5] Degree setback varied by thermostat vendor, with the majority of vendors adjusting up to 3-degrees only.

method for reference. The first test strategy had the same event length as a typical implementation method, but randomly rolled customers off the event within a 30-minute period just after the event ended (e.g. 9 AM – 9:30 AM). The second test strategy was 8 hours in length, with only a 2-degree offset. The results of the test implementation strategies can be found in Section 4.4 of this report.

Table 2-1: Summary of 2019 Test Implementation Strategies

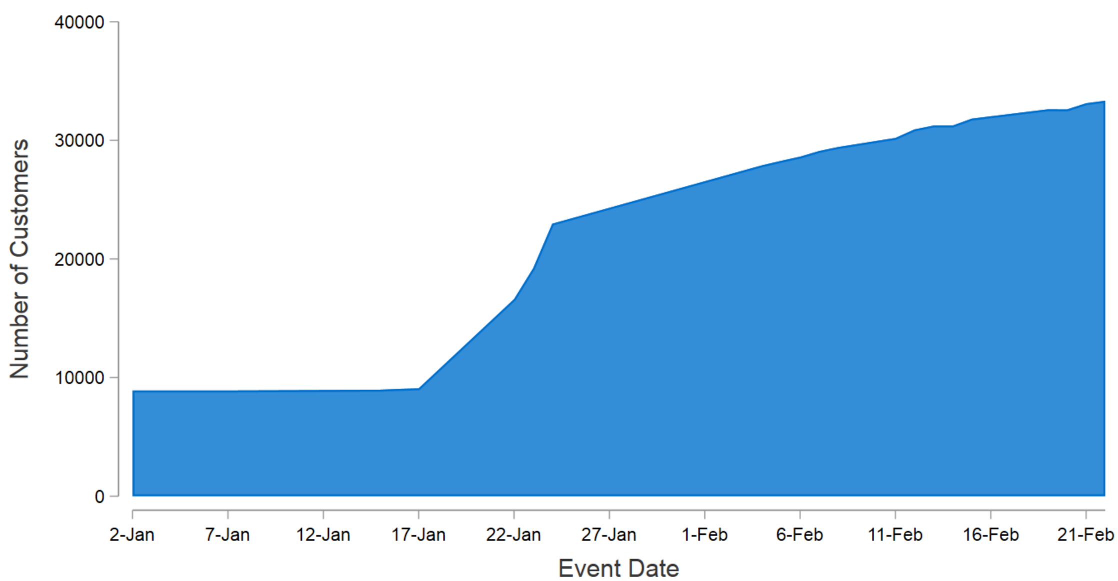
Implementation Method	Event Length	Degree Offset	Event Time
Default Strategy	4 hours	Up to 4 degrees	5 AM – 9 AM or 6 PM – 10 PM
Test Strategy 1	4 hours	3 degrees	5 AM – 9 AM, with a 30-minute randomized device withdrawal between 9:00-9:30 am
Test Strategy 2	8 hours	2 degrees	5 AM – 1 PM

2.3 Program Participants

2.3.1 Enrollment

At the time of the evaluation (March 1, 2019), the vendors had 37,159 customers and 42,627 thermostats enrolled in the program and at the end of recruitment (June 2019), the vendors had a total of 44,400 enrolled customers and 50,034 thermostats. As can be seen in Figure 2-1, the DR season started in 2019 with just under 10,000 enrollees. Growth was flat through the first two weeks of January, but then increased rapidly in late January. This growth was driven by recruiting efforts that took place over the course of the season for each thermostat vendor.

Figure 2-1: 2019 Season Program Participation



2.3.2 Participant Characteristics

Customers who signed up to participate in the Smart Therm 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 2-2 compares the portion of CARE customers who enrolled in the program to the overall population. Program participants were less likely to be CARE customers compared to the general residential population.

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

CARE	% of Program Participants	% of SoCalGas Residential Customers
Yes	15.1%	28.5%
No	84.9%	71.5%
All	100%	100%

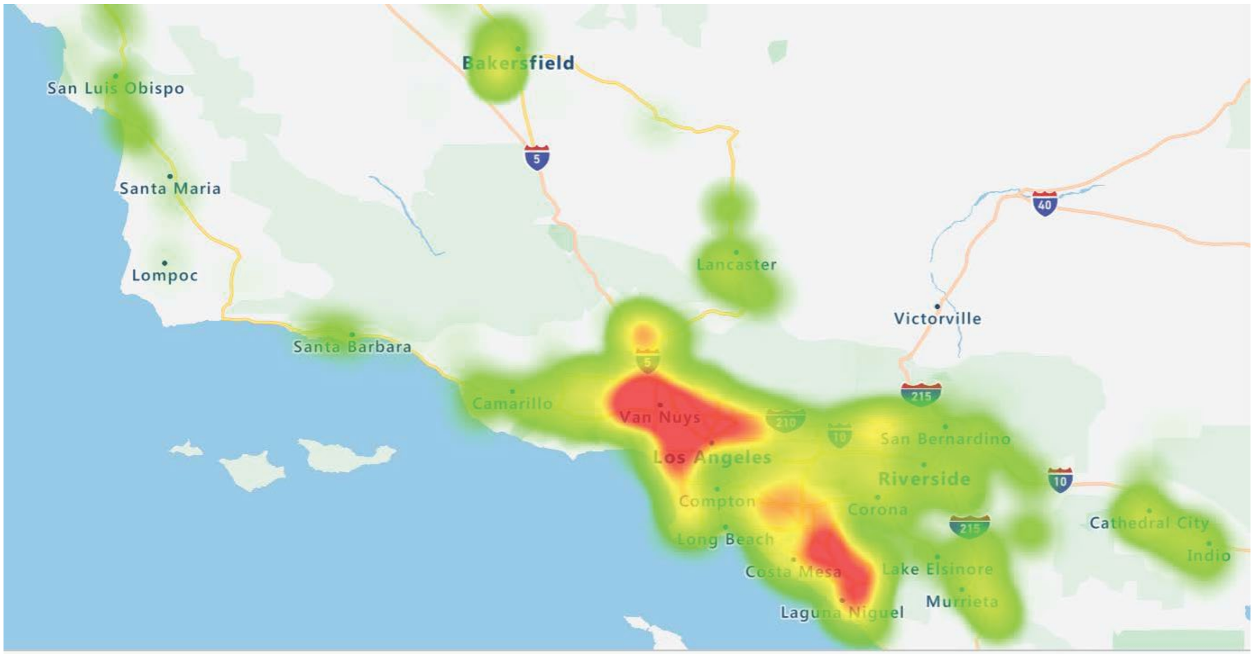
Table 2-3 compares the breakout of Smart Therm participant housing type to the SoCalGas residential customer population. Program participants were more likely to reside in a single family home compared to the general population.

Table 2-3: Comparison of Program and Population Housing Types

Housing Type	% of Program Participants	% of SoCalGas Residential Customers
Single Unit	78.3%	64.0%
2 or More Separate Units	2.3%	2.8%
2-4 Connected Units	5.3%	10.5%
5 or More Connected Units	14.0%	22.6%
Mobile Home Park	0.00%	0.02%
All	100%	100%

The location of program participants was also examined. Figure 2-2 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 2-2: Heat Map of Program Participant Location



2.4 Event Summary

During the 2018-2019 winter season, there were 29 events called over 24 days. The first event was called on January 2, 2019 and the last event was called on February 22, 2019. The majority of events were called in the morning (5:00 AM to 9:00 AM). However, on five days in February, both a morning and evening event (6:00 PM to 10:00 PM) were called. On days with multiple events, customers were called for either a morning event or an evening event. No customers participated in multiple events in a single day.

Table 2-4 provides an overview of the events called during the 2018-2019 season by date and time. In the next column, we list the number of smart thermostats that were activated for each event.

Table 2-4: Overall Event Summary

Event	Date	Event Window	Devices Targeted
1	2-Jan	5am – 9am	10,780
2	3-Jan	5am – 9am	10,789
3	4-Jan	5am – 9am	10,790
4	7-Jan	5am – 9am	10,808
5	15-Jan	5am – 9am	10,891
6	16-Jan	5am – 9am	10,887
7	17-Jan	5am – 9am	10,997
8	22-Jan	5am – 9am	11,141
9	23-Jan	5am – 9am	19,884
10	24-Jan	5am – 9am	22,934
11	4-Feb	5am – 9am	32,033
12	5-Feb	5am – 9am	33,241
13	6-Feb	5am – 9am	33,769
14	7-Feb	5am – 9am	34,178
15	8-Feb	5am – 9am	34,732
16	11-Feb	5am – 9am	32,469
17	11-Feb	6pm – 10pm	2,694
18	12-Feb	5am – 9am	24,992
19	12-Feb	6pm – 10pm	11,073
20	13-Feb	5am – 9am	25,477
21	13-Feb	6pm – 10pm	11,069
22	14-Feb	5am – 9am	25,813
23	14-Feb	6pm – 10pm	11,068
24	15-Feb	5am – 9am	25,825
25	15-Feb	6pm – 10pm	11,065
26	19-Feb	5am – 9am	37,528
27	20-Feb	5am – 9am	38,510
28	21-Feb	5am – 9am	38,547
29	22-Feb	5am – 9am	39,165

2.4.1 Event Participation

Table 2-5 depicts the participation for each event. Full participation refers to devices that were successfully programmed by the vendor, where the DR settings were in place for the entire event and the customer did not opt out. Approximately 51% of customers fully participated in an event on average. Partial participation refers to devices that only participated in a portion of the DR activation because they were either “off” or in a cooling mode for the rest of the time period, which was the case for approximately 1% of event participants on average. An opt-out refers to customers that overrode the DR event settings by manually changing their thermostat. Approximately 20% of event participants opted out on average. Other refers to a device not being accessible due to technical issues, the device being “off”, or the device being in a cooling mode. Approximately 27% of devices were not accessible for an event on average.

Overall, participation was relatively constant throughout all of the events, with an average of 51% of customers fully participating in events. The lowest level of full participation was 39%, which occurred on February 8 and February 11 for morning events. On these days, a larger number of thermostats were in the “Other” category, indicating that there may have been difficulties accessing the thermostats on those days. The highest level of full participation was 74%, which occurred on the February 11 evening event. It is worth noting however, that for that evening event a very low number of devices were targeted (2,694) and so this is likely why the participation was so much higher than average.

Overall, the average full participation rate of 51% was lower than the 2018 average full participation rate of 57%. There are several possible reasons for this. Events were called much earlier in the year and were called over a longer period of time compared to last year. Additionally, there were more than four times the number of customers enrolled in the program this year compared to last year, which resulted in essentially an entirely different participant population. The opt-out rates or thermostat settings of the new customers may differ from 2018 customers for the existing implementation strategy.

Table 2-5: Event Participation Summary

Date[6]	Time	Devices Targeted	Full Participation	Partial Participation[7]	Opt-Out Before[8]	Opt-Out During[9]	Other[10]
2-Jan	5am – 9am	10,780	51%	1%	1%	21%	26%
3-Jan	5am – 9am	10,789	51%	2%	1%	21%	25%
4-Jan	5am – 9am	10,790	52%	1%	1%	20%	26%
7-Jan	5am – 9am	10,808	51%	2%	1%	21%	25%
15-Jan	5am – 9am	10,891	53%	3%	1%	20%	23%
16-Jan	5am – 9am	10,887	55%	3%	1%	17%	24%
17-Jan	5am – 9am	10,997	56%	4%	1%	15%	24%
22-Jan	5am – 9am	11,141	50%	3%	1%	19%	27%
23-Jan	5am – 9am	19,884	46%	0%	0%	26%	28%
24-Jan	5am – 9am	22,934	53%	0%	1%	17%	29%
4-Feb	5am – 9am	32,033	50%	0%	0%	20%	30%
5-Feb	5am – 9am	33,241	50%	0%	0%	22%	28%
6-Feb	5am – 9am	33,769	47%	0%	0%	20%	33%
7-Feb	5am – 9am	34,178	47%	0%	0%	20%	33%
8-Feb	5am – 9am	34,732	39%	0%	0%	14%	47%
11-Feb	5am – 9am	32,469	39%	0%	0%	15%	46%
11-Feb	6pm – 10pm	2,694	74%	0%	0%	20%	6%
12-Feb	5am – 9am	24,992	52%	0%	0%	19%	29%
12-Feb	6pm – 10pm	11,073	50%	0%	0%	24%	26%
13-Feb	5am – 9am	25,477	55%	0%	0%	16%	29%
13-Feb	6pm – 10pm	11,069	49%	0%	0%	29%	22%
14-Feb	5am – 9am	25,813	57%	0%	0%	16%	27%
14-Feb	6pm – 10pm	11,068	53%	0%	0%	25%	22%
15-Feb	5am – 9am	25,825	56%	0%	0%	15%	29%
15-Feb	6pm – 10pm	11,065	51%	0%	1%	25%	23%
19-Feb	5am – 9am	37,528	51%	0%	0%	22%	27%
20-Feb	5am – 9am	38,510	52%	0%	0%	21%	27%
21-Feb	5am – 9am	38,547	54%	0%	0%	21%	25%
22-Feb	5am – 9am	39,165	49%	0%	1%	19%	31%

6 Not all devices able to report on event participation summary statistics for events after Jan 22

7 Participated in only part of the event because device was "off" or in cooling mode for the remainder of the event

8 Customer overrode DR settings by manually changing the thermostat before the event started

9 Customer overrode DR settings by manually changing the thermostat during the event. On average devices participated for 60 minutes.

10 Device was not accessible because of technical issues, because device was "off", or because device was in cooling mode

3 Load Impact Estimation Methodology

The primary challenge in estimating load impacts for DR programs such as the Smart Therm 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 Results

During the 2018-2019 winter, 29 events were called on 24 different days. All 29 events ran for four hours and were called either from 5 AM to 9 AM or from 6 PM to 10 PM[11]. The remainder of this section presents the load impacts for the Smart Therm program.

The results section focuses on the following three key metrics:

1. **Hourly impact:** The demand reduction for the average hour during the 4-hour event window. Hourly impacts were calculated by using the methodology described in Section 3.

2. **Event savings:** The total energy savings for the DR event across the full 4-hour event. Event savings were calculated by summing the four hourly impacts in the event window.

3. **Daily savings:** The net savings across the entire event day (CCF saved during the event minus CCF lost due to the "snap back" after the event). Daily savings were calculated by summing all 24 hourly impacts on the event day. In order to avoid including impacts that were not a result of the event, Nexant assumed that all hourly impacts after 3 PM were 0 CCF/hr for morning events, and all impacts before 12 PM were 0 CCF/hr for evening events. More information on this methodology can be found in Appendix A.

4.1 Load Impact Results

Table 4-1 summarizes the average hourly and aggregate hourly impacts for all customers that participated in the event. The schedule of event day, timing, and number of thermostats targeted can be found in Table 2-4. In total, there were twenty-four events called during the morning and five events called during the evening.

The average hourly impact during a morning event was .027 CCF/hr per participant representing a 15.1% load reduction from an average reference load of .181 CCF/hr. The aggregate hourly impact was a 0.093 MMcf/hr reduction during an average morning event hour. The average hourly impact during an evening event was .020 CCF/hr per participant representing a 15.5% load reduction from the average reference load of .134 CCF/hr. The aggregate hourly impact for an evening event was 0.019 MMcf/hr.

Table 4-2 summarizes the average event savings and aggregate event savings for all customers that participated in the event. The average event savings during a morning event was .110 CCF per participant representing a 15.1% load reduction from an average reference load of .751 CCF. The aggregate event savings was 0.372 MMcf during an average morning event. The average event savings during an evening event was .083 CCF per participant

[11] A small subset of customers were part of a testing strategy that involved an 8-hour event with a 2-degree setback. Testing strategy results are reported in Section 4.4.

representing a 15.5% load reduction from the average reference load of .537 CCF. The aggregate event savings for an average evening event was 0.076 MMcf.

Table 4-3 summarizes the average daily savings and aggregate daily savings for all customers that participated in the event. The average daily savings on a day with a morning event was .061 CCF per participant leading to aggregate daily savings of 0.207 MMcf, or 2.2%. The average daily savings for a day with an evening event was .034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.3%.

Time of day and corresponding levels of consumption, which are at least partially influenced 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. There was a five degree temperature difference between the average morning event hour and the average evening event hour. The evening 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: Average Hourly Impacts for All Events and Average Events[12]

Date	Event Window	Average Hourly Load w/o DR (CCF/hr)	Average Hourly Load w DR (CCF/hr)	Average Hourly Impact (CCF/hr)	Aggregate Hourly Impact (MMcf/hr)	Hourly Impact (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.215	0.179	0.036	0.032	16.86%	41.5
3-Jan	5am – 9am	0.210	0.176	0.034	0.030	16.06%	46.99
4-Jan	5am – 9am	0.205	0.167	0.038	0.034	18.57%	48.74
7-Jan	5am – 9am	0.143	0.110	0.033	0.030	23.22%	51.19
15-Jan	5am – 9am	0.155	0.119	0.035	0.032	22.89%	60.15
16-Jan	5am – 9am	0.134	0.100	0.034	0.031	25.29%	61.88
17-Jan	5am – 9am	0.103	0.072	0.030	0.028	29.71%	60.42
22-Jan	5am – 9am	0.176	0.158	0.018	0.029	9.99%	51.53
23-Jan	5am – 9am	0.180	0.153	0.026	0.050	14.62%	49.24
24-Jan	5am – 9am	0.157	0.132	0.024	0.056	15.49%	56.99
4-Feb	5am – 9am	0.130	0.100	0.030	0.083	23.00%	53.78
5-Feb	5am – 9am	0.155	0.123	0.032	0.090	20.57%	49.75
6-Feb	5am – 9am	0.217	0.189	0.028	0.081	13.00%	45.5
7-Feb	5am – 9am	0.219	0.192	0.027	0.078	12.22%	47.26
8-Feb	5am – 9am	0.208	0.180	0.029	0.084	13.72%	47.03
11-Feb	5am – 9am	0.212	0.186	0.026	0.072	12.14%	44.29
11-Feb	6pm – 10pm	0.146	0.112	0.034	0.008	23.43%	50
12-Feb	5am – 9am	0.193	0.169	0.024	0.052	12.31%	47.26
12-Feb	6pm – 10pm	0.124	0.106	0.017	0.016	14.05%	57.2
13-Feb	5am – 9am	0.131	0.106	0.025	0.054	18.74%	56.98
13-Feb	6pm – 10pm	0.151	0.128	0.023	0.021	15.26%	52.61
14-Feb	5am – 9am	0.101	0.080	0.021	0.047	20.79%	58.48
14-Feb	6pm – 10pm	0.127	0.106	0.021	0.019	16.45%	55.72
15-Feb	5am – 9am	0.136	0.110	0.026	0.060	19.35%	52.25
15-Feb	6pm – 10pm	0.133	0.112	0.021	0.020	16.05%	55.27
19-Feb	5am – 9am	0.217	0.192	0.025	0.079	11.71%	46.54
20-Feb	5am – 9am	0.208	0.179	0.029	0.091	13.98%	47.98
21-Feb	5am – 9am	0.186	0.156	0.030	0.095	16.22%	46.04
22-Feb	5am – 9am	0.219	0.189	0.031	0.103	14.06%	45.55
All Events							
Avg.	**AM**	**0.180**	**0.153**	**0.027**	**0.093**	**15.21%**	**49.72**
Avg.	**PM**	**0.134**	**0.113**	**0.021**	**0.019**	**15.46%**	**54.68**

[12] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

Table 4-2: Event Savings for All Events and Average Events[13]

Date	Event Window	Average Total Event Load w/o DR (CCF)	Average Total Event Load w DR (CCF)	Average Event Savings (CCF)	Aggregate Event Savings (MMcf)	Event Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.861	0.716	0.145	0.129	16.86%	41.5
3-Jan	5am – 9am	0.841	0.706	0.135	0.120	16.06%	46.99
4-Jan	5am – 9am	0.822	0.669	0.153	0.136	18.57%	48.74
7-Jan	5am – 9am	0.573	0.440	0.133	0.119	23.22%	51.19
15-Jan	5am – 9am	0.618	0.477	0.142	0.127	22.89%	60.15
16-Jan	5am – 9am	0.536	0.401	0.136	0.123	25.29%	61.88
17-Jan	5am – 9am	0.410	0.288	0.122	0.111	29.71%	60.42
22-Jan	5am – 9am	0.703	0.633	0.070	0.117	9.99%	51.53
23-Jan	5am – 9am	0.718	0.613	0.105	0.202	14.62%	49.24
24-Jan	5am – 9am	0.626	0.529	0.097	0.223	15.49%	56.99
4-Feb	5am – 9am	0.519	0.399	0.119	0.333	23.00%	53.78
5-Feb	5am – 9am	0.621	0.494	0.128	0.361	20.57%	49.75
6-Feb	5am – 9am	0.870	0.757	0.113	0.324	13.00%	45.5
7-Feb	5am – 9am	0.875	0.768	0.107	0.311	12.22%	47.26
8-Feb	5am – 9am	0.833	0.719	0.114	0.336	13.72%	47.03
11-Feb	5am – 9am	0.849	0.746	0.103	0.286	12.14%	44.29
11-Feb	6pm – 10pm	0.585	0.448	0.137	0.033	23.43%	50
12-Feb	5am – 9am	0.771	0.676	0.095	0.206	12.31%	47.26
12-Feb	6pm – 10pm	0.494	0.425	0.069	0.064	14.05%	57.2
13-Feb	5am – 9am	0.523	0.425	0.098	0.216	18.74%	56.98
13-Feb	6pm – 10pm	0.603	0.511	0.092	0.085	15.26%	52.61
14-Feb	5am – 9am	0.406	0.322	0.084	0.186	20.79%	58.48
14-Feb	6pm – 10pm	0.507	0.423	0.083	0.077	16.45%	55.72
15-Feb	5am – 9am	0.545	0.440	0.105	0.239	19.35%	52.25
15-Feb	6pm – 10pm	0.532	0.447	0.085	0.078	16.05%	55.27
19-Feb	5am – 9am	0.868	0.766	0.102	0.316	11.71%	46.54
20-Feb	5am – 9am	0.833	0.716	0.116	0.362	13.98%	47.98
21-Feb	5am – 9am	0.743	0.622	0.120	0.381	16.22%	46.04
22-Feb	5am – 9am	0.878	0.755	0.123	0.411	14.06%	45.55
All Events							
Avg.	**AM**	**0.721**	**0.611**	**0.110**	**0.373**	**15.21%**	**49.72**
Avg.	**PM**	**0.537**	**0.454**	**0.083**	**0.076**	**15.46%**	**54.68**

[13] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

Table 4-3: Daily Savings for All Events and Average Events[14]

Date	Event Window	Average Total Daily Load w/o DR (CCF)	Average Total Daily Load w DR (CCF)	Average Daily Savings (CCF)	Aggregate Daily Savings (MMcf)	Daily Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	3.246	3.243	0.003	0.003	0.10%	41.5
3-Jan	5am – 9am	2.944	2.927	0.018	0.016	0.61%	46.99
4-Jan	5am – 9am	2.806	2.774	0.032	0.028	1.13%	48.74
7-Jan	5am – 9am	2.297	2.219	0.078	0.069	3.39%	51.19
15-Jan	5am – 9am	2.799	2.727	0.072	0.064	2.56%	60.15
16-Jan	5am – 9am	2.167	2.065	0.102	0.092	4.72%	61.88
17-Jan	5am – 9am	1.812	1.666	0.145	0.132	8.01%	60.42
22-Jan	5am – 9am	2.392	2.342	0.050	0.082	2.07%	51.53
23-Jan	5am – 9am	2.238	2.165	0.073	0.140	3.26%	49.24
24-Jan	5am – 9am	1.790	1.721	0.069	0.159	3.87%	56.99
4-Feb	5am – 9am	2.346	2.224	0.122	0.340	5.20%	53.78
5-Feb	5am – 9am	2.818	2.702	0.116	0.329	4.13%	49.75
6-Feb	5am – 9am	3.287	3.232	0.055	0.157	1.67%	45.5
7-Feb	5am – 9am	3.034	2.987	0.047	0.136	1.54%	47.26
8-Feb	5am – 9am	2.791	2.731	0.060	0.176	2.14%	47.03
11-Feb	5am – 9am	2.962	2.898	0.064	0.177	2.15%	44.29
11-Feb	6pm – 10pm	3.322	3.271	0.051	0.012	1.54%	50
12-Feb	5am – 9am	2.540	2.506	0.035	0.075	1.36%	47.26
12-Feb	6pm – 10pm	2.961	2.916	0.045	0.041	1.52%	57.2
13-Feb	5am – 9am	2.417	2.327	0.089	0.197	3.69%	56.98
13-Feb	6pm – 10pm	2.711	2.703	0.008	0.008	0.31%	52.61
14-Feb	5am – 9am	1.966	1.896	0.070	0.156	3.58%	58.48
14-Feb	6pm – 10pm	2.207	2.146	0.061	0.056	2.75%	55.72
15-Feb	5am – 9am	2.249	2.169	0.080	0.181	3.55%	52.25
15-Feb	6pm – 10pm	2.586	2.567	0.019	0.017	0.72%	55.27
19-Feb	5am – 9am	3.077	3.035	0.042	0.131	1.37%	46.54
20-Feb	5am – 9am	3.323	3.253	0.070	0.217	2.10%	47.98
21-Feb	5am – 9am	3.257	3.168	0.088	0.280	2.71%	46.04
22-Feb	5am – 9am	3.075	3.027	0.049	0.162	1.58%	45.55
All Events							
Avg.	**5am – 9am**	**2.721**	**2.660**	**0.061**	**0.207**	**2.24%**	**49.72**
Avg.	**6pm – 10pm**	**2.651**	**2.618**	**0.034**	**0.031**	**1.27%**	**54.68**

[14] Customers who were in the implementation strategy test groups were excluded from the results on Feb 19 – Feb 21. For details on the implementation strategy results please see Section 4.4.

4.1.1 Event Day Load Shapes and Snap Back

Figure 4-1 and Figure 4-2 show the full 24-hour profile for average customer load impacts, reference loads, and observed loads for the average morning and evening event day. While there were five days that had both morning and evening events called across the different thermostats, no set of customers was called for both event windows within a single event day. Therefore, there is no load profile for both a morning and evening event taking place in a single day, as no customer experienced this type of event in the 2018-2019 DR season. 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. 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 in the hour following morning events was 0.033 CCF/hr, with the load of the average participant 29% greater than customers that did not participate in the event. The 2019 morning event snap back is 15% lower than the 2018 morning event snap back, which is discussed in more detail in section 4.3.

The average snap back in the hour following evening events was 0.035 therms, representing a 35% load increase compared to customers that did not participate in the event. For an evening event, the snap back was large enough that it shifted the evening peak for DR participants from 7-8 PM to 10-11 PM. However, the 10-11 PM peak created by DR customers is smaller than the counterfactual peak, 0.136 CCF/hr versus 0.141 CCF/hr for the average customer between 7 and 8 PM. The 2019 evening event snap back is twice the size of the 2018 evening event snap back, which is correlated with the large event savings seen during 2019 evening events compared to 2018 evening events. Last year’s evening snap back also created a DR participant peak that was higher than the counterfactual peak, while this year’s snap back does not. A comparison of 2019 impacts to 2018 impacts is described in more detail in section 4.3.

Figure 4-1: Load Shape on Average Morning Event Day

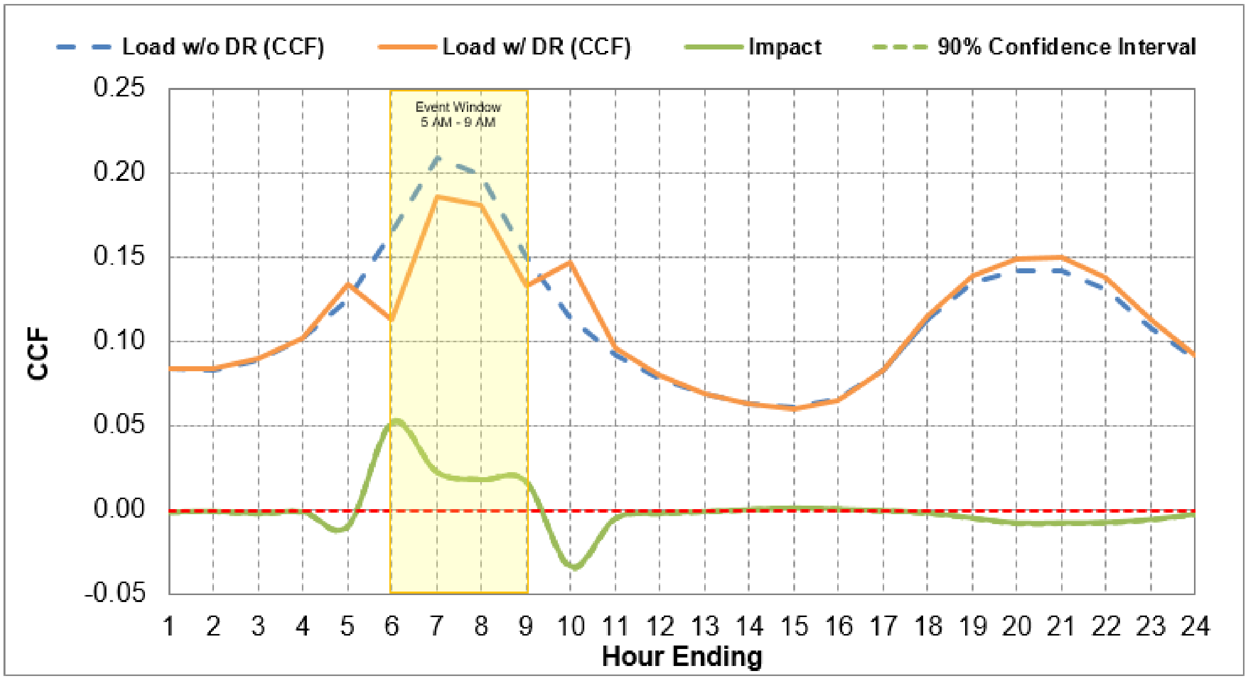
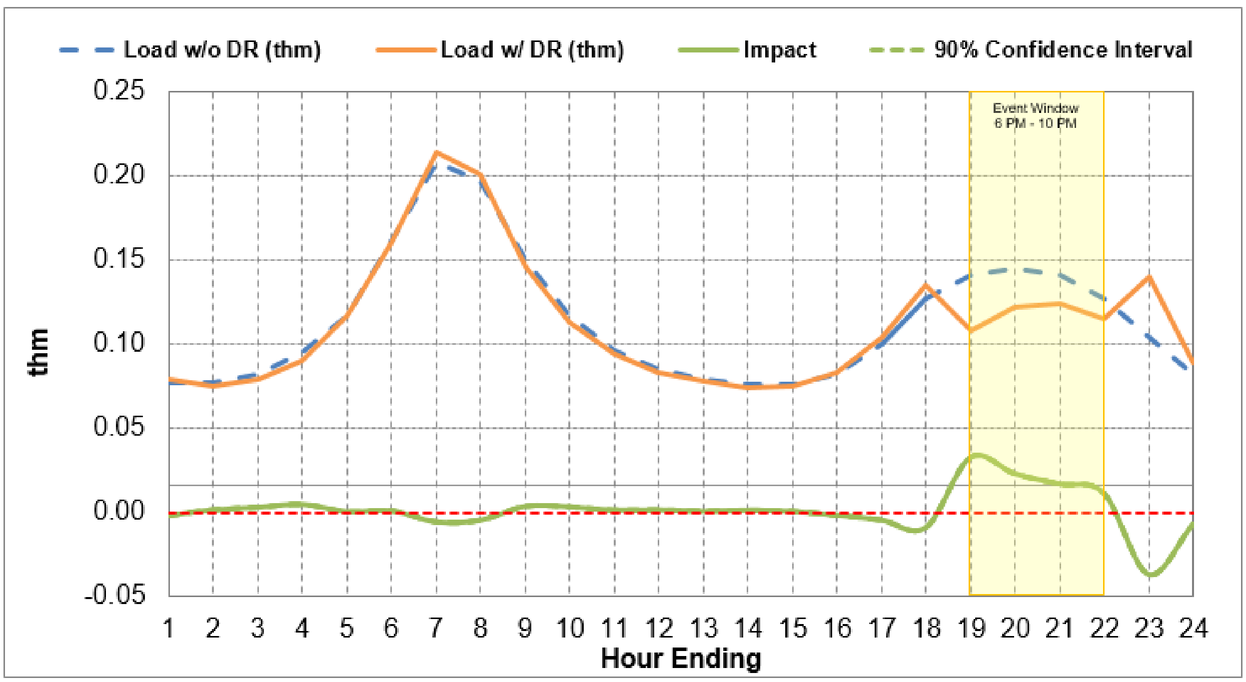


Figure 4-2: Load Shape Average Evening Event Day

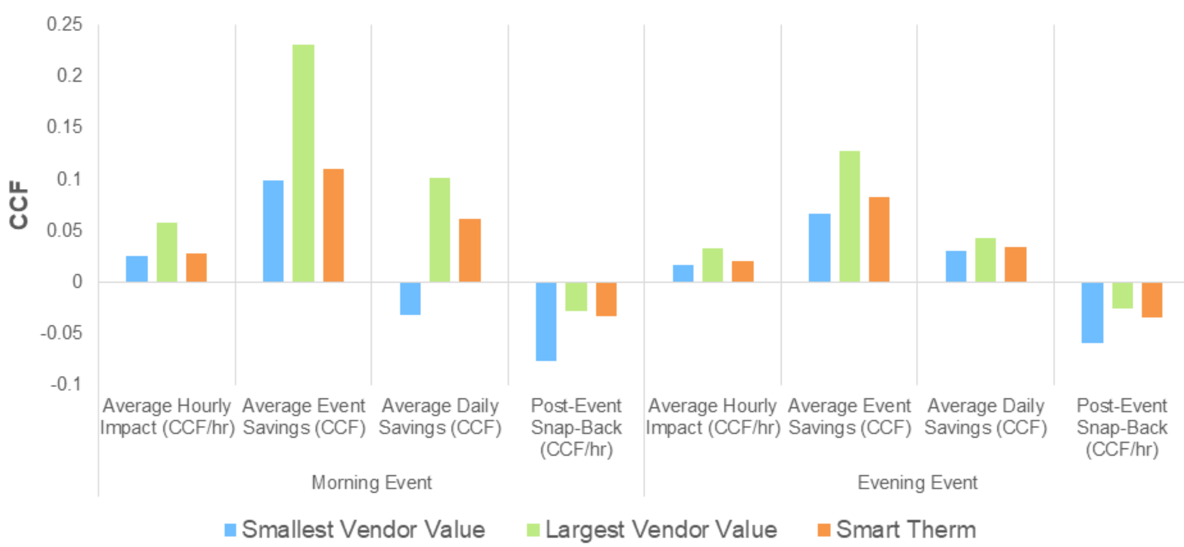


4.2 Vendor Comparison

In addition to evaluating program-level results, Nexant evaluated load impact results for each vendor. Figure 4-3 compares the program results to the range of vendor-specific load impacts, with the green bar representing vendors with the largest savings, blue representing the smallest savings, and orange representing the program-level savings summarized in Section 4.1. For the average morning event, some vendors were able to achieve more than twice the average hourly impacts and event savings compared to the overall program. Daily savings varied greatly by vendor, with some vendors experiencing negative daily savings and other vendors experiencing daily savings much larger than program level daily savings. For the average evening event, there was less variation between vendors, although some achieved large event savings and hourly impacts relative to the overall Smart Therm program. For both morning and evening events, some vendors experienced significantly larger snap backs compared to the overall program. In the evening, the increase in gas consumption for some vendors was large enough that it created a new DR participant evening peak that was significantly larger than the counterfactual 7-8 PM peak. However, that was not the case for the Smart Therm program as a whole.

Several different reasons could explain the variation we see in event savings, snap back, and daily savings. The first could be the different implementation strategies each vendor used. Vendor strategies include 4-degree setback, 3-degree setback, and up to 3-degree setback based on a customer's comfort setting. Each strategy yielded different levels of load reduction and snap back, which affected overall daily savings. There was also variation depending on the size of the average customer, with the vendor with the largest average customer also experiencing the largest event savings. Finally, it is important to note that some vendors had very few participants and were evaluated for relatively few events. Accordingly, some of the vendor-specific results below (such as the negative daily savings) are not statistically significant and could change next year when more data is available.

Figure 4-3: Vendor Comparison of Metrics for Average Morning and Evening Event



4.3 Comparison to 2018 Results

In 2018, 9,267 customers participated in SoCalGas' demand response program. A total of 13 events were called over 9 days, with two days in which all vendors were called for a morning-only event and two days in which all vendors were called for an evening-only event. Only days with all vendors participating in morning- or evening-only events have been included in the year-over-year comparison depicted below. Including days where only a single vendor was called or days where customers participated in both the morning and evening would not be an appropriate comparison to the current evaluation.

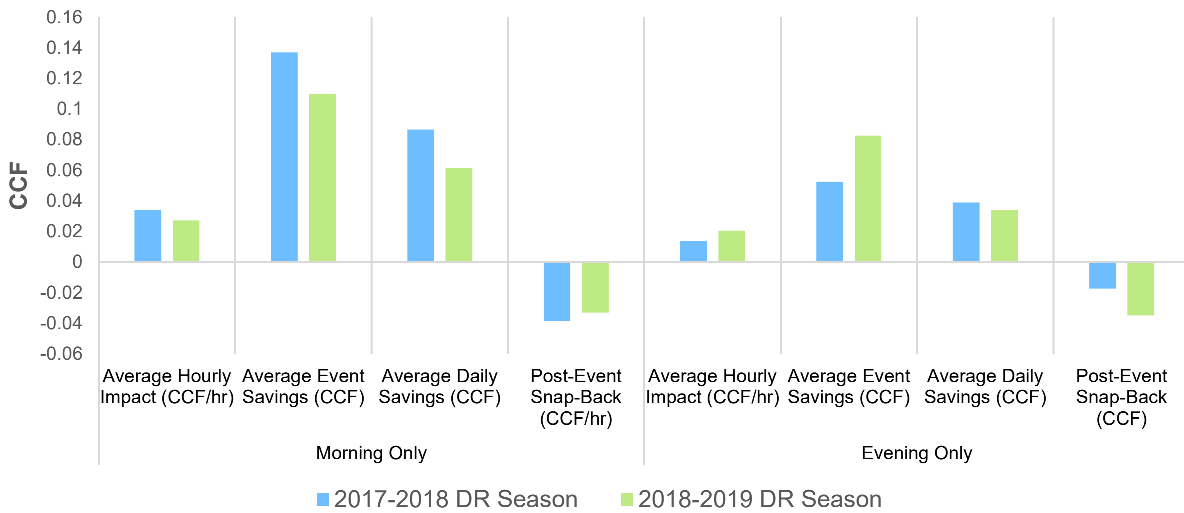
Figure 4-4 compares the results from the 2018 evaluation to the current evaluation for the average morning and evening event. For the average morning event, the average hourly impact and average event savings are approximately 20% lower compared to 2018, and the daily savings are about 30% lower than in 2018. There are several possible reasons for these differences. First, this comparison is based on an average over 24 events (2019) to an average over 2 events (2018), which means that each event day in 2018 carries significantly more weight than each event day in 2019. Second, 2019 morning events were generally called earlier in the season compared to 2018, with 40% of 2019 morning events called in January compared to all 2018 morning events called at the end of February or early March. Finally, the customer mix for morning events changed substantially in 2019, with enrollment in the program increasing by over 300%. Compared to 2018 participants, new participants were more likely to be enrolled in CARE and on average had lower annual consumption levels than 2018 participants. The new customers and their lower average gas consumption levels affected morning event impacts by reducing the amount of consumption available for curtailment. Additionally, as participation grew, the share of participants represented by the vendor with the largest event savings declined, which reduced the average impacts of the overall program.

Unlike the morning events, evening events largely contained customers who participated in the program in both winters and were only called towards the end of February. In the evening, the average hourly impact and average event savings increased by about 50% in 2019 compared to the 2018 impacts. This is likely due to the shift of the evening event to a later time, which coincided better with the evening peak for residential customers. Despite the improved event performance in 2019, the average daily savings decreased, which is possibly driven by the larger snap back for evening-only events in 2019 compared to 2018.

Overall, the daily savings this year were lower than 2018 for both morning and evening events. However, it is important to note that while last year's daily savings were not statistically significant, due in part to a relatively small number of customers and few events, this year the results are statistically significant. Therefore, with the larger participant population and larger number of events, this year's results are likely more representative of what this program is capable of delivering across all metrics with the current implementation strategy[15].

[15] It should be noted that, as seen in Sections 4.2 and 4.4, implementation strategies do affect impacts. Therefore, if vendors change their implementation methods, as some plan to do in the upcoming DR season, it is likely that these impacts will change.

Figure 4-4: Year-Over-Year Comparison of Metrics



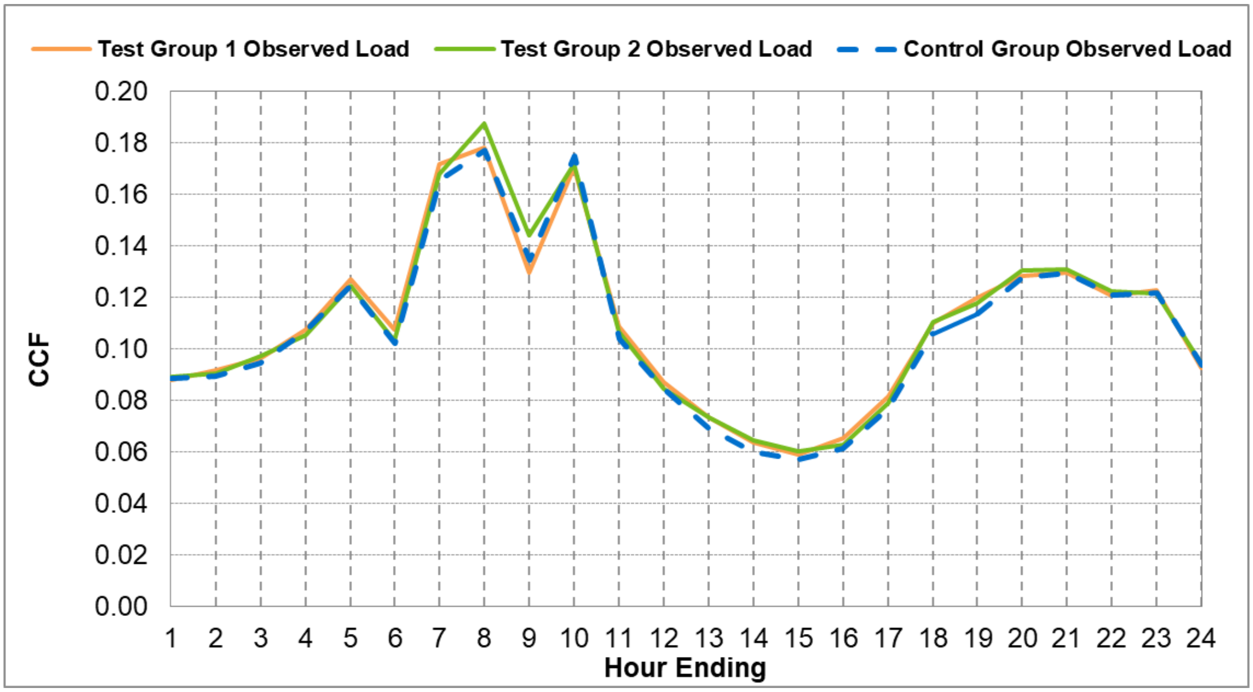
4.4 Strategy Implementation Results

As stated in Section 2.2, SoCalGas tested two new strategies during the 2019 season. These strategies were implemented from February 19 through February 21 in order to test their effectiveness. SoCalGas selected a subset of Smart Therm customers and randomly assigned them to one of three groups:

1. Control Group – these customers received the same implementation strategy they had received the entire DR season
2. Treatment Group #1 – These customers participated in a 4-hour event with a 3-degree setback. The event lasted from 5 AM – 9 AM, and then customers were randomly rolled off the event from 9:00 AM – 9:30 AM.
3. Treatment Group #2 – These customers participated in an 8-hour event with a 2-degree setback. The event lasted from 5 AM – 1 PM.

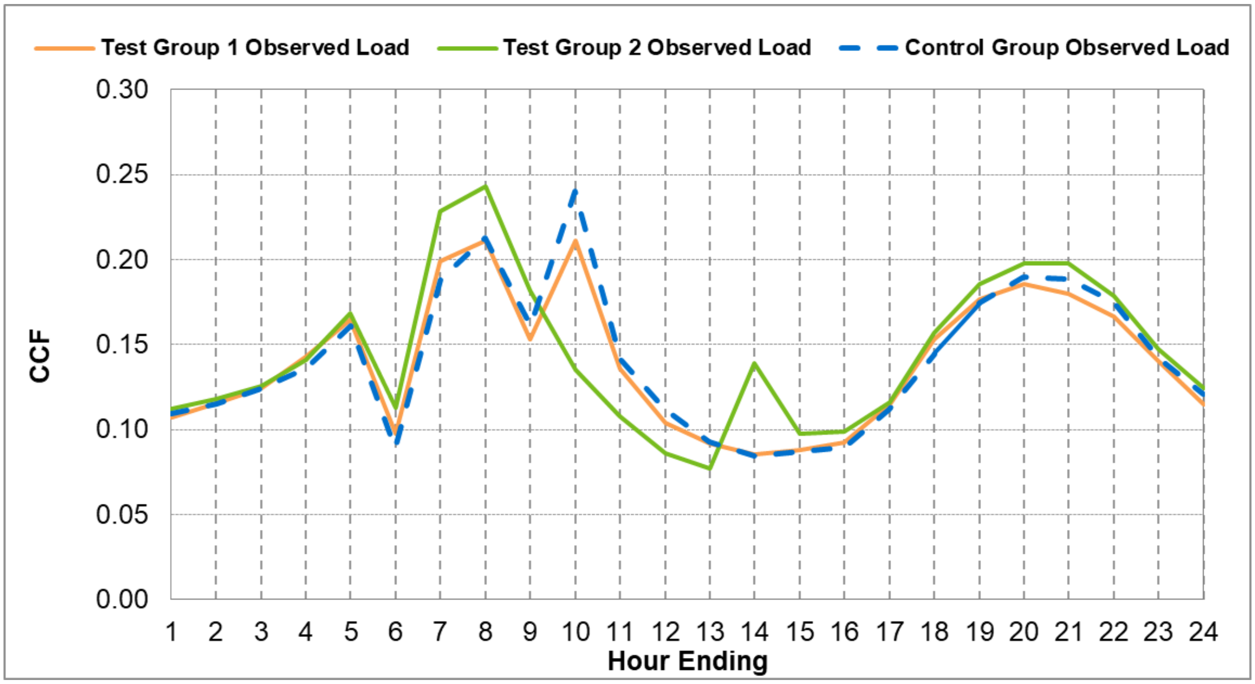
Each group contained approximately 900 customers, for a total of approximately 2,700 customers participating in the implementation strategy tests. In order to ensure that the control group was a valid representation of the other two test groups, Nexant first compared the behavior of each group on event days when all customers received the same implementation strategy. Figure 4-5 plots the observed load from the three groups on the average morning event day when all customers received the same implementation strategy. Overall, the three groups behaved similarly on event days where they received the same implementation strategy.

Figure 4-5: Comparison of Control Group and Test Groups on non-Test Event Days



Nexant then compared the behavior of each group on the three test days to determine the impact of the different implementation strategies. Figure 4-6 shows the observed load of the three groups on the average morning event day when the different strategies were tested. Overall, Test Group #2 had the highest observed load from 5 AM to 9 AM, 19% higher than the control group on average, and the lowest observed load from 9 AM to 1 PM, 27% lower than the control group on average. Test group #1 had an observed load almost identical to that of the control group from 5 AM to 9 AM, but a snap back 12% lower than the control group in the hour following the event. Over the course of the entire day, the control group consumed 3.39 CCF, Test Group #1 consumed 3.36 CCF, and Test Group #2 consumed 3.48 CCF. So, while both implementation strategies were able to reduce post-event snap back, Test Group #1 saw very little change in daily consumption relative to the control group and Test Group #2 saw higher daily consumption relative to the control group.

Figure 4-6: Comparison of Control Group and Test Groups on Test Event Days



5 Conclusions and Recommendations

Figure 5-1 provides a summary of the 2018-2019 winter Smart Therm Program hourly event impacts for each event and for the average morning and evening event. The average hourly load reduction for a morning event was 0.027 CCF/hr per participant leading to an aggregate reduction of 0.093 MMcf/hr, or 15.1%. The average hourly load reduction for an evening event was 0.020 CCF/hr, leading to an aggregate reduction of 0.019 MMcf/hr, or 15.5%. Morning events also consistently had larger impacts than evening events, with the exception of February 11 when relatively few customers were called for an evening event and had much higher than average participation.

Figure 5-1: Winter 2018-2019 Hourly Load Impact Estimates

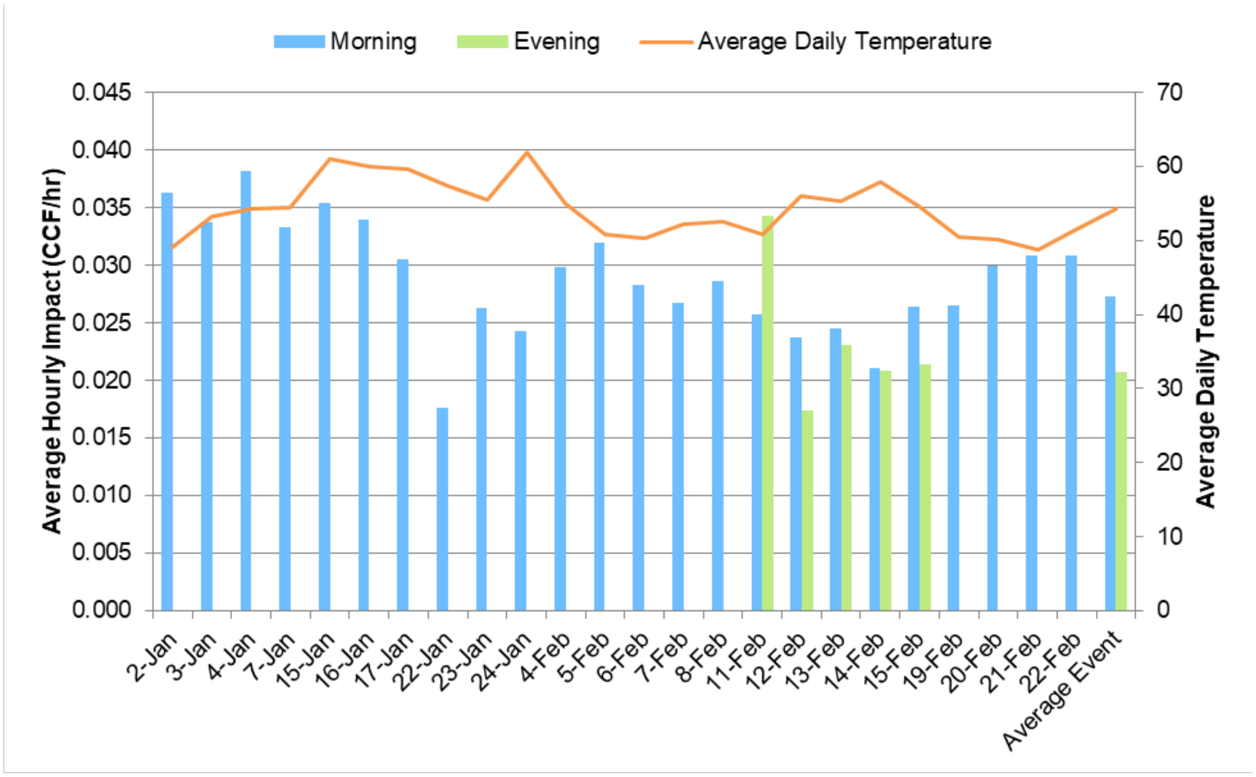


Figure 5-2 provides a summary of 2018-2019 event savings for each event and for the average morning and evening event. The average event savings for a morning event was 0.110 CCF per participant leading to aggregate event savings of 0.372 MMcf. The average event savings for an evening event was 0.083 CCF per participant, leading do aggregate event savings of 0.076 MMcf.

Figure 5-2: Winter 2018-2019 Event Savings Estimates

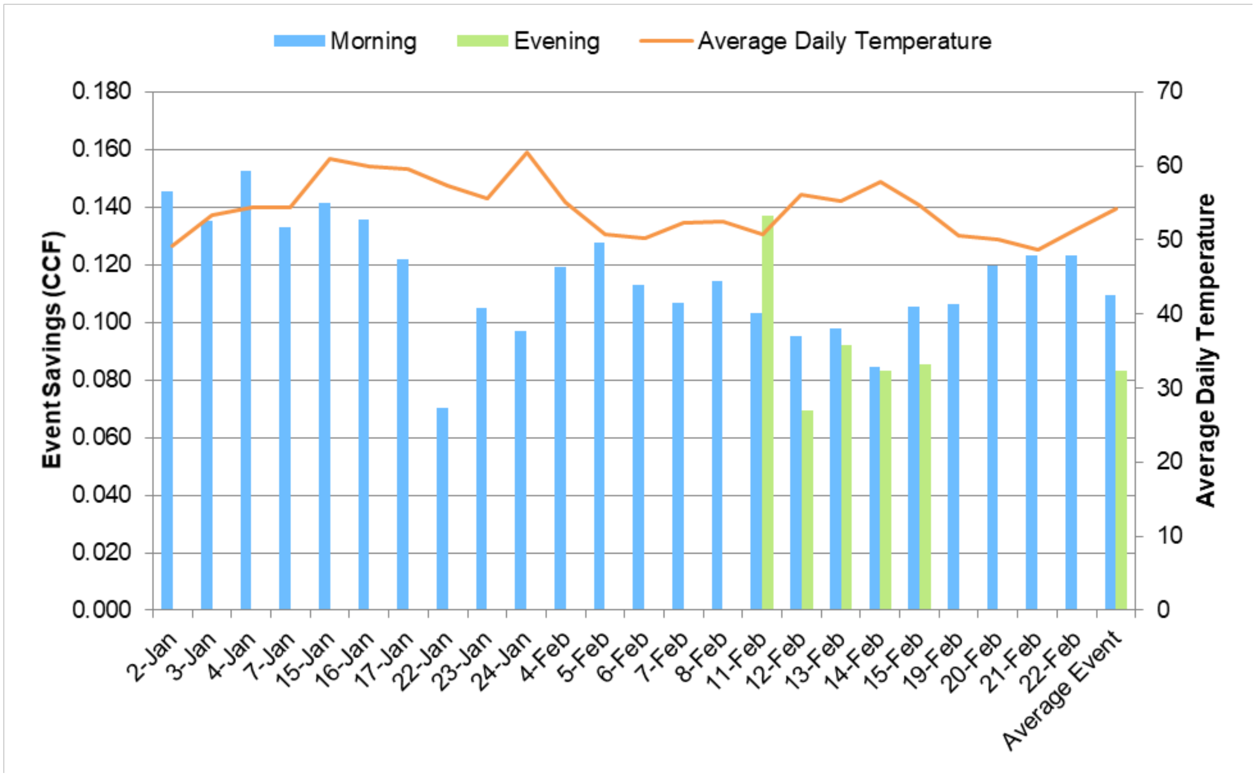
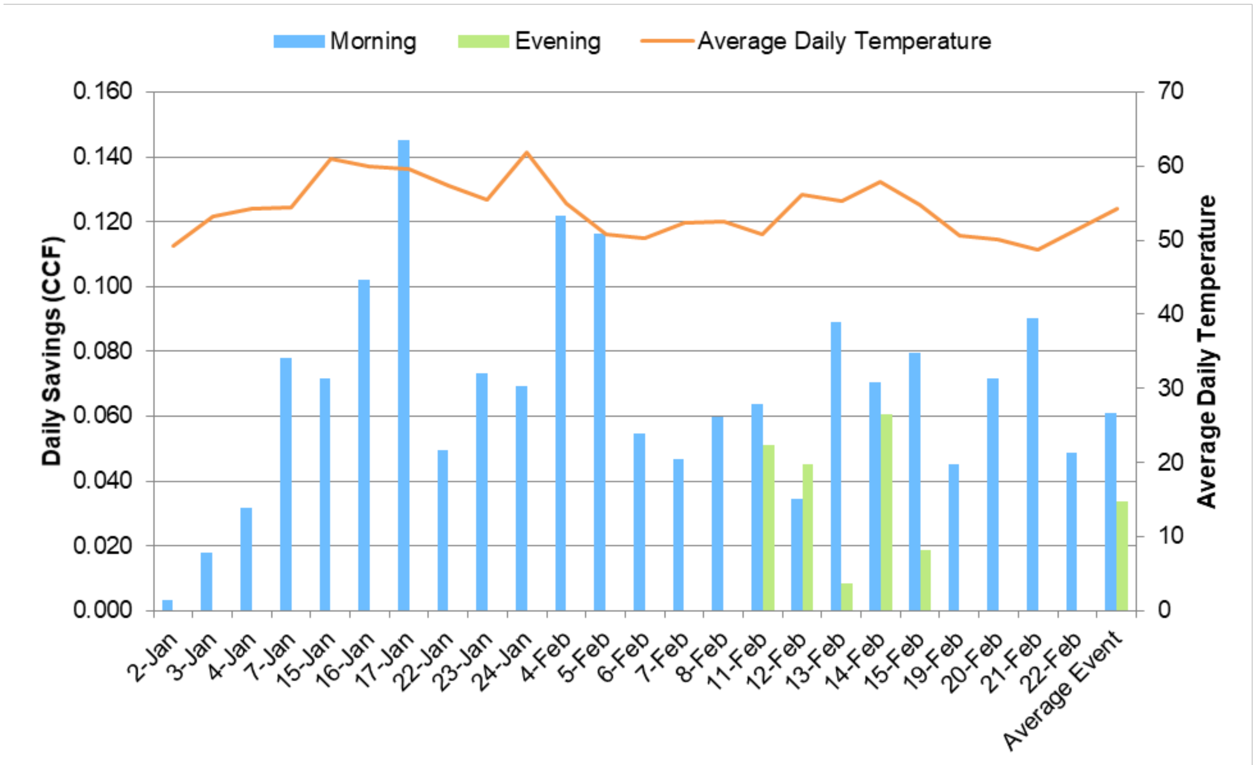


Figure 5-3 provides a summary of 2018-2019 net daily savings for each event and for the average morning and evening event. Overall, we see more variation between the events for daily savings than we see for hourly impacts or event savings. The average daily savings for a morning event was 0.061 CCF per participant leading to aggregate savings of 0.207 MMcf, or 2.24%. The average daily savings for an evening event was 0.034 CCF per participant leading to aggregate daily savings of 0.031 MMcf, or 1.27%.

Figure 5-3: Winter 2018-2019 Daily Savings Estimates



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 and can achieve net daily savings as a result of calling these events. However, the snap back following the event when a customer's preferred temperature settings are restored can be quite significant, and greatly reduces net daily CCF savings when compared to event savings.

From a technical perspective, it's clear the program met the objectives of significantly reducing gas consumption during specific windows of time. However, due to gas usage snap backs in the hours following events, the net daily CCF savings that resulted from this program were only in the 1% to 2% range depending on the timing of the event.

Appendix A Load Impact Methodology Details

A.1 Selection of Matched Control Group

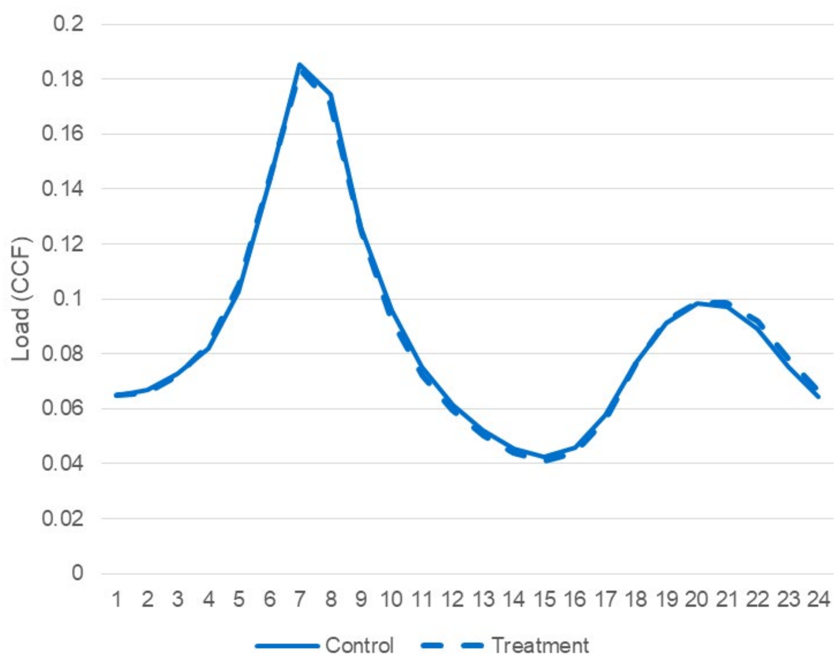
Customers who signed up to participate in the Smart Therm program are inherently different from customers who did not sign up to participate in the Smart Therm program or customers who were not targeted by the thermostat vendors. For this reason, a control group must be constructed using statistical matching. It is possible that the customers who enrolled in the Smart Therm program 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 Smart Therm 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 Smart Therm 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 the Smart Therm program. A probit model is a regression model designed to estimate probabilities—in this case, the probability that a customer would enroll in the Smart Therm 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 Smart Therm. 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 the Smart Therm program based on the included independent variables. Thinking of it this way, each customer in the control group was matched to a Smart Therm customer with a similar probability of joining the Smart Therm 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 Smart Therm 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 Smart Therm customers were split out by vendor to find the optimal probit model for each vendor. This provided much closer matches for each of the vendor customers.

Figure A-1 shows the results of the matched control group for Smart Therm participants. The customers match very well to their matched control group on proxy days. This is expected due to the large number of participants in the program.

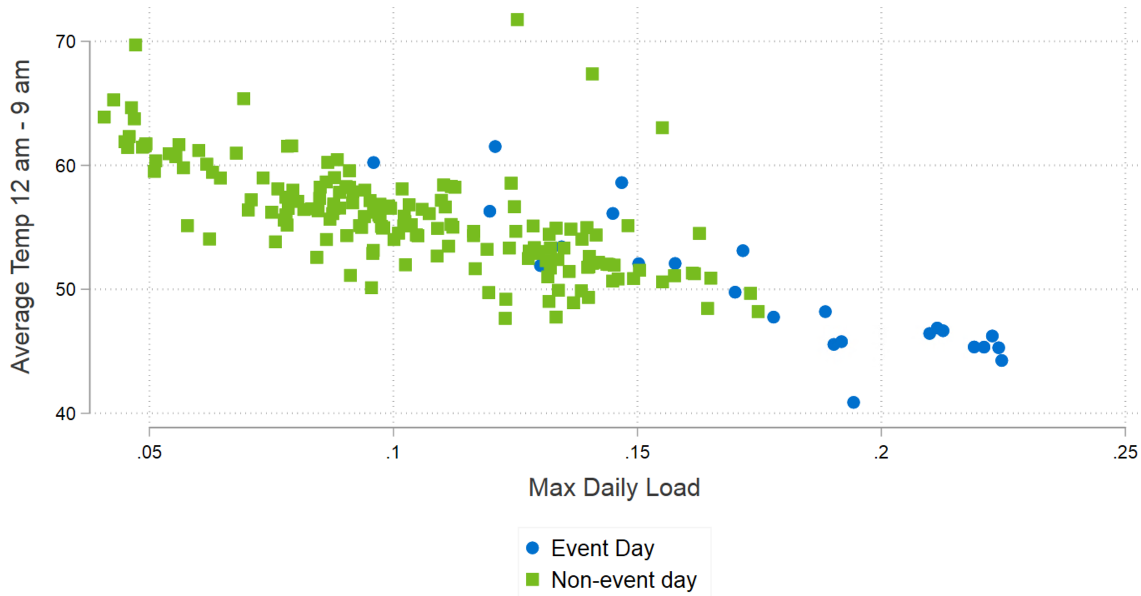
Figure A-1: Hourly Average Demand for All Customers on Proxy Days



Proxy Day Selection

As stated above, in order to validate the matching model to ensure customers would behave similarly on an event day, Nexant uses out-of-sample testing to match customers on event-like nonevent days, referred to here as “proxy days”. To select these days, Nexant looks at the load of the control pool and different temperatures metrics on event days and non-event days. Non-event days with a similar combination of load and temperature conditions to event days are then selected as proxy days for out-of-sample testing. Figure A-2 shows the maximum daily load for the average control customer plotted against the average temperature from 12 AM – 9 AM for each event day in the 2018-2019 DR season and each non-event day for the 2017-2018 and 2018-2019 winters. Although there are two seasons from which Nexant could select proxy days, there are no non-event days that are similar to the relatively cold and high load conditions that are seen on the event days this season. As a result, even though the treatment and control customers match up well on more moderate days it is difficult to determine if their similarities carry over to the more extreme event days. This reduces the overall accuracy of the control group when estimating load impacts on event days. While program goals and operational needs should drive event dispatch, we note that withholding a few very cold days for evaluation purposes will provide key data points to further strengthen the Smart Therm evaluator's ability to develop credible ex post estimates.

Figure A-2: Average Temperature from 12-9 AM vs. Max Daily Load



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

$$thm_{i,t} = a + b \cdot Treatment_i + c \cdot Event_t + d \cdot (Treatment_i \cdot Event_t) + u_t + v_i + \varepsilon_{i,t} \text{ for } i \in \{1, \dots, n_i\} \text{ and } t \in \{1, \dots, n_t\}$$

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[1]
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
ε	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 Smart Therm (*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.

A.3 Calculating Daily Savings

Due to the lack of proxy days that mirrored event day conditions, as described in section A.1, when estimating hourly load impacts across all 24 hours of the event day there was often differences between the Smart Therm participant load and the reference load. Figure A-3 depicts these load shapes during an average morning event, as shown in section 4. In the evening we can see that there are differences between the reference load and observed load in the evening, several hours after the two groups came together in the middle of the day. For the purpose of calculating daily savings, it was assumed that these differences were not due to “treatment effects”, or an event being called in the morning. This means that for morning events, it was assumed that after 3 PM the two groups had equal amounts of load each hour and for evening events, it was assumed that before 12 PM the two groups had equal amounts of load

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

for each hour. Figure A-4 illustrates what this assumption looks like for the average morning event.

Figure A-3: Load Shape on Average Morning Event Day

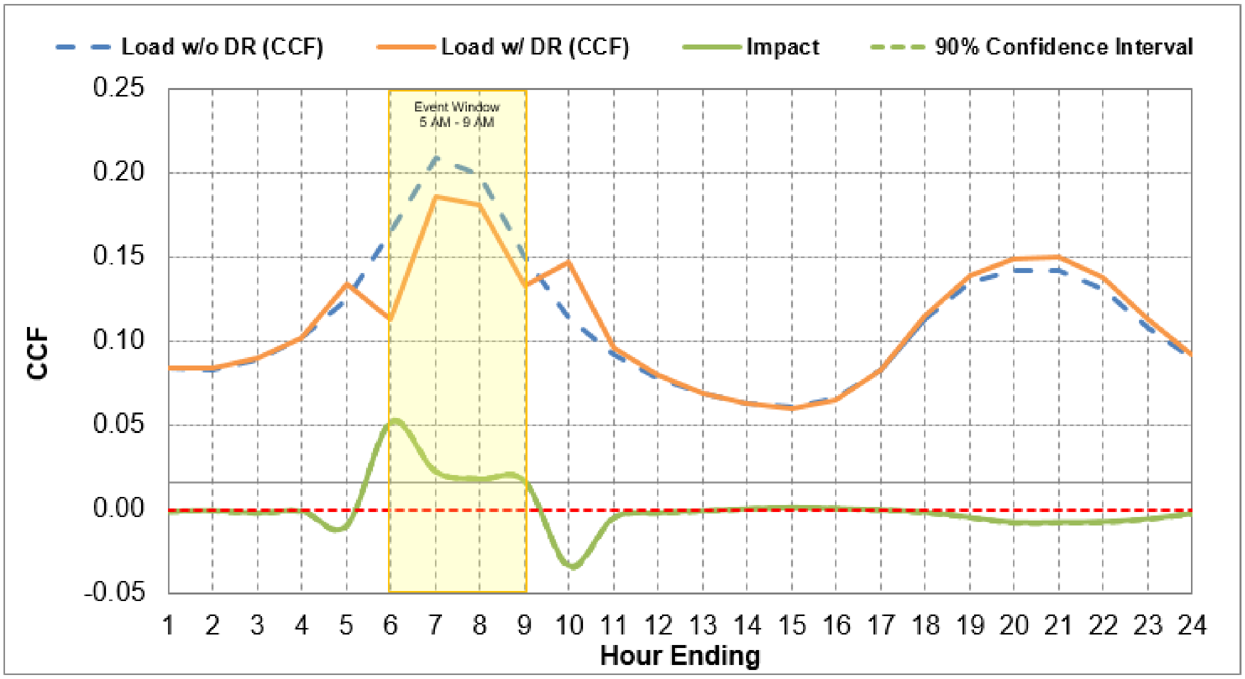
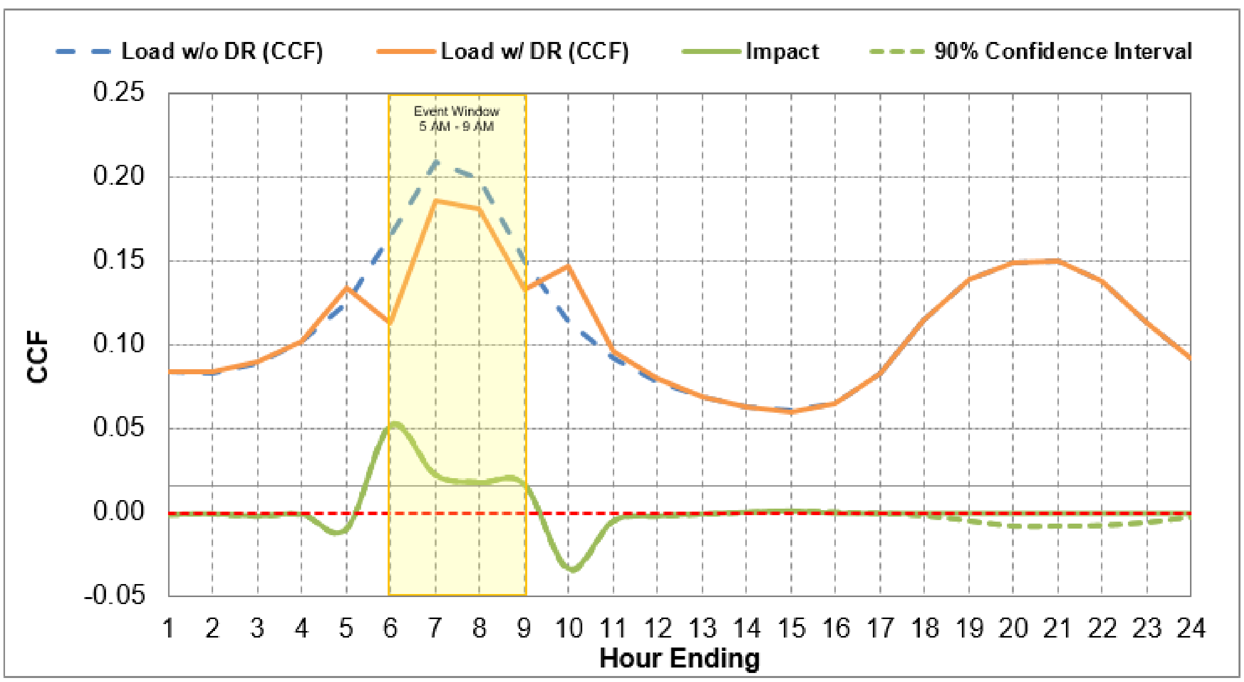


Figure A-4: Load Shape on Average Morning Event Day with Daily Savings Adjustment



Appendix B Results (thm)

Table B-2, and Table B-3 present the results from section 4 in therms rather than CCF. All results were originally calculated in therms, and then divided by a conversion factor of 1.03 to get the results in CCF.

Table B-1: Average Hourly Impacts for All Events and Average Events (thm)

Date	Event Window	Average Hourly Load w/o DR (thm)	Average Hourly Load w DR (thm)	Average Hourly Impact (thm)	Aggregate Hourly Impact (thm)	Hourly Impact (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.222	0.184	0.037	333.30	16.90%	41.5
3-Jan	5am – 9am	0.216	0.182	0.035	309.82	16.10%	46.99
4-Jan	5am – 9am	0.212	0.172	0.039	350.01	18.60%	48.74
7-Jan	5am – 9am	0.148	0.113	0.034	305.51	23.20%	51.19
15-Jan	5am – 9am	0.159	0.123	0.036	327.48	22.90%	60.15
16-Jan	5am – 9am	0.138	0.103	0.035	316.07	25.30%	61.88
17-Jan	5am – 9am	0.106	0.074	0.031	285.54	29.70%	60.42
22-Jan	5am – 9am	0.181	0.163	0.018	300.60	10.00%	51.53
23-Jan	5am – 9am	0.185	0.158	0.027	519.76	14.60%	49.24
24-Jan	5am – 9am	0.161	0.136	0.025	574.10	15.50%	56.99
4-Feb	5am – 9am	0.134	0.103	0.031	857.22	23.00%	53.78
5-Feb	5am – 9am	0.160	0.127	0.033	930.41	20.60%	49.75
6-Feb	5am – 9am	0.224	0.195	0.029	833.68	13.00%	45.5
7-Feb	5am – 9am	0.225	0.198	0.028	801.34	12.20%	47.26
8-Feb	5am – 9am	0.214	0.185	0.029	866.25	13.70%	47.03
11-Feb	5am – 9am	0.219	0.192	0.027	737.52	12.10%	44.29
11-Feb	6pm – 10pm	0.151	0.115	0.035	85.79	23.40%	50
12-Feb	5am – 9am	0.199	0.174	0.024	531.40	12.30%	47.26
12-Feb	6pm – 10pm	0.127	0.109	0.018	164.46	14.10%	57.2
13-Feb	5am – 9am	0.135	0.109	0.025	556.92	18.70%	56.98
13-Feb	6pm – 10pm	0.155	0.132	0.024	217.77	15.30%	52.61
14-Feb	5am – 9am	0.105	0.083	0.022	479.61	20.80%	58.48
14-Feb	6pm – 10pm	0.130	0.109	0.021	197.17	16.50%	55.72
15-Feb	5am – 9am	0.140	0.113	0.027	615.23	19.30%	52.25
15-Feb	6pm – 10pm	0.137	0.115	0.022	201.96	16.00%	55.27
19-Feb	5am – 9am	0.224	0.197	0.026	814.79	12.20%	46.54
20-Feb	5am – 9am	0.214	0.184	0.030	932.78	14.30%	47.98
21-Feb	5am – 9am	0.191	0.160	0.031	980.98	16.50%	46.04
22-Feb	5am – 9am	0.226	0.194	0.032	1,059.59	14.10%	45.55
All Events							
Avg.	**AM**	**0.186**	**0.157**	**0.028**	**959.92**	**15.10%**	**49.72**
Avg.	**PM**	**0.138**	**0.117**	**0.021**	**196.79**	**15.50%**	**54.68**

Table B-2: Event Savings for All Events and Average Events (thm)

Date	Event Window	Average Total Event Load w/o DR (thm)	Average Total Event Load w DR (thm)	Average Event Savings (thm)	Aggregate Event Savings (thm)	Event Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	0.887	0.738	0.150	1,333.19	16.90%	41.5
3-Jan	5am – 9am	0.866	0.727	0.139	1,239.30	16.10%	46.99
4-Jan	5am – 9am	0.846	0.689	0.157	1,400.02	18.60%	48.74
7-Jan	5am – 9am	0.590	0.453	0.137	1,222.06	23.20%	51.19
15-Jan	5am – 9am	0.637	0.491	0.146	1,309.93	22.90%	60.15
16-Jan	5am – 9am	0.552	0.413	0.140	1,264.28	25.30%	61.88
17-Jan	5am – 9am	0.423	0.297	0.126	1,142.18	29.70%	60.42
22-Jan	5am – 9am	0.724	0.652	0.072	1,202.39	10.00%	51.53
23-Jan	5am – 9am	0.740	0.632	0.108	2,079.05	14.60%	49.24
24-Jan	5am – 9am	0.645	0.545	0.100	2,296.39	15.50%	56.99
4-Feb	5am – 9am	0.534	0.411	0.123	3,428.89	23.00%	53.78
5-Feb	5am – 9am	0.640	0.508	0.132	3,721.64	20.60%	49.75
6-Feb	5am – 9am	0.896	0.779	0.116	3,334.72	13.00%	45.5
7-Feb	5am – 9am	0.901	0.791	0.110	3,205.34	12.20%	47.26
8-Feb	5am – 9am	0.858	0.740	0.118	3,464.98	13.70%	47.03
11-Feb	5am – 9am	0.874	0.768	0.106	2,950.08	12.10%	44.29
11-Feb	6pm – 10pm	0.603	0.461	0.141	343.17	23.40%	50
12-Feb	5am – 9am	0.794	0.697	0.098	2,125.60	12.30%	47.26
12-Feb	6pm – 10pm	0.509	0.438	0.072	657.83	14.10%	57.2
13-Feb	5am – 9am	0.539	0.438	0.101	2,227.69	18.70%	56.98
13-Feb	6pm – 10pm	0.621	0.527	0.095	871.10	15.30%	52.61
14-Feb	5am – 9am	0.418	0.331	0.087	1,918.44	20.80%	58.48
14-Feb	6pm – 10pm	0.522	0.436	0.086	788.69	16.50%	55.72
15-Feb	5am – 9am	0.562	0.453	0.109	2,460.92	19.30%	52.25
15-Feb	6pm – 10pm	0.548	0.460	0.088	807.83	16.00%	55.27
19-Feb	5am – 9am	0.894	0.789	0.105	3,259.16	12.20%	46.54
20-Feb	5am – 9am	0.858	0.738	0.120	3,731.11	14.30%	47.98
21-Feb	5am – 9am	0.765	0.641	0.124	3,923.93	16.50%	46.04
22-Feb	5am – 9am	0.904	0.777	0.127	4,238.37	14.10%	45.55
All Events							
Avg.	**AM**	**0.743**	**0.630**	**0.113**	**3,839.69**	**15.10%**	**49.72**
Avg.	**PM**	**0.553**	**0.467**	**0.085**	**787.18**	**15.50%**	**54.68**

Table B-3: Daily Savings for All Events and Average Events (thm)

Date	Event Window	Average Total Daily Load w/o DR (thm)	Average Total Daily Load w DR (thm)	Average Daily Savings (thm)	Aggregate Daily Savings (thm)	Daily Savings (%)	Avg. Event Temp. (F)
2-Jan	5am – 9am	3.343	3.340	0.003	30.55	0.10%	41.5
3-Jan	5am – 9am	3.033	3.014	0.018	164.79	0.60%	46.99
4-Jan	5am – 9am	2.890	2.857	0.033	291.34	1.10%	48.74
7-Jan	5am – 9am	2.366	2.286	0.080	714.39	3.40%	51.19
15-Jan	5am – 9am	2.883	2.809	0.074	662.76	2.60%	60.15
16-Jan	5am – 9am	2.232	2.127	0.105	952.60	4.70%	61.88
17-Jan	5am – 9am	1.866	1.716	0.150	1,360.44	8.00%	60.42
22-Jan	5am – 9am	2.464	2.413	0.051	848.75	2.10%	51.53
23-Jan	5am – 9am	2.305	2.230	0.075	1,446.10	3.30%	49.24
24-Jan	5am – 9am	1.844	1.772	0.071	1,641.09	3.90%	56.99
4-Feb	5am – 9am	2.416	2.290	0.126	3,506.92	5.20%	53.78
5-Feb	5am – 9am	2.903	2.783	0.120	3,391.69	4.10%	49.75
6-Feb	5am – 9am	3.385	3.329	0.056	1,614.91	1.70%	45.5
7-Feb	5am – 9am	3.125	3.077	0.048	1,398.50	1.50%	47.26
8-Feb	5am – 9am	2.875	2.813	0.062	1,811.12	2.10%	47.03
11-Feb	5am – 9am	3.051	2.985	0.066	1,820.15	2.10%	44.29
11-Feb	6pm – 10pm	3.421	3.369	0.053	127.68	1.50%	50
12-Feb	5am – 9am	2.617	2.581	0.036	775.58	1.40%	47.26
12-Feb	6pm – 10pm	3.050	3.003	0.046	426.49	1.50%	57.2
13-Feb	5am – 9am	2.489	2.397	0.092	2,024.98	3.70%	56.98
13-Feb	6pm – 10pm	2.793	2.784	0.009	80.43	0.30%	52.61
14-Feb	5am – 9am	2.025	1.953	0.073	1,601.90	3.60%	58.48
14-Feb	6pm – 10pm	2.273	2.211	0.063	574.29	2.80%	55.72
15-Feb	5am – 9am	2.316	2.234	0.082	1,859.98	3.50%	52.25
15-Feb	6pm – 10pm	2.663	2.644	0.019	175.23	0.70%	55.27
19-Feb	5am – 9am	3.169	3.126	0.043	1,353.27	1.50%	46.54
20-Feb	5am – 9am	3.423	3.351	0.072	2,235.26	2.10%	47.98
21-Feb	5am – 9am	3.354	3.263	0.091	2,879.44	2.80%	46.04
22-Feb	5am – 9am	3.168	3.117	0.050	1,671.77	1.60%	45.55
All Events							
Avg.	**5am – 9am**	**2.802**	**2.740**	**0.063**	**2,132.74**	**2.20%**	**49.72**
Avg.	**6pm – 10pm**	**2.731**	**2.696**	**0.035**	**318.69**	**1.30%**	**54.68**

Headquarters
101 2nd Street, Suite 1000
San Francisco CA 94105-3651
Tel: (415) 369-1000
Fax: (415) 369-9700
www.nexant.com