Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***EPIC Project #1.24 - Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction***
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1.0 Executive Summary

Pacific Gas and Electric Company's (PG&E) Electric Program Investment Charge (EPIC) Project 1.24 Demonstrate Demand-Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction (in short, referred to as the Real-Time Monitoring System (RTMS) Project), successfully deployed a sample of data logging devices on Air Conditioning (A/C) Direct Load Control (DLC) installations to collect data that can be used to gain insights into performance of these data logging devices at both the customer-level and local-level. The three primary objectives of this EPIC project were:

(1) Enable near real-time visibility of A/C DLC installations to Transmission and Distribution (T&D) Operations;
(2) Improve PG&E's ability to estimate A/C DLC load impacts at the distribution system level to better understand localized impact of AC direct load control devices on meeting distribution feeder level reliability concerns; and
(3) Enable Demand Response (DR) program administrators to have near real-time feedback on any problems with direct load control devices before, during or after an event is called to support T&D operations.

Similar to other appliance load control programs in North America, PG&E's A/C DLC system employs a one-way paging system platform to control A/C compressor loads using signals generated and dispatched by a central station controller. The one-way nature of the communication between the A/C Direct Load Control (DLC) switch and electricity system operators imposes significant limitations on the use of appliance load control at all levels of the system (i.e. generation, transmission and distribution). PG&E's 2009 Ancillary Services Project (ASP) demonstrated the usefulness of A/C load control for providing ancillary services and load relief on targeted distribution feeders, but identified the need for better visibility of available controllable load and the load impacts of operations at all levels of the system.

For this project, communicating data loggers were purchased and installed on samples of residential customers participating in PG&E's SmartAC™ program. In addition to the loggers, PG&E used a newly developed database management system to schedule data collection, store the load measurements and display information about the availability and performance of the load control system in near real-time. PG&E then operated the RTMS dashboard over the course of summer 2015 to observe the operational status of its A/C load control program and provided recommendations for dashboard improvements throughout the project. The dashboard was also used to track specific load control operations on two targeted substations (Barton and Bogue, located in Fresno and Marysville, California, respectively) to assess the ability of the system to observe the operational readiness of the system and estimate load impacts in near real- time on those substations' distribution circuits.

While there were a number of technical achievements resulting from the EPIC 1.24 RTMS project, the primary results were the following:

- Using a representative sample of the A/C load control system, the RTMS dashboard provided visibility of the daily operational status (i.e., whether the load control devices were in operation) for approximately 99% of PG&E's A/C load control devices during the period;
- The average notch test load impact per A/C load control device was 0.57 kW at Barton and 0.73 kW at Bogue—the load impacts varied significantly from test to test, depending on ambient temperature and timing of the notch, which varied across the weekday 5 PM to 9 PM window;

- The average notch test load impact measured at the substation level (from aggregate feeder loads) was 617 kW at Barton and 526 kW at Bogue—the impact varied in a manner similar to the way in which each device's measurements varied;
- The multiple-hour tests were conducted on five occasions at the Barton Substation at temperatures ranging from 92˚F to 97˚F; and on three occasions at Bogue at temperatures ranging from 76˚F to 84˚F. To have the greatest impact, the multiple-hour tests were called on days forecasted to exceed 102°F; however, were precluded by SmartAC™ and SmartRate™ measurement and evaluation (M&E) days; and
- The average multiple-hour test load impacts per device—.33 kW and .29 kW respectively for devices located in Barton and Bogue—load impacts for these tests were lower than the notch tests because multiple-hour tests employed 50% cycling rather than the full shed strategy used for notch tests.

This project has demonstrated the usefulness of the RTMS dashboard for observing the operational readiness and performance of PG&E's load control system, using both a customer- and location-specific approach, which could be useful for load relief on targeted distribution feeders. This type of approach will become increasingly important and useful as load control is integrated into the modern grid in California. In order to not interfere with existing customer programs, the notch tests and multiple-hour tests conducted during this project were carried out under relatively cool weather conditions, which most likely underestimated the full capability of A/C load control. Nevertheless, these tests demonstrated that the impacts of A/C load control are readily observable using the RTMS loggers deployed on substation feeders, as well as on Supervisory Control and Data Acquisition (SCADA) measurements taken at the feeder level. Given that load impacts of A/C load control operations are also readily observable using SCADA when the market penetration of A/C load control is high enough, this may prove to be a more practical approach to monitoring the load impacts of A/C load control on circuits on a targeted basis, when it becomes necessary to do so.

The results of the EPIC 1.24 project offer additional opportunities for PG&E to leverage RTMS technology. One opportunity is to redeploy the available loggers to obtain visibility of the operational status of the A/C load control system at the substation level. Secondly, the loggers could be redeployed to a sample of customers designed to more precisely measure the load that is available for and currently under control as a proportion of the total A/C load control system.

Through the RTMS Project, PG&E successfully tested a data collection and management system that provides increased visibility into SmartAC™ operations without incurring the significant costs associated with a wholesale replacement of an existing one-way load control communication system with two-way load control devices. The learnings from this EPIC project can be leveraged by the industry, to provide near real-time information to multiple stakeholders (including electric utilities, CAISO, and distribution system operators) regarding the A/C load available for control and under control during the summer cooling season. The RTMS technology can be critically important tool for operating load control programs in the future because it does not require wholesale replacement of existing load control platforms and can be adapted to other utility DLC programs.

Availability of such information and the technical capability of A/C load control are becoming critically important as the modern grid becomes increasingly dependent on load control as a resource for balancing loads on the generation, transmission and distribution systems. A/C load control can be a key solution for supplying load reductions from A/C units at critical times (i.e. when solar generation subsides during the day or at the end of the day to minimize loads on selected circuits are needed). A/C load control may also be used to clip local distribution system peaks, thereby delaying needed investments in distribution equipment. Both of these strategies that improve the economic efficiency of utility investments require near real-time visibility of the loads available for control and under control on local distribution equipment, which was a capability successfully demonstrated in this project.

Ultimately, due to the successful results and insights gained from the loggers at the two substations, PG&E plans to redeploy loggers from the Barton and Bogue substation locations to better represent the overall SmartAC™ program participant population by geographic concentrations, control device technology, customer segment, and control strategies. Finally, PG&E will offer recommendations to refine the RTMS dashboard, after gaining experience in implementing the near-real time dashboard.

2.0 Introduction

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this project. The CPUC initially issued Decision 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[1], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued Decision 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020,*[2] which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, the CPUC defined technology demonstration as the installation and operation of pre-commercial technologies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments, to enable the financial community to effectively appraise the operational and performance characteristics of a given technology and the financial risks it presents.

The decision also required the EPIC Program Administrators[3] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application at the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E’s EPIC plan, including $49,328,000 for this program category. Pursuant to PG&E’s approved EPIC triennial plan, PG&E initiated, planned and implemented the following project: Project #1.24: Demonstrate Demand Side Management (DSM) for Transmission and Distribution (T&D) Cost Reduction, also referred to in short as the Real-Time Monitoring System (RTMS) Project. Through the annual reporting process, PG&E kept the CPUC staff and stakeholders informed of the progress of the project.

This is PG&E’s final report on this project, whose results successfully demonstrate the feasibility of deploying an RTMS to existing one-way load control systems. This ultimately makes them useful in an environment where real-time information about resource ability and performance are becoming increasingly important for supplying load reductions at critical times and delaying needed investments in distribution equipment. It documents the EPIC 1.24 RTMS project’s achievements, highlights key findings and recommendations from the project that have industry-wide value, and identifies future opportunities for PG&E to leverage this project.

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[1] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF
[2] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF
[3] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)

3.0 Project Summary

3.1 Problem/Opportunity Addressed

Similar to other appliance load control programs in North America, PG&E's A/C direct load control system employs a one-way paging system platform to control A/C compressor loads using signals generated and dispatched by a central station controller. The system does not provide information on the loads available for control, nor the operational status of the load control devices in the field. The one-way nature of the communication between the A/C loads and electricity system operators imposes significant limitations on the use of appliance load control at all levels of the system (i.e., generation, transmission and distribution). PG&E's 2009 Ancillary Services Project (ASP) demonstrated the usefulness of A/C load control for providing ancillary services and load relief on targeted distribution feeders, but identified the need for better visibility of available controllable load and the load impacts of operations at all levels of the system.

The availability of such information is becoming critically important as the modern grid becomes increasingly dependent on load control as a resource for balancing loads on the generation, transmission and distribution systems. Until very recently, A/C load control has been useful as an emergency resource and has been valued in terms of its impact on resource adequacy (i.e., the reserve required to support foreseeable peak demand). This situation is changing in several ways as distributed energy resources are integrated with the electric grid.

The CAISO has developed a wholesale market for DR and new rules are emerging for providing telemetry about loads available and under control to participate in that market. The stakeholder discussions are far from complete, but what is certain is that aggregators participating in the emerging market with load reductions in excess of 10 MW will be required to supply telemetry regarding loads available and under control—either using directly connected load measurements or samples thereof. Therefore, in the future, participation of A/C load control in the DR market in California (and other ISOs) could require a system like the RTMS to support participation in wholesale DR markets.

A/C load control may also play an important role in future transmission and distribution planning, as well as operations, by supplying load reductions from A/C units at critical times when solar generation subsides during the day or at the end of the day to minimize loads on selected circuits when needed. It might also be used to clip local distribution system peaks—thereby delaying needed investments in distribution equipment. Both of these strategies for improving the economic efficiency of utility investments require near real-time visibility of the loads available for control and under control on local distribution equipment.

3.2 Project Overview and Objectives

This project sought to develop, test, and utilize near real-time data streams from data loggers installed on one-way direct load control devices on SmartAC™ Program participants[4]. The specific objectives of this project were to:

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[4] PG&E's SmartAC™ Program currently consists of over 160,000 residential customers, which have a free direct load control device installed on their air conditioner. During peak times of the summer months between May 1 and October 1, PG&E may send a signal to the customer's device to run the A/C at a lower capacity, as one opportunity to manage peak load through customer participation. Customers are rewarded with a $50 incentive for participating.

1. Improve PG&E's ability to estimate A/C direct load control load impacts at the distribution system level to aid in better understanding the localized impact of A/C direct load control devices on meeting distribution feeder level loading or reliability concerns;
2. Enable DR program administrators to have near real-time feedback on any problems with direct load control devices before, during or after an event is called; and
3. Enable near real-time visibility of A/C direct load control installations to transmission and distribution operations.

3.3 Project Scope

In PG&E's approved EPIC 1 Application (A.12-11-003), PG&E indicated the project would execute an integrated approach to package DSM resources to create customer- and location-specific solutions to reduce local peak loads. This included possibly exploring several potential items related to reducing peak load, including:

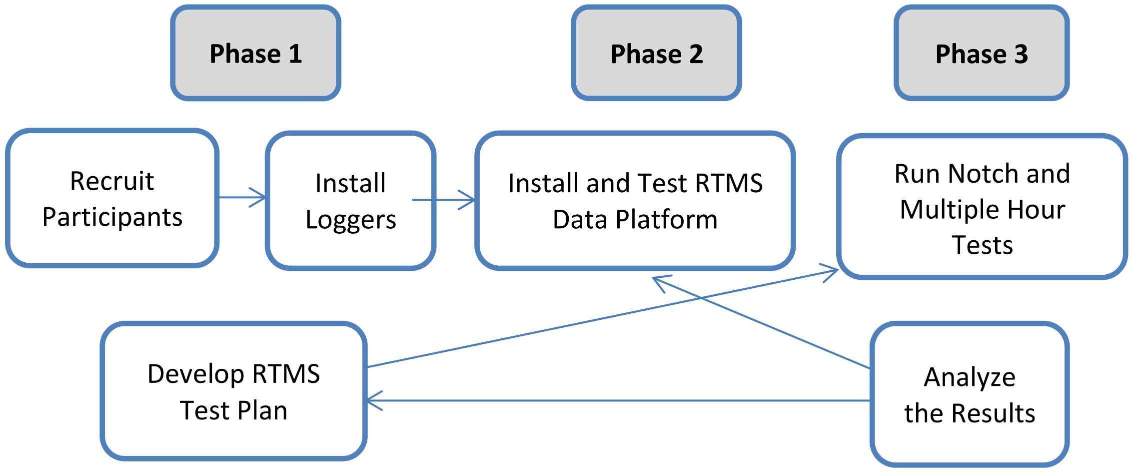
- Identify specific targeted substations or feeders where capacity expansions are planned to address a forecasted overload or anticipate significant growth of DG, EVs or ZNE buildings.
- Identify strategic customers to target for demand reduction and test new technologies that combine and integrate DSM tools (EE, DR, distributed energy storage, and consumer-oriented SmartMeter™ tools) to achieve a measurable amount of demand reduction.
- Evaluate the demand reduction delivered, while attributing to each technology/DSM tool used, the value and contribution to the reduction, and customer satisfaction with the solution.
- Develop economic model to compare the planned traditional utility investment with alternatives using selected distributed or demand-side investments (i.e. recommend targeted outreach to SmartAC™ customers for substations facing potential capacity constraints).
- Implement the most appropriate investment and while preserving reliability.
- Determine the cost-effectiveness of the planned utility investment versus a combination of alternative distributed or demand-side investments (i.e. compare traditional capital substation upgrade investments to either DR alternatives or a combination of alternative and demand response investments).

Between the time of the application and the launch of the project, some of these objectives were achieved and/or in progress through other initiatives. Therefore, as indicated in the 2014 and 2015 EPIC Annual Report, the project met the filed objectives through assessing how to best utilize DSM resources to create a customer- and location-specific approach to assist with distribution capacity constraints. In order to do this, the project would improve the ability to estimate heating, ventilation, and air conditioning (HVAC) direct load control load impacts at the distribution feeder level to aid in better understanding of the localized impact of HVAC direct load control devices on meeting distribution feeder-level reliability concerns, focusing on central air conditioning.

This project tested a data collection and management system that provides visibility into SmartAC™ operations without incurring the significant costs associated with a wholesale replacement of an existing one-way load control system with two-way load control devices.

The project was implemented in three phases, as represented in Figure 1.

Figure 1: Overview of RTMS Project Program Deployment Effort



Phase 1

In the first phase, sample designs were developed that would be used to recruit the SmartAC™ customers whose air conditioners would be monitored via the installation of data loggers. Additionally, a project test plan was developed (see Exhibit A) that identified the measurements that would be taken over the course of the project, as well as the tests that would be carried out, including the conditions under which testing was to take place. Lastly, data loggers were deployed on a sample of air conditioners participating in PG&E's local A/C cycling program, SmartAC™, to enable near real-time monitoring of device performance and load impacts at the feeder-level.

Phase 2

In the second phase, work was undertaken to integrate the logger measurements into a coherent historical database and to develop a software platform to monitor and control the logger population (i.e. schedule the recording intervals).

Phase 3

Finally, in the third phase, test events were carried out during a portion of the 2015 summer Demand Response season (July through September) and the data was analyzed.

Through these phases, the goal of the project was ultimately achieved by developing an integrated dashboard/tool and testing near real-time visibility of loads currently controlled with customers in the SmartAC™ program as well as loads available for control on local distribution equipment at two substations: Bogue and Barton. This provided PG&E the information needed to assess direct correlation to peak load demand, which primarily drives distribution capacity improvements.

3.4 Project Tasks, Milestones, and Deliverables

There were six major tasks associated with this project:

1. **Recruit participants:** This task first identified specific targeted substations or feeders where capacity expansions are planned to address a forecasted overload or anticipate significant growth of DG, EVs or ZNE buildings. Then strategic customers were identified to target for demand reduction and test new technologies that combine and integrate DSM tools (EE, DR, distributed energy storage, and consumer-oriented SmartMeter™ tools) to achieve a measurable amount of demand reduction.
2. **Install loggers:** This task executed the installation of data on or near the sampled outdoor A/C units outside of the selected residential or commercial premises.
3. **Develop and test the data portal:** This task executed an integrated approach to package DSM resources to create customer- and location-specific solutions to reduce local peak loads.
4. **Develop testing protocols:** This task developed a detailed testing plan that included both notch tests[5] and multiple-hour tests[6] (also referred to as test events).
5. **Conducting tests:** This task involved conducting two types of load control tests over the course of the summer: notch tests and multiple-hour tests.
6. **Analyze system performance during notch and multiple-hour test events:** Evaluate the demand reduction delivered, while attributing to each technology/DSM tool used, the value and contribution to the reduction, and customer satisfaction with the solution.

The project had six major milestones with associated deliverables:

1. **Recruited customer samples:** Customers were recruited into two samples: (1) Substation sample; and (2) Visibility sample. The substation sample was deployed on the distribution feeders served by PG&E's Barton and Bogue substations. The Bogue substation is located near Marysville in the northern part of the Central Valley, and Barton is in Fresno down south in the San Joaquin Valley. This sample was designed to provide relatively high-resolution visibility of the impact of A/C load control operations on the circuits served by these substations. The Bogue and Barton substations were chosen for this test because they have been identified as systems where DR might be used to defer distribution system investments and both substations had reasonably large concentrations of SmartAC™ participants. To ensure the reliability of the second, visibility sample, the design called for installing loggers on two residential and two commercial A/C load control customers for each different type of control device in the load control system across all of PG&E's 16 sub-LAPs[7]. There are about 111 different device type and sub-LAP combinations on the system (See Exhibit B).
2. **Installed loggers for customers in the samples:** PG&E's SmartAC™ field implementation contractor called each customer to schedule the installation of the data loggers. Overall, 586 data loggers were installed outside the residences on or near the sampled outdoor A/C units.

[5] Notch tests are load control operations in which the compressor load on participating air conditioners is completely interrupted for a period of 15 minutes.

[6] Multiple-hour tests were designed to measure the full operation capability of the A/C load control system to suppress loads on the designated substations during times when loads were peaking.

[7] Sub-LAPs describe different geographic regions

They were connected to record a variety of important measurements at controllable pre-set intervals for each A/C unit, ranging from 1 to 10 minutes:

- Thermostat status (i.e., whether the thermostat was calling for A/C service)
- Whether the load control device was interrupting compressor load
- Compressor and fan load AMPS cumulative
- Voltage average
- VARs average
- Maximum cumulative demand (kW)
- Electricity Consumption (kWh)
- Alarm status

Device installation procedures were developed for three types of A/C load control configurations: (1) direct load control switches installed on package units; (2) direct load control switches installed on split systems; and (3) thermostat load control systems installed on package units or split systems. It was identified that blower motor loads are present in package system load measurements and not on split systems. This causes the appearance of phantom loads on the package units, because the A/C load control switches are designed to interrupt compressor motor loads only. The wiring diagrams for these configurations are provided in Exhibit C.

3. **Developed a new, web-based dashboard tool:** The new dashboard displayed the status of the sample's loggers and A/C units and their compressor loads in near real-time. The dashboard was accessible by PG&E, and the other partners involved in the project, including PG&E's SmartAC™ field implementation contractor and the project's evaluation consultant. The dashboard was designed to share data from individual loggers and aggregate this data across the participant population, as well as subpopulations of interest (e.g., customers located on substations involved in testing and separate aggregations for SmartAC™-only and SmartAC™/SmartRate™, etc.).

   The dashboard was used to observe the operational status of all the loggers and connected A/C units in the samples, schedule the data logging intervals and summarize the load impacts of operations for any number of subset groups of loggers. The dashboard helped the program managers identify loggers that were not functioning properly, loggers with communications issues and individual load control units that were not responding to communications.

4. **Developed testing protocols:** Prior to commencement of the operating season, a detailed testing plan for the summer operating season was developed (Exhibit A). Testing protocols for notch tests and multiple-hour tests were developed by the evaluation consultant in consultation with PG&E. The testing protocols were integrated with other SmartAC™ and SmartRate™ testing that as carried out during the summer.

5. **Conducted both notch and multiple-hour tests:** The testing plan called for carrying out notch test on participating A/C load control customers served by the Barton and Bogue substations only. They could be scheduled in either or both locations when local weather conditions and other testing criteria were met. The notch tests were to be carried out once daily on days when the maximum temperature in the vicinity of the substations was forecast as of 2 PM to

reach above 95°F. When called for, the daily single notch would be scheduled to start over varying hours between 5 PM and 9 PM.

Multiple-hour tests were designed to last between three and four hours between 5 PM and 9 PM during the summer. They were scheduled to occur on Tuesdays, Wednesdays or Thursdays, historical periods when the Barton and Bogue substation loads peak; however, the event days were ultimately expanded to all weekdays to allow for more potential event days that met the RTMS event protocols. Unlike the notch tests, the load control event was not designed to shut off the user's A/C compressor entirely. A cycling algorithm developed by Eaton, called TrueCycle2, was programmed into each device and reduced the A/C compressor demand to 50% of what would otherwise have occurred. The algorithm did this by only allowing the A/C unit to be on for 50% of the time that it was predicted to be in operation based on the most recent 42 hours during which the load on the appliance exceeded 38%. During the multiple-hour event, control signals were sent every 30 minutes throughout the control period. The multiple-hour tests were intended to occur on hotter days when the daily maximum was forecast at 2:00 p.m. to reach above 102°F. This temperature threshold was selected based on the historical relationship between daily maximum temperature and substation peak loads. However, as was pointed out earlier, the SmartAC™ program was called on virtually all hot days during the summer and precluded the RTMS tests from being operated on most hot days. Consequently, in order to not interfere with the existing programs, the RTMS tests were run on days when the temperatures in Fresno and Marysville were well below the threshold called for in the test plan (i.e., 102°F).

6. **Analyzed system performance during notch and multiple-hour test events:** Following each test event, logger load measurements were downloaded from the RTMD dashboard's server by the project's evaluation consultant and an analysis was conducted of the system's performance. The results of these analyses were reported to PG&E within 24 hours of each test.

   The notch tests were analyzed by comparing the average kW demand (or current converted into a demand value) in the 15 minutes before the notch test with the average demand during and after the notch period. The expected load during the notch period was estimated based on a straight-line extrapolation of the loads that were present immediately prior to the onset of the test. The notch test impact was estimated as the difference between the loads that were projected to be present (based on the prior 15 minutes) and loads that were observed during the test periods.

   The multiple-hour events were analyzed using a two-part regression analysis protocol. First, hot non-event weekdays were selected as proxy days for each multiple-hour test event using a statistical matching algorithm. Second, a regression model was used to adjust the average load measurements observed on the proxy days for each logger, SmartMeter™ and SCADA measurement to control for the effects of weather conditions on the testing day on energy use. Finally, the observed loads before, during and after the test were compared with the predicted loads from the proxy event days to determine how much the load during the test events differed from the loads that would have occurred given the relationship between load, weather and time of day from previous days at similar temperatures.

The following are the five key deliverables produced from this project:

1. **RTMS dashboard**: A new, near real-time "dashboard" that can be used by SmartAC™ program administrators to confirm that SmartAC™ DLC devices are operating as intended before, during and after events.
2. **Inventory of data loggers**: An inventory of 600 customized data loggers, with 580 installed in the residential customer homes, that collect and transmit near real-time data on a sample of A/C compressor loads, SmartAC™ telecommunications signals and status of A/C DLC switches across the PG&E service territory.
3. **Project Test Plan (Exhibit A)**: Document that details the daily activities required to verify the operational status of the monitoring system and describes specific tests that were designed to assess the performance of the load control and monitoring systems throughout the project.
4. **Sampling Plan (Exhibit B):** Methodology to recruit customers to participate in the project.
5. **This Final Report:** This final report will be posted and made publically available describing the demonstration project's success in addressing each of the identified concerns, problems or gaps, and suggests future research that can leverage the work done in this initial demonstration project in order to enable the greater use of HVAC DLC programs to address distribution-level reliability concerns on a targeted basis.

A comprehensive description of the methodology behind the project's major tasks can be found in Exhibit E.

4.0 Project Results and Key Findings

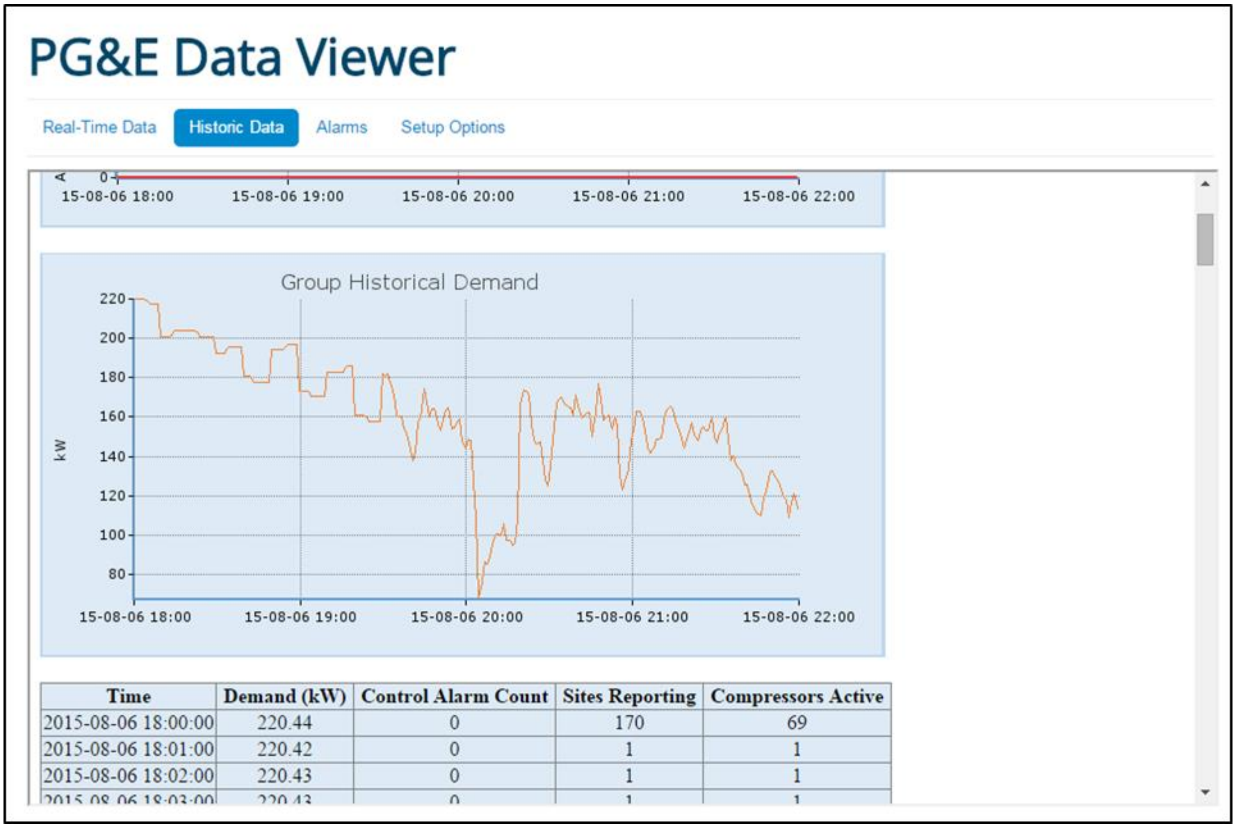
4.1 Detailed Technical Results

The following section includes technical results, findings and recommendations related to the dashboard capabilities, impacts of notch testing that utilized a full-shed load control signal, and impacts of load impact from individual multi-hour test events at the feeder and substation level. While the project did face some unique technical challenges, such as communication issues with the data loggers and technical challenges with the data dashboard, they were not outside the realm of what would be expected for an innovative project such as EPIC 1.24. A comprehensive discussion of the process and technical challenges of this project can be found in Exhibit F.

4.1.1 RTMS Dashboard Capabilities

A key feature of the RTMS project was developing the access and availability of near real-time performance data for participating A/C units. As part of the project, PG&E utilized a web-based dashboard where the data was displayed. The RTMS dashboard has the ability to show graphs of usage over time as well as tables of summary statistics. Groups of loggers were defined by the PG&E program team to provide insights into the usage of any particular segments of interest (e.g., geography or other customer characteristics). In addition to the near real-time data, historical data is also available through the dashboard. A sample screenshot of a notch test from the dashboard is shown in Figure 2.

Figure 2: Screenshot of Notch Test from the RTMS Historical Information Dashboard

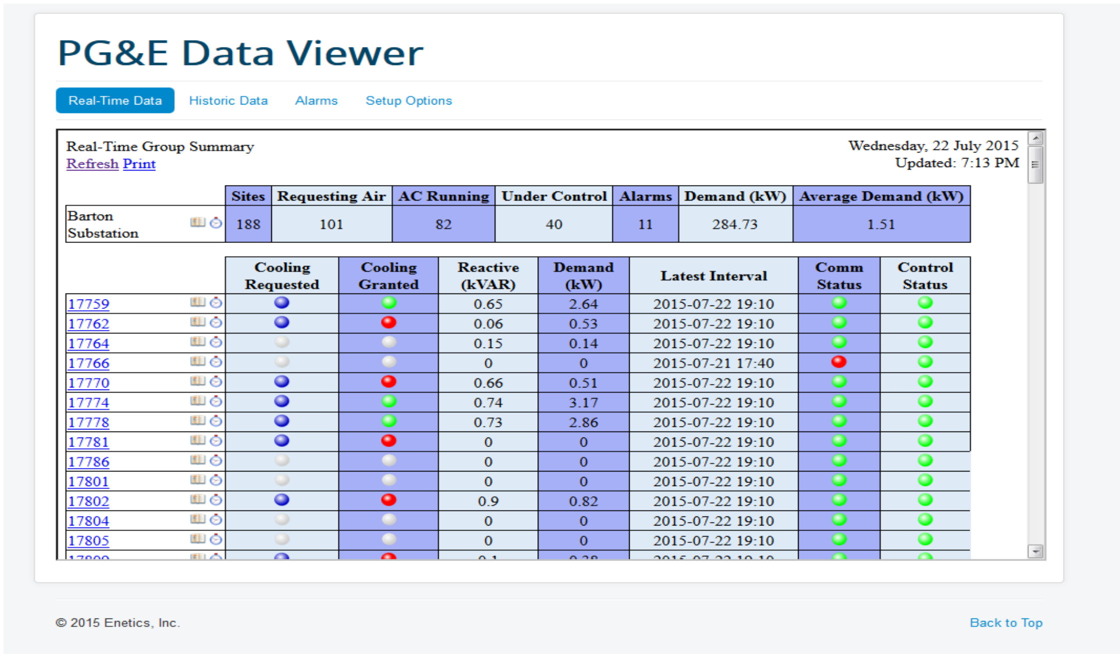


During an event, the RTMS system can be set to report usage with a higher level of resolution to monitor the usage of A/C units experiencing load control during the event. This feature allows for collecting data over shorter time intervals (i.e., one minute) and reporting it more frequently (i.e., five minutes) during critical times (i.e., testing periods). It is important to note that the RTMS dashboard is capable of displaying the performance of load control devices during an event at a high level of resolution, but cannot provide precise load impact estimates in real-time because impact estimates require the estimation of what load would have been for controlled units in the absence of the event. These impact estimates can only be calculated after the event has occurred and are the subject of Sections 4.1.2 and 4.1.3.

Another important feature of the RTMS dashboard is the "Site View." The Site View allows PG&E's program managers to monitor whether the logger is communicating with the dashboard's server as expected (labeled "Comm Status" in Figure 3) and whether the A/C unit had been under control for longer than expected (labeled "Control Status" in Figure 3). To determine the color of the Comm Status circle, the RTMS system keeps a list of the expected next call-in time for each site. If the current time is greater than the expected call in time, but still less than the expected time plus four hours (and following repeated communication attempts), a yellow caution indicator is displayed for that logger. It means the logger is "late" calling in. If the current time is more than four hours after the expected call-in time of the logger, a red indicator is displayed in the Comm Status column. This condition indicates that the logger may require repair or service. Any unit, for which a load control switch has denied cooling for over an hour (beyond the test window), will display a red indicator button under the control status column of the alarm display. This alarm condition is only relevant for sites where a switch is installed. This condition should never occur and requires immediate attention by the

SmartAC™ program manager, and results in a request for the SmartAC™ program's implementation contractor to contact the involved customer and roll a truck to facilitate a repair. Based on these findings, PG&E provided process recommendations for the various scenarios incurred.

Figure 3: Screenshot of the RTMS Dashboard Site View



	Sites	Requesting Air	AC Running	Under Control	Alarms	Demand (kW)	Average Demand (kW)
Barton Substation	188	101	82	40	11	284.73	1.51

	Cooling Requested	Cooling Granted	Reactive (kVAR)	Demand (kW)	Latest Interval	Comm Status	Control Status
17759			0.65	2.64	2015-07-22 19:10		
17762			0.06	0.53	2015-07-22 19:10		
17764			0.15	0.14	2015-07-22 19:10		
17766			0	0	2015-07-21 17:40		
17770			0.66	0.51	2015-07-22 19:10		
17774			0.74	3.17	2015-07-22 19:10		
17778			0.73	2.86	2015-07-22 19:10		
17781			0	0	2015-07-22 19:10		
17786			0	0	2015-07-22 19:10		
17801			0	0	2015-07-22 19:10		
17802			0.9	0.82	2015-07-22 19:10		
17804			0	0	2015-07-22 19:10		
17805			0	0	2015-07-22 19:10		

In addition to the alarm conditions, the Site View screen indicates the operational status of A/C units included in the observation group. In this example, as displayed for April 15, 2015 (a cooler part of the year in California), the system had 586 visible sites, of which 27 were running air conditioning with 8 compressors operational—producing a combined demand of 37 kW. One of the sites was reported under control by the load control system, which was either a sensory error or a problem to be rectified. The Site Viewer also provides the ability to display the above status indicators for every site in any of the selected groups or sub-groups.

The RTMS dashboard provides visibility of 107 different device type/sub-LAP combinations representing about 99% of the entire load control system. As explained above, a small number of device type/Sub-LAP combinations were not included in the monitoring system because of their rarity. Because of the redundancy in the allocation of loggers to the 111 sample cells (i.e. 2 loggers per cell) the visibility of the load control system over the course of the demonstration was quite reliable. This can be seen by inspecting the frequency with which the operational status of the A/C units within any given sample cell was not visible for one or more days.

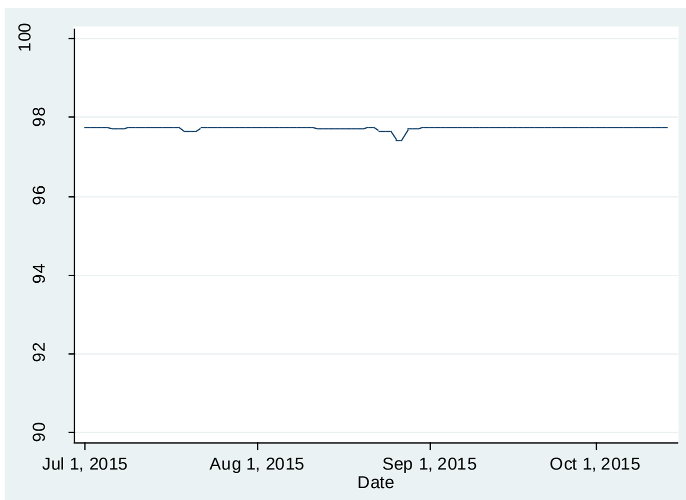
Table 1 shows that nearly all of the sample cells had at least one logger reporting status data every day during the operations window.

Table 1: Distribution of Days without RTMS dashboard Visibility

Days Without Visibility	Number of Sample Cells
0	102
2	1
3	6
5	1
15	1

It is also possible to describe the reliability of the visibility provided by the RTMS by calculating the percentage of the A/C load control system (in devices) that were visible each day throughout the operational period of the project. This was done by weighting the device type/sub-LAP combinations by the number of load control devices in each cell; and summing over the number of devices that were not visible each day. Figure 4 shows that a fairly constant 97.6% of load control devices in the system were visible throughout the project period.

Figure 4: System Visibility Timeline



4.1.2 Notch Tests

A total of 18 notch tests[8] were conducted in the Barton and Bogue footprints between July 2 and September 9. Average load impacts during the notch tests were calculated using both logger and feeder level data and results are shown in Table 2. The average logger load reduction was calculated by summing the average difference between the loads on the monitored A/C units in the 15 minutes immediately preceding and following the notch test window. It means that on average the loads on the A/C units during the notch tests was .57 kW less than the average load on the A/C units prior to the onset of the test. The average load impacts for the feeders were calculated in a similar fashion from SCADA measurements on the feeders that were monitored during the test. The feeder average

8 "Notch tests" are load control operations in which the compressor load on participating air conditioners is completely interrupted for a period of 15 minutes.

load impacts can be interpreted to mean the monitored feeders on the substations experienced an average load reduction during the notch test—in the case of Barton, about 616 kW, and in the case of Bogue, 526 kW. The logger and feeder level load impact measurements are similar. The load impact measured using the loggers installed on the feeders at Bogue is within 7% of the load impacts measured by aggregating the loads observed on the feeder-level power quality metering for the Bogue feeders. The loads observed using the loggers installed on the feeders at Barton are not as close. There, the load reductions measured by the loggers are approximately 30% lower than the load reductions measured at the feeder. There are two potential reasons for this performance difference: (1) the subpopulation of A/C units on which loggers were installed in the Barton substation has lower performance relative to the total population of A/C load control customers installed on the Bogue substation. (2) As further highlighted below, the paging systems that served Barton appeared weaker and contains a high concentration of programmable communicating thermostats that require exceptionally strong communications signals to overcome the fact that they are installed inside buildings.

Table 2: Average Load Impacts during Notch Tests

Substation	Data Source	Average Load Impact (kW)	SE
Barton	Logger	0.57	0.07
	Feeders	616.50	62.62
Bogue	Logger	0.73	0.06
	Feeders	526.20	480.85

Figure 5 shows the average load shape for the 116 devices on the Barton substation used to calculate load impacts during the notch tests using logger data that measures the usage of the A/C units.[9] Figure 6 shows the comparable information for the 149 devices used for calculating load impacts on the Bogue substation. In both figures, the x-axis is measured in fractions of an hour after the start of the event, which is denoted by zero.

The dashed lines in Figure 5 and Figure 6 show the load that would have occurred if the notch signal had not been sent. Impact estimates were calculated relative to these dashed lines, which were themselves calculated by taking the average usage for study devices in the 15 minutes immediately preceding and following the notch test window. Within-subjects estimates of the counterfactual load for the notch tests are appropriate due to the short duration of the notch tests.

The first result of note in Figure 5 and Figure 6 is the magnitude of the load drop after the start of the notch tests. During notch tests, the load control signal sent to each control device is intended to interrupt power to the A/C's compressor. In Figure 5 and Figure 6, however, the observed average load drop as measured by the data logger sample is about 0.8 kW (about 50% load reduction) for Barton control devices and about 0.6 to 0.8 kW (50 to 60% load reduction) for Bogue devices. A very substantial fraction of the load on the appliance remains after the compressor load control signals

[9] A total of 52 logger units were dropped from the Barton analysis for a variety of reasons including: customers dropped out of the AC load control program between the time the loggers were installed and tests were completed; loggers were malfunctioning during one or more of the tests; and loggers were replaced during the testing period. A smaller number of units were dropped from the analysis of load impacts for the Bogue substation for similar reasons. Exhibit D contains a list of the logger IDs that were dropped from the analysis in each substation area.

have been sent. We believe this occurs for three reasons. First, according to the SmartAC™ implementation contractor, the initial logger installation protocols provided to them called for measuring the load on the outside A/C unit, including any fan loads, which were present. Some, potentially substantial load should be present in the load measurements from the loggers when the compressor loads (which the switches are designed to interrupt) have been interrupted. In addition, the paging system serving Barton appears to be weak and contains a high concentration of programmable communicating thermostats (ExpressStats and Utilipros) that require exceptionally strong communications signals to overcome the fact that they are installed inside buildings. A detailed explanation of the communication issues with switches and programmable communicating thermostats (PCTs) can be found in Exhibit F.

Figure 5: Average A/C Load Shape for Loggers on Barton Substation during Notch Tests

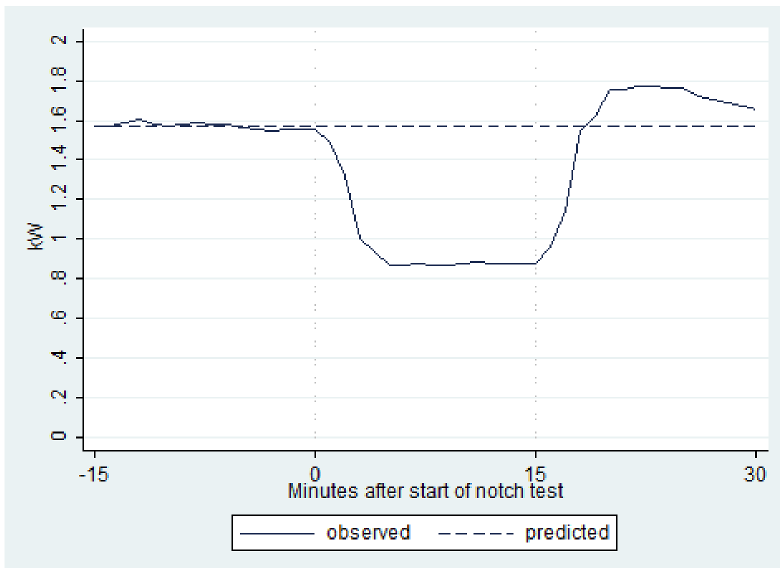
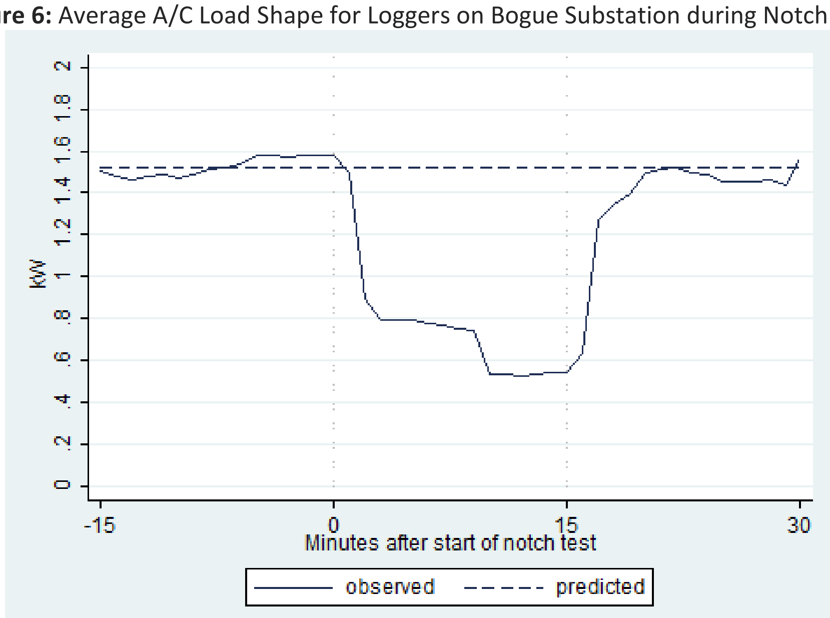


Figure 6: Average A/C Load Shape for Loggers on Bogue Substation during Notch Tests



In the case of the notch tests made at the Barton substation, beyond the magnitude of the impact, the shape of the load curve for devices during the notch test is intuitive. The load control devices respond as expected (i.e., the appliance loads decline significantly within one to two minutes after the signal is scheduled to be sent and stabilize approximately three to four minutes after its start). Thereafter, the A/C loads remain constant until the end of the notch test and at that point, load increases rapidly as the units return to their normal cycling rate. In Barton, there is a brief period of snapback after the test when usage levels are above the pre-test level by about 12%. Snapback is a common feature of direct load control programs involving A/C units. The magnitude and duration of snap-back are a function of the following: time of day in which the load control operation occurs; severity of the control strategy; and duration of the control event. The magnitude of snap back is usually controlled by “ramping out” the control randomly so that all of the customers under control do not come back on all at once. The notch test control strategy releases all the customers at once; as a result, it can produce a pronounced but short snapback.

The load shape of the notch tests for Bogue is different than the average load shape observed in Barton. Instead of the more or less instantaneous reduction in load observed in Barton, the load reduction in Bogue occurs in two steps. The first step occurs within about 1 minute of the start of the notch load control operation. This is followed by a second downward step at about 12 minutes. There is also no clear sign of snap back in the Bogue tests. There are a number of differences in the testing circumstances that might explain these differences. The Bogue tests occurred under cooler conditions and there is a different mix of control technologies installed in the Bogue population (there were no UtiliPro thermostats operating in the Bogue testing area). Given the available data, it is not possible to further isolate the causes of the observed differences in load shapes.

Table 3 reports the notch test results for each of the tests carried out in the Barton and Bogue substations. It appears that the first two notch tests failed to bring loads under control as both of these tests showed zero or negative load impacts in both substations. Discounting these tests, the average load reductions obtained in both substations were similar—.57 kW in Barton and .73 kW in Bogue. However, the results of the tests varied significantly from day to day in both stations.

In Barton, load impacts ranged from a low of .14 kW (at 81 degrees ^{o}F) to a high of .92 kW (at 99 degrees ^{o}F). The impacts of the load control program at this station were highly influenced by temperature, but as discussed in Section 4.1.3, they are not perfectly correlated and the temperatures under which the Bogue tests were carried out were too mild to detect a temperature trend in any case. While the protocol for scheduling the multiple-hour tests called for scheduling an event when the forecasted maximum temperature in either substation was in excess of 102°F, as mentioned, the other load control tests took precedent in order to not impact customer satisfaction for calling too many events in one day, while also avoiding impact to existing programs’ measurement and evaluation requirements.

Table 3: Load impact estimates for RTMS notch tests in Barton and Bogue Substations

Date	Barton							Bogue						
	Start Time	Load w/o DR (kW)	Load w/ DR (kW)	Impact (kW)	Impact (%)	SE	Event Temperature (F)	Start Time	Load w/o DR (kW)	Load w/ DR (kW)	Impact (kW)	Impact (%)	SE	Event Temperature (F)
7/2	17:00	1.77	1.72	0.05	2.9%	0.11	93.5	17:00	1.78	2.29	-0.50	-28.1%	0.13	98.0
7/16	14:00	1.49	1.50	0.00	-0.3%	0.09	98.5	14:00	1.43	1.44	-0.01	-0.5%	0.07	93.5
7/20	-	-	-	-	-	-	-	18:00	2.24	0.99	1.25	56.0%	0.14	96.5
7/21	18:00	2.16	1.24	0.92	42.6%	0.14	99.0	19:00	1.92	1.50	0.41	21.6%	0.08	88.5
7/22	19:00	1.91	1.23	0.68	35.5%	0.13	91.0	-	-	-	-	-	-	-
7/23	20:00	1.18	0.53	0.65	55.1%	0.10	87.5	-	-	-	-	-	-	-
7/27	17:00	1.62	1.12	0.50	31.1%	0.12	96.0	20:00	1.47	0.72	0.74	50.7%	0.11	82.5
8/3	18:00	1.87	1.06	0.82	43.5%	0.12	93.5	-	-	-	-	-	-	-
8/4	19:00	0.67	0.52	0.14	21.7%	0.07	81.0	-	-	-	-	-	-	-
8/6	20:00	0.85	0.55	0.30	35.0%	0.09	87.0	20:00	0.85	0.32	0.53	62.0%	0.08	81.5
8/12	17:00	1.43	1.16	0.27	19.1%	0.12	95.5	17:00	1.08	0.52	0.55	51.5%	0.10	90.5
8/13	18:00	1.94	1.18	0.76	39.2%	0.13	97.0	-	-	-	-	-	-	-
8/14	19:00	1.36	0.90	0.46	33.5%	0.13	91.5	-	-	-	-	-	-	-
8/20	20:00	1.37	0.86	0.51	37.3%	0.11	87.5	-	-	-	-	-	-	-
8/24	17:00	1.95	1.21	0.74	37.8%	0.13	98.0	-	-	-	-	-	-	-
8/25	17:00	2.11	1.28	0.83	39.5%	0.15	100.5	-	-	-	-	-	-	-
9/1	18:00	1.45	0.95	0.50	34.8%	0.13	92.0	-	-	-	-	-	-	-
9/9	20:00	1.69	1.14	0.54	32.2%	0.11	88.5	20:00	1.58	0.67	0.90	57.4%	0.11	76.5

In theory, the most precise measurements of the performance of the load control system are obtainable by analyzing end use measurements recorded using data loggers. However, the logger recruiting and installation process could have resulted in sampling error (leading to bias). In response, another objective of the project was to determine whether the impacts measured by the loggers during notch tests are comparable to those that can be obtained by measuring changes in feeder-level SCADA data, which are not subject to sampling error. Figure 7 and Figure 8 show the load impacts measured at the feeder level for Barton and Bogue, respectively, for the average notch test in each area based on the feeders selected for monitoring. As with the logger data, estimates of the counterfactual are generated using data immediately prior and after the notch test and serve as the basis of comparison for determining impacts. These figures capture the aggregate feeder level impacts associated with notch tests, which equal the average impacts (Figure 5 and Figure 6) multiplied by the total number of SmartAC™ and SmartRate™ customers, as well as dually enrolled SmartAC™ and SmartRate™ customers, in each area.

Figure 7: Average Demand on Barton Monitored Feeders during Notch Tests

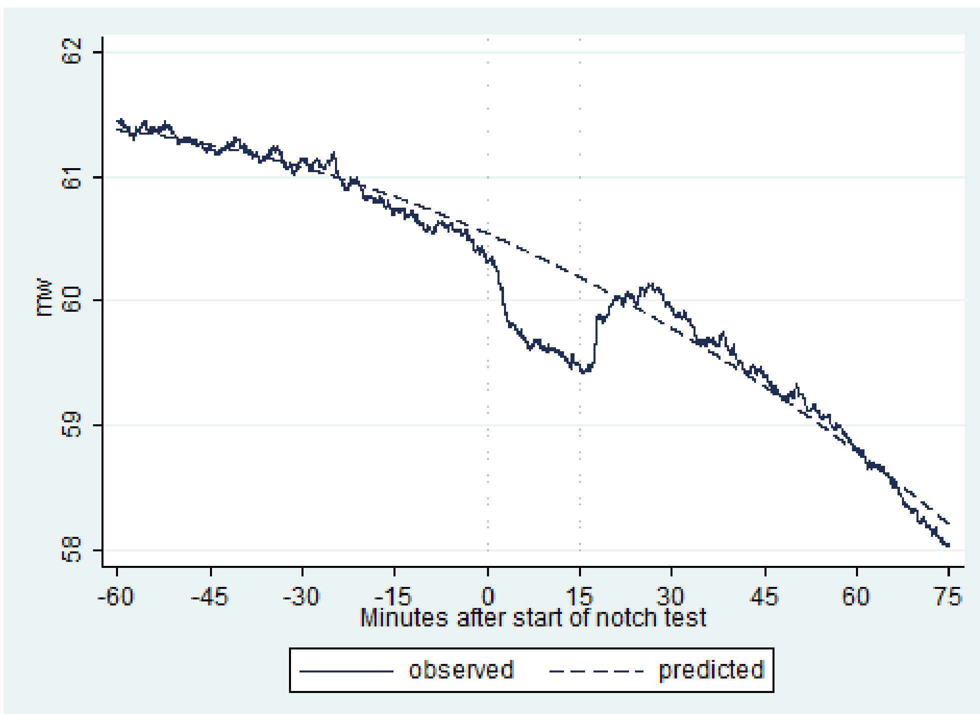
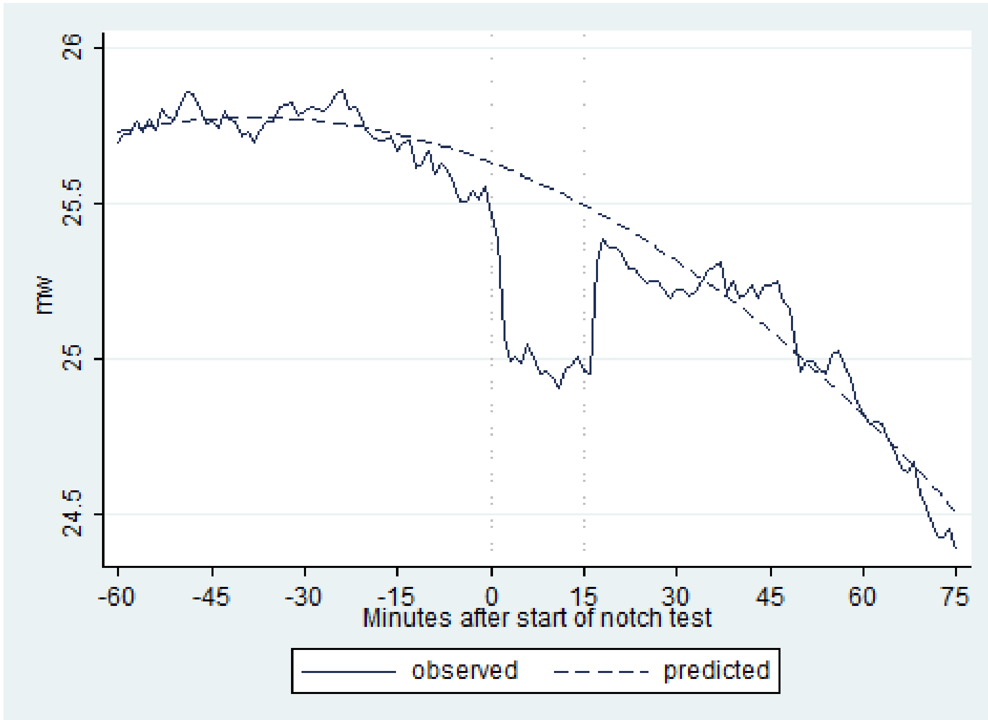


Figure 8: Average Demand on Bogue Monitored Feeders during Notch Tests



For an average notch test, the aggregate impacts were approximately 617 kW for Barton and 526 kW for Bogue. The load drop during the notch tests is clearly visible in the feeder level data. The load drop is not instantaneous, but is phased in and out over a one to two minute period at both the beginning and end of the notch tests. This occurs due to the variation in the times at which individual devices received the load control signal to initiate the notch.

4.1.3 Multiple-hour Tests

In addition to the short notch tests discussed above, several multiple-hour test events were carried out to observe the load impacts that occur under conditions similar to a load control operation designed to reduce loads on distribution circuits. Whereas notch tests utilized a full-shed load control signal, loads during multiple-hour test events were controlled using a combination of 50% Cycling (ExpressStat thermostats) and 50% TrueCycle2 adaptive cycling (UtiliPro thermostats and load control switches). All A/C load control devices on the Barton and Bogue substations were controlled during the event tests.[10] Five test events were carried out during August and September 2015. Three of these events (8/26, 9/8 and 9/21) involved participating devices in both Barton and Bogue, while the other two events (8/19 and 8/25) involved only the devices on the Barton substation. The start time, end time and temperature conditions for each event are shown in Table 4.

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[10] At the start of the project, there were approximately 914 SmartAC™ devices installed in Barton and 818 in Bogue. The maximum number of minutes a device can be controlled in a 60 minute interval is 44 minutes.

Table 4: Multiple-Hour Test Event Details

Date	Start Time	End Time	Barton		Bogue	
			Avg. Event Temperature (F)	Max Temperature (F)	Avg. Event Temperature (F)	Max Temperature (F)
19-Aug	17:00	21:00	97	100	-	-
25-Aug	18:00	21:00	96	103	-	-
26-Aug	17:00	21:00	97	102	84	97
8-Sep	18:00	21:00	92	99	76	98
21-Sep	17:00	21:00	95	102	81	97

The planned start times and temperature conditions called for in the tests were determined by analyzing the historical load shapes on the Barton and Bogue substations to identify the conditions under which multiple-hour test events might be called in the future. Similar to the notch tests, estimating load impacts during multiple-hour test events required an estimate of load that would have occurred on event days had the loads not been controlled. To produce these so-called *reference loads*, a regression model was developed to predict A/C usage based on observable conditions during the operating periods, including temperature and hour of day. The parameters in the regression prediction model were estimated using loads and conditions occurring on hot days during which loads were not controlled, called proxy days[11], for each event and the resulting parameter estimates were then used to predict the loads that would have occurred on the event days if the loads had not been controlled. Several regression models were tested in an iterative fashion to find a specification that provided the most reliable prediction of hourly loads for the nonevent data. The final model specification used for the analysis is shown in Equation 1. Once these reference loads were estimated, load impacts were calculated as the difference between the observed A/C usage during the tests and the predicted A/C reference loads.

Load impact estimates for the individual test events called for each substation are presented in Table 5. The table shows the average estimated impact per device in each event hour as well as for the average hour during the event. Impacts across event days vary substantially, with average hourly impacts ranging from approximately .2 to .4 kW per device for Barton load control devices and .3 to .4 kW per device for load control devices installed at Bogue. The load impacts on all tests are significantly different from zero—although in some cases the load impacts are quite small (i.e., in the range of 10%).

The statistical reliability of the estimates presented in Table 5 depends on the reliability of the regression models used to predict the hourly customer loads from weather conditions. A weakness of the data available from the tests is that there are relatively few hot days with which to estimate the reference load regression models. This is because SmartAC™ and SmartRate™ operations were

[11] SmartAC™ and SmartRate™ event days were excluded from the dataset used to model reference loads. This was done because the RTMS event operations criteria excluded running tests on SmartAC™ M&E test event and SmartRate™ days, so participants were not overburdened with extensive cycling across back to back events, which may have extended well into the evenings.

conducted mostly on days that could otherwise have been used to estimate the reference load models. This causes the fit of the models to be relatively good on average but not very reliable for specific hot days. The load shapes on hot days during which load control occurred (and were not available for the event tests or the reference load measurements) had slightly different load shapes than days that were available for model estimation. A detailed discussion of the weather conditions during test events can be found in Exhibit F. In essence, loads on unavailable (and hotter days) were somewhat higher during the early evening hours than the proxy days for which reference loads were estimated. This may have caused a downward bias in the predicted loads in the later evening hours—leading to underestimated load impacts during these hours. This problem cannot be corrected with the currently available data.

Equation 1: Generic Model Used for Multiple-Hour Impact Analysis[12]

$$kW_{it} = a * event_t + b * ma5_t + c * kw17_{it} + \sum_{p=2}^{n} d_p * participant_{pi} + e_{it}$$

[12] kW is the average hourly demand read for that given unit in that given hour; event is a dummy variable equal to one when that unit is experiencing an event and zero otherwise; ma5 is a moving average of the 4 previous hours' and the current hour's temperature; kw17 is the demand for that customer in hour 17 before any event, $participant_p$ is a dummy equal to one if participant p and zero otherwise; e is the error term; a, b, c, and d_p are all estimated parameters, i indexes customers, and t indexes day. The model is run separately for each hour except for the average event impact model which fully interacts ma5 and kw17 with hour.

Table 5: Hourly load impact estimates for RTMS events in Barton and Bogue Substations

Date	Hour Ending	Barton							Bogue						
		Load w/o DR (kW)	Load w/ DR (kW)	Impact (kW)	Impact (%)	SE	95% CI		Load w/o DR (kW)	Load w/ DR (kW)	Impact (kW)	Impact (%)	SE	95% CI	
							Lower	Upper						Lower	Upper
19-Aug	18	1.94	1.53	0.41	21.20%	0.1	0.22	0.6	-	-	-	-	-	-	-
	19	1.9	1.38	0.52	27.30%	0.1	0.32	0.72	-	-	-	-	-	-	-
	20	1.51	1.36	0.16	10.40%	0.09	-0.02	0.34	-	-	-	-	-	-	-
	21	1.34	1.2	0.14	10.20%	0.09	-0.03	0.31	-	-	-	-	-	-	-
	Avg. Event	1.73	1.37	0.36	20.70%	0.07	0.22	0.5	-	-	-	-	-	-	-
25-Aug	19	1.82	1.59	0.24	13.00%	0.13	-0.02	0.5	-	-	-	-	-	-	-
	20	1.5	1.32	0.18	12.10%	0.12	-0.05	0.42	-	-	-	-	-	-	-
	21	1.35	1.22	0.14	10.20%	0.11	-0.09	0.36	-	-	-	-	-	-	-
	Avg. Event	1.58	1.37	0.2	12.80%	0.09	0.01	0.39	-	-	-	-	-	-	-
26-Aug	18	2.11	1.64	0.47	22.10%	0.15	0.18	0.75	1.4	1.04	0.36	25.50%	0.07	0.21	0.5
	19	2	1.54	0.46	23.00%	0.14	0.18	0.74	1.48	1.08	0.4	27.30%	0.08	0.25	0.56
	20	1.65	1.36	0.29	17.80%	0.13	0.03	0.56	1.3	1.05	0.26	19.90%	0.07	0.11	0.41
	21	1.49	1.19	0.3	20.10%	0.12	0.05	0.55	1.06	0.92	0.15	13.90%	0.06	0.04	0.26
	Avg. Event	1.83	1.43	0.39	21.50%	0.1	0.19	0.59	1.4	1.02	0.38	27.00%	0.06	0.26	0.49
8-Sep	19	1.42	1.09	0.33	23.50%	0.1	0.14	0.53	1.26	0.88	0.39	30.60%	0.11	0.18	0.6
	20	1.14	0.92	0.22	19.60%	0.09	0.05	0.4	1.13	0.73	0.4	35.60%	0.1	0.21	0.59
	21	0.98	0.89	0.09	9.10%	0.11	-0.13	0.31	0.89	0.66	0.24	26.40%	0.07	0.09	0.38
	Avg. Event	1.21	0.97	0.25	20.50%	0.07	0.11	0.39	1.11	0.75	0.36	32.40%	0.08	0.21	0.51
21-Sep	18	1.88	1.48	0.4	21.50%	0.12	0.18	0.63	1.16	0.96	0.2	16.80%	0.08	0.04	0.35
	19	1.76	1.35	0.41	23.30%	0.12	0.17	0.65	1.22	0.83	0.39	31.90%	0.07	0.25	0.53
	20	1.42	1.19	0.24	16.70%	0.1	0.04	0.43	1.03	0.74	0.29	28.00%	0.06	0.17	0.41
	21	1.25	1.1	0.15	11.80%	0.09	-0.03	0.32	0.75	0.67	0.08	11.20%	0.05	-0.01	0.18
	Avg. Event	1.59	1.28	0.31	19.70%	0.08	0.16	0.47	1.09	0.8	0.29	26.30%	0.05	0.19	0.39

Average A/C Load Shape Charts for Barton

Figure 9: August 19 Test Event

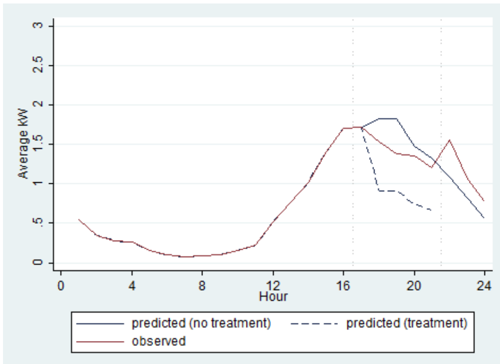


Figure 10: August 25 Test Event

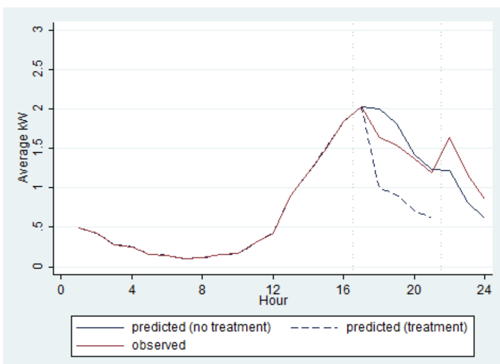


Figure 11: August 26 Test Event

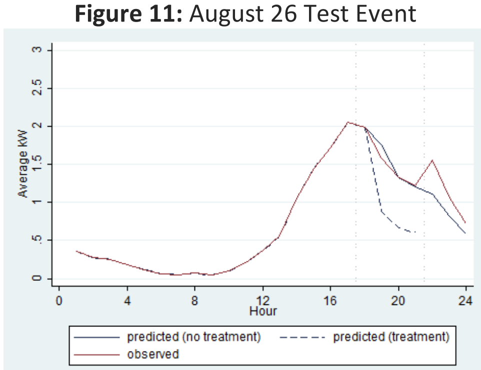


Figure 12: September 8 Test Event

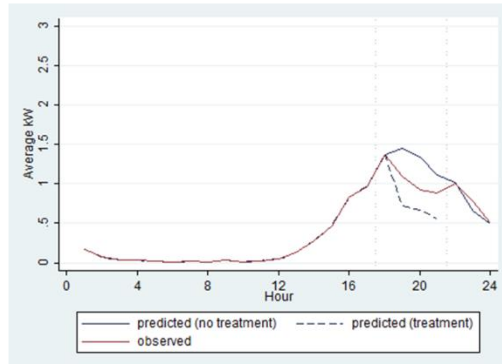
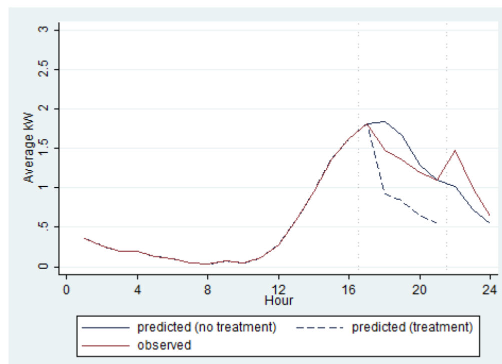


Figure 13: September 21 Test Event



Average A/C Load Shape Charts for Bogue

Figure 14: August 26 Test Event

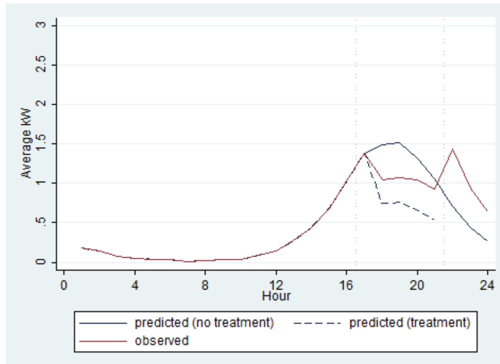


Figure 15: September 8 Test Event

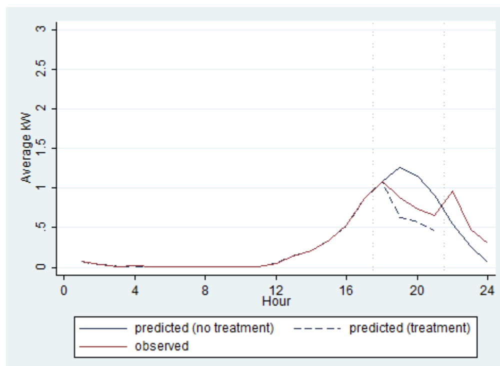
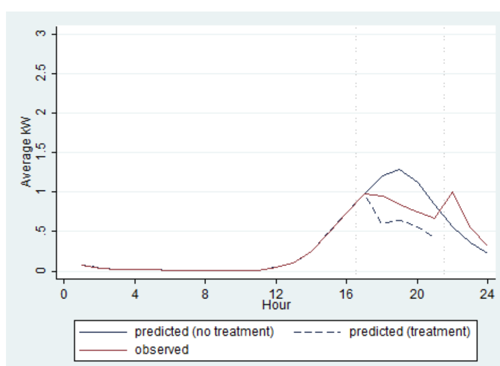
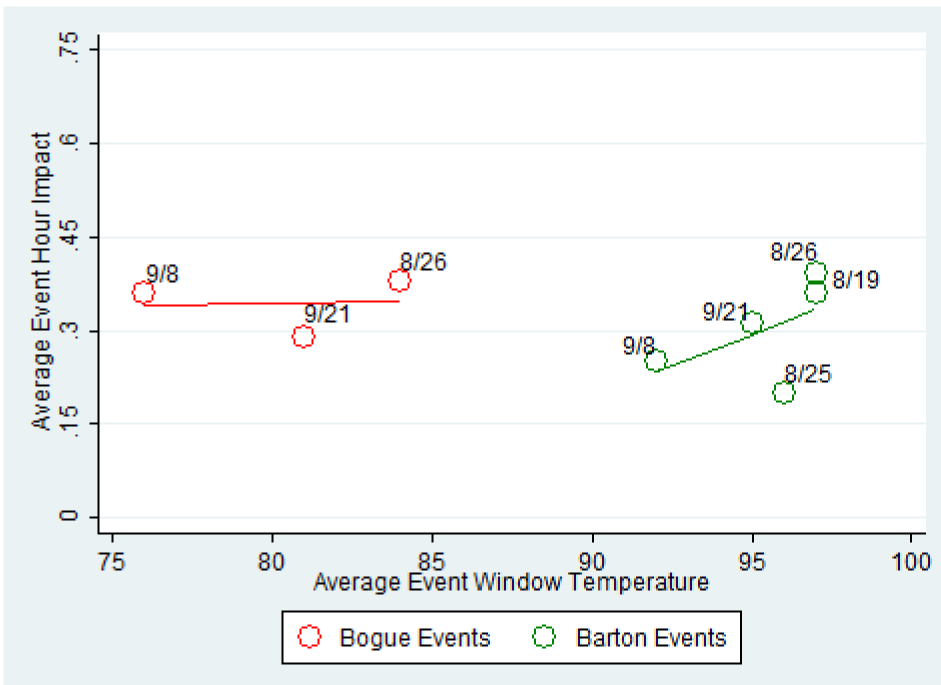


Figure 16: September 21 Test Event



An interesting pattern in the load impacts can be seen by plotting average impacts against average temperature during the hours of the event for each substation as shown in Figure 17. For direct load control programs, impacts typically increase with temperature because the air conditioning units must work harder to maintain the desired temperature indoors. This trend is apparent for the Barton events in green ion the right side of Figure 17, where event temperatures are above 90 degrees. In Bogue, event temperatures were much lower and do not exhibit the same pattern. The final point to note in Figure 17 is that despite the lower temperatures, average impacts in Bogue are approximately the same magnitude as the impacts in Barton. This suggests the A/C load control system is producing smaller impacts than it should under the circumstances. A more detailed discussion of this issue can be found in Exhibit F.

Figure 17: Average Test Event Impacts and Temperatures



Another important objective of the RTMS project was to validate the use of feeder and substation level load measurements (e.g., SCADA) in estimating the impacts of load control on circuits. This aspect of the project was motivated by the objective to develop the ability to detect load impacts using SCADA and explore integrating a utility's distribution control systems with automated load control in order to control loads on substations and feeders. Given the expected aggregate impacts implied by the logger data analysis (approx. 500 to 600 kW), detecting the impacts on substations that have loads on the order of 15 to 30 MW equates to detecting impacts in the range of 1.5 to 3%. This is a relatively small fraction of feeder loads.

An ideal strategy for estimating the load impacts using SCADA would be to use an A/B experimental design, in which the underlying load control population in the substations is randomly assigned into groups A and B and then operated on randomly selected alternating days when temperature and other conditions are met. In this design, the A group serves as a control group for the B group when the B group loads are controlled and vice versa. Unfortunately, there was not a sufficient quantity of SmartAC™ program participants with data loggers available to employ this design. Moreover, the tests of the RTMS platform (notch test and multiple-hour tests) were carried out in the context of other testing required to demonstrate the efficacy of PG&E's SmartAC™ and SmartRate™ programs. The combined operational requirements of these other programs made it virtually impossible to schedule an A/B treatment design even if sufficient observations were possible.

Given the above described constraints, the best hope for detecting impacts at the substation level is to take an approach similar to the logger analysis. For this approach, reference loads are estimated for the substation using a regression model based on proxy, nonevent days and then compared to the actual loads observed on event days. The challenge in applying this approach to SCADA data is that, unlike the end-use level data analysis (where data from more than 150 loggers are used to estimate the regression model for each day), much less data is available for the substation analysis where only proxy days associated with that one substation are used in the model estimation process. The estimated substation level equation is the same as Equation 1 without index i or the customer fixed effects. Robust standard errors were used to correct for serial correlation that may be present.

Examples of the results using aggregated feeder level data at Barton are shown in Figure 19 through Figure 21. Surrounding the predicted loads in each graph (dashed lines) are the 95% confidence intervals. Statistically significant differences between the load shapes on proxy and event days were found on only one occasion: August 19. That is, using SCADA measurements, a statistically significant effect of load control was observed on only one of five test occasions. This is in sharp contrast to the findings from the notch testing where the evidence of the impacts of A/C load control were quite apparent even to the naked eye.

Substation Level Load Shapes

Figure 18: August 19 Test Event in Barton

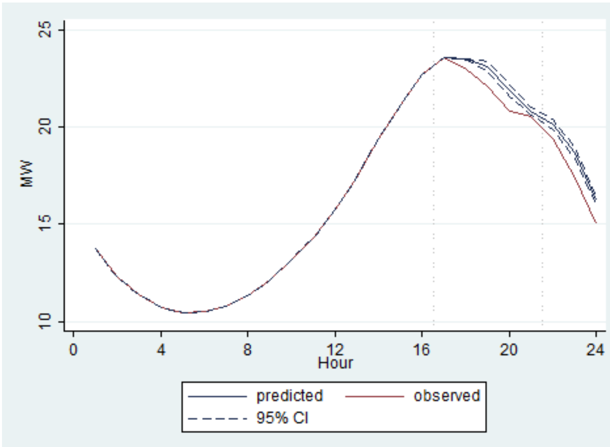


Figure 19: September 8 Test Event in Barton

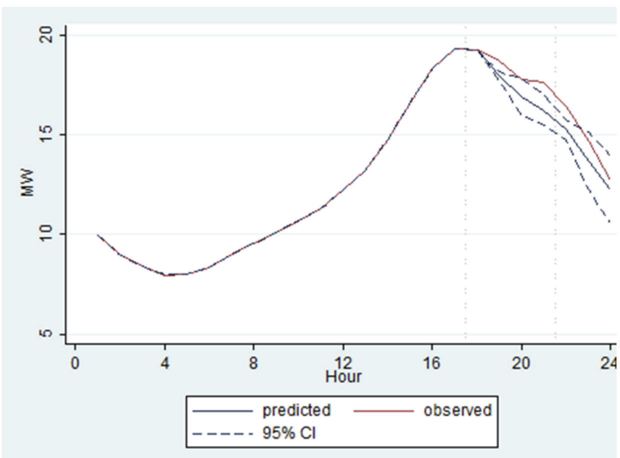


Figure 20: August 26 Test Event in Bogue

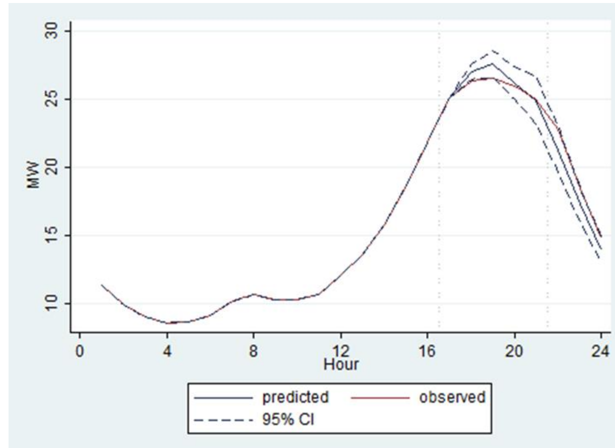
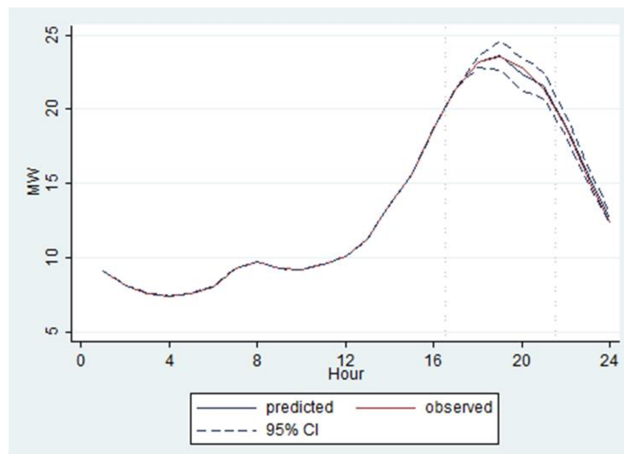


Figure 21: September 21 Test Event in Bogue



This raises the question of whether the August 19 observation is a false positive or whether the results of the other test occasions are false negatives. Table 6 presents reasonably strong evidence that proxy event days used to estimate the reference loads for this analysis were significantly cooler than the actual multiple-hour test event days for Barton. On some days the average temperatures in the five hours preceding the test event was nearly 10 degrees higher on the event day than on the proxy days. It is notable that the only day for which the temperatures in the five hours preceding the test event were nearly the same is August 19. The average temperatures for the proxy days for the other test events were significantly cooler. The fact that the proxy event days were on average cooler than the event days may have caused a significant downward bias in the predicted hourly loads (in the absence of load control) and thereby produced a significant downward bias in the estimated load impacts of load control for the days and hours in question. This problem cannot be corrected analytically because there are no other hotter proxy events days available to estimate the reference loads for this calculation. This is because all hotter days were used for SmartAC™ or SmartRate™ tests and these events can be expected to have perturbed the A/C loads prior to the test—leading to higher evening A/C loads.

Table 6: Summary Statistics for Explanatory Variables for Event Days and their Corresponding Proxy Days

Substation	Event date	Event Day		Proxy Days					
		ma5 (°F)	mw17 (MW)	ma5 (°F)			mw17 (MW)		
		Observed	Observed	Mean	Min	Max	Mean	Min	Max
Barton	19-Aug	95.8	23.57	94.23	89.7	97.9	22.69	20.64	26.33
Barton	25-Aug	101.3	23.93	93.18	87.5	98.2	18.65	15.26	21.05
Barton	26-Aug	101.1	24.14	92.22	87.1	98.2	19.48	17.13	21.05
Barton	8-Sep	98.1	19.31	95.05	87	103.2	13.75	0	20.18
Barton	21-Sep	100.6	22.86	92.43	87.1	98.2	18.78	15.26	21.05
Bogue	26-Aug	94.9	25.025	88.24	84	94.6	19.475	15.225	23.7
Bogue	8-Sep	95.4	21.575	93.23	88.3	100.4	13.975	0	20.725
Bogue	21-Sep	95.1	21.4	89.79	84.1	94.6	19.375	16.3	23.7

4.2 Key Findings and Recommendations

Key Finding #1: The near real-time information provided the ability to monitor and take corrective actions; however, the current scale of customer participation in PG&E's SmartAC™ program on a given feeder is insufficient to provide significant capacity support to grid operators at this time.

Recommendation: Once adequate customer participation is achieved in both the SmartRate™ and SmartAC™ programs, it is recommended that the type of information provided in the RTMS platform be integrated into the utility's Demand Response Management Systems (DRMS) to make the information in the system generally available to DR operations and available for transmission to CAISO as necessary to support participation in the emerging DR market.

Recommendation: PG&E can utilize the simulator model to identify the magnitude of impacts that could be achieved by load control under varying assumptions about the performance of the load control system and market penetration of SmartAC™ within the substations. A detailed description of the simulator model can be found in Exhibit G.

Key Finding #2: While the average notch test load impact per A/C load control device was .57 kW at Barton and .73 kW at Bogue, the load impacts varied significantly from test to test, depending on ambient temperature and timing of the notch, which varied across the weekday 5 PM to 9 PM window. Similarly, the average notch test load impact measured at the substation level (from aggregate feeder loads) was 617 kW at Barton and 526 kW at Bogue—the impact varied in a manner similar to the way in which each device's measurements varied.

Key Finding #3: Multiple-hour tests were conducted on five occasions at the Barton Substation at temperatures ranging from 92 to 97°F; and on three occasions at Bogue at temperatures ranging from 76 to 84°F. The average multiple-hour test load impacts per device — 0.33 kW and 0.29 kW respectively for devices located in Barton and Bogue. The load impacts for these tests were lower than the notch tests because multiple-hour tests employed 50% cycling rather than the full shed strategy used for notch tests.

Key Finding #4: The notch tests and multiple-hour tests conducted during this project were carried out under relatively cool weather conditions, due to the priority of not calling on existing event days for SmartAC™ of SmartRate™ M&E days to manage customer satisfaction. This reality most likely underestimated the full capability of A/C load control. Nevertheless, these tests demonstrated that the impacts of A/C load control are readily observable using the RTMS loggers deployed on substation feeders, as well as on Supervisory Control and Data Acquisition (SCADA) measurements taken at the feeder level. This was an unexpected finding that provides additional support for using load control and demand response to support distribution operations.

Recommendation: Given that load impacts of A/C load control operations are readily observable using SCADA when the market penetration of A/C load control is high, SCADA could be used to monitor the load impacts of A/C load control on circuits with high A/C penetration on a targeted basis, when it becomes necessary to do so.

Recommendation: The 382 communicating loggers sited on the Barton and Bogue substations and the 60 loggers currently installed on commercial customers (those planned for non-operation in the future) should be reallocated to a more useful purpose. There are two useful alternatives:

1. In the short term, redeploy the available loggers to obtain visibility of the operational status of the A/C load control system at the substation level. This deployment would provide visibility of the availability and performance of the system down to the substations on the system containing the vast majority of customers. It would allow for better management of the operational readiness of the system by making information available about the reliability of the communications infrastructure serving the geographical locations where the load control devices are located.
2. In the longer term, redeploy the available loggers to a sample of customers designed to more precisely measure the load available for control and load under control on the total A/C load control system, which did not take place in this project in order to control recruiting costs. The purpose of this more precise sample would be to strengthen the RTMS to provide a near real-time measurement of the load available for curtailment and the load reduction obtained during A/C load control operations. Such a system should be capable of collecting one minute interval load data on A/C loads for a statistically representative sample of SmartAC™ and SmartRate™ customers throughout the operating season. When called upon, the RTMS would

be able to display the expected A/C loads prior to, during and after load control operations on the system to within a known level of statistical precision.

Another advantage of deploying loggers to a representative sample of SmartAC™ installations is that the RTMS can produce very detailed measurements of the load available and under control at different times of day under varying weather conditions. This information, when combined with information about local weather conditions, can be used in a wide range of applications, which include detecting and resolving operational issues and providing information useful for predicting program performance under varying conditions.

4.3 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

4.4 Value Proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity ratepayers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). The California Public Utilities Commission (CPUC) requires that each EPIC project advance at least one mandatory guiding principle and at least one complementary guiding principle. The implementation of the EPIC 1.24 SmartAC™ RTMS Project has shown that increased visibility, near real-time feedback on performance of direct load control programs and the wealth of data that is collected has a great value in the daily operation of the electric system.

4.4.1 Primary & Secondary Principles

The primary principles of EPIC are to invest in clean energy technologies and approaches that provide benefits to electricity ratepayers by promoting greater reliability, lower costs, and increased safety. The EPIC 1.24 RTMS Project advances two of these three primary principles: lower costs and greater reliability.

The near real-time visibility and data collected by the RTMS data loggers can be used to reduce program operation costs and potentially reduce T&D infrastructure costs. Near real-time visibility into program performance advances a strategic objective to utilize DR resources not only to displace generation capacity, but also to support transmission and distribution grid reliability and improve performance of load control programs. This could be particularly important in the context of the increasing need to support renewables integration onto the distribution grid. Given the large amount of residential and commercial A/C direct load control programs using legacy one-way paging communication systems across the country, widespread deployment of RTMS may be of great interest to a number of utilities.

4.4.1.1 Real-time SmartAC™ Operations Visibility

The RTMS provides the ability to measure A/C loads before during and after load control operations in near real-time. This capability allows the load control system operator to identify and correct operational problems (e.g., scheduling errors and communications failures) on a daily basis. This reduces the cost to operate the system. Pairing the RTMS dashboard tool with well-designed tests that can also isolate causes of A/C load control under-performance will allow program managers to focus on the most urgent concerns and discover them earlier in the operating season. For example, it was possible to identify the fact that the devices in the vicinity of the Barton substation were producing significantly less load relief than expected from the TruCycling algorithm. Beyond identifying the problem it was possible to narrow the potential causes of underperformance down to several contributing factors (i.e., performance of the thermostat based load control device and intermittent performance problems with the paging system in the area). These problems can be corrected quickly when the operator knows about them.

The RTMS project demonstrated the ability to detect the magnitude of A/C load available for control aggregating over feeders with substantial numbers of SmartAC™ participants. This was true for both of the substations involved in the project using notch testing techniques. The measurement of the load impacts of extended operations were inconclusive because the temperatures at which tests were conducted were too low. Further work designed to use SCADA measurements to manage the performance of the load control system should be undertaken. However, this program demonstrated the ability to use A/C load control to reduce load demand on a substation and feeder and further demonstrated the potential to use this type of program to avoid or delay T&D investment.

4.4.1.2 Improved Grid Management Flexibility and Reliability

PG&E is committed in designing the electric transmission and distribution systems to facilitate the integration of renewable resources into the grid. These resources are intermittent and relatively unreliable (compared with conventional generation) and have load shapes that can undermine the stability and reliability of the electric grid at all levels. Direct load control may be an important component of the grid in the future when it may be necessary to rapidly reduce system loads in response to unexpected (or predicted) shortfalls in renewable generation. In addition, utilities may be able to use direct load control to defer distribution investments if distribution grid operators are able to make use of the near real-time data streams from both SCADA systems and program participants with loggers to call and observe changes in demand at the substation and feeder levels. As reported in in the main body of the EPIC 1.24 report (Section 4.1), the current scale and performance of PG&E's SmartAC™ system and the penetration of the RTMS monitoring system are insufficient to provide adequate support to grid operators at this time. However, in anticipation of the growing need for load control resources at the distribution system level, a simulation model was developed to identify the magnitude of impacts that could be achieved by load control under varying assumptions about the performance of the load control system and market penetration of SmartAC™ within the Barton and Bogue substations.

The simulator calculates the impacts on substation loads using existing substation load shapes and assumptions about the load impacts achievable from SmartAC™ and the necessary market penetration of SmartAC™ within the substations. The model is attached as an electronic appendix to the report that can be applied generally to substations on the PG&E system, and a detailed description of the simulator can be found in Exhibit G.

4.5 Technology Transfer Plan

4.5.1 PG&E Technology Transfer Plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E and across the other IOUs and the CEC. To facilitate this knowledge sharing, PG&E will share the results of the EPIC 1.24 SmartAC™ RTMS Project in industry workshops and through public reports published on the PG&E website[13]. This report and subsequent presentations at professional meetings, such as the Demand Response and Smart Grid National Town Meeting, Peak Load

[13] www.pge.com/epic

Management Alliance (PLMA), the Western Load Research Association (WLRA), the Association of Energy Services Professionals (AESP) and other meetings attended by DSM professionals, will be used to disseminate the findings of the project to the industry. Specifically, below is a list of information sharing forums which PG&E will approach in terms of sharing where the results and lessons learned from this EPIC project:

Information Sharing Forums Planned:

1. **Peak Load Management Alliance (PLMA)**
   San Francisco, CA | April 19, 2016
2. **Demand Response and Smart Grid National Town Meeting** (abstract pending approval)
   Washington D.C. | July 11-13, 2016
3. **Western Load Research Association (WLRA)** (abstract pending approval)
   TBD | Fall 2016
4. **Association of Energy Services Professionals (AESP)** (abstract pending approval)
   Summer Conference - Chicago, IL | August 16-18, 2016
   National Conference - TBD | February 13-16, 2017

4.5.2 Adaptability to other Utilities / Industry

More than 90% of the direct load control programs in the U.S. are based on one-way communicating load control systems. These systems cannot sense the operational status of the control devices (for purposes of determining operational readiness or unintentional operations), nor sense the existing available load that could be controlled. Also, they cannot quickly report the impacts of load control on the system. As system operators increasingly think of load control as a resource for controlling the economic cost of service delivery and preventing reliability and stability problems, the ability to deliver this information to system operators is becoming increasingly important. This technology, or one like it, is a critical requirement for operating load control programs in the future because it does not require wholesale replacement of existing load control platforms.

4.6 Overall Project Results

The SmartAC™ RTMS demonstration project involved development, testing and utilization of near real-time data streams from data loggers installed on one-way direct load control devices on SmartAC™ Program participants. In this project, 586 data loggers were installed alongside air conditioning units for residential and commercial customers participating in PG&E's SmartAC™ program—a direct load control program with approximately 160,000 participants. The loggers were connected to data transmission technology using cellular networks to pass appliance load measurements for participating air conditioning units in near real-time (and in one minute increments) to a web server. At the web server, the data was organized and ultimately displayed in a web portal dashboard for Pacific Gas and Electric (PG&E) SmartAC™ program administrators.

Overall, the project achieved its three objectives:

1. Improving PG&E's ability to estimate A/C direct load control load impacts at the distribution system level to aid in better understanding the localized impact of A/C direct load control devices on meeting distribution feeder level reliability concerns;

2. Enabling near real-time visibility of A/C direct load control installations to Transmission and Distribution Operations; and
3. Enabling DR program administrators to have near real-time feedback on any problems with direct load control devices before, during or after an event is called.

This project successfully tested a data collection and management system that provides visibility into SmartAC™ operations without incurring the significant costs associated with a wholesale replacement of an existing one-way load control communication system with two-way load control devices. The availability of such information, especially at low cost, is becoming critically important as the modern grid becomes increasingly dependent on load control as a resource for balancing loads on the generation, transmission and distribution systems.

Historically, A/C load control has been useful as an emergency resource and has been valued in terms of its impact on resource adequacy (i.e., the reserve required to support foreseeable peak demand). This situation is changing in several ways as distributed energy resources are integrated with the electric grid. This project demonstrated that the RTMS can provide sufficient visibility to help understand the impact of A/C load control on distribution feeders and substation loading during normal operations.

Finally, this project demonstrated the usefulness of RTMS for observing the operational readiness and performance of PG&E's load control system and it will become increasingly important and useful as load control is integrated into the modern grid in California. The learnings from this EPIC project can be leveraged by the industry, to provide near real-time information to multiple stakeholders (including electric utilities, California Independent System Operator (CAISO) and distribution system operators) regarding the A/C load available for control and under control during the summer cooling season.

5.0 Metrics

The following metrics as identified in CPUC Decision 12-05-037 were addressed in this project:

- **1h. Potential energy and cost savings: Customer bill savings (dollars saved)**
  The technology tested in this project will likely not lead to significant customer bill savings (i.e., beyond the savings customers on SmartAC™ experience), as a result of selecting the SmartAC™ service alternative. There is the potential for minimal savings through the improved operations and near real-time visibility into the effectiveness of the SmartAC™ by taking immediate corrective action upon identification of any concerns with the A/C cycling system.
- **4a. Environmental benefits: GHG emissions reductions (MMTCO2e)**
  The technology tested in this project will not directly result in significant reductions in GHG emissions produced by customers using central air conditioning in California. PG&E's SmartAC™ system is already in place and while it can produce relatively small energy savings over the course of a summer, the work carried out in this project will not increase these savings substantially. For PG&E the net energy savings from A/C load control is estimated to be about .62 kWh per customer per load control operation. Given that there are ~160,000 A/C units under control in any given operation; and about 9 operations per summer the net energy savings for the program over the course of a year is about 910 MWh – or about 155 metric tons of CO_2.[14] The use of the RTMS

[14] Per customer energy savings estimated from 2015 load control operations (analysis underway), conversion from kWh to Co2 based for PG&E obtained from http://www.pge.com/includes/docs/pdfs/shared/environment/calculator/pge_ghg_emission_factor_info_sheet.pdf

technology may improve the performance of the system by helping to identify paging system areas that require repair or maintenance.

The technology employed in this project can play an important supporting role in significantly reducing GHG emissions in California and throughout North America by providing grid operators and other stakeholders with a useful tool for ensuring the reliability of the energy supply system as renewable resources are integrated with grid operations. This is particularly true in California where distributed solar installations are becoming increasingly pervasive. A/C load control can be used to strategically curtail air conditioning loads when variations in the output from renewable resources require an immediate offsetting reduction in loads to balance loads with available resources. However, in order for A/C load control to be used in this manner, technology must be developed that allows system operators and automated control systems to monitor the A/C load available for curtailment and the status of the A/C load control system. In recent years, some operators of A/C load control programs have begun to experiment with two-way load control devices that provide this capability. However, more than 90% of the load control systems in operation today use one-way communications technology to control loads; and cannot sense or transmit either the load available for curtailment or the operational status of the A/C unit after load control is initiated. Most A/C load control systems cannot be used to balance loads. The technology tested in this project can overcome this problem by providing the ability to use existing load control infrastructure to deliver the information needed to operate the modern grid.

- **7b. Identification of barriers or issues resolved that prevented widespread deployment of technology or strategy: b. Increased use of Cost-effective Digital Information to improve the reliability, security and efficiency of the electric grid (PU Code § 8360)**

This project has demonstrated the practicality and usefulness of a digital information system (including digital data loggers, communications infrastructure, database management servers and user interface) for monitoring the operational performance of an extant load control system based on one-way communications technology. The technology tested in this project can be employed throughout North America to assist grid operators in maintaining the reliability of the power supply system as grid modernization takes place. It can very strongly influence the usefulness of A/C load control systems in balancing loads with resources at all levels of the electric system.

Appendix: Exhibits A through G

Exhibit A. **Testing Plan**

Exhibit B. **Sampling Plan**

Exhibit C. **Device Wiring Diagrams**

Exhibit D. **Loggers Excluded from Study**

Exhibit E. **Detailed Project Methodology**

Exhibit F. **Unique Technology Implementation Issues**

Exhibit G. **Simulation Model**