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Demand Response Spinning Reserve Demonstration – Phase 2 Findings from the Summer of 2008

Prepared for
Energy Systems Integration
Public Interest Energy Research Program
California Energy Commission

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Environmental Energy Technologies Division

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Abstract

The Demand Response Spinning Reserve project is a pioneering demonstration showing that existing utility load-management assets can provide an important electricity system reliability resource known as spinning reserve. Using aggregated demand-side resources to provide spinning reserve as demonstrated in this project will give grid operators at the California Independent System Operator (CA ISO) and Southern California Edison (SCE) a powerful new tool to improve reliability, prevent rolling blackouts, and lower grid operating costs.

In the first phase of this demonstration project, we target marketed SCE's air-conditioning (AC) load-cycling program, called the Summer Discount Plan (SDP), to customers on a single SCE distribution feeder and developed an external website with real-time telemetry for the aggregated loads on this feeder and conducted a large number of short-duration curtailments of participating customers' air-conditioning units to simulate provision of spinning reserve. In this second phase of the demonstration project, we explored four major elements that would be critical for this demonstration to make the transition to a commercial activity:

1. We conducted load curtailments within four geographically distinct feeders to determine the transferability of target marketing approaches and better understand the performance of SCE's load management dispatch system as well as variations in the AC use of SCE's participating customers;
2. We deployed specialized, near-real-time AC monitoring devices to improve our understanding of the aggregated load curtailments we observe on the feeders;
3. We integrated information provided by the AC monitoring devices with information from SCE's load management dispatch system to measure the time required for each step in the curtailment process; and
4. We established connectivity with the CA ISO to explore the steps involved in responding to CA ISO-initiated requests for dispatch of spinning reserve.

The major findings from the second phase of this demonstration are:

1. Demand-response resources can provide full response significantly faster than required by NERC and WECC reliability rules.
2. The aggregate impact of demand response from many small, individual sources can be estimated with varying degrees of reliability through analysis of distribution feeder loads.
3. Monitoring individual AC units helps to evaluate the efficacy of the SCE load management dispatch system and better understand AC energy use by participating customers.
4. Monitoring individual AC units provides an independent data source to corroborate the estimates of the magnitude of aggregate load curtailments and gives insight into results from estimation methods that rely solely on distribution feeder data.

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Finally, the project team extends thanks to reviewers who provided helpful comments on the first draft of this report: John Goodin, Roger Levy, and Jeremy Laundergren.

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List of Acronyms

AC	Air conditioning
ACP	Autonomous Control Protocol
ADS	Automated dispatch system
CA ISO	California Independent System Operator
CPUC	California Public Utilities Commission
EMRP	Emergency Management Research Plan
HD	High Desert
IE	Inland Empire
MRTU	Market Redesign and Technology Update
NERC	North American Electric Reliability Corporation
RAA	Remotely Alterable Address
RMSE	Root mean square error
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDP	Summer Discount Plan
VHF	Very high frequency
WAN	Wide-area network
WECC	Western Electric Coordinating Council

Executive Summary

The Demand Response Spinning Reserve project is a pioneering demonstration showing that existing utility load-management assets can provide an important electricity system reliability resource known as spinning reserve. Using aggregated demand-side resources to provide spinning reserve as demonstrated in this project will give grid operators at the California Independent System Operator (CA ISO) and Southern California Edison (SCE) a powerful new tool to improve reliability, prevent rolling blackouts, lower grid operating costs, and reduce power plant emissions.

Deploying spinning reserve is an electricity grid operator's first strategy for maintaining reliability following a major contingency, such as the unplanned loss of a large generation facility or critical transmission line. Using demand-side resources to provide spinning reserve would increase the total contingency reserve available to a grid operator and might thus prevent situations in which operators would otherwise run short of generator-provided spinning reserve and have to call for rolling blackouts.

We demonstrate that it is both technologically feasible to provide spinning reserve using demand-side resources and that it may be preferable to rely on these resources (rather than the traditional form of spinning reserve, which relies on generation facilities) because of inherent advantages of demand-side resources. These advantages include: 1) response that is near instantaneous (rather than the ten minutes allowed for generating facilities to deliver full response), and 2) responses that can be targeted geographically anywhere electricity is consumed within a utility's service territory (rather than being restricted to the fixed locations of the handful of generators that are contracted to provide contingency reserve). These advantages are especially attractive because the power curtailments required for demand-side resources to provide contingency reserves are typically very short (lasting 10 minutes or less) and may not even be noticed by customers.

Through the choice of technologies employed in this project (SCE's 25+ year-old air-conditioning load-cycling program), we also demonstrate that a traditional utility load-management asset can be repositioned as a competitive asset whose value would be established by wholesale markets for reliability services.[1] In doing so, we illustrate the potential for assets that have long been paid for by utility ratepayers to provide even greater value when used by the utility to both improve reliability and lower the cost of securing reliability services in California's competitive wholesale electricity market.[2]

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[1] This is not to say, however, that additional technical enhancements to the load manage dispatch system would not further improve performance and hence further increase the value of these assets.

[2] Many other demand-side technologies could provide spinning reserve in a manner comparable to what we demonstrated in this project. These technologies include other utility load-management assets, as well as newer demand-response technologies such as programmable communicating thermostats.

In Phase 1 of this demonstration project, we target marketed SCE's air-conditioning (AC) load-cycling program, called the Summer Discount Plan (SDP), to customers on a single SCE distribution feeder and developed an external website with real-time telemetry for the aggregated loads on this feeder. We then conducted a large number of short-duration curtailments of participating customers' air-conditioning units to simulate provision of spinning reserve (see Eto, et. al. 2006).

In Phase 2, we explored four major elements that would be critical for this demonstration to make the transition to a commercial activity:

1. We conducted load curtailments within four geographically distinct feeders to determine the transferability of target marketing approaches and better understand the performance of SCE's load management dispatch system as well as variations in the AC use of SCE's participating customers.
2. We deployed specialized, near-real-time AC monitoring devices to improve our understanding of the aggregated load curtailments we observe on the feeders.
3. We integrated information provided by the AC monitoring devices with information from SCE's load management dispatch system to measure the time required for each step in the curtailment process.
4. We established connectivity with the CA ISO to explore the steps involved in responding to CA ISO-initiated requests for dispatch of spinning reserve.

During the period when this research was conducted (summer of 2008), the California Public Utilities Commission (CPUC) ordered California's investor-owned utilities to initiate pilot demand-response programs that will participate in CA ISO's day-ahead energy and contingency reserve markets (non-spinning reserve, initially) in conjunction with CA ISO's revisions to these markets, known as the Market Redesign and Technology Update (MRTU).[3] The formal creation of these Participating Load Pilots is the next logical step toward full commercialization of the concepts demonstrated in this research project. Accordingly, the results and findings from our analysis were specifically tailored to support this next phase of the move toward commercialization.

The major findings from Phase 2 are:

1. Demand-response resources can provide full response significantly faster than required by reliability rules. North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) rules for contingency reserve response (both spinning and non-spinning) require full response in 10 minutes. The SCE load management dispatch system consistently demonstrated full response from all four distribution feeder groups in less than 80 seconds. This performance includes fixed delays totaling 1 minute, which are inherent in the preparation and transmission protocols of SCE's current dispatch system. In the future, these fixed delays might be improved or eliminated through enhancements to SCE's dispatch software. The actual time between the instant when an individual tower is directed to send a dispatch

[3] California Public Utilities Commission. 2007. *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications*. February 27.

signal to a distribution feeder group and the time when the switches within this group confirm receipt of the signal is consistently less than 20 seconds. We also examined a variety of scenarios in which load-shedding and restoration was initiated by simulated requests received from the CA ISO's automated dispatch system and found that a complete end-to-end dispatch could be completed reliably in less than two minutes.

2. *The aggregate impact of demand response from many small, individual sources can be estimated with varying degrees of reliability through analysis of distribution feeder loads.*[4] We developed a new analytical method to both quantify the magnitude of demand response and establish the statistical significance of this estimate. We demonstrated that the method could be applied with roughly comparable results using either high-time-resolution, real-time (eight-second) or low-time-resolution, archived (two-minute) distribution feeder data. We also found that applying the method to data combined from multiple feeders further improved the statistical reliability of the estimates. However, the method did not provide statistically significant results for two of the four distribution feeder groups. The reasons for this unexpected finding were explored and found to be related to problems with the dispatch signals sent from one of the transmission towers in the SCE's load management dispatch system for one feeder and due to the small number of participants in and low use of air conditioning by these participants in the second feeder.

3. *Monitoring individual AC units helps to evaluate the efficacy of the SCE load management dispatch system and better understand AC energy use by participating customers.* A significant number of installed monitoring devices were not able to confirm receipt of dispatch signals from the SCE load management dispatch system, which among other things pointed to a limitation of the communication portion of the system, as previously noted. We also found very modest levels of AC energy use by many of the monitored units on the days when curtailments were conducted, which both gave insight into AC energy use patterns related to temperature and geographic location and helped us more accurately analyze the extent of actual (and potential) load curtailment (see item 4 below).

4. Monitoring individual AC units provides an independent data source to corroborate the estimates of the magnitude of aggregate load curtailments and gives insight into results from estimation methods that rely solely on distribution feeder. When estimates of actual load curtailed based on distribution feeder data were statistically significant, they were also close in magnitude to estimates based on AC monitoring data. We were able to further close the gap between the absolute values from these two sources by adjusting the sample of monitored units to include data from only those units that confirmed receipt of dispatch signals. In other words, monitoring AC units allowed us to decide with greater confidence that units that did not confirm receipt of load-shed signals likely did not take the requested action; by narrowing our sample to the units that we knew had received the dispatch signal, we could more accurately measure the actual curtailment.

[4] This year's research did not examine the frequency responsive capability of demand response in provision of spinning reserve.

Based on the above findings as well as our experience signing up participants for this project, we conclude the following with regard to future efforts:

1. Monitoring individual end-use devices is warranted and desirable for obtaining an independent estimate of load curtailments and assessing the performance of the load management dispatch system. Monitoring need not be ongoing if its sole purpose is to document the time required for loads to respond. For the purposes of independently estimating load curtailments, samples of 20 to 30 individually monitored AC units appears to be adequate to characterize populations of 200 to 400 or even 600 participants.

2. Estimating the magnitude of curtailed load by analyzing distribution feeder data requires methods that can reliably extract the "signal" that indicates the aggregate effect of responding AC units from the ever-present background "noise" (i.e., the stochastic nature of the loads) on distribution feeders). The strength of the signal depends on the number of participants on a feeder as well as the load relief provided by each participant. In this regard, it will be important to understand the relationship between program recruitment methods and the energy use behavior of program participants. The relative amount of noise in distribution feeder data compared to the strength of the signal provided by responding participants diminishes as the number of feeders is combined. Thus, although low participation on any given feeder may make it difficult to estimate load curtailment, combining data from multiple feeders will likely improve relative precision, other things (such as the amount of load relief provided by each participant) being equal.

3. Maximizing the effectiveness of target marketing requires careful coordination among multiple groups within a utility and among contractors supporting the utility in its marketing efforts. The sequencing of mass mailing, targeted mailings, and targeted telemarketing, along with recruitment procedures (mail-in and call-in) and ultimately installations should be planned as a whole. The execution of these elements, especially, when conducted by different departments, some of whom rely on contractors, should be centrally coordinated to minimize customer confusion and process applications and installations efficiently.

1. Introduction

The Demand Response Spinning Reserve project is a pioneering demonstration of using existing utility load-management assets to provide an important electricity system reliability resource known as spinning reserve. Using aggregated demand-side resources to provide spinning reserve will give grid operators at the California Independent System Operator (CA ISO) and Southern California Edison (SCE) a powerful new tool to improve reliability, prevent rolling blackouts, and lower grid operating costs.

Deploying spinning reserve is an electricity grid operator's first strategy for maintaining reliability following a major contingency, such as the unplanned loss of a large generation facility or critical transmission line. Using demand-side resources to provide spinning reserve would increase the total contingency reserve available to a grid operator and might thus prevent situations in which operators would otherwise run short of generator-provided spinning reserve and have to call for rolling blackouts.

We demonstrate that it is both technologically feasible to provide spinning reserve using demand-side resources and that it may be preferable to do so because of inherent advantages of demand-side resources. These advantages include: 1) near-instantaneous response (less than 20 seconds in this study, compared to the 10 minutes allowed for full response from generators), and 2) responses that can be targeted geographically anywhere electricity is consumed within a utility's service territory (rather than being restricted to the fixed location of the handful of generators that are contracted to provide contingency reserve services). These advantages are especially attractive because the curtailments involved in providing contingency reserves are typically very short (lasting 10 minutes or less) and may not even be noticed by customers.

Through the choice of technologies employed in this demonstration (SCE's 25+ year-old air-conditioning load-cycling program), we also show how a traditional utility load-management asset can be repositioned as a competitive asset whose value would be established by wholesale markets for reliability services.[5] In doing so, we illustrate the potential for assets for which utility ratepayers have long paid to provide even greater value when the utility employs them to both improve reliability and lower the cost of securing reliability services in California's competitive wholesale electricity market.

In Phase 1 of this demonstration project, we target marketed SCE's air-conditioning (AC) load-cycling program, called the Summer Discount Plan (SDP), to customers on a single SCE distribution feeder and developed an external website with real-time telemetry for the aggregated loads on this feeder. We then conducted a large number of short-duration curtailments of the air-conditioning units of participating customers on this feeder to simulate provision of spinning reserve (see Eto, et. al. 2006).

[5] Many other demand-side technologies could provide spinning reserve in a manner comparable to what we demonstrated in this project. These technologies include other utility load-management assets as well as newer demand-response technologies such as programmable communicating thermostats.

Key findings from Phase 1 include:

1. Target marketing a utility's AC load-cycling program to customers served by a single distribution feeder can be a successful strategy.
2. Repeated curtailment of customers' AC in a manner similar to the deployment of spinning reserve can be accomplished *without a single customer complaint*.
3. Load curtailments can be made visualizable in real time using an open platform and secure website.
4. Analysis methods developed for this project could one day be used to predict the magnitude of load curtailments as a function of weather and time of day.
5. Load curtailments can be fully implemented much faster than ramp-up of spinning reserve from thermal generation.

Phase 1 was a first-ever, full-scale demonstration that small, individual demand-response resources (residential central AC units) could be aggregated to provide spinning reserve. In Phase 2, we build on Phase 1 findings by exploring four major topics; the results of these explorations lay the groundwork to transition this demonstration project to commercial viability:

1. We curtailed load within four geographically distinct feeders to determine the transferability of target marketing approaches and better understand the performance of SCE's load management dispatch system as well as variations in the AC use of SCE's participating customers.
2. We deployed specialized, near-real-time AC monitoring devices to improve our understanding of the aggregated load curtailments we observe at the feeder.
3. We integrated information provided by the AC monitoring devices with information from SCE's load management dispatch system to measure the time required for each step in the curtailment process.
4. We established connectivity with CA ISO to explore the steps involved in responding to CA ISO-initiated requests for dispatch of spinning reserve.

During the period when this research was conducted (summer 2008), the California Public Utilities Commission (CPUC) ordered California's investor-owned utilities to initiate pilot demand response programs that will participate in CA ISO's day-ahead energy and contingency reserve markets (non-spinning reserve, initially) in conjunction with CA ISO's revisions to these markets, known as the Market and Technology Redesign Update (MRTU)[6]. The formal creation of these Participating Load Pilots is the next logical step toward full commercialization of the concepts demonstrated in this research project. Accordingly, the results and findings from our analysis have been specifically tailored to support this next phase of the move to commercialization.

Following this introductory section, the remainder of the report is organized as follows:

[6]California Public Utilities Commission. 2007. *Administrative Law Judge's Ruling Providing Guidance on Content and Format of 2009-2011 Demand Response Activity Applications*. February 27

Section 2 describes the basic features of SCE's SDP, the regulatory approvals secured to conduct this demonstration, the selection of distribution feeders for the demonstration, and the enhanced marketing efforts used to recruit program participants on the targeted feeders.

Section 3 gives an overview of the SCE AC load management dispatch system focusing on the steps involved in conducting curtailments. We also describe the connectivity we established with CA ISO's automated dispatch system (ADS), which we used to examine end-to-end dispatch of curtailments based on simulated dispatch commands from CA ISO.

Section 4 reviews the dates and times when curtailments were conducted during summer 2008.

Section 5 describes the data we collected for analysis of the curtailments. We discuss the impacts of unforeseen events that complicated our analysis, including SCE's splitting off of some participants from the original distribution feeders onto different distribution feeders and problems we encountered in collecting reliable data from metering equipment installed on individual AC units.

Section 6 presents findings on the end-to-end performance of the SCE AC load management dispatch system. Performance is measured by the time required to execute each step in the dispatch sequence as well as the total time required to dispatch all controlled AC units.

Section 7 describes the new method we developed to estimate aggregated load impacts from distribution feeder data and the findings from this method. We use the method to explore a number of important questions related to estimating aggregated load impacts from distribution feeder data.

Section 8 presents findings from our efforts to estimate the magnitude of aggregated load impacts from a sample of metered, individual AC units as well as our efforts to use these data to corroborate and better understand the load impacts estimated from distribution feeder data.

Section 9 reviews critical issues that should be considered in moving the concepts explored in this demonstration toward a full-scale utility program. We draw on earlier findings to discuss issues associated with estimating aggregated load impacts using distribution feeder and individually metered AC data.

Four appendices supplement the main body of the report.

Appendix A reproduces, from the Phase 1 report on this project, the rationale for providing system reliability resources, specifically spinning reserve, with demand-side resource (Eto, et. al. 2006).

Appendix B augments the discussion in Section 2 with findings from SCE's post-summer survey of customers' experiences with SCE's 2008 marketing approaches and their use of AC.

Appendix C presents additional information on enhancements to the BPL Global data platform that was used to collect, integrate, and present the data used in the project.

Appendix D compares the performance of the distribution feeder load data analysis method developed in Phase 1 of the project to the analysis method developed in this phase of the project. The comparison uses identical data from one of the distribution feeders.

2. Target Marketing Southern California Edison's Summer Discount Plan Program

In Phase 1 of this demonstration project, we target marketed SCE's AC load-cycling SDP to customers on a single SCE distribution feeder (see Eto, et al. 2006). In Phase 2, we expanded the target marketing effort to four geographically distinct regions in southern California: the Inland Empire, the High Desert, Temecula Valley, and Simi Valley. We describe below the basic features of the SDP, the regulatory approvals secured to conduct the demonstration, the selection of distribution feeders for the demonstration, and the enhanced marketing efforts used to recruit program participants on the targeted distribution feeders. More than 1,200 customers were recruited to participate in the summer 2008 demonstration.

2.1 SCE's Summer Discount Plan

SCE's AC load-cycling program dates from the first generation of California utility load-management programs during the early 1980s. The load-cycling program was revitalized in 2000 as part of the state's response to the electricity crisis at that time.

SCE's program is among the largest AC load management programs in the U.S. Currently, more than 330,000 participants are enrolled in the program, representing nearly 700 MW of controllable load.

The program targets residential and commercial customers who agree to allow SCE to cycle their central air conditioners when necessary to lower electricity demand. Cycling is carried out by radio-controlled switches installed by SCE at no charge on participating customers' AC units. In return for participating, customers receive a monthly credit on their summer electricity bills. The incentives for participating vary according to the cycling strategy the customer chooses and his or her tariff.

Currently, load shedding for the SDP is triggered either following a CA ISO Warning Notice with Stage-1 imminent or by SCE grid operators in response to a local emergency condition. No single load-shedding, cycling event can exceed six hours. However, multiple events can be called on a single day. Cycling events are limited to 15 per summer season for the Base program. The Enhanced program removes the 15 per season limit (i.e. unlimited events per season) in exchange for a larger incentive.

2.2 Regulatory Approval for Recruiting Participants

Participation in the demonstration project required explicit approvals from the CPUC because ratepayer funds are used for the load control equipment, its operation, and the incentives given to customers for participating in the program. For this reason, the demonstration was approved as a distinct element, called the Circuit Saver Pilot, within the overall tariff that guides the funding and operation of SCE's SDP.

On February 8, 2007, SCE submitted Advice Letter 2100-E for the Extension and Modification of Southern California Edison Company's Circuit Saver Pilot Through 2007. The extension was to allow SCE to collect additional test data not obtained during the earlier pilot. SCE requested an effective date of March 10, 2007. No objections were received, and the Pilot Extension was approved. For summer 2008, SCE again requested, in Advice Letter 2197-E, an extension for the pilot, to take advantage of the equipment in the field and additional testing. This request was approved on January 22, 2008.

2.3 Selection of Distribution Feeders

The project team worked with SCE's Transmission and Distribution Business Unit to identify four distribution feeders for use in the demonstration. Three criteria were used to select the feeders:

First, the feeder had to be composed primarily of residential and small commercial customers and have loads that were close to the feeder's maximum design rating. Because a primary driver of residential and small commercial customer loads is summer AC use, selecting feeders with high summer loads helped ensure that there were many customers on the feeder who would be eligible for participation. As we learned too late in summer 2008 and discuss in greater detail in Section 5, high summer loads also trigger SCE distribution engineers to undertake preventive actions, such as splitting feeders by shifting some customers from one feeder to another, to lower the risk of overloads.[7]

Second, the distribution feeders had to be located in geographically distinct regions within SCE's service territory. We wanted to understand how differences in both climate and population might affect our results. For example, customers in hotter climates would tend to have greater AC use.

Third, for practical reasons, we also sought distribution feeders that already had significant numbers of SDP participants. As noted above, SDP participation was a prerequisite for participation in the demonstration.

The four selected distribution feeders were given fictitious names that corresponded to their approximate geographic locations within southern California: Inland Empire, High Desert, Temecula Valley, and Simi Valley. Table 2.1 summarizes the composition of customers within each feeder, as of March 2008.

[7] For SCE's annual planning process, peak loads and temperatures are tracked each summer, by substation. Geospatial load is forecast for normal and above-average summer temperatures (1-in-5, 1-in-10), also by substation. In addition, SCE forecasts equipment and line loadings and compares these to equipment capacity. Overloads are relieved by load balancing and other mitigation activities (e.g., rolling load to other circuits). Where loads cannot be relieved, projects are identified to address equipment and line overloads.

Table 2.1 Composition of Customers on Four Distribution Feeders

Service Accounts Per Feeder				
	Inland Empire	High Desert	Temecula Valley	Simi Valley
Commercial SDP	9	9	3	2
Commercial Non-SDP	167	189	99	150
Residential SDP	185	362	421	134
Residential Non-SDP	1477	2155	1626	1407
Totals	1838	2715	2149	1693

2.4 Target Marketing Activities and Results

Two targeted activities were conducted to enroll participants in the demonstration: letters sent directly to potential participants and telemarketing. Ultimately, more than 1,200 customers enrolled in the demonstration across the four distribution feeders.

Letters were developed for both residential and non-residential customers and addressed both customers participating in SDP and customers not enrolled but eligible. The customers enrolled in SDP received a letter thanking them for their participation and offering the opportunity to increase their summer incentive amount by participating in the demonstration. Customers not enrolled in SDP were given the opportunity to enroll for both SDP and the demonstration project. An enrollment form was included in the mailing, which confirmed the customers' consent to participate and their contact information for later use.

Building on the previous direct mail effort and based on the telemarketing results from 2007, SCE enlisted the assistance of a third party to do telemarketing for the demonstration. The results of the telemarketing activities are summarized in Table 2.2.

After the summer of 2008, SCE conducted a telephone survey of a sample of both participating and non-participating customers within the four distribution feeders to solicit input on SCE's recruiting efforts and self-reports on AC use. Appendix B presents the survey results.

Table 2.2 Summary of Telemarketing Activities

	Call Results Summary - 05/16/08 to 05/29/09									
	SDP Participants				Non-SDP Participants				Total	
	Residential		Business		Residential		Business			
	(n)	%	(n)	%	(n)	%	(n)	%	(n)	%
Initial Mailout	954	100%	20	100%	5,882	100%	560	100%	7,416	100%
Customer Records w/Unique Valid Phone Numbers	935	98%	16	80%	5,704	97%	340	61%	6,995	94%
Reached for Telephone Interview	325	34%	7	35%	1,413	24%	77	14%	1,822	25%
Initial Refusals & Soft Refusals	48	5%	4	20%	613	10%	14	3%	679	9%
Completed Telephone Interview	277	29%	3	15%	800	14%	63	11%	1,143	15%
Already Signed Up (If Got Letter)	162	17%	-	0%	71	1%	8	1%	241	3%
Not Interested / Don't Want Callback	22	2%	1	5%	376	6%	34	6%	433	6%
Requested Callback to Sign Up	93	10%	2	10%	353	6%	21	4%	469	6%

Table 2.3 Recruitment into the Demonstration by Week

Date	Inland Empire	High Desert	Temecula Temecula	Simi Valley	Total
25-Apr	228	157	212	142	739
2-May	16	16	22	16	70
9-May	49	32	28	16	125
16-May	5	4	12	1	22
23-May	8	33	29	5	75
30-May	10	3	14	6	33
6-Jun	1	9	4	4	18
13-Jun	0	7	6	3	16
20-Jun	0	6	12	0	18
27-Jun	5	6	8	5	24
4-Jul	1	0	1	3	5
11-Jul	1	9	12	0	22
18-Jul	0	0	4	2	6
25-Jul	1	1	5	9	16
1-Aug	4	0	0	1	5
8-Aug	0	2	1	0	3
15-Aug	1	1	1	0	3
22-Aug	0	0	0	4	4
29-Aug	2	0	0	3	5
Total	332	286	371	220	1209

3. SCE's AC Load Management and CA ISO's Automated Dispatch Systems

During summer 2008, SCE conducted 51 short-duration load curtailments of participating customers on the four target distribution feeders. In this section, we describe the SCE AC load management dispatch system used to conduct the curtailments and CA ISO's ADS, which we used to simulate dispatch of some of the curtailments based on hypothetical requests from CA ISO.

3.1 SCE's AC Load Management Dispatch System

SCE dispatches SDP from a central control system that has been modified to target interruptions to pre-selected groups of customers within the utility's service territory. The targeting feature enabled SCE to curtail only customers who agreed to participate in the demonstration. Instructions to curtail or restore load are conveyed via a wireless, very high frequency (VHF) radio network that is owned and operated by SCE. The curtailments are carried out via load control switches installed on each participating customer's AC unit; these switches respond to the radioed instructions by either opening or closing a relay in the low-voltage thermostat control line to the AC compressor.

A core research objective is to measure the time required to execute each step in the dispatch process (see Section 6). Below, we describe each of these steps in detail.

3.1.1 SCE AC Load Management Dispatch Operator

The SCE AC load management dispatch system is controlled by a human operator who must execute three actions for each curtailment:

1. Prepare the system to initiate a curtailment,
2. Issue the command to initiate a curtailment (shed), and
3. Issue the command to end a curtailment (restore).

The SCE system does not support scheduling of these steps and thus each step is always manually triggered. For the majority of our tests, the SCE operator executed each step at a pre-determined time that was scheduled in advance through discussion with the project team.

3.1.2 SCE AC Load Management Dispatch Application

The SCE AC load management dispatch application consists of the back-end systems and software that convey the two instructions (initiate curtailment, and end curtailment), as well as other information on system configuration, to the VHF transmitter towers. See Figure 3.1.

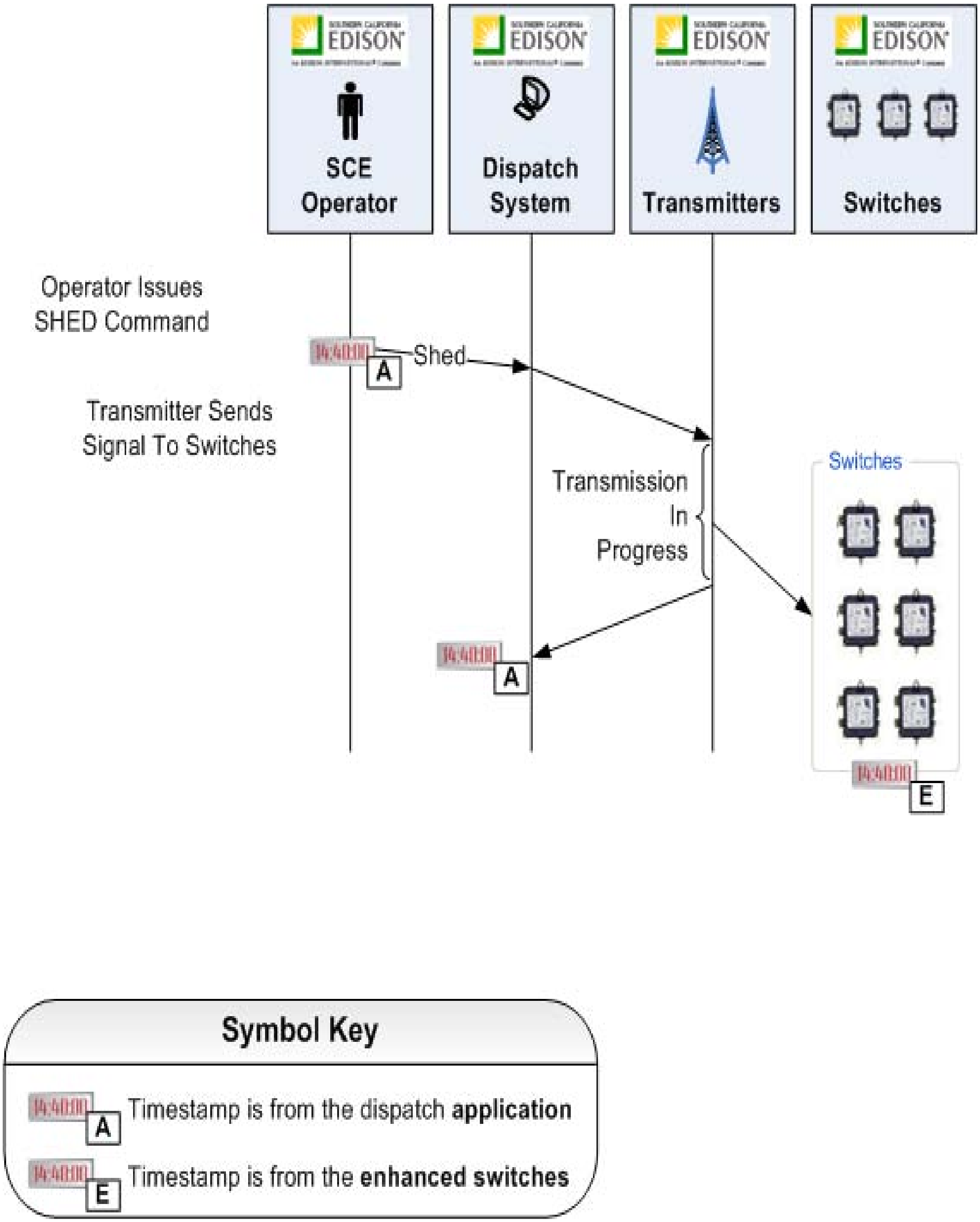

Figure 3.1 Communication between SCE Load Management Dispatch Application and SCE Transmitter System

3.1.3 SCE Transmitter System

The SCE transmitter system is composed of VHF transmitter towers located throughout the utility service area. Each tower is assigned to broadcast instructions to one or more regions within the service territory. Each instruction is sent twice to each region from two distinct towers. The first tower is called the primary transmitter, and the second is called the secondary transmitter. Each tower may serve as the primary or secondary transmitter for two locations. Figure 3.2 shows tower and distribution feeder locations.

To prevent interference, the towers are operated in coordination with one another. That is, only one tower broadcasts an instruction to a given region at any time. There is a 10-second delay between each broadcast. Thus, initiating a dispatch involves a series of instructions sent sequentially first from primary transmitters and then from secondary transmitters to each of the targeted regions (Figure 3.3 shows the communications sequence). As noted, the load management dispatch application records the time when each instruction is sent to each tower and the time when each tower confirms that it has transmitted the instruction to each region.

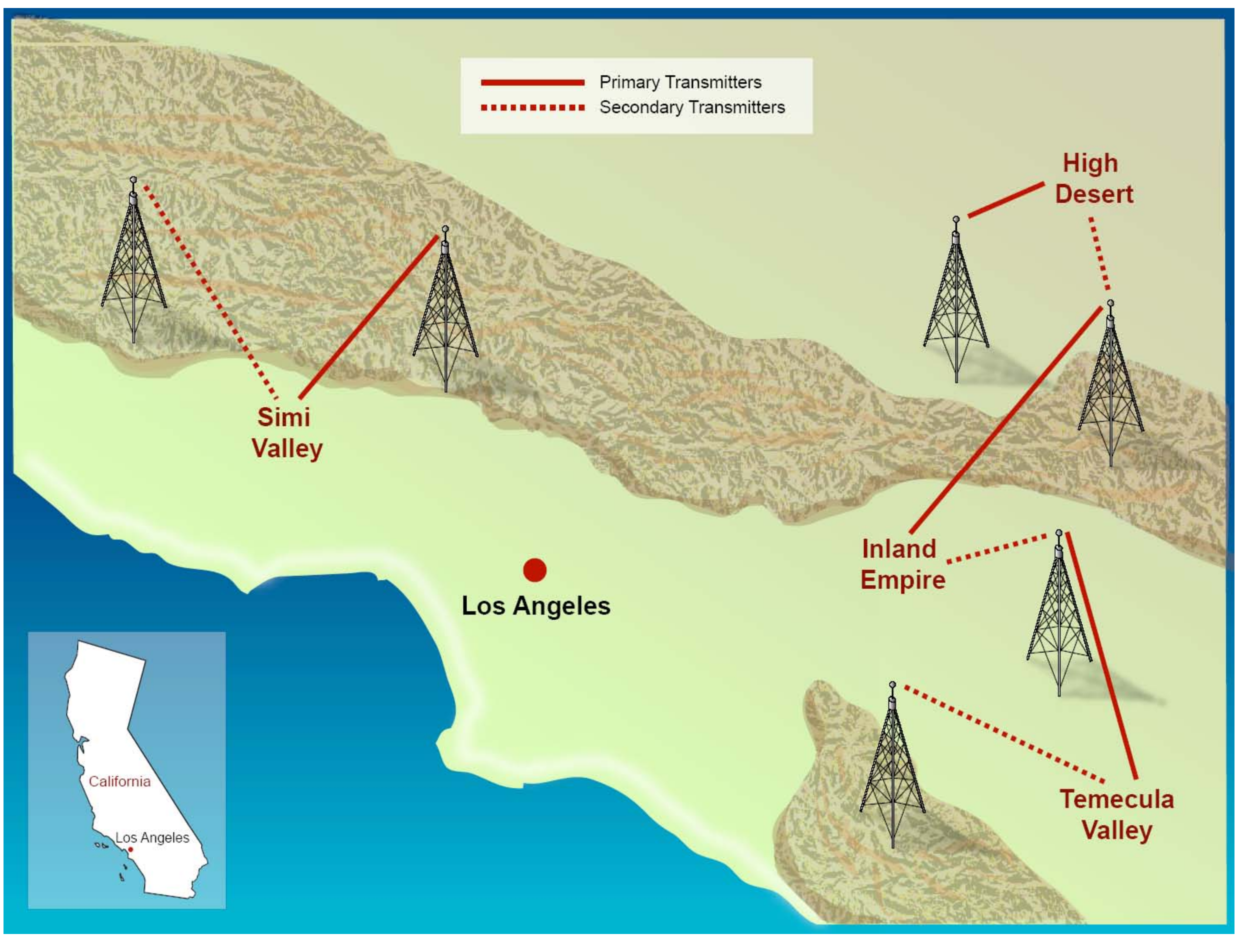

Figure 3.2 Location of SCE Transmitter Towers and Distribution Feeders

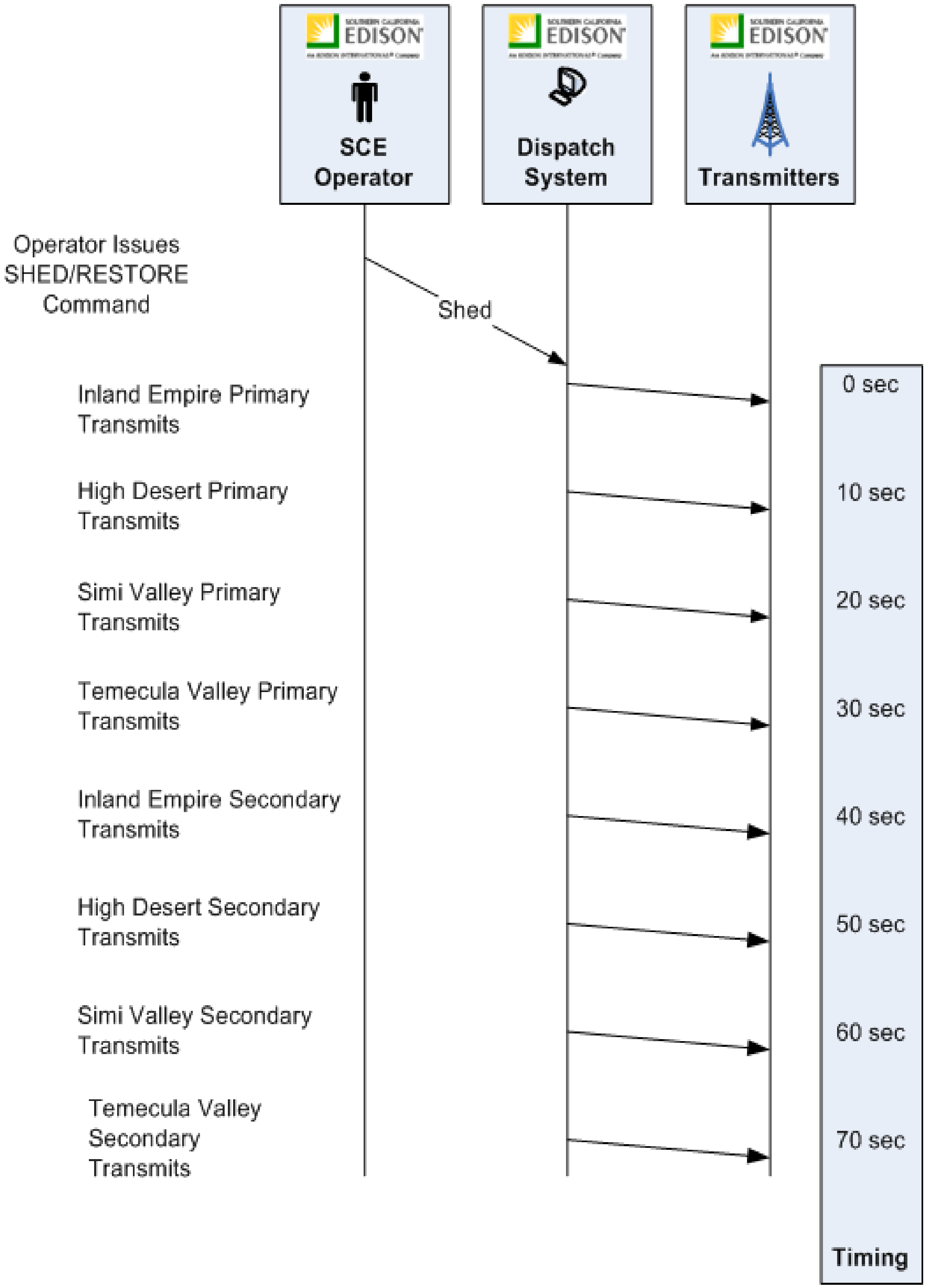

Figure 3.3 Sequence of Communications between SCE Load Management Dispatch Application and SCE Transmitter Towers

3.1.4 SCE Load Control Switches

SCE's AC load control switches consist of a communication interface that receives instructions from the transmitter system and executes the instructions by either opening or closing a relay in the low-voltage thermostat control line to the AC compressor. Figure 3.4 shows the load control switch. Two generations of AC load control switches were used; each has a different communications protocol. The protocols affect how quickly the switches can respond to instructions from the transmitter towers.

Figure 3.4 SCE AC Load Control Switch

The communication interface is one-way; switches receive instructions from transmitter towers, but they do not send information back to the towers. Thus, when a tower sends information back to the SCE dispatch application that an instruction has been transmitted to the switches in a region, it is only reporting that the transmission of information has been executed. The tower has no confirmation that the instructions have been received by the switches.

A VHF module within each of the switches receives instructions from either the primary or secondary transmitter tower or both. When an instruction is received, the switch first executes a series of internal error checks to confirm that it has received a complete instruction from the transmitter. If the instruction is valid, the switch will perform the desired operation (i.e., shed or restore load).

3.1.4.1 SCE AC Load Control Switch Communication Protocols

Two different protocols are used for communication between the switches and the SCE transmission system. Older-model switches utilize a protocol known as Remotely Alterable Address (RAA); newer models use a protocol known as Autonomous Control Protocol (ACP). In the four feeders targeted for this demonstration, roughly one-third of the switches utilize the RAA protocol, and two-thirds of the switches use the newer ACP protocol.

The two protocols are not compatible with one another; an ACP switch does not understand an instruction sent to an RAA switch and vice-versa.[8] As a result, more time is required to send instructions to all the switches in a given region as each tower must broadcast each instruction twice: first using the ACP protocol and using the RAA protocol.

3.1.4.2 SCE AC Load Control Switch Operations

The load control switches either open or close the relay to the AC thermostat control line to initiate a load curtailment (shed load) or to restore load. When a switch receives a "restore" command, the switch inserts a random delay of a few seconds to prevent all AC units from restarting at the same time.

In addition, all of the AC switches have a feature that prevents the relay from staying open even if the switch never receives a restore command. This feature ensures that the customer's air conditioner will not remain off even if the SCE dispatch system fails or a communication error occurs during the restoration process. For the curtailments conducted in our demonstration, the switches were configured to automatically close the relay 7.5 minutes (RAA switches) or 6 minutes (ACP switches) after the most recent "shed" command was received. This feature placed an upper limit on the maximum length of the curtailments.

At all times, there is ongoing communication between the transmitter towers and all of the switches in the field. The communication consists of the following types of instructions:

1. Changes in switch configurations
2. Testing of switches
3. Confirmation of switch configuration

The SCE dispatch system operator must interrupt these ongoing communications to initiate a curtailment.

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[8] In addition, each switch communication protocol uses a different mechanism for detecting errors in the transmission. The legacy RAA protocol uses a simple parity check that can detect simple errors in the transmission. The ACP protocol uses a cyclic redundancy check (CRC) to detect these types of errors; this is more robust than the simple parity check.

3.2 CA ISO Automated Dispatching System

CA ISO sends operating dispatch commands to market participants that have been accepted to provide energy and ancillary services, via a software application called the Automated Dispatching System (ADS). We worked with CA ISO to create a test ADS server and client environment and used it to send simulated dispatch requests for spinning reserve to the SCE load management system operator.

The ADS client software program runs on the market participant's computer and communicates over the internet through secure connections with the ADS server application running at the CA ISO data center. The ADS client software application allows market participants to receive CA ISO dispatch requests, acknowledge them, and look at the history of dispatches that have been received.

We implemented the ADS application on the BPL Global data platform and used the platform to transmit requests to the SCE load management system operator via a variety of means, including email, text messages, and pager.

The CA ISO ADS application conveys instructions to market participants in both the five-minute and hourly markets. Our test dispatches were conducted using the instructions provided to participants in the five-minute market, which is the system CA ISO uses to dispatch spinning reserve.

The five-minute market consists of sequential time segments starting at 00:00 and continuing every five minutes. For example, the CA ISO's ADS server sends instructions for the 10:05 segment at approximately 10:03:45. The instructions indicate the changes that are to be made to the current operating point of a resource. For example, an instruction to a generating resource will direct the generator to increase or decrease power output by a certain amount (e.g., 15 MW).

When instructions are sent, the CA ISO assumes that market participants will comply. However, market participants always have the ability to respond immediately (e.g., within a few seconds of receiving the direction) or to reject or modify the instruction through their ADS client application.

4. Summer 2008 Load Curtailments

During summer 2008, we conducted more than 50 load curtailments using the SCE load management dispatch system. All curtailments were scheduled in advance. No curtailments were scheduled on days when CA ISO Warning Notices were issued or when SCE grid operators issued comparable notices. The vast majority were scheduled to last no more than six minutes each. The schedule was designed to produce information that would be useful in fully characterizing the AC load that could be deployed in CA ISO's spinning reserve markets. Accordingly, curtailments were conducted primarily during the hottest summer months of July, August, and September when AC use is greatest. We also conducted a limited number of curtailments during May, June, and October to understand how AC use might change during these shoulder months. Figure 4.1 shows summer curtailments by month.

Curtailments were conducted primarily during weekdays when spinning reserve prices are highest. We also conducted some curtailments on weekend days to determine whether the AC "signal" might be easier to discern with our analysis methods when the total load on a feeder was lower. Figure 4.2 shows summer curtailments by day of the week.

Curtailments took place almost exclusively during the afternoon between the hours of 2 and 8 PM as these are the times of day both when AC is in use and spinning reserve prices are highest. Figure 4.3 show the summer curtailments by time of day.

In summary, curtailments were conducted under a wide variety of summer afternoon climate conditions experienced by each of the feeders during 2008. Figure 4.4 shows the outdoor temperatures at the time of the curtailments. Appendix D includes a discussion of the weather stations that were the source of the temperature data associated with each distribution feeder.

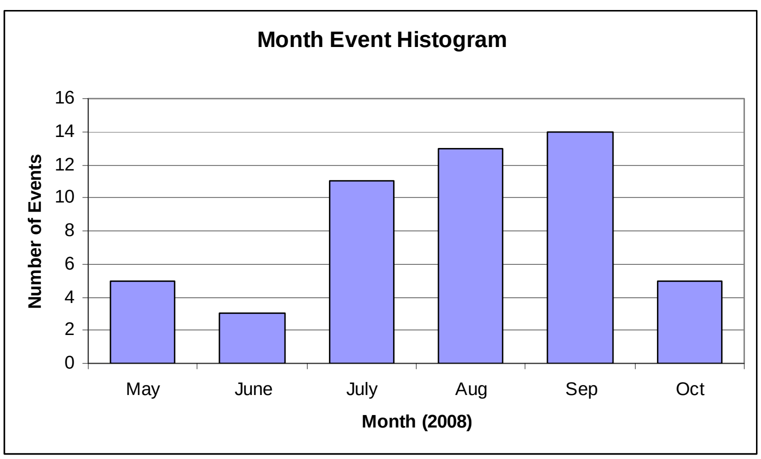


Figure 4.1 Summer 2008 Curtailments by Month

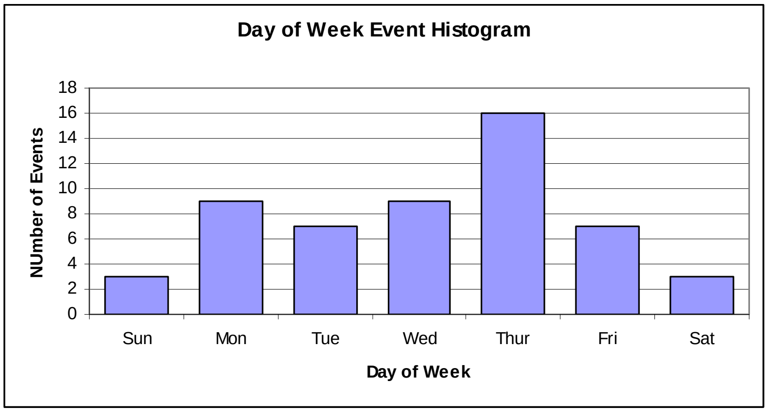


Figure 4.2 Summer 2008 Curtailments by Day of Week

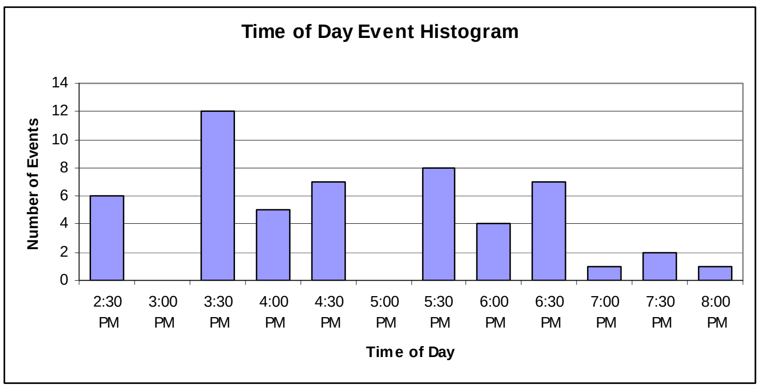


Figure 4.3 Summer 2008 Curtailments by Time of Day

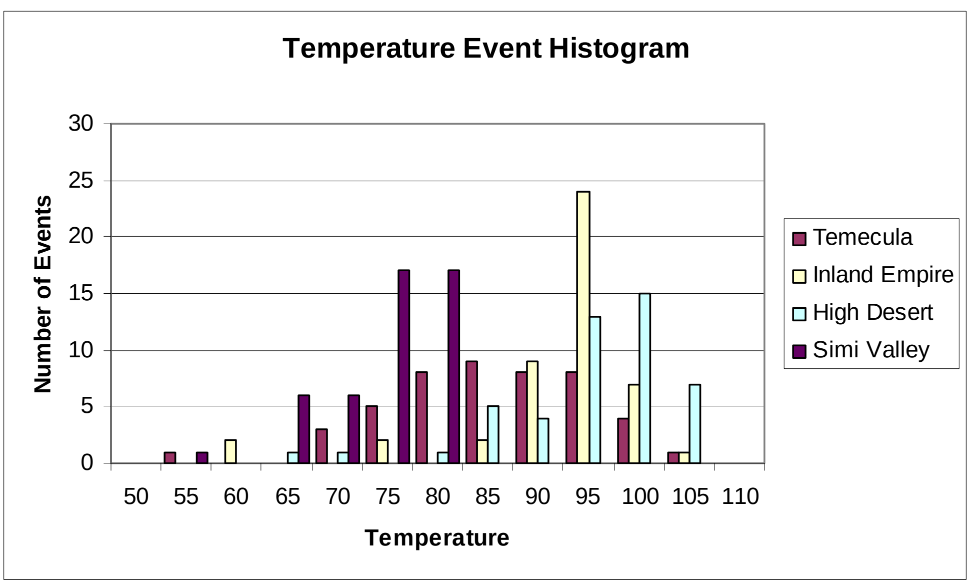


Figure 4.4 Summer 2008 Curtailments by Temperature

5. Data Collected to Analyze Load Curtailments

Building on the accomplishments from the first phase of this project, in Phase 2 we collected data to answer specific questions related to providing demand-side spinning reserves on a commercial basis. These questions, and the Sections of this report where they are discussed, are:

1. What is the time required for each step in the dispatch sequence, including initiating requests from CA ISO? (Section 6)
2. How well can aggregated load impacts be estimated from distribution feeder data? (Section 7)
3. How well can aggregated load impacts be estimated from a sample of individually metered AC units? (Section 8)

This section gives an overview of the data used to answer the above questions.

Two key data sources were used: 1) load data from the distribution feeders and 2) load data and information on switch status from a sample of individually metered AC units.

An unexpected reassignment of customers from one distribution feeder to another during summer 2008 affected both sources of data and complicated the methods we developed to analyze the data as well as the character of the results we obtained.

5.1 Distribution Feeder Load Data

Distribution feeder loads were analyzed to determine how well the "signal" created by the simultaneous curtailment of individual AC units within a feeder could be extracted from the stochastic "noise" that is characteristic of distribution feeder loads. Section 7 presents the results of this analysis.

Load data from each of the original four distribution feeders were collected automatically via a data bridge from the SCE Supervisory Control and Data Acquisition (SCADA) system to the BPL Global data platform. (See Eto, et. al. 2006 for a description of the BPL Global data platform.)

A significant factor affecting analysis of distribution load data was SCE's reassignment of customers off of each of the original four feeders onto different feeders during summer 2008. As discussed in Section 2, when the total load on a feeder approaches its maximum design limit, SCE will "split" the feeder by reassigning some customers (and their load) to a different feeder. In some cases, the feeder receiving the reassigned customers is a new feeder; in other cases, it is a feeder that already has customers on it (or is a new feeder that also has customers from other feeders reassigned to it). In discussing the effect of feeder splitting, we label the original feeder to which customers were assigned as the "A" feeder, and the feeder receiving reassigned customers as the "B" feeder. Table 5.1 lists the number customers participating in this project served by the four sets of A and B SCE distribution feeders.

Table 5.1 Participating Customers on SCE Distribution Feeders

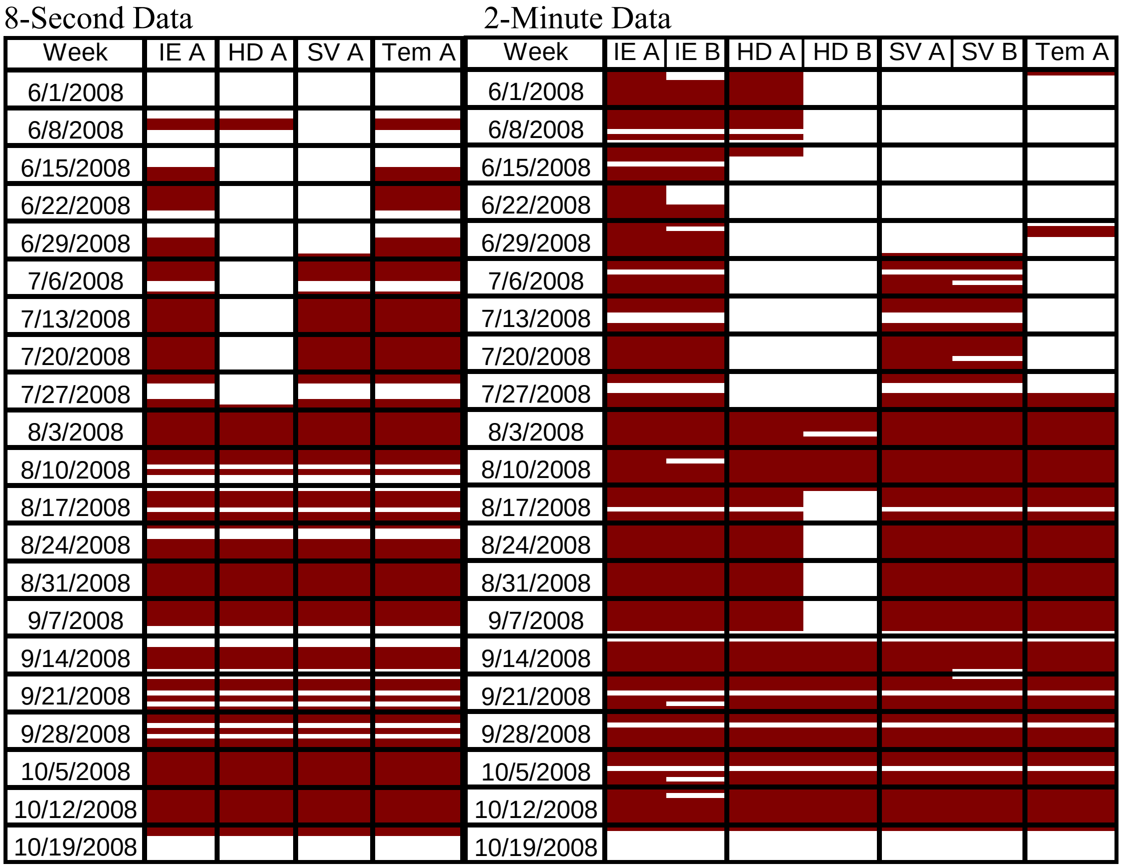
	Original Total Number of Customers on Feeder A	Customers Remaining on Feeder A After Split	Customers Moved to Feeder B	Notes on Feeder B
Inland Empire	330	105	225	Includes loads moved from another feeder
High Desert	276	174	102	Includes loads moved from another feeder
Temecula Valley	373	354	19	Unable to determine whether loads from another feeder were also moved to it
Simi Valley	213	156	57	Includes loads moved from another feeder

Feeder splitting had two impacts on our analysis. First, because some of the participating customers were moved onto the new (B) feeders, it decreased the number of participating customers on each of the original four (A) feeders. Having smaller numbers of participating customers on a feeder can either increase or decrease the strength of the load curtailment signal compared to the noise on the feeder. That is, whether the strength of the signal increases or decreases depends on whether and to what degree the noise on the feeder increases or decreases relative to this signal. Sections 7 and 9 discuss our findings on this topic.

The second factor affecting our analysis of distribution load data was that splitting feeders introduced differences in the sampling intervals of the data available for our analysis. The data bridge to the BPL Global data platform collected distribution load data from the original A feeders at the same rate it is monitored by the SCE SCADA system, which is every eight seconds. We did not learn about the feeder splitting until mid-summer; as a result, the data bridge never collected eight-second data from the B feeders. Instead, data for the B feeders had to be requested manually from SCE's archive of feeder data.

When data from the data bridge were not available, which was the case for the B feeders for the entire summer of 2008, or when the data bridge was temporarily unavailable, which affected data from the A feeders periodically, distribution load data had to be collected manually by querying the SCE data archive. The SCE data archive stores only one data observation for every two minutes' worth of eight-second observations. Section 7 discusses the impact of using distribution load data recorded at different sampling intervals (once every eight seconds versus once every two minutes) on our load curtailment estimation methods.

Figure 5.1 shows a weekly summary of the eight-second and two-minute feeder data collected to support our analysis. Table 5.2 tabulates the number of days for which data were available.



Key: IE – Inland Empire
HD – High Desert
SV – Simi Valley
Tem – Temecula Valley

Note: 2-minute data were not available from the Temecula "B" feeder

Figure 5.1 Availability of Feeder Data by Sampling Interval by Week

Table 5.2 Days of Feeder Data by Sampling Interval

8-Second Data Availability

Feeder	IE A	HD A	SV A	Tem A
Days Data	99	65	86	99

2-Minute Data Availability

Feeder	IE A	IE B	HD A	HD B	SV A	SV B	Tem A
Days Data	124	115	83	46	93	89	77

The red bars in the left side of Figure 5.1 indicate the availability of eight-second data across the four A feeders from June 1 to October 19. The High Desert A feeder did not begin recording reliable data until the beginning of August. Similarly, the Simi Valley A feeder did not have reliable data for this analysis until July after a portion of the feeder was split off and joined to Simi Valley feeder B. The rest of the feeders show a number of days of missing or otherwise corrupted data during the summer. Ultimately, as shown in Table 5.2, 99 days of data were available for Inland Empire A and Temecula Valley A, and 86 days and 65 days of data were available, respectively, for the Simi Valley A and High Desert feeders.

Because we only became aware of the splitting of the study feeders (into A and B feeders) near the end of the summer, the above data were the only data we were able to obtain for the B feeders. The B feeder archived two-minute data streams experienced some of the same missing/unreliable data problems as the eight-second data collected for the A feeders, but are more complete for the full period of the project.[9]

The red bars on the right side of Figure 5.1 indicate the availability of two-minute data across the eight A and B feeders. When we realized that only two-minute data would be available for the B feeders, we also requested two-minute data from the A feeders so that we could compare the results of our analysis method applied to eight-second and two-minute data for a single feeder for the same observation period.

Both of the High Desert feeders were unreliable until August, and data from the Simi Valley feeders are not included in the study until after these feeders got their final configuration on July 8. Temecula A doesn't have reliable data until the beginning of July. Approximately a month of data (from July-August) from High Desert B feeder were inconsistent. Temecula B never had a complete data stream and never exceeded 0.5 MW. For this reason, it was excluded from the current analysis. A number of days on each feeder also showed major departures from the general load shape for the day, possibly because of either load switching or errors in the data stream. To ensure consistency among the modeled days, we removed these days from the analysis. Table 5.2 shows the number of days of two-minute data available for each feeder.

5.2 Individual AC Unit Data

Approximately 80 specialized monitoring devices were installed on individual AC units. The devices were called "enhanced switches" because they were enclosed in the housing for the AC load control switches. The primary purpose of the enhanced switches was to collect and transmit real-time information on dispatch signals received from the SCE transmitter towers and on AC energy use immediately before, during, and after load curtailments.[10] A second purpose was to collect longer-term information on AC energy use over the course of the entire summer.

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[9] Although a more "complete" stream in terms of number of days was available for the two-minute data, much of the model development and testing was done using the actual observed energy data, i.e., the eight-second data. Much of the discussion in this report thus uses the eight-second data and results as the baseline for comparison.

[10] The switches actually record changes in current. Information on voltage and power factor collected through field measurements must be added to translate changes in current to changes in power demand and ultimately changes in energy use.

The enhanced switches had both a monitoring and a communication function. First, they recorded and time-stamped either receipt of a dispatch signal from a transmitter tower or a change in energy use by the AC unit. Second, they transmitted this information via a cell-phone-based communication system to a central repository. The transmissions were triggered either automatically or manually. Transmissions were triggered automatically during each curtailment event to provide near-real-time information to the central repository, which in turn also automatically and immediately transmitted the information to the BPL Global data platform for display. Transmissions were triggered manually at various times during the summer to upload longer-term records of AC energy use to the BPL Global data platform for analysis. The time stamps came from the cell-phone-based network provider.

The enhanced switches were installed in roughly equal proportions on each of the four original feeders. As a result of the feeder splitting discussed above, the proportions of enhanced switches installed varied between the A and B feeders for each geographic location.

We encountered two challenges in using data from the network of enhanced switches to support our analyses.

First, 12 (roughly 15%) of the enhanced switches could not be included in our analysis for the following reasons: Three malfunctioned, and were physically removed from the sites early in the study period. Another three never transmitted data during the entire study period. A final six were removed from the analysis because their locations could not be determined.

Second, some of the remaining enhanced switches did not consistently provide usable data or in some cases required us to implement post-processing adjustments to make the data usable for our analysis. Because many of the anomalies were intermittent, it was not possible in some cases to determine whether they were a reflection of true AC use behavior or simply a problem with the transmission of data from the enhanced switches. As a rule, we sought to include as much data as possible in our analysis; this bias meant that we sometimes might have included bad data to minimize the risk of excluding good data.

We encountered three generic problems in using the data provided by the enhanced switches: 1) gaps in the overall data record, 2) missing data specifically for receipt of dispatch signals, 3) unusual (though not necessarily bad) information on AC energy use.

5.2.1 Gaps in the overall data record

The enhanced switches track AC energy use by recording the value and time when the AC unit's current or power demand (see footnote 9) changes by more than a prescribed amount or when energy use drops to zero. From the data record, we can construct a load profile of energy use by interpolating values between each time-stamped change.

Gaps in the data record for an individual enhanced switch are easy to detect if the last recorded AC energy value is positive. Figure 5.2 shows a data record for which there is an apparent gap starting on May 13 and ending on June 24 (the last recorded value was approximately 30 on May 13). It was generally straightforward to identify these data gaps and eliminate them from our analysis.

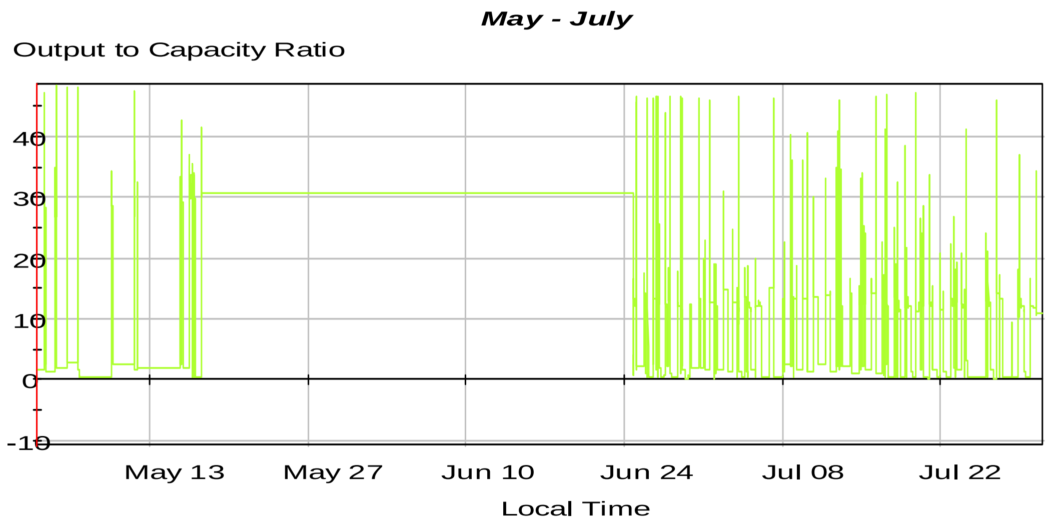


Figure 5.2 Example of a Gap in the Data Record for an Enhanced Switch

Gaps in the data record are much more difficult to detect if the last recorded value is zero. In this case, we cannot distinguish between a true gap and a period when the AC unit was simply not in use. Figure 5.3 shows an example of this type for the period between July 1 and July 15. We chose to include data records that reported long periods of zero AC energy use, especially if these same switches also recorded receiving dispatch signals.

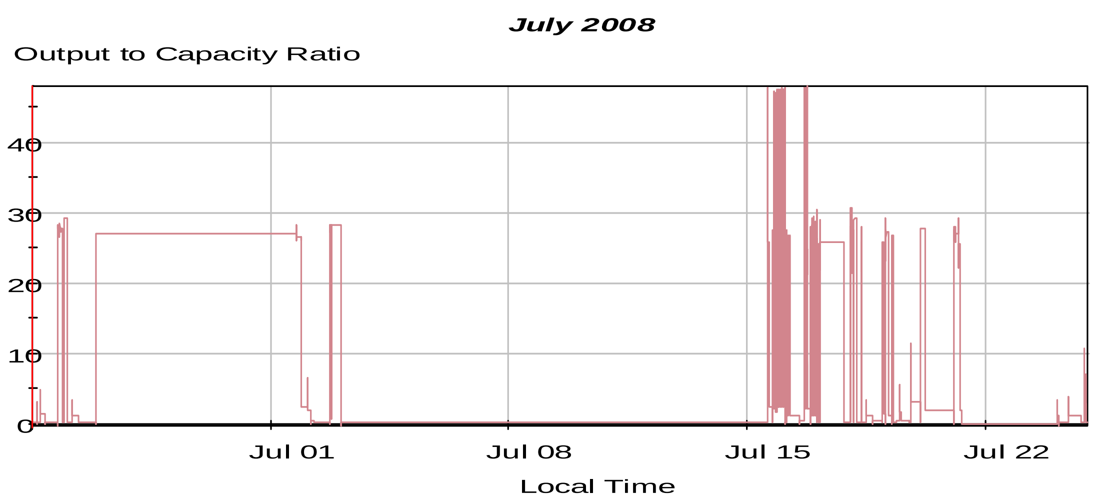


Figure 5.3 Example of a Possible Gap in the Data Record for an Enhanced Switch

5.2.2 Missing Dispatch Signals

The enhanced switch also records the time it receives a dispatch signal from the SCE transmitter tower. A number of switches at times did not record receiving a dispatch signal yet did record changes in AC energy use. We concluded that these switches were somehow blocked or shielded from receiving dispatch signals. In many cases, we were able to include the AC energy use recorded by these units during dispatch events and use this information to compare to AC energy use recorded by units that did confirm receipt of dispatch signals.

5.2.3 Unusual information on AC energy use

The AC energy use recorded by several enhanced switches was sometimes unusual in one of two ways.

First, some switches recorded small non-zero values at times when AC energy use would otherwise be expected to drop to zero (i.e., the AC unit was "off"). Figure 5.4 shows an example of this type of "phantom" load. There are three possible explanations, but we cannot verify which is correct in each instance: 1) calibration error in the energy monitoring unit, 2) sampling error in which the zero value is not recorded correctly, or 3) actual low levels of energy use because of the design of the AC unit. Generally speaking, because the values were very small compared the energy use recorded by switches when the AC units are "on," we ignored these small phantom loads and set them equal to zero.

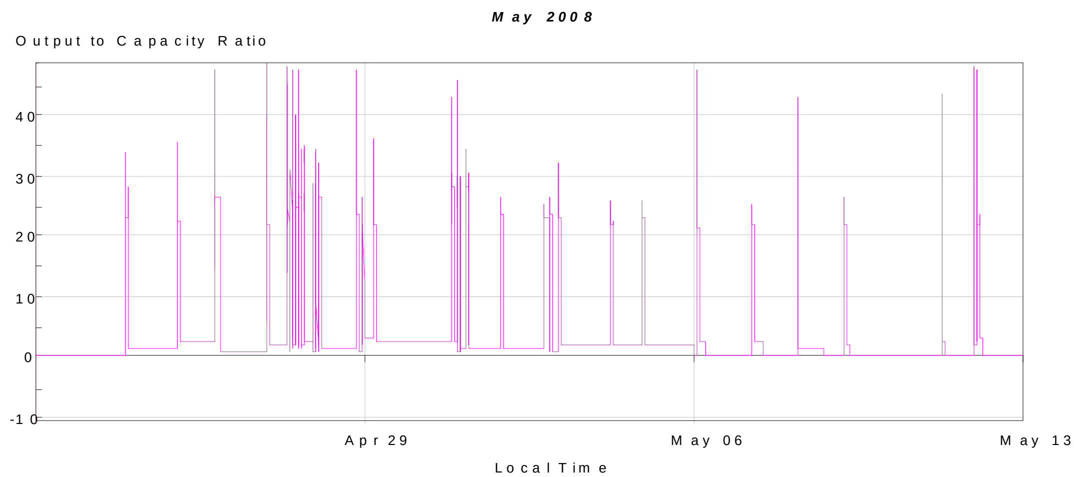


Figure 5.4 Example of Phantom Loads Recorded by an Enhanced Switch

A second type of unusual energy use data were negative values recorded when AC energy use would otherwise be expected to be a zero. Figure 5.5 shows an example of this type of negative record. This situation appeared to us to be due entirely to miscalibration of the monitoring unit. We were able to address this miscalibration by calculating energy use as the absolute difference between the low and high values recorded.

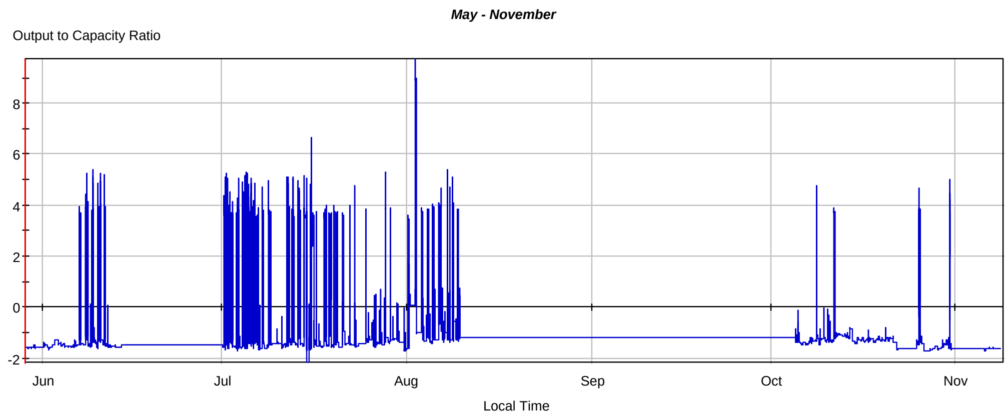


Figure 5.5 Example of Negative Energy Use Recorded by an Enhanced Switch

5.2.4 Summary of Enhanced Switch Data

Figures 5.6 through 5.9 summarize the data issues we identified for the population of enhanced switches for each of the four geographic regions. Each figure identifies, for each enhanced switch, one of four conditions: 1) No data received, 2) Received dispatch signals and AC energy use, 3) Received dispatch signals but no information on AC energy use, and 4) Did not receive dispatch signals but did record AC energy use.

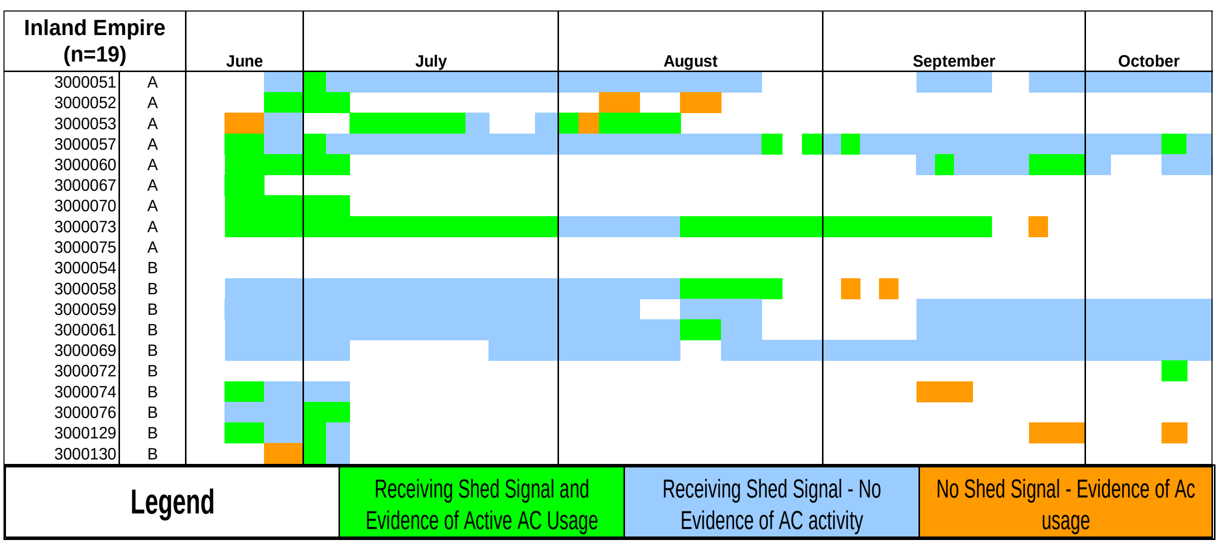


Figure 5.6 Overview of Enhanced Switch Data Collected from Inland Empire

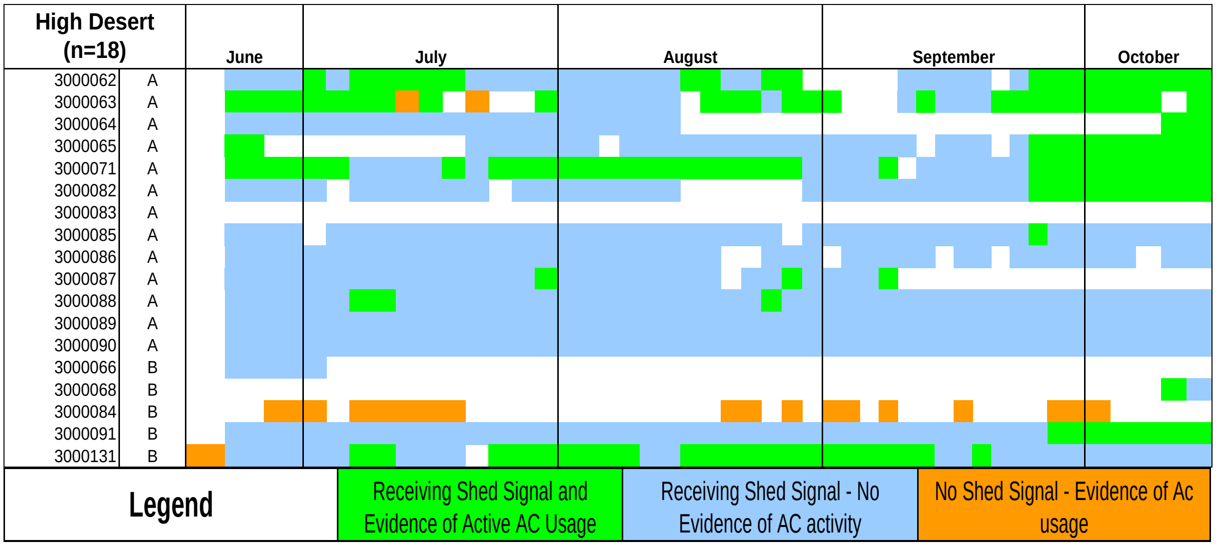


Figure 5.7 Overview of Enhanced Switch Data Collected from High Desert

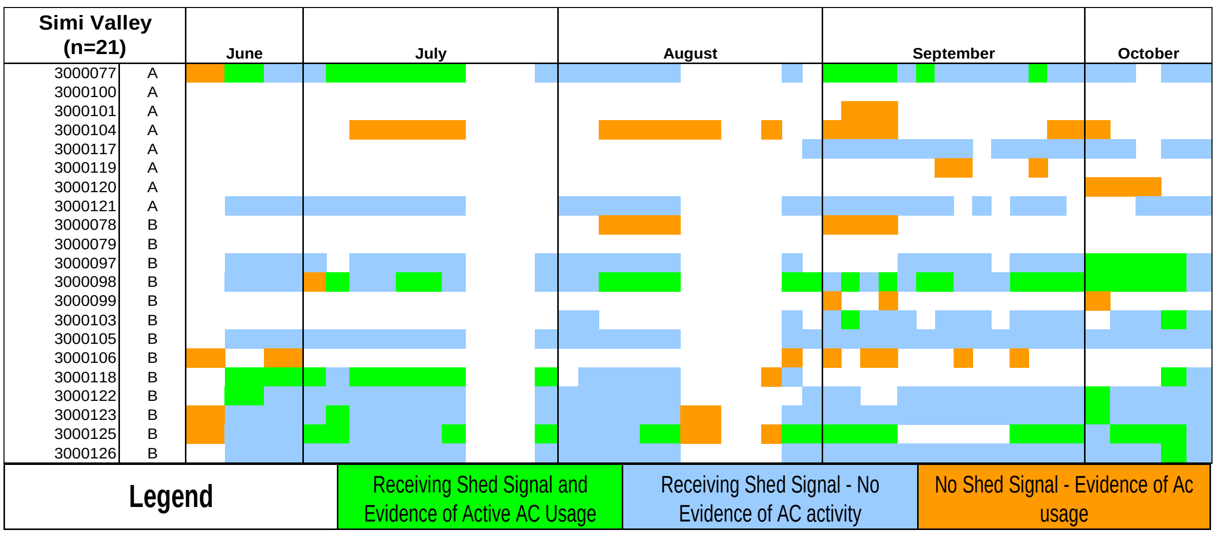


Figure 5.8 Overview of Enhanced Switch Data Collected from Simi Valley

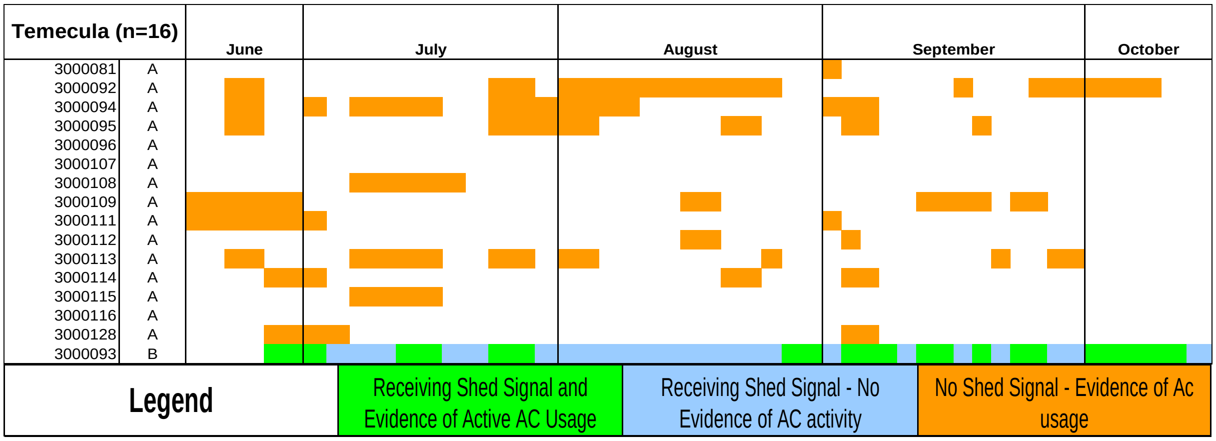


Figure 5.9 Overview of Enhanced Switch Data Collected from Temecula Valley

Several characteristics of the data usable for our analysis can be gathered by reviewing the above data summary figures.

First, there are significant gaps in the data available at various times throughout the summer. Only a handful of switches on the High Desert feeder provided near-continuous data during the entire monitoring period.

Second, many of the switches with longest periods of usable data also record long periods of no energy use by the AC unit. This suggests that these participants were on vacation or turned their AC units off for significant portions of the summer.

Third, the two gaps in data records for Simi Valley suggest that there were systematic problems in the retrieval of data from the switches in this area.

Fourth, only one switch in Temecula Valley received dispatch signals. The fact that other switches recorded AC energy use suggests that there were systemic problems that affected the ability of the majority of switches to receive dispatch signals.

6. Measurement of the Time Required to Dispatch Load Curtailments

Determining the time required to curtail loads after the initiation of a system dispatch request is critical for providing contingency reserves to CA ISO. Both spinning reserve (and non-spinning) reserve require that full output from a resource contracted to provide spinning reserve be available in 10 minutes.[11]

This section presents findings on the time required to curtail loads using the SCE Load Management Dispatch System. We report on the total time required as well as the time required for each step in the dispatch sequence. Because we recorded timing information from multiple curtailments, we also comment on the predictability of our results as reflected by the variability in times recorded. A final subsection discusses additional measurements made of the time required to receive and transmit dispatch signals from the CA ISO ADS client software to the SCE Load Management Dispatch System operator.

6.1 Time Required by SCE to Dispatch Load Curtailments

As discussed in Section 3, the SCE dispatch sequence consists of manual initiating actions followed by automated dispatch actions:

1. Preparation of the system for a dispatch operation
2. Initiation of a dispatch command to shed load
3. Transmission of dispatch commands to switches located on AC units via a network of transmitter towers, in which
    a. Each tower transmits only to switches within a single distribution feeder group (A and B)
    b. Each of four towers transmits to one of the four distribution feeder groups in a prescribed sequence (primary transmitters)
    c. Following an initial transmission to each distribution feeder group, the sequence is repeated a second time from a different set of transmitter towers in a prescribed sequence (secondary transmitters)

Then, after a pre-determined amount of time:

4. Initiation of a dispatch command to restore load, followed by the above sequence of transmission of this command to switches via the transmitter towers

Figure 6.1 shows an integrated overview of this dispatch sequence. It is based on combining dispatch elements and concepts first presented in Figures 3.1, 3.2, and 3.3. It also indicates the sources of timing data for each element in the dispatch sequence: 1) times recorded via logs created by the SCE operator, 2) times recorded by the SCE AC load management dispatch system, and 3) times recorded by the enhanced switches located in each of the distribution feeders.

[11] This year's research did not examine the frequency responsive capability of demand response in provision of spinning reserve.

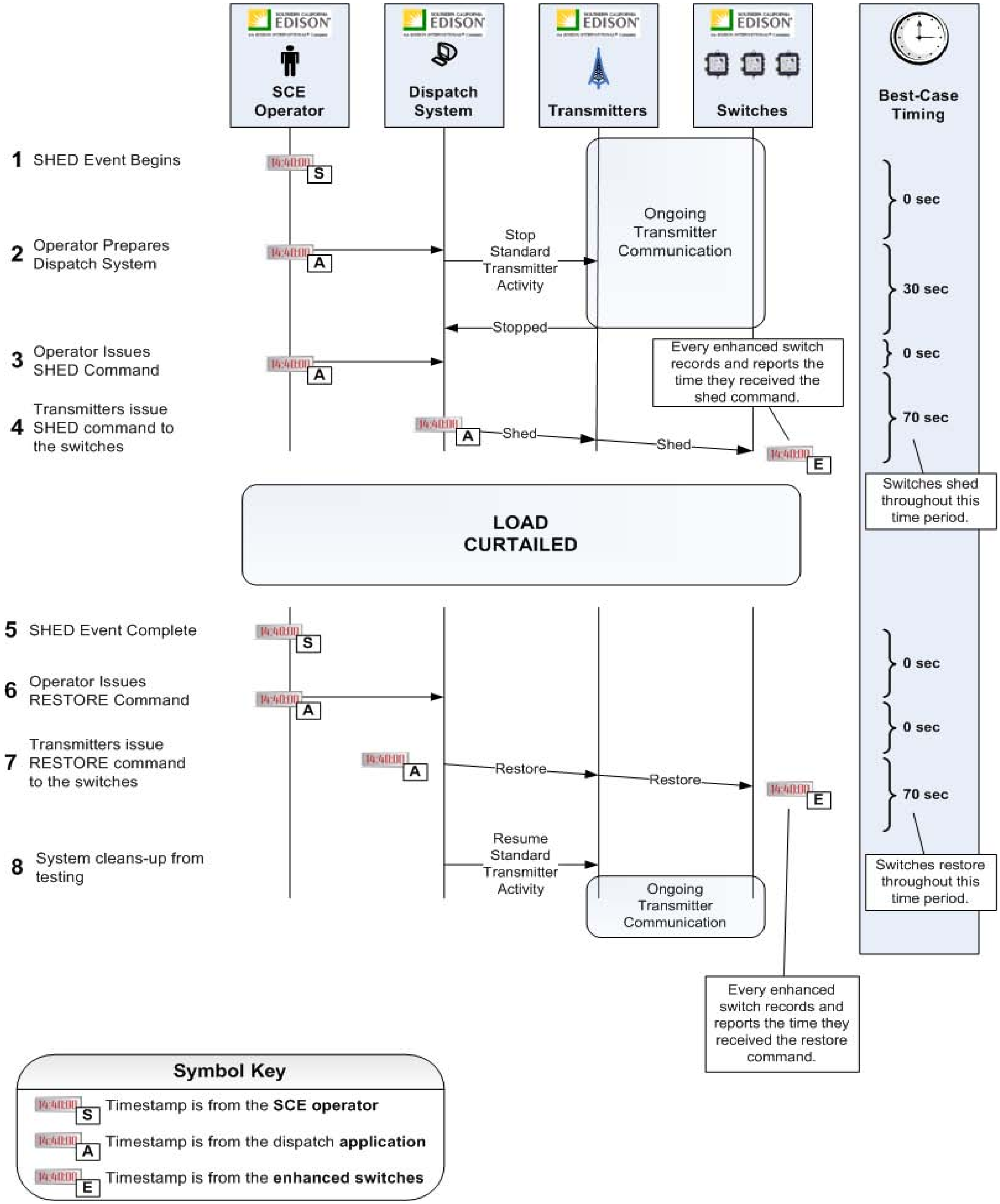


Figure 6.1 Steps in the Load Curtailment Dispatch Sequence

As described in Section 3 and indicated in the right-hand column in Figure 6.1, the time required to execute two elements of the dispatch sequence is fixed. First, the time required to prepare the system for a dispatch involves a series of operations that interrupt ongoing communications between the SCE AC load management application and transmission towers; this series of operations takes 30 seconds. Second, the time delay between transmissions from each tower (both primary and secondary) is 10 seconds. As a result, 100 seconds is the shortest amount of time in which the system can both prepare itself for a dispatch operation and cycle through primary and secondary transmission of dispatch commands to switches in each of the four distribution feeder groups.

The time required to curtail load, however, depends on when the signal to curtail is actually received by the switch (which may result from receipt of a dispatch command from either the primary or secondary transmitter) as well as the time the switch takes to respond to the command. In the next two subsections, we discuss the time required by these two elements: 1) the time required by the transmission towers to confirm transmission of dispatch commands, and 2) the time required by enhanced switches to confirm receipt of dispatch commands.

6.1.1 Time Required to Confirm Transmission of Dispatch Commands by Transmitter Towers

As indicated in Figure 6.1 (and Figure 3.1), the time required to confirm transmission of dispatch commands is recorded by SCE's AC load management application. The application records both the time that it sends the dispatch command to each transmitter tower and the time that it receives a confirmation that the tower has transmitted the dispatch command to the switches.

Table 6.1 below shows the breakdown of the time taken by each of the eight transmitters to respond to the dispatch application with confirmation that the "shed" command was sent. This includes the time to send the command to the transmitter through the wide-area network (WAN), the time it takes the transmitter to send the command to the switches, and the time for the response from the transmitter to return through the WAN to the dispatch application.

Table 6.1 Time Required by Transmitter Towers to Confirm Transmission of Dispatch Command to Shed Load

Circuit	Transmitter	Min (sec)	Max (sec)	Avg (sec)	Std. Dev.	Samples
Inland Empire	Primary	20	21	20.33	0.49	12
Inland Empire	Secondary	20	22	20.83	0.58	12
High Desert	Primary	20	22	20.75	0.62	12
High Desert	Secondary	20	21	20.67	0.49	12
Temecula Valley	Primary	20	31	23.08	4.80	12
Temecula Valley	Secondary	11	14	12.75	1.06	12
Simi Valley	Primary	20	21	20.71	0.49	10
Simi Valley	Secondary	11	13	12.30	0.95	10

The majority of the transmitters show comparable average times with small standard deviations. However, both the Temecula Valley and Simi Valley secondary transmitters have notably shorter averages than all of the other transmitters.

This observation suggests that the time for the command to propagate through the WAN is non-negligible. The transmitters are all sending the same message to the switches, so there is no difference in the data being communicated over the WAN to each transmitter or to the switches from each transmitter. However, each transmitter tower is located in a different geographic region and thus is connected to the main dispatch application by a different path through the WAN. Because this is the only difference among the transmitters that could impact this result, the WAN communication time must be responsible for a noticeable portion of the delay.

Table 6.2 depicts the same transmitter response timing data except that it includes data from the “restore” command. The results are the same as for the “shed” command data.

Interestingly, the average time for the “restore” command is substantially shorter for each transmitter than for the time for the “shed” command. This is because more data are required to issue a “shed” command than to issue a “restore” command. As described in Section 3, the “shed” command consists of both an ACP and RAA message; by contrast, a “restore” command consists of only an ACP message (because, RAA switches automatically restore load after a fixed period of time). This results in roughly 80% fewer data being sent to the transmitter towers from the dispatch application during a “restore” command versus a “shed” command. As a result, it takes substantially less time for the “restore” command to be sent through the WAN to the transmitters and for the transmitters to send the message to the switches.

Table 6.3 below shows the relative differences in the delay between the “shed” and “restore” commands for each transmitter. Of particular interest is the substantially shorter response time for the Simi Valley secondary transmitter relative to every other transmitter. Because the percent difference is less than the 80% message size reduction between “shed” and “restore” commands that applies for all transmitters, it appears that other variables in addition to message size affect the time it takes for a transmitter to receive and respond to a command.

Table 6.2 Time Required by Transmitter Towers to Confirm Transmission of Dispatch Command to Restore Load

Circuit	Transmitter	Min (sec)	Max (sec)	Avg (sec)	Std. Dev.	Samples
Inland Empire	Primary	10	11	10.17	0.39	12
Inland Empire	Secondary	10	11	10.42	0.51	12
High Desert	Primary	10	12	10.50	0.67	12
High Desert	Secondary	9	11	10.33	0.65	12
Temecula Valley	Primary	10	36	13.92	8.05	12
Temecula Valley	Secondary	4	5	4.67	0.49	12
Simi Valley	Primary	10	11	10.29	0.49	10
Simi Valley	Secondary	8	11	10.11	0.93	10

Table 6.3 Comparison of Times Required by Transmitter Towers to Confirm Transmission of Commands to Shed and Restore Load

Circuit	Transmitter	Shed Avg. (sec)	Restore Avg. (sec)	Percent Difference
Inland Empire	Primary	20.33	10.17	50%
Inland Empire	Secondary	20.83	10.42	50%
High Desert	Primary	20.75	10.50	49%
High Desert	Secondary	20.67	10.33	50%
Temecula Valley	Primary	23.08	13.92	40%
Temecula Valley	Secondary	12.75	4.67	63%
Simi Valley	Primary	20.71	10.29	50%
Simi Valley	Secondary	12.30	10.11	18%

Table 6.4 Time Required by Enhanced Switches to Confirm Receipt of Dispatch Command to Shed Load

Circuit	Transmitter	Min (sec)	Max (sec)	Avg (sec)	Std. Dev.	Avg. Switches Per Sample	Samples	Total Switches
Inland Empire	Primary	16	23	17.32	0.95	7.75	16	124
Inland Empire[12]	Secondary	ND	ND	ND	ND	ND	ND	ND
High Desert	Primary	16	23	17.05	1.30	6.4	10	64
High Desert[13]	Secondary	ND	ND	ND	ND	ND	ND	ND
Temecula Valley	Primary	16	17	16.33	0.58	1	3	3
Temecula Valley[14]	Secondary	ND	ND	ND	ND	ND	ND	ND
Simi Valley	Primary	16	18	16.88	0.64	1.33	6	8
Simi Valley	Secondary	16	22	16.90	1.29	4.88	8	39

6.1.2 Time Required by Enhanced Switches to Confirm Receipt of Dispatch Commands

Any given switch can respond to the dispatch command sent by either a primary or secondary transmitter. In this subsection, we review the time that elapses between the moment when the primary tower is first told by the SCE load management application to issue a dispatch command and the time when an enhanced switch records receipt of this command.

Table 6.4 above indicates the minimum, maximum, and average elapsed time that switches took to respond to a "shed" event for each of our eight transmitters. The "samples" column indicates the number of "shed" operations included in the averages, and the "total switches" column indicates the total number of switches that received a "shed" command during each of the transmissions in all of the samples.

[12] No enhanced switches responded to the Inland Empire secondary transmitter in the tests that comprise this data.
[13] No enhanced switches responded to the High Desert secondary transmitter in the tests that comprise this data.
[14] No enhanced switches responded to the Temecula Valley secondary transmitter in the tests that comprise this data.

For each transmitter, the response time for switches within that region was fairly consistent. The average response time for all of the switches is very similar despite the disparities between the transmitter response times. Table 6.5 below shows the percentage difference between transmitter response times and switch response times. The range is between -37% and 29% with only two of the transmitters having any consistency between their results.

Based on the data collected during the test period, we cannot determine a reason for the disparity among transmitter response times. The disparate results could be explained if there is a skew between the time synchronization source used by the enhanced switches and the source used by SCE. The results could also be explained if the time drifted on either the SCE server or any of the enhanced switches. The disparity may be further compounded by the small sample sizes associated with some of the transmitters.

Table 6.6 below shows a breakdown of the switch response timing for the "restore" command based on the transmitter that triggered the operation on the switch. The observations are identical to those for the switch responses to the "shed" command. For the Temecula Valley primary transmitter, the same single enhanced switch that responded to the "shed" event was also the only responder to any of the "restore" events.

Table 6.5 Comparison of Time Requirements

Circuit	Transmitter	Avg. Transmitter Response (sec)	Avg. Switch Response (sec)	Percent Difference
Inland Empire	Primary	20.33	17.32	15%
Inland Empire	Secondary	20.83	ND	ND
High Desert	Primary	20.75	17.05	18%
High Desert	Secondary	20.67	ND	ND
Temecula Valley	Primary	23.08	16.33	29%
Temecula Valley	Secondary	12.75	ND	ND
Simi Valley	Primary	20.71	16.88	19%
Simi Valley	Secondary	12.30	16.90	-37%

Table 6.6 Time Required by Enhanced Switches to Confirm Receipt of Dispatch Command to Shed Load

Circuit	Transmitter	Min (sec)	Max (sec)	Avg (sec)	Std. Dev.	Avg. Switches Per Sample	Samples	Total Switches
Inland Empire	Primary	15	18	16.73	0.54	6.89	18	124
Inland Empire	Secondary	ND	ND	ND	ND	ND	ND	ND
High Desert	Primary	16	18	16.77	0.62	7.5	8	60
High Desert	Secondary	ND	ND	ND	ND	ND	ND	ND
Temecula Valley	Primary	16	17	16.67	0.58	1	3	3
Temecula Valley	Secondary	ND	ND	ND	ND	ND	ND	ND
Simi Valley	Primary	16	18	17	0.89	1.2	5	6
Simi Valley	Secondary	14	24	17.13	1.55	5.43	7	38

Table 6.7 Integrated Assessment of Time Required by Enhanced Switches to Confirm Receipt of Dispatch Command to Shed Load

	Min Elapsed Time (sec)	Max Elapsed Time (sec)	Average Elapsed Time (sec)	Std. Dev.	Samples
Operator Issues Shed	0	0	0	NA	NA
Dispatch Application Sends Command to Transmitter	0	0	0	NA	NA
Dispatch Application Receives Response from Transmitter	11	31	18.98	4.21	92
Switches Respond to Shed	16	23	17.15	1.11	238

Table 6.8 Integrated Assessment of Time Required by Enhanced Switches to Confirm Receipt of Dispatch Command to Restore Load

	Min Elapsed Time (sec)	Max Elapsed Time (sec)	Average Elapsed Time (sec)	Std. Dev.	Samples
Operator Issues Restore	0	0	0	NA	NA
Dispatch Application Sends Command to Transmitter	0	0	0	NA	NA
Dispatch Application Receives Response from Transmitter	4	36	10.03	3.82	92
Switches Respond to Restore	14	24	16.81	0.83	231

6.1.3 Integrated Assessment of Time Required by Enhanced Switches to Confirm Receipt of Dispatch Commands

Table 6.7 above shows a high-level overview of the steps in a “shed” operation. For each step in the sequence, the minimum, maximum, and average elapsed times are listed, indicating when the step occurred. The baseline time for the “shed” operation is when the SCE operator clicks the “shed” button in the dispatch application, so the elapsed time for this step is zero.

The results show that the switches respond to the “shed” command at roughly the same time that the dispatch application receives the response from the transmitters. However, the standard deviation on the transmitter response time is very high because of the wide spread of average times for each transmitter, as discussed above.

Table 6.8 above shows the switch timing overview for the “restore” command. The most noticeable differences between these data and the data for the “shed” command are that the elapsed times are shorter, and there is more of a difference between the dispatch application receiving a response from the transmitter and the switches responding to the “restore” command.

The smaller elapsed times for the transmitter response are attributable the “restore” command containing fewer data than the “shed” command and the command thus taking less time to propagate through the system. The shed initiation time difference for ACP vs. RAA should be a few seconds, and is certainly under 10 seconds. However, the restore time difference should average about 1½ minutes – ACP switches should restore after approximately 6 minutes. The RAA switches should restore after 7½ minutes, possibly with a +/- 20% randomization on the restore. Because no RAA restore command is sent, the 7½ minutes restore time is the same regardless of when the restore was requested via the CERTS Dispatch application.

6.2 Measurements of Time Required for End-to-End Load Curtailments Initiated by CA ISO's Automated Dispatch System

CA ISO sends operating dispatch commands via the ADS software application to market participants that provide energy and ancillary services. We worked with CA ISO to create a test ADS server and client environment and used it to send simulated dispatch requests for spinning reserve to the SCE load management system operator. This subsection describes the types of end-to-end tests that we performed and the time required to execute each.

We performed four variations of end-to-end tests based on CA ISO system availability and the type of timing data we sought to collect:

1. Events initiated by simulated dispatches created by the BPL Global application with:
    a. SCE AC load management dispatch system already prepared for dispatch
    b. SCE AC load management dispatch system not already prepared for dispatch
2. Events initiated by simulated dispatches created by the CA ISO ADS application based on:
    a. Immediate dispatch
    b. Dispatch according to a schedule

6.2.1 Simulated CA ISO-Initiated Dispatch with Advance Notification to SCE System

The CA ISO events were initiated from the BPL Global CA ISO demand response dispatch application. This software sends notification of a "shed" or "restore" command based on a CA ISO data signal. For these simulated events, we replaced the real CA ISO data signal with an artificial signal that dispatched "shed" and "restore" commands at fixed times. The SCE operator was made aware of the approximate time of the "shed" and "restore" events, but the exact time was not conveyed until the notification was sent by the BPL Global dispatching application.

For each test, we sent out e-mail, pager, and phone notification, so we could assess the different types of communication delays with each technology. The notification was sent at the exact time the "shed" or "restore" operation was to be performed by the operator.

For this test, there were two types of events. For the first type, the SCE operator had the transmission system prepared before the notification was received. Because the dispatch system preparation time is typically 30 seconds, the intent of this test was to determine what system performance would be if that delay could be improved or eliminated in a future version of the platform. In the second type of event, the dispatch system was not prepared before the notification was sent, so the result was typical of what is possible with the current architecture.

Figure 6.2 below shows the sequence of steps in the first type of CA ISO simulated event. The sequence begins with the SCE operator preparing the dispatch system shortly before the approximate scheduled start time for the event. Once the system was prepared, the SCE operator notified BPL Global that the event could begin.

At this point, BPL Global sent a simulated "shed" dispatch to the BPL Global demand management application, which, in turn, sent notification to the SCE operator to start the normal sequence of events for a "shed" event.

The average, minimum, and maximum elapsed times for each step in the sequence are depicted in the right portion of Figure 6.2. We performed four end-to-end tests of this type.

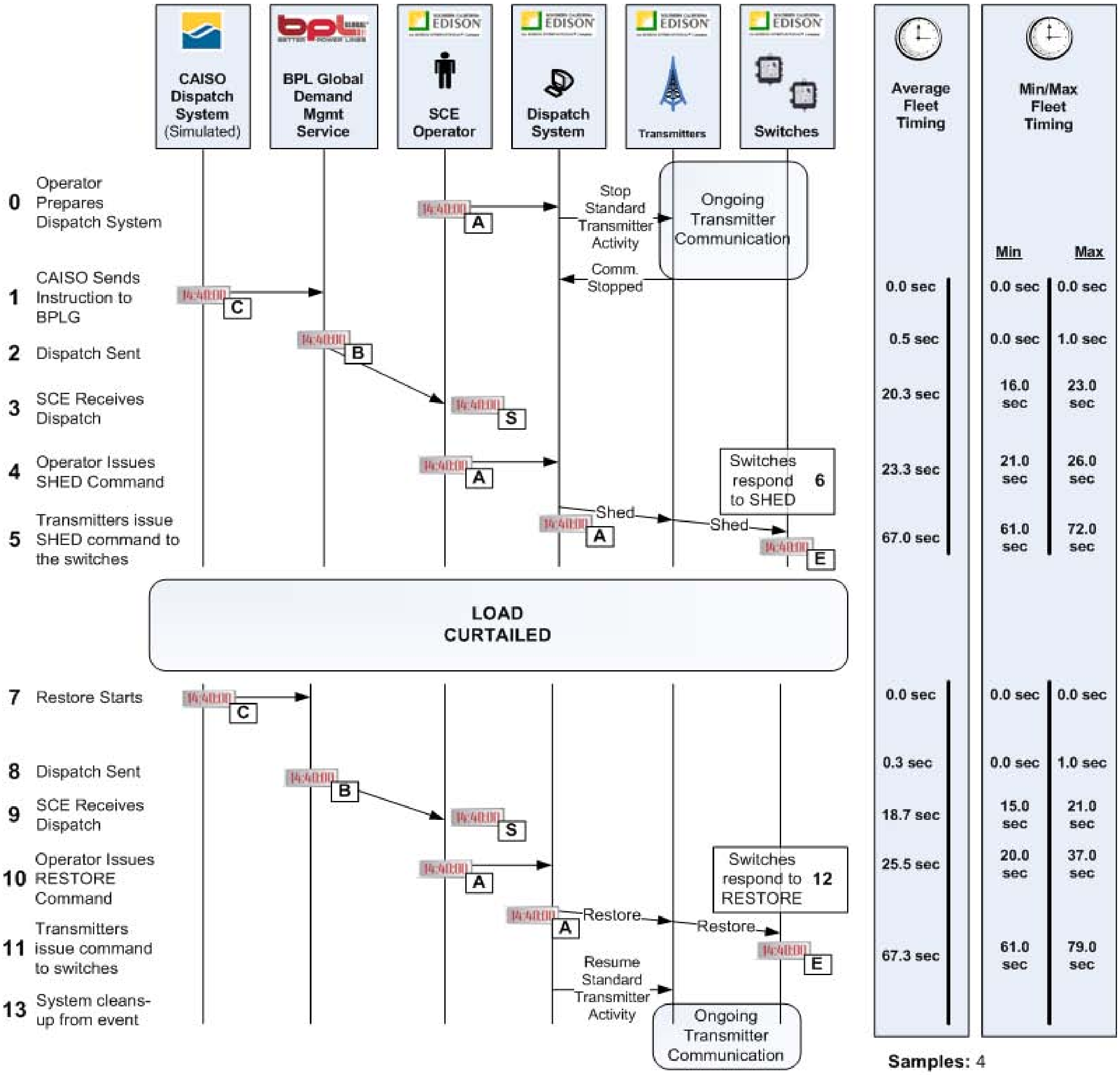
After a random duration, BPL Global generated a simulated CA ISO "restore" signal, which was sent to the BPL Global demand management application. This caused another notification to be sent to the SCE operator who then sent a "restore" command to the switches.

Table 6.9 below shows the detailed timing results for each step in the event. The switch response times have high standard deviations because they are averages of switches responding from eight different transmitters.

The "First Switch Response" and "Average Switch Response" steps look at the entire fleet of enhanced switches that responded to the test. For example, the minimum first switch response time is the fastest that any switch responded to any of the end-to-end tests of this variation. Likewise, the average of the first switch response is the average of the first responding switches from each of the samples.

Table 6.9 Simulated CA ISO-Initiated Dispatch with Advance Notification to SCE System

Step	Description	Min Time (sec)	Max Time (sec)	Average Time (sec)	Std. Dev.	Number of Tests
1	Shed Start Time	0.00	0.00	0.00	0.00	4
2	Shed Notification Sent to SCE	0.00	1.00	0.50	0.58	4
3	SCE Receives Notification	16.00	23.00	20.33	3.79	3
4	SCE Dispatches Shed	21.00	26.00	23.33	2.52	3
6	First Switch Response	38.00	48.00	42.25	4.35	4
6	Average Switch Response	61.00	72.00	67.00	4.55	4
7	Restore Start Time	0.00	0.00	0.00	0.00	4
8	Restore Notification Sent to SCE	0.00	1.00	0.25	0.50	4
9	SCE Receives Notification	15.00	21.00	18.67	3.21	3
10	SCE Dispatches Restore	20.00	37.00	25.50	7.77	4
12	First Switch Response	36.00	54.00	41.75	8.26	4
12	Average Switch Response	61.00	79.00	67.25	8.02	4



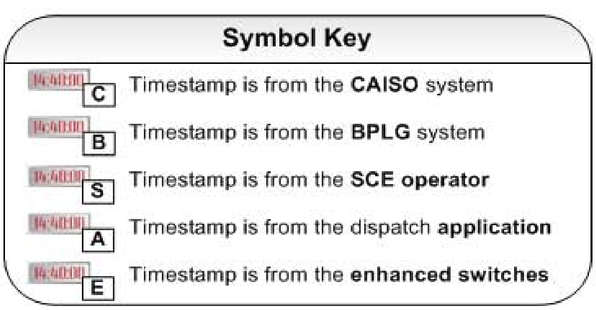


Figure 6.2 Simulated CA ISO-Initiated Dispatch with Advance Notification to SCE System

Because the SCE dispatch system was prepared prior to receiving the “shed” and “restore” notification, switches started to respond to the event 42 seconds after the target “shed” time, with the average switch responding in just over one minute. This is an unrealistic scenario, however, because it factors out the time it takes for the SCE operator to prepare the dispatch system. Even so, these tests demonstrate what could be achieved if the dispatch system were modified to significantly reduce or eliminate the system preparation time.

6.2.2 Simulated CA ISO- Initiated Dispatch without Advance Notification to SCE System

Figure 6.3 below shows the sequence of steps for the second type of CA ISO simulated event. This event assumes that the SCE system preparation time cannot be eliminated and thus shows a significantly longer delay before the switches begin responding to the event than in the previous type of test.

Table 6.10 below shows the detailed timing results for this type of simulated CA ISO test. It takes roughly 50 seconds longer for the first switch and average switch to respond to the test than when the dispatch system was pre-prepared. This is consistent with what would be expected because it takes at least 30 seconds to prepare the dispatch system, and the SCE operator is required to take manual steps, which further add to the delay.

Table 6.10 Simulated CA ISO-Initiated Dispatch Without Advanced Preparation of SCE System

Step	Description	Min Time (sec)	Max Time (sec)	Average Time (sec)	Std. Dev.	Number of Tests
1	Shed Start Time	0.00	0.00	0.00	0.00	5
2	Shed Notification Sent to SCE	0.00	1.00	0.20	0.45	5
3	SCE Receives Notification	13.00	21.00	18.40	3.44	5
4	SCE Transmitters Fully Prepared	68.00	83.00	72.75	6.95	4
5	SCE Dispatches Shed	71.00	88.00	76.75	7.63	4
7	First Switch Response	88.00	105.00	92.80	6.94	5
7	Average Switch Response	112.00	130.00	117.60	7.23	5
8	Restore Start Time	0.00	0.00	0.00	0.00	5
9	Restore Notification Sent to SCE	0.00	1.00	0.80	0.45	5
10	SCE Receives Notification	11.00	24.00	18.00	5.48	4
11	SCE Dispatches Restore	12.00	29.00	20.60	8.05	5
13	First Switch Response	29.00	44.00	37.20	7.56	5
13	Average Switch Response	53.00	75.00	66.20	9.12	5

In both of these tests, the deviation between the number of test runs and the number of samples for one particular step of the sequence is attributable to missing data. Because some of these time stamps are recorded manually by the SCE operator and because the operator was trying to execute the steps as quickly as possible, the operator missed recording some values.

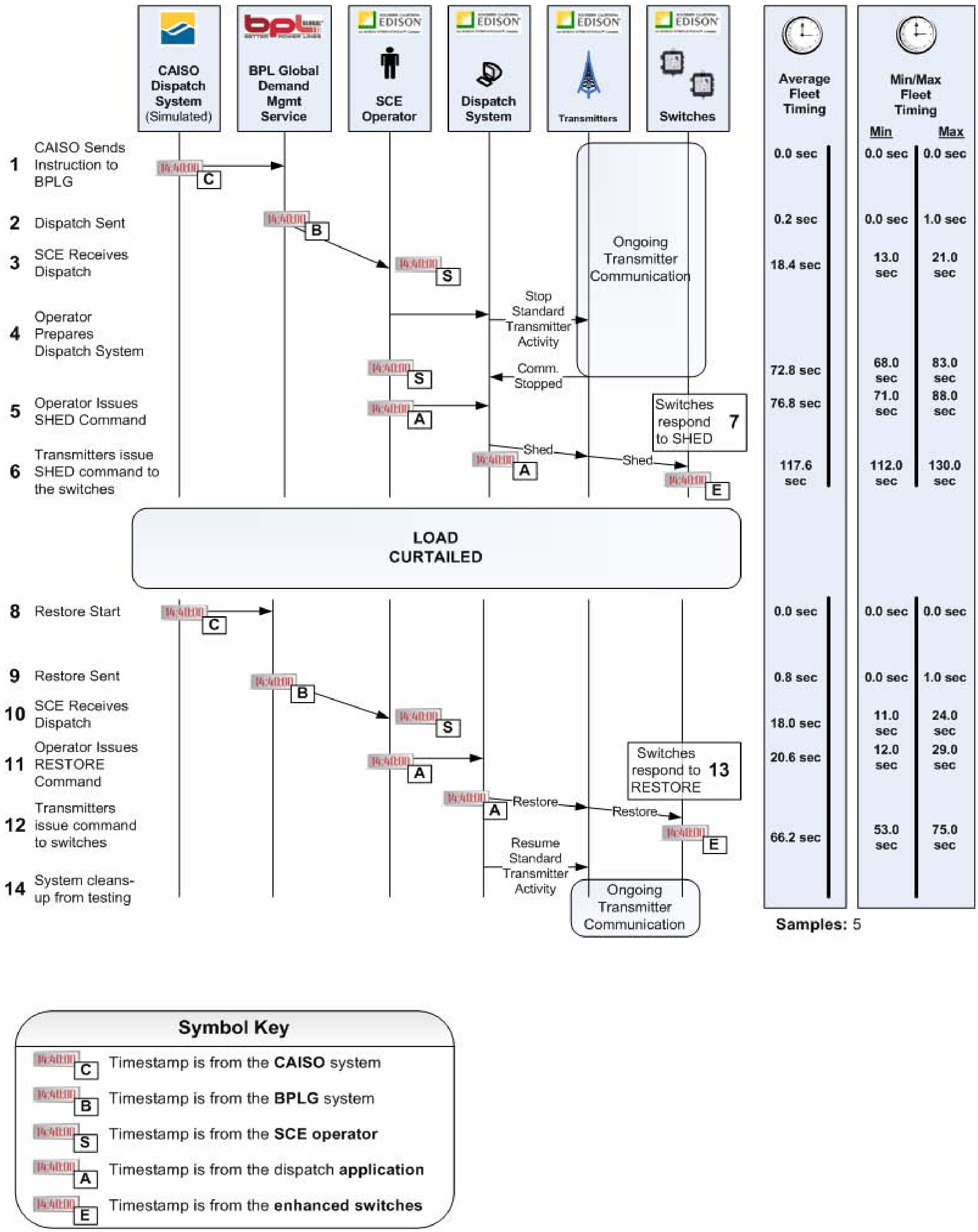


Figure 6.3 Simulated CA ISO-Initiated Dispatch Without Advance Preparation of SCE System

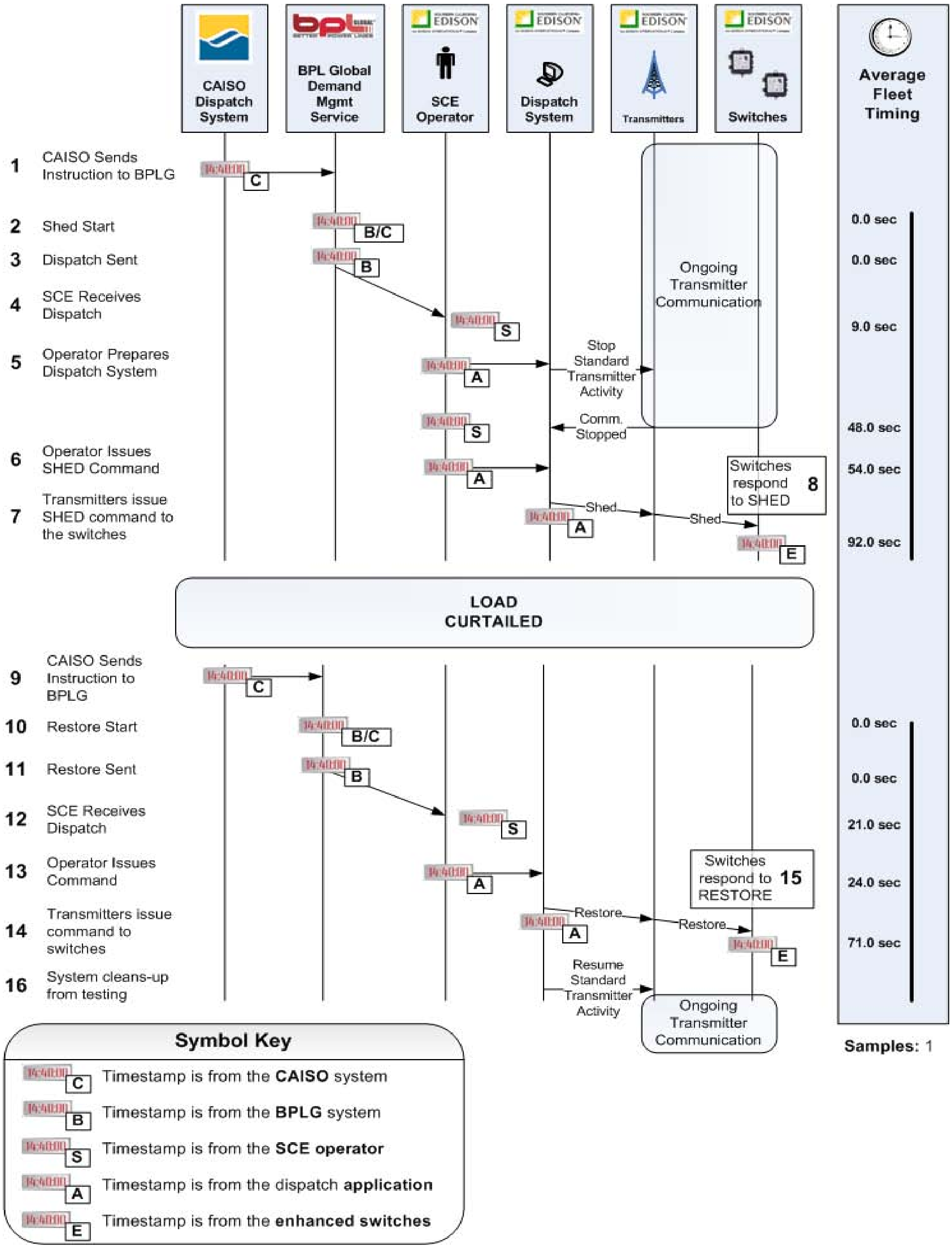


Figure 6.4 CA ISO Initiated Dispatch – Immediate Curtailment

6.2.3 CA ISO-Initiated Dispatch – Immediate Curtailment

Immediate curtailment events were identical to the CA ISO simulated events described in the prior section except the input signal came from the real CA ISO dispatching system setup rather than being simulated by BPL Global. For all of these events, the dispatch system was not prepared before the notification was sent (similar to the second type of simulated event described in the previous section).

As discussed previously, the CA ISO dispatch system normally instructs a particular generation resource slightly in advance to change its output to a specified level at a specified time. Because we received instructions roughly 1.75 minutes before the applicable interval began, we had the possibility of capitalizing on this lead time to allow the SCE operator to prepare the system and be ready to click the "shed" button at the exact time the interval was scheduled to begin. However, for this variation of our end-to-end test, we decided not to capitalize on this lead time. After receiving the instruction, the BPL Global dispatching system waited until the five-minute interval began before sending notification to the SCE operator. We expect this type of test to be more aligned with a production program in that there will typically not be 1.75 minutes of advance notice before action is required.

Figure 6.4 above shows the steps in this testing variation. Only one test of this type was performed so the "Average Fleet Timing" on the right side of the diagram displays the results from only this single test. The steps involved in this type of test are the same as in the second type of CA ISO simulated event.

Table 6.11 CA ISO-Initiated Dispatch – Immediate Curtailment

Step	Description	Time (sec)	Samples
1	BPLG Receives CAISO Dispatch	0.00	1
2	Shed Start Time	0.00	1
3	Shed Notification Sent to SCE	0.00	1
4	SCE Receives Notification	9.00	1
5	SCE Transmitters Fully Prepared	48.00	1
6	SCE Dispatches Shed	54.00	1
8	First Switch Response	70.00	1
8	Average Switch Response	92.00	1
9	BPLG Receives CAISO Dispatch	0.00	1
10	Restore Start Time	0.00	1
11	Restore Notification Sent to SCE	0.00	1
12	SCE Receives Notification	21.00	1
13	SCE Dispatches Restore	24.00	1
15	First Switch Response	40.00	1
15	Average Switch Response	71.00	1

Table 6.11 above shows the detailed results from this end-to-end test. In theory, the results should be nearly identical to the CA ISO simulated test with the SCE dispatch system not prepared because the only difference between these two types of tests is the use of a real CA ISO signal. However, the results are improved in this test, with a notable portion of the improvement in the time it takes SCE to receive the notification from BPL Global. However, the notification was sent out just as rapidly as in the prior tests, so the improvement must be within the paging or e-mail systems used to route the notification.

6.2.4 CA ISO-Initiated Dispatch – Scheduled Curtailment

This final variation of an end-to-end test differs from the previous type in that we sent notification to the SCE operator as soon as we received the instruction from CA ISO, well before the time the instruction was scheduled to take effect. The notification indicated the exact time the "shed" command should be executed by the operator. This effectively capitalized on the 1.75 minutes of lead time, allowing the SCE operator to dispatch the event extremely close to the actual "shed" time even including the dispatch system preparation time.

The "restore" command was also sent to the SCE operator as soon as the applicable instruction from CA ISO was received. This command included a requested "restore" start time but, in fact, the restore was expected to take place as soon as this notification was received. As a result, when we received another instruction from CA ISO to change the target output of the resource, we treated that as the restore for the curtailment. In terms of restoring on notification versus on schedule, the restore sequence requires no lead time by the SCE operator and also was not part of the questions we were seeking to answer through the testing. As a result, it was simplest to simply restore on notification. If we had an opportunity to perform more end-to-end tests, this may have been something we could have changed for another type of end-to-end test.

Figure 6.5 below shows the detailed sequence of steps in this type of CA ISO end-to-end test. We performed this type of test three times.

The sequence for this type of test is very similar to that for the "shed" notification with one significant difference; instead of the BPL Global system waiting for the "shed" time to begin after the notification is received, this delay is shifted to the SCE operator after the operator has prepared the system. This is shown between steps 4 and 5 in Figure 6.5.

Because of this change to the event sequence, it was more meaningful to split the "shed" portion of the event into two high-level tasks:

1. Receive CA ISO dispatch and schedule the "shed" with the SCE operator.
2. Dispatch the "shed" operation at the scheduled time.

By splitting the timestamps up in this fashion, we can easily see how quickly the switches respond relative to when the "shed" was scheduled to occur. Table 6.12 below shows the detailed timing data from these end-to-end tests.

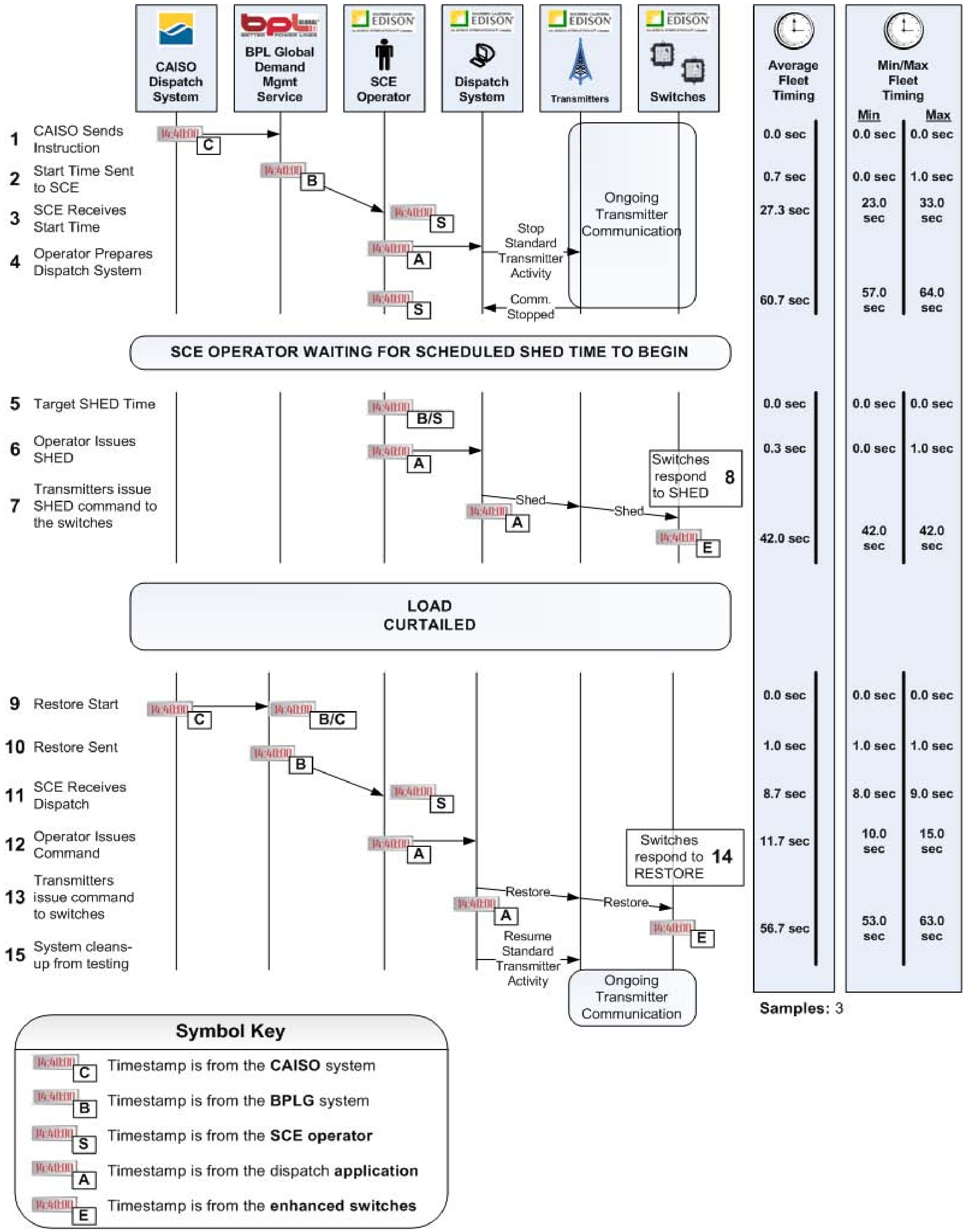


Figure 6.5 CA ISO-Initiated Dispatch – Scheduled Curtailment

Table 6.12 CA ISO-Initiated Dispatch – Scheduled Curtailment

Step	Description	Min Time (sec)	Max Time (sec)	Average Time (sec)	Std. Dev.	Number of Tests
1	BPLG Receives CAISO Dispatch	0.00	0.00	0.00	0.00	3
2	Schedule Sent to SCE	0.00	1.00	0.67	0.58	3
3	SCE Receives Schedule	23.00	33.00	27.33	5.13	3
4	SCE Transmitters Fully Prepared	57.00	64.00	60.67	3.51	3
5	Target Shed Time	0.00	0.00	0.00	0.00	3
6	SCE Dispatches Shed	0.00	1.00	0.33	0.58	3
8	First Switch Response	17.00	18.00	17.33	0.58	3
8	Average Switch Response	42.00	42.00	42.00	0.00	3
9	Restore Start Time	0.00	0.00	0.00	0.00	3
10	Restore Notification Sent to SCE	1.00	1.00	1.00	0.00	3
11	SCE Receives Notification	8.00	9.00	8.67	0.58	3
12	SCE Dispatches Restore	10.00	15.00	11.67	2.89	3
14	First Switch Response	26.00	31.00	28.33	2.52	3
14	Average Switch Response	53.00	63.00	56.67	5.51	3

For every test performed, SCE received the notification from BPL Global and fully prepared the dispatch system prior to the scheduled shed time. As a result, the switches responded extremely rapidly relative to the target "shed" time. The first switch responded in less than 20 seconds, and the average switch took a mere 42.0 seconds. The average switch delay for the "shed" portion of the event was exactly 42.0 seconds for each of the three samples.

Although the "shed" segment of this test (steps 5 through 8) is very similar to the CA ISO simulated test with the dispatch system prepared, the first switch and average switch response times are slightly faster. This can be attributed to the SCE operator being able to get ready to click the "shed" button prior to the "shed" time thereby removing the one- to two-second human delay between finishing the prior step and then moving on to dispatching the "shed."

6.3 Summary of Findings

Demand response resources can provide full response to "shed" and "restore" load commands significantly faster than required by reliability rules. NERC and WECC rules for contingency reserve response (both spinning and non-spinning) require full response in 10 minutes. The SCE load management dispatch system consistently demonstrated full response from all four distribution feeder groups in less than 80 seconds. This performance includes fixed delays totaling one minute, which are inherent in the design of SCE's current dispatch system. This includes both a fixed period of 30 seconds that is set aside to prepare the system for dispatch and three fixed 10-second delays between the transmission of dispatch signals from each of the four transmitter towers relaying these signals to each of the four distribution feeder groups. In the future, it might possible to reduce these fixed delays through further enhancements to SCE's dispatch software. The actual time required between the moment when an individual tower is directed to send a dispatch signal to a distribution feeder group and the time when the switches within this group confirm receipt of the signal was consistently less than 20 seconds. We also examined a variety of scenarios in which dispatch was initiated by requests received from the CA ISO's automated dispatch system and found that a complete end-to-end dispatch could be completed reliably in less than two minutes.

7. Estimation of Aggregate Load Curtailments Using Distribution Feeder Data

A core research objective of this demonstration project was to develop and evaluate the effectiveness of analysis methods to estimate the magnitude of aggregated load curtailed based solely on distribution feeder load data. The research challenge involves extracting the "signal" created by the simultaneous curtailment of individual AC units within a feeder from the stochastic "noise" that is characteristic of distribution feeder loads. As was discussed in Section 5, this challenge was made more complicated by the fact that SCE "split" each of the four feeders in the study so that there were fewer participants on each of the resulting eight feeders.

In Phase 1 of this demonstration project, we developed a simple regression-based method that predicted a baseline load for the period of the curtailment event (see Eto, et al. 2006). The difference between predicted and recorded load was taken as an estimate of the magnitude of the curtailment event. The predicted load was based on the average trend in the distribution feeder load recorded during the 10 minutes prior to each curtailment event. One unresolved issue associated with this method is that it cannot perform reliably during times when the overall load trend is changing, such as in the late afternoon or early evening when loads reach their maximum for the day and begin to fall as night approaches. Simple trending methods, such as the one we developed in Phase 1, will not perform well during such inflection points in the diurnal pattern of daily distribution feeder loads.

For Phase 2 of this demonstration project, we developed a new method for predicting a baseline against which to measure the magnitude of load curtailments using distribution feeder data. The method was developed to address both the expected problem of having fewer participants (lower signal) on each distribution feeder and the previously experienced problem with extrapolation of trends during inflections in the diurnal pattern of loads.

This section describes the new method and its application in six parts.

First, we discuss the methods we developed for preparing the distribution feeder load data for analysis, which involved first aligning the data with the known time of the curtailments and then aggregating the data during and surrounding the curtailment period into five-minute blocks.

Second, we describe the load-matching technique we developed to select patterns of five-minute loads from days without curtailments that were "closest" to loads on the days with curtailments (and that were recorded at the same time of day as the curtailment). The basic intuition behind this step is that, for any given feeder, the evolution of loads over the course of a day follows a repeatable pattern. By finding matching patterns of loads from non-curtailment days for the time immediately prior to the time of a curtailment, we can use the loads recorded at the time of the curtailment from the non-curtailment days to estimate what the load would have been on the curtailment day. Special attention is paid to the criteria used to select both the number of matching non-curtailment days to use as well as the number of periods prior to the curtailment to use in predicting the load for the time of the curtailment.

Third, we explore a number of issues that arise in applying the method to the distribution feeder data we collected, including: 1) whether to include weekend days along with weekdays in selecting non-curtailment days, 2) how to use the method to predict loads for curtailments lasting longer than five minutes, 3) whether to apply the method to the combined distribution loads from feeders A and B.

Fourth, we present the final models we developed and describe their application to the distribution load data. Separate models are developed for the four feeders (and combinations among them) that had eight-second data available and for the eight feeders (and combinations among them) that had two-minute data available.

Fifth, we present the results from application of the models to estimate the magnitude of load shed during each curtailment event. The results are assessed using statistical criteria that establish whether the estimated aggregate amount of load curtailed (i.e., the signal) can be distinguished from the inherent stochastic variability of distribution feeder loads (i.e., the noise).

Appendix D compares the new method developed for Phase 2 of this project with the older method developed in Phase 1 of the project.

7.1 Data Preparation

As a preliminary smoothing technique and to produce a data set that could be analyzed in a reasonable amount of time, we aggregated the eight-second and two-minute feeder data streams into five-minute periods. Because the tests conducted over the course of the summer were all either five or 10 minutes in length, the minimum period for which we needed to predict load was five minutes, so this was sufficient for computing demand savings over the test periods.

For each five-minute period, T, the eight-second MW readings ending in the period were averaged to produce a series of five-minute readings, such that

$$Load_T = \frac{\sum_{t=T-5\min}^{T} Load_t}{n}$$

where T is the ending timestamp of the five-minute period.

The system employed by SCE for these tests sends an isolated signal from each of 12 broadcast towers one at a time. The tower nearest the Inland Empire is the first to broadcast; only after it has completed its signal does the High Desert tower signal, and so on. Section 3 contains more information on the details of the transmission system. There was also an approximately 19-second delay between the start of an event and the first tower being cleared to broadcast. The result of these system characteristics was that the actual start time of an event on a given feeder was different from the nominal start time of the event. To account for these differences, the five-minute analysis windows were shifted for each feeder by a number of seconds that allowed the periods to line up with the beginning of the typical feeder response to a curtailment event, rather than the nominal beginning of the test event. This required a shift of 19 seconds for the Inland

Empire, 49 seconds for Simi Valley, 79 seconds for Temecula, and 28 seconds for the High Desert feeder. Thus, for example, the Inland Empire's five-minute periods were calculated such that

$$Load_T = \frac{\sum_{t=T-281\,\mathrm{sec.}}^{T+19\,\mathrm{sec.}} Load_t}{n},$$

where the counting of the period begins at 281 seconds prior to the end-of-period timestamp and ends 19 seconds after it.

In order to focus derivation and evaluation of the model on the part of the day most likely to see test events, we included only the hours of 11:00 a.m. to 8:00 p.m. in the analysis. For the initial application of the prediction model, we wanted to model typical feeder load unaffected by a load-shed event, so we excluded all observations that overlapped a test period or occurred in the hour following it.

7.2 Development of a New Load Prediction Method

We used a number of linear prediction models on the Inland Empire feeder's five-minute aggregation of eight-second data, including various combinations and functional forms of: temperature; lagged temperature; lagged load values; time; and two-, three-, and four-period trending. The results were mixed. Temperature and time alone gave the proper load shape but failed to provide precise enough load estimates for us to estimate curtailment. The two-period and three-period trending variables, which were essentially an aggregation and systematic evaluation of the 10-minute trending approach used in Phase 1, showed considerable promise, producing models with an estimated root mean squared error (RMSE) of 0.090 MW and a coefficient on the predictive term of 0.9993, indicating that the prediction was accurate within 0.07% and had a precision of about 150 kW on a 4,000 – 6,000 kW load.[15] However, the team concluded that these predictions were too sensitive to variability during the 10-15 minutes preceding an event, which could override the prevailing load curve. For example, two flat observations during the 10 minutes preceding an event at a typically down-trending time of day could result in a significant overestimate of load. Furthermore, the revised model described below outperformed these models across all of the feeders.[16]

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[15] The team also tried a four-period trend prediction, but the accuracy of this estimate dropped from 99% to 73%, indicating that including four periods in the to often straddle inflections to be a reliable indicator of the subsequent 5 minutes of feeder load.

[16] Although the model outlined here predicts five-minute periods very precisely and thus can quantify five-minute event impacts very well, its usefulness is limited to that time scale; it quickly breaks down when applied to longer events, such as those called by peak-reducing uses of a curtailment system. These longer events need a model that can predict load for the entire duration of the event. This model could be adjusted to perform well for 10-minute or 20-minute events, by aggregating data to those intervals instead of five minutes. However, once the duration reaches an hour, the granularity of the aggregated data will begin to undermine the precision of the estimate. As part of a continued exploration of this model, we are currently investigating these trade-offs.

We felt that a more robust predictive model could be developed if we took advantage not only of information in the periods immediately preceding the estimated period, but also the behavior of the feeder load during that same time period on other days when load was similar. Producing this estimate required a multi-step process, which can be summarized simply as follows:

1. Select 12 days from the rest of the feeder data when the load during the same five-minute interval immediately preceding the curtailment was closest to that on the curtailment day (six closest days with load above that for the day in question and six closest days with load below).
2. Average the loads from the 12 historic days, and take the ratio between the result and the same preceding interval on the curtailment day to obtain an adjustment factor.
3. Take the average load from the 12 historic days for the curtailment interval itself. Use the ratio determined in step 2 to adjust the average for the curtailment interval. This is the best estimate of what the load would have been had the curtailment not occurred.

A number of approaches were tested for sensitivity to the number of historic days, length of the preceding period, and whether introducing a bound to the historic days used for comparison had an impact. The details of the methodology are as follows:

Step 1. First, for each five-minute period, we estimated the average load during the preceding n-minute period, starting at five minutes and working up in five-minute increments to the average load during the preceding 50 minutes. We denote this average:

$$PLoad_{T,n} = \frac{\sum_{i=1}^{n} Load_{T-i}}{n} \; .$$

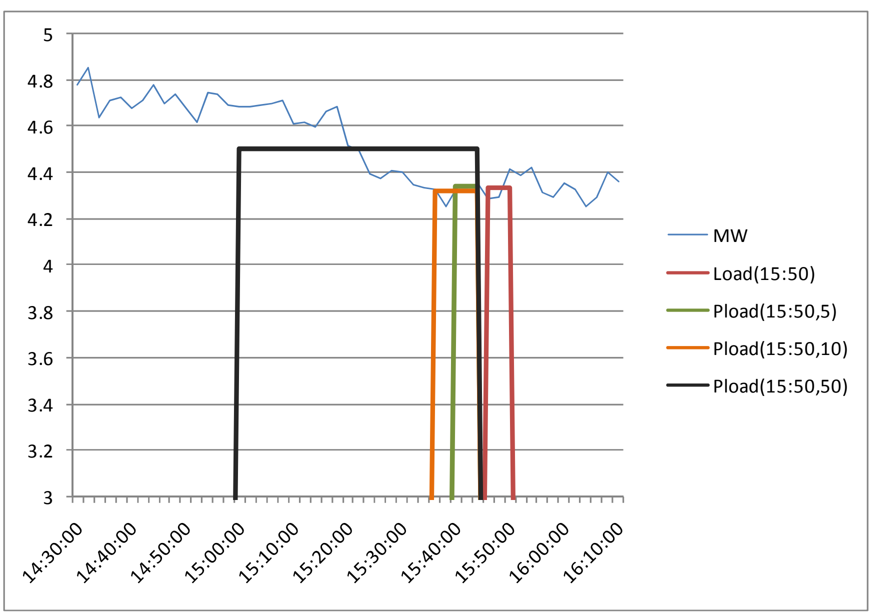

Figure 7.1 Step 1: Calculate the average load during the 5, 10, 15,…50 minutes preceding each five-minute period

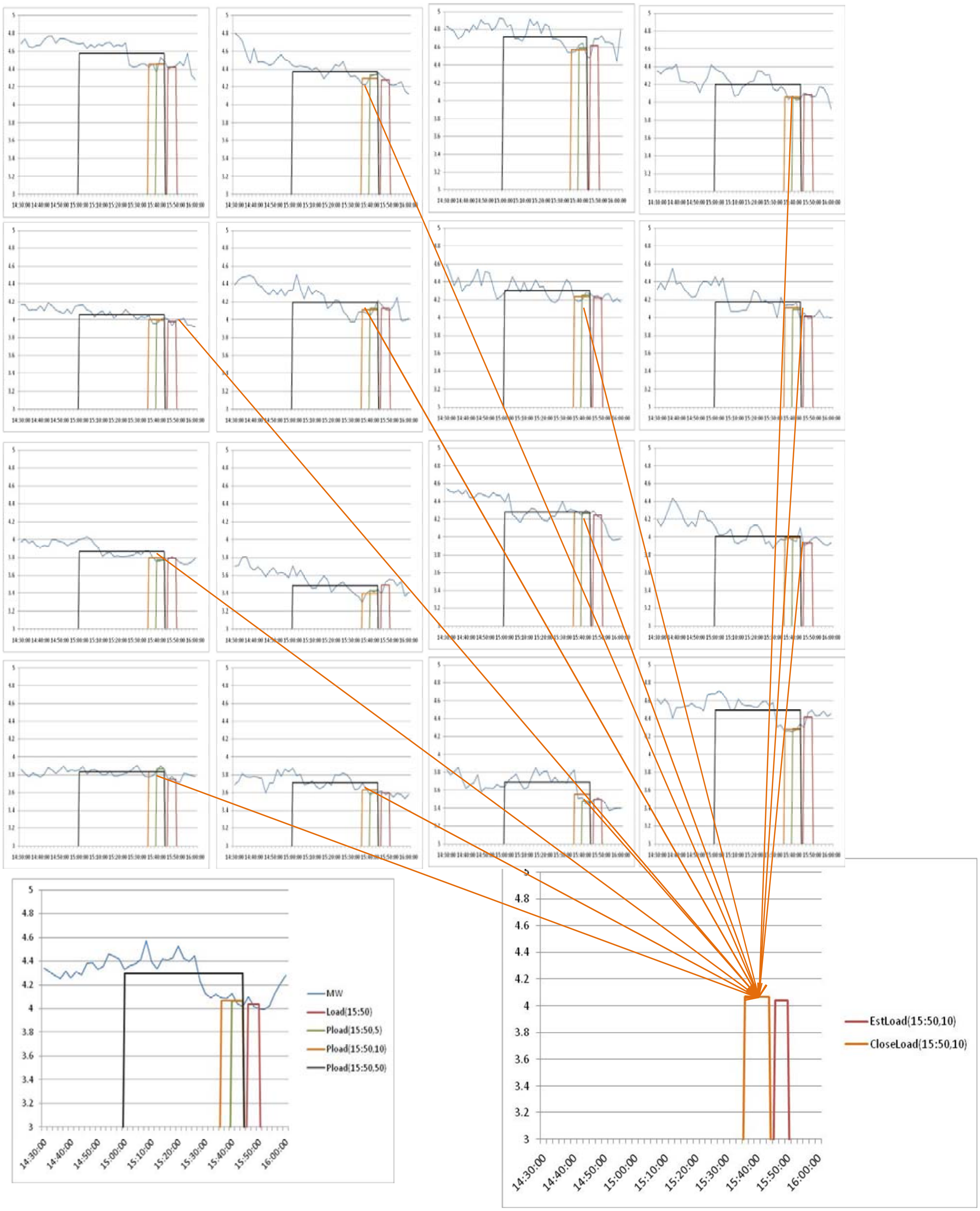

Figure 7.2 Steps 3 and 4: Find the 12 days with the closest preceding average (*$PLoad_{d,p,n}$*) for the 5, 10, 15,…50 minutes before each five-minute period.

Step 2. We then specified d as the date of the period T, and $p \in \{1–288\}$ to denote which of the 288 five-minute periods is represented by period T. Thus, $Load_{d,p} = Load_T$ and $PLoad_{d,p,n} = PLoad_{T,n}$.

Step 3. For each of these preceding averages, $PLoad_{d,p,n}$, we identified the twelve $PLoad_{d^*,p,n}$, where $d^* \neq d$, that are closest in value to $PLoad_{d,p,n}$; six greater and six less, calling the set

$$Close_{d,p,n} = \{Pload_{d(1),p,n}, \ldots, Pload_{d(12),p,n}\}.$$

Elements were excluded if they were more than a given percentage, CutPerc, away from $PLoad_{d,p,n}$. For example, for 1:15 to 1:20 on June 19th, we identified the six 1:15 to 1:20 periods on other days with the closest five-minute preceding averages that exceed the 1:10 to 1:15 average for June 19, and the six closest that were less than it. The same was repeated for the n minutes preceding, all the way up to the 50 minutes prior.

Step 4. Next, we calculated the mean of each of these sets such that:

$$CloseLoad_{d,p,n} = \frac{\sum_{i}^{m} Pload_{d(i),p,n}}{m}$$

where m is the number of elements in $Close_{d,p,n}$. This represents the average load in the preceding n periods on the m days with the closest load to the n periods preceding period p on date d. We call the group $Close_{d,p,n}$ and average the group to create $CloseLoad_{d,p,n}$.

Step 5. The final piece needed to make the prediction is average load in period p on the days determined to have the most similar n periods. Because these days' load patterns are determined to be similar during periods p-n through p-1 to the day whose load we are estimating, then the load experienced in period p on those days should be a very good estimation of the load in period p on day d. Taking the d(1)-d(m) from the set $Close_{d,p,n}$,

$$EstLoad_{d,p,n} = \frac{\sum_{i}^{m} Load_{d(i),p,n}}{m}.$$

Step 6. The estimate, $EstLoad_{d,p,n}$, may be biased up or down depending on the relationship between the load of day d and the loads on days d(1)-d(m). Therefore, we made a final adjustment to the estimated load of each period, truing it up or down by the ratio of the actual prior load,
$PLoad_{d,p,n}$, to the prior load on the closest comparison days, $CloseLoad_{d,p,n}$. The final load estimate is thus written

$$AdjEstLoad_{d,p,n} = EstLoad_{d,p,n} \cdot \frac{Pload_{d,p,n}}{CloseLoad_{d,p,n}}.$$

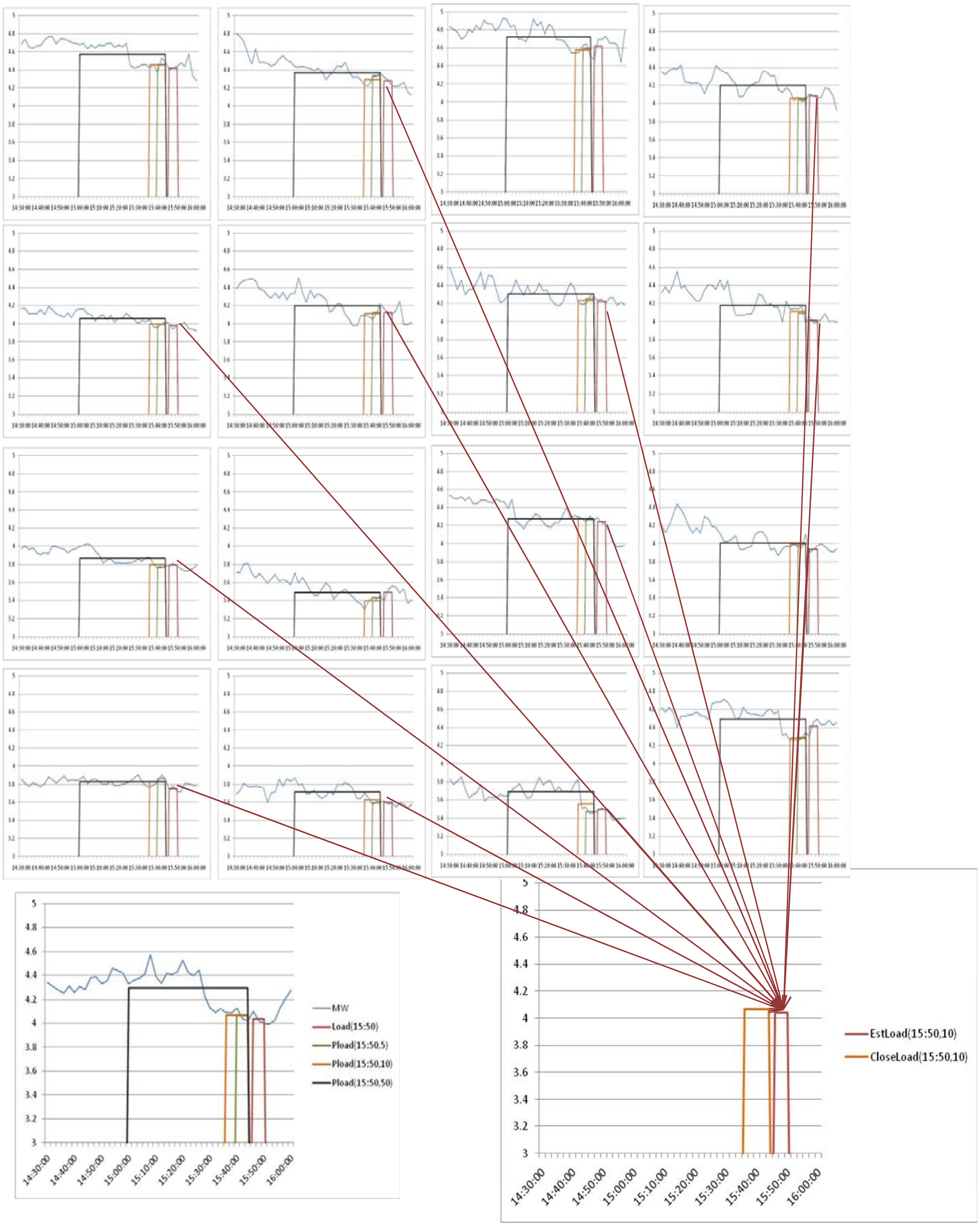

Figure 7.3 Step 5: Average the $Load_{d,p}$ that corresponds to each of the 12 closest preceding loads. Call this average $EstLoad_{d,p,n}$; it is the unadjusted estimate of the period's load.

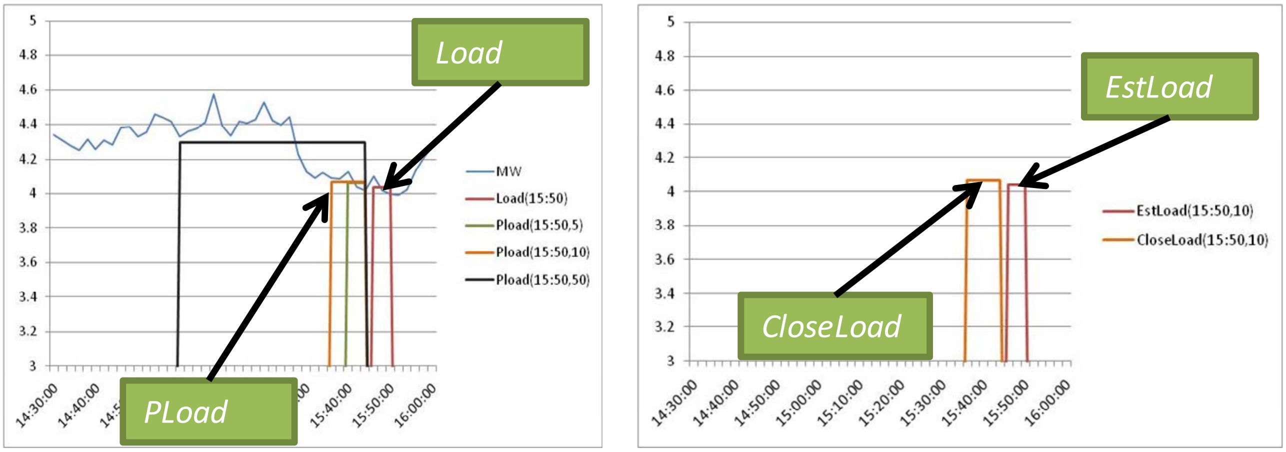

Figure 7.4 Step 6: Adjusted estimated load for each period.

7.2.1 Testing the Predictions

To test how well $AdjEstLoad_{d,p,n}$ was a predictor of $Load_{P,D}$, for each n, we used ordinary least-squares estimation for the regression equation

$$Load_{P,D} = \beta_1 \cdot AdjEstLoad_{d,p,n} .$$

The value of β1, if the model is accurate predictor of $Load_{P,D}$, should be close to 1, while the RMSE will be an indication of the precision of the estimate and thus a measure of the uncertainty of any predictions made with the model.

7.2.2 Choosing the CutPerc and n

We produced predictions, $AdjEstLoad_{d,p,n}$, based on an inclusion cut-point, CutPerc, of 2.5% to 25% in increments of 2.5% and n values of 1 through 10, for each day, d, and five-minute period, p, for which we had viable load data. The results were consistent across the feeders we tested and indicated two things:

First, n = 1 produced the most precise results. This indicates that looking further back than five minutes detracts from the precision of the predictions. The most precise estimate focuses on the five minutes prior to the predicted period.

Second, higher CutPerc values were associated with better precision, which indicates that the true-up described in Step 6 above is sufficient to control for differences in magnitude between comparison days and the predicted day. The estimate improves if more comparison periods inform the load shape, even if they are from the prior period's load.

An example of these results is shown below in Tables 7.1 and 7.2. Table 7.1 shows the values of β1 for each combination of n and CutPerc for the Inland Empire A feeder's eight-second data. At all combinations of n and CutPerc, β1 is greater than 0.9997 and has a t-statistic greater than

4,000, indicating an excellent fit between the predicted value and the actual value. At higher levels of CutPerc and lower values of n, the coefficient β1 is even closer to 1.

Table 7.2 shows the RMSE values for the same set of regressions on the same feeder. Here, the improvement in precision for higher values of CutPerc is apparent; with an n of 1, the RMSE reduces from 0.0793 at 2.5% to 0.0745 at 25%. The impact of n on precision is even more pronounced: at a CutPerc of 25%, n=1 produces an RMSE of 0.0745, as compared to 0.0827 at n=2. Higher values of n produce estimates with even higher levels of statistical error. Based on these observations, we chose 25% as the value for CutPerc and n = 1 for our prediction models.

Table 7.1 β1 Values for Regression Test on Predictions, by n and CutPercent

n \CutPerc	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	22.5%	25.0%
1	0.99998	0.99992	0.99993	0.99993	0.99996	0.99994	0.99998	0.99999	1.00001	0.99999
2	0.99989	0.99986	0.99983	0.99990	0.99995	0.99992	0.99994	1.00001	1.00003	1.00000
3	0.99985	0.99985	0.99985	0.99986	0.99993	0.99997	1.00000	1.00003	1.00003	1.00000
4	0.99982	0.99981	0.99976	0.99992	0.99997	0.99993	0.99999	1.00004	1.00004	1.00005
5	0.99982	0.99984	0.99979	0.99989	0.99996	0.99992	0.99999	1.00005	1.00003	1.00005
6	0.99980	0.99977	0.99980	0.99987	0.99994	0.99990	0.99999	1.00007	1.00004	1.00005
7	0.99981	0.99978	0.99982	0.99982	0.99994	0.99989	0.99999	1.00007	1.00002	1.00003
8	0.99975	0.99977	0.99975	0.99979	0.99994	0.99991	1.00001	1.00009	1.00006	1.00002
9	0.99982	0.99973	0.99977	0.99978	0.99998	0.99993	1.00003	1.00015	1.00008	1.00003
10	0.99981	0.99970	0.99976	0.99984	1.00000	0.99993	1.00006	1.00014	1.00007	1.00002

Table 7.2 RMSE of Regression Test on Predictions, by n and CutPerc

n \CutPerc	2.5%	5.0%	7.5%	10.0%	12.5%	15.0%	17.5%	20.0%	22.5%	25.0%
1	0.0793	0.0776	0.0775	0.0773	0.0769	0.0747	0.0757	0.0756	0.0748	0.0745
2	0.0863	0.0851	0.0880	0.0868	0.0851	0.0834	0.0829	0.0838	0.0830	0.0827
3	0.0963	0.0936	0.0938	0.0922	0.0934	0.0897	0.0893	0.0895	0.0889	0.0886
4	0.0964	0.0979	0.1000	0.1023	0.1002	0.0956	0.0950	0.0958	0.0954	0.0958
5	0.1024	0.1032	0.1074	0.1100	0.1062	0.1018	0.1016	0.1016	0.1006	0.1009
6	0.1098	0.1092	0.1145	0.1151	0.1099	0.1068	0.1059	0.1061	0.1049	0.1051
7	0.1146	0.1130	0.1181	0.1189	0.1132	0.1111	0.1100	0.1104	0.1091	0.1095
8	0.1163	0.1187	0.1230	0.1247	0.1177	0.1150	0.1147	0.1149	0.1140	0.1136
9	0.1191	0.1255	0.1283	0.1303	0.1219	0.1193	0.1184	0.1190	0.1176	0.1174
10	0.1236	0.1312	0.1316	0.1345	0.1256	0.1229	0.1223	0.1225	0.1213	0.1208

7.3 Issues Addressed in Applying the New Load Prediction Model

As noted in the introduction to Section 7, we explored a number of questions that arose in applying the new load prediction model to the distribution feeder data we had collected, including: 1) whether to include weekend days along with weekdays in selecting non-curtailment days, 2) whether the method could be used to reliably predict loads for curtailments lasting longer than 5 minutes, and 3) whether to apply the method to the combined distribution loads from feeders A and B.

7.3.1 Inclusion of Weekdays Only or Both Weekdays and Weekends

On many feeders, such as those dominated by commercial load, the load shapes of weekdays – i.e., timing of peaks and inflection points – can be significantly different from the shape on weekends when commercial load is typically much less. This variation could undermine the type of predictive model we developed, which relies on an assumption of similarity in load shapes among days to make its prediction. Therefore, for each feeder, we tested whether a weekday-only model produced a better estimate of load than a model that included both weekdays and weekends (and thus would offer a broader pool of days to draw from for comparison purposes).

For all feeders except Simi Valley, the weekday-only model either offered no improvement over or produced worse results than the weekday plus weekend model. For Simi Valley, the weekday-only model produced better, more precise results. Thus, we modeled the Simi Valley feeders using weekdays only, and drew from the broader set of weekend and weekend data for the other feeders.

7.3.2 Application to Curtailments Lasting Longer than Five Minutes

The prediction model described above relies on a valid observation made immediately preceding the period being predicted. As defined, this will exist for almost every test-event period because the time preceding the prediction period will be a “non-event” period and thus a valid reading. For the handful of 10-minute test events, however, the period preceding the second five-minute observation during the event is itself an event period and thus was excluded from the model. For these observations and the few other five-minute periods in the analysis data sets that lacked a valid preceding period, we substituted the n=2 estimate for the preceding period. This observation essentially relies on the five-minute observation two periods before the predicted event for making the comparison to other days.

Across all six feeders and feeder combinations, the second half of the 10-minute test events significantly underperformed the first half and similar-temperature events. This is most likely a result of either: the timing of those events being off by a significant enough amount that snap-back (restoration of significant load after the “restore” command) took place during the second five-minute period and reduced load drop, or the substitution model used to predict those periods systematically underestimating load. Additional diagnostics on the models could easily identify the cause.

7.3.3 Application to the Combined Data Involving More Than One Feeder

Another source of uncertainty in our load predictions is the adding and removing of loads to the feeders, which results in the observation-to-observation variation in load around the load shape trend. Although the load shapes across multiple feeders may be correlated, these variations should be independent of one another; the random "noise" on one feeder will not affect the "noise" on another feeder because each feeder is composed of wholly separate loads. Thus, the errors around the predictions of each feeder will be independent of one another.

Because the errors are independent, we would expect that when we add any two feeders together, the error bound of their combined estimate would be equal to the square root of the sum of the squares of the constituents' error bounds. For example, for feeders A and B,

$$EB_{A+B} = \sqrt{EB_A{}^2 + EB_B{}^2} .$$

Because the error bound will increase at a slower rate than the sum of their loads, we would expect that as we add feeders together into larger, combined feeders, the precision of the model estimates relative to the feeder load (and thus relative to the potential test event load drops) would increase. That is, the combined feeder would have a lower ratio of RMSE to average load than the individual component feeders. Thus, it can be useful to roll feeders with observable impacts into larger units of analysis; the impacts will add linearly while the error bounds will increase at the slower rate of the square-root of their summed squares and thus be smaller relative to the estimated load impacts.

Where data were available for all feeders in a combined set, the loads were added together. If any feeder was missing data in a period, the combined feeder load was labeled as missing. The combined load was then run through the same predictive model as was used for each individual feeder, creating a predictive load profile of the combined total of the constituent feeders, as if their loads had been served by a single feeder.

7.4 Final Models and Their Use to Estimate Curtailed Loads

We developed separate models for the four feeders (and combinations among them) for which eight-second data were available and for the eight feeders (and combinations among them) for which two-minute data were available.

7.4.1 Final Models, Based on Eight-Second Feeder Data

Table 7.3 shows the regression coefficients and RMSE on the predictions from the four A feeders for which we had eight-second data, along with the sums of the Inland Empire and High Desert feeders and of all four A feeders. The table also includes the estimated error bound of the predictions at the 90% level of confidence (1.645*RMSE).

Table 7.3 Regression Results for Models Based on Eight-Second Data

Feeder	Coefficient	RMSE	Error Bound
Inland Empire A 8 sec	0.99998	0.075	0.124
High Desert A 8 sec	0.99992	0.054	0.088
IE A + HD A 8 sec	0.99997	0.091	0.149
Simi Valley A 8 sec	0.99992	0.057	0.094
Temecula A 8 sec	1.00002	0.077	0.126
Total A 8 sec	0.99998	0.122	0.201

All six feeders and feeder combinations produced load predictions with $\beta 1$ values within 0.00008 of 1, indicating non-biased predictors. The RMSE, the indicator of the precision of the predictions, varies more from feeder to feeder: Temecula and the Inland Empire have relatively high RMSE values, 0.077 and 0.075 respectively, representing a higher amount of period-to-period variability than on the High Desert and Simi Valley feeders. These latter two had RMSE values of 0.054 and 0.057 respectively. These translated into error bounds ranging from 0.088 on High Desert A to 0.126 on Temecula, meaning that an event test on Temecula would have to be estimated above 126 kW to be considered statistically significant, but an event on High Desert estimated at 88 kW would be significant. The summed feeders, as expected, have RMSEs that are less than the square root of the sum of the squares of their constituent feeders.

7.4.2 Final Models, Based on Two-Minute Feeder Data

Table 7.4 shows the regression coefficients and RMSEs on the predictions from the feeders for which we used two-minute data. The table includes the feeder A and B results as well as results for the A and B feeders added together for each pair of feeders. The sums of all four A feeders and all seven A and B feeders for which we had two-minute data are also reported. The estimated error bound of the predictions at the 90% level of confidence (1.645*RMSE) is also included in the table.

The A feeders, with the exception of Temecula, reflect the same precision levels seen in the eight-second predictions. The two-minute Temecula data seem more precise than the eight-second data, but this ultimately has more to do with which eight-second observations happened to be kept in the two-minute set than anything fundamentally different about the feeder. The B feeders produced precision results that are relatively close to their corresponding A feeders, reflecting that the loads on each have similar levels of variation. The Inland Empire B feeder, however, had more precise results than the corresponding A feeder. At this point we think this may have to do with B having a smaller proportion of commercial load. Combining the A and B feeders markedly improves the relative error bound as we expected; all three summed A and B pairs are within 0.02 of the root sum of squares of the constituent feeders' error bounds.

Table 7.4 Regression Results for Models Based on Two-Second Data

Main Feeder	Sub Feeder	Coefficient	RMSE	Error Bound (MW)
Inland Empire	A	0.99991	0.074	0.121
	B	0.99960	0.065	0.107
	A + B	0.99978	0.099	0.162
High Desert	A	0.99985	0.059	0.097
	B	0.99983	0.065	0.108
	A + B	0.99986	0.089	0.146
Simi Valley	A	0.99994	0.058	0.095
	B	0.99997	0.059	0.097
	A + B	0.99998	0.085	0.141
Temecula	A	0.99997	0.068	0.112
Totals	A	0.99993	0.133	0.219
	A + B	0.99989	0.177	0.291

7.4.3 Estimating the Load Impacts of Each Curtailment

For each period when a curtailment occurred, we calculated the percentage of the period that was curtailed, CurtailPerc. For most of the tests, when the timing of the event lined up exactly with our observation periods, this value was 100%. For a handful of tests in which the start of the event was delayed for a few seconds (and even more than a minute for one test), these values were less than 1. We dropped from the analysis any test periods during which the curtailment event ended part way through the period. We observed significant load returning to the feeder immediately following a “restore” event. This snap-back, if included in the estimate of load drop by looking at a five-minute period including it, would understate the actual magnitude of the event; thus we removed clear instances of snap-back from the analysis. Ultimately, 40 test events could be quantified from the eight-second feeder data and 41 test events from the two-minute data.

For each 5-minute period (d, p) within each of these test events, the estimated load reduction, $ELR_{d,p}$, was calculated by first subtracting the actual load, $Load_{d,p}$, from the estimated load for that period, $AdjEstLoad_{d,p,n}$. The difference between these is the average amount by which the load was reduced during the five-minute period (p, d). Some events curtailed for less than the full length of a five-minute analysis period (i.e., CurtailPerc was less than 1). This meant that the average load reduction would be an average of the zero load reduction preceding the event and the load reduction of the event itself. We dealt with this by dividing the $ELR_{d,p}$ by the percentage of the period that was curtailed to produce the test event load reduction,

$$TELR_{d,p} = \frac{AdjEstLoad_{d,p,1} - Load_{d,p}}{CurtailPerc}.$$

For 10-minute-long test events, two estimates of the test were produced; one for the first five minutes and one for the second five minutes.

7.5 Load Curtailment Results

This subsection presents the results from using the models to estimate the load shed during each curtailment event. The results are assessed using statistical criteria that establish whether the estimated aggregate amount of load curtailed (i.e., the signal) can be distinguished from the inherent stochastic variability of distribution feeder loads (i.e., the noise). First, using the models based on eight-second data, we present results for three sets of feeder data: 1) Inland Empire and High Desert, 2) Simi Valley and Temecula Valley, and 3) Inland Empire and High Desert combined and all four feeders combined. Next, using the models based on two-minute feeder data, we present results for each of the four feeders.

7.5.1 Aggregated Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Inland Empire and High Desert

The Inland Empire and High Desert feeders showed a number of events with estimated drops that were statistically different from zero. The results of the events can be seen below in Table 7.5. The Inland Empire A test estimates are consistently positive and often above 0.100 MW during the course of the summer. These test results are generally lower than expected, but, given the number of switches that were split off into the Inland Empire B feeder, they are not surprising. The relatively high variability of the feeder prediction model, however, resulted in many of the tests falling below the threshold of statistical significance. The High Desert A feeder, which had fewer switches moved to its B feeder, showed a similar number of reliable tests. Its lower error bound meant that more of the lower test estimates were deemed significant.

Inland Empire A **High Desert A**

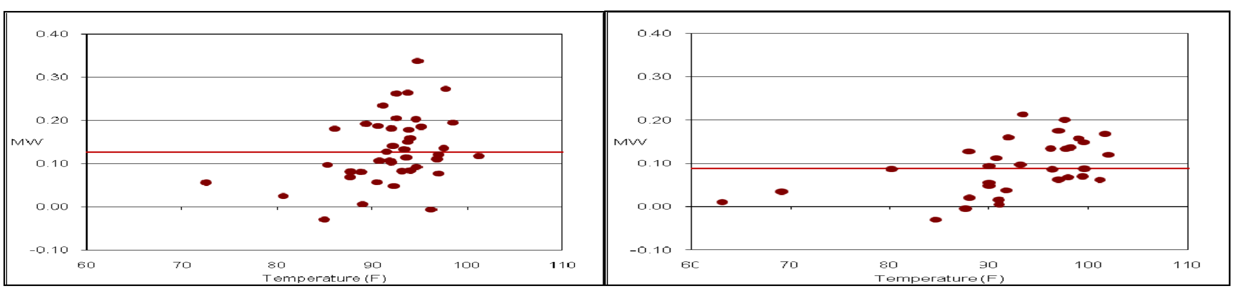

Figure 7.5 Aggregate Load Curtailed vs. Temperature for Inland Empire and High Desert

These results become clearer when graphed against the temperature during the test, as shown in Figure 7.5. The red line on each graph represents the cutpoint for statistical significance on that feeder. The Inland Empire feeder A shows a relatively steep relationship to temperature, with most of the events at times when the temperature was above 90˚F showing a statistically significant load response. The High Desert A feeder temperature response is less steep, and the events exhibit a smaller average response. However, the events above 90˚F exhibit an even greater proportion of events with statistically significant load response than the Inland Empire feeder. The consistency of the relationship between temperature and both of these feeders' load responses speaks to the reliability of the impact of curtailment events on these loads. Although the statistical error around each feeder's load predictions produces variation around the prevailing relationship between load response and temperature, the relationships are evidence of an underlying, consistent temperature-dependent response.

Table 7.5 Aggregated Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Inland Empire and High Desert

		Inland Empire			High Desert		
Test #	Test Event Time	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	05/22/08 18:35	3.16	-0.069	NO	2.33	0.011	NO
2	06/23/08 17:35	4.41	0.006	NO			.
3	07/02/08 18:05	4.65	0.047	NO			.
4	07/07/08 18:05	4.27	-0.102	NO			.
5	07/15/08 16:05	4.42	0.107	NO			.
6	07/15/08 18:05	4.17	0.191	YES			.
7	07/16/08 15:50	4.84	0.140	YES			.
8	07/16/08 18:05	4.34	0.068	NO			.
9	07/17/08 15:05	4.96	0.102	NO			.
10	07/22/08 16:05	4.26	0.080	NO			.
11	07/24/08 15:05	4.76	0.158	YES			.
12	07/24/08 17:10	4.70	0.181	YES			.
13	07/25/08 15:50	4.87	-0.007	NO			.
14	08/01/08 15:20	4.71	0.202	YES	5.34	0.120	YES
15	08/01/08 16:05	4.59	0.178	YES	5.56	0.168	YES
16	08/02/08 14:20	3.84	0.083	NO	5.28	0.086	NO
17	08/02/08 15:20	4.12	0.082	NO	5.53	0.127	YES
18	08/04/08 14:20	5.57	0.184	YES	5.36	0.157	YES
19	08/04/08 15:20	5.11	0.113	NO	5.72	0.136	YES
20	08/07/08 14:20	5.62	0.110	NO	5.67	0.133	YES
20	08/07/08 14:25	5.66	0.120	NO	5.70	0.068	NO
21	08/07/08 16:20	5.19	0.273	YES	5.87	0.148	YES
21	08/07/08 16:25	5.17	0.135	YES	5.90	0.070	NO
22	08/10/08 16:20	3.64	0.187	YES	5.17	0.174	YES
22	08/10/08 16:25	3.64	0.056	NO	5.17	0.062	NO
23	08/10/08 18:20	3.43	0.097	NO	5.09	0.160	YES
23	08/10/08 18:25	3.42	-0.030	NO	5.01	0.038	NO
24	08/14/08 15:25	5.51	0.194	YES	5.83	0.087	NO
25	08/24/08 16:20	4.14	0.117	NO	5.23	0.061	NO
26	08/30/08 15:20	4.10	0.204	YES	5.22	0.096	YES
27	09/02/08 17:20	4.76	0.133	YES	4.91	0.016	NO
28	09/03/08 17:20	5.06	0.337	YES	5.44	0.212	YES
29	09/04/08 17:20	4.80	0.264	YES	5.67	0.134	YES
30	09/05/08 17:20	4.58	0.149	YES	5.91	0.200	YES
31	09/16/08 15:50	4.68	0.180	YES	3.66	0.094	YES
32	09/17/08 15:20	5.06	0.234	YES	4.25	0.112	YES
33	09/18/08 15:20	5.16	0.262	YES	4.35	-0.005	NO
34	09/23/08 19:35	3.57	0.025	NO	3.76	0.087	NO
35	09/25/08 19:20	3.94	0.081	NO	4.35	0.005	NO
36	09/29/08 14:20	5.24	0.091	NO	3.15	0.055	NO
37	09/29/08 17:20	4.00	0.106	NO	3.30	0.048	NO
38	10/01/08 18:20	4.42	0.127	YES	4.14	-0.030	NO
39	10/07/08 16:20	4.22	0.076	NO	3.27	0.021	NO
40	10/10/08 15:20	3.01	0.055	NO	2.26	0.035	NO

7.5.2 Aggregated Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Simi Valley and Temecula Valley

The Simi Valley and Temecula A feeders both showed much smaller curtailment responses than the Inland Empire and High Desert feeders. As Table 7.6 shows, only one Simi Valley and two Temecula events showed statistical significance at the 90% confidence level. At a 90% confidence level, there is a 10% chance of a statistically significant estimate occurring by chance. With 40 tests on each of these feeders, one or two significant events fall within the realm of possibly random events.

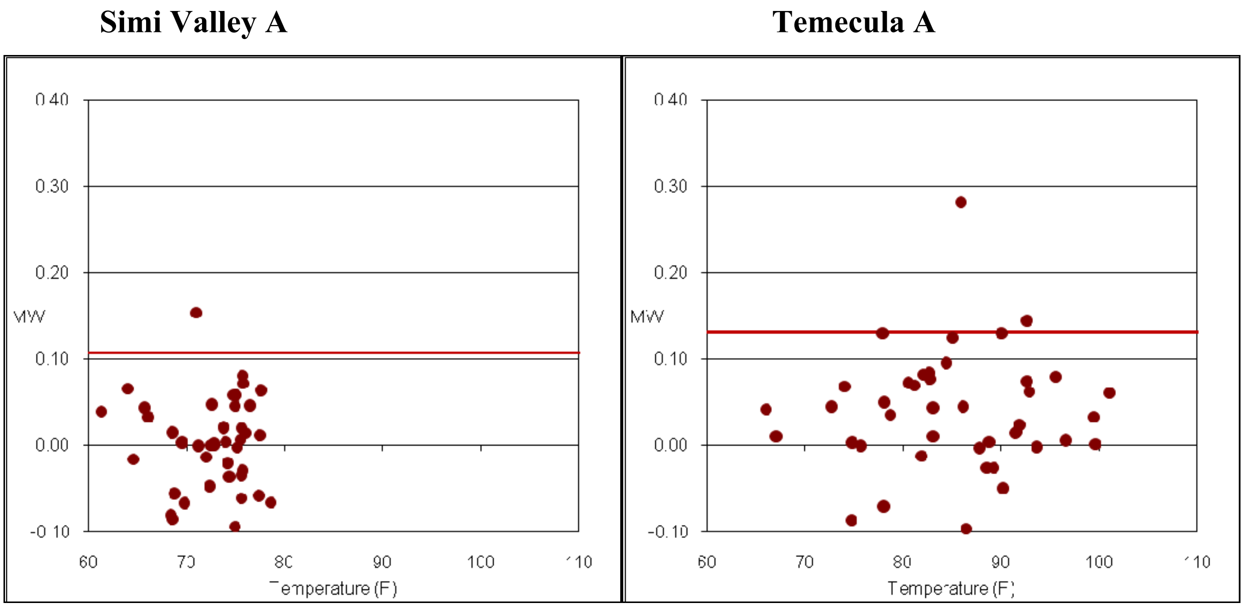

Figure 7.6 Aggregate Load Curtailed vs. Temperature for Simi Valley and Temecula Valley

Graphing these feeders' estimated load response against temperature (Figure 7.6), we can see clearly that for Simi Valley the significant result is an outlier from the general group. For Temecula, one significant result is an outlier, and the other falls within the distribution of the rest of the test events.

Figure 7.6 shows clearly that the Simi Valley feeder A results are distributed evenly around 0 MW. The relatively low temperatures on this feeder are a likely explanation of this result. Simi Valley is located relatively close to the coast of California and thus has a much more mild climate than the areas served by the rest of the feeders in the project. Thus, it is not surprising that the AC load would be light and show a low load response to the summer tests. Temecula A has no such excuse for its non-performance; it is an inland feeder in a heavy-AC-use climate with more than 300 load-response switches on it. Given the poor performance of enhanced two-way switches on this feeder (only 1 of 16 switches regularly reported in), we suspect that communication problems are the reason for the low response, i.e., the switches were not receiving the signal to curtail.

Table 7.6 Aggregated Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Simi Valley and Temecula Valley

		Simi Valley			Temecula		
Test #	Test Event Time	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	05/22/08 18:35	3.05	0.039	NO	2.76	0.045	NO
2	06/23/08 17:35	6.43	-0.081	NO	6.85	-0.001	NO
3	07/02/08 18:05	5.61	-0.047	NO	7.90	0.072	NO
4	07/07/08 18:05	6.08	0.154	YES	7.05	0.032	NO
5	07/15/08 16:05	5.49	0.081	NO	6.70	0.049	NO
6	07/15/08 18:05	5.22	-0.148	NO	6.48	-0.087	NO
7	07/16/08 15:50	5.80	0.058	NO	6.82	0.124	NO
8	07/16/08 18:05	5.61	0.014	NO	6.61	0.083	NO
9	07/17/08 15:05	5.36	-0.030	NO	6.80	0.095	NO
10	07/22/08 16:05	4.77	-0.014	NO	5.29	0.044	NO
11	07/24/08 15:05	4.11	0.002	NO	5.14	-0.027	NO
12	07/24/08 17:10	4.50	0.003	NO	5.85	-0.003	NO
13	07/25/08 15:50	5.20	0.072	NO	6.40	0.023	NO
14	08/01/08 15:20	4.75	0.058	NO	5.87	0.129	NO
15	08/01/08 16:05	4.99	0.000	NO	6.05	-0.050	NO
16	08/02/08 14:20	5.12	-0.037	NO	5.96	0.061	NO
17	08/02/08 15:20	5.46	-0.021	NO	6.22	-0.002	NO
18	08/04/08 14:20	5.13	0.014	NO	6.49	0.076	NO
19	08/04/08 15:20	5.29	-0.003	NO	7.01	0.281	YES
20	08/07/08 14:20	4.89	0.064	NO	6.81	-0.013	NO
20	08/07/08 14:25	4.94	0.011	NO	6.86	0.081	NO
21	08/07/08 16:20	5.39	-0.035	NO	7.89	0.010	NO
21	08/07/08 16:25	5.37	0.007	NO	7.89	0.043	NO
22	08/10/08 16:20	4.46	0.047	NO	6.87	0.014	NO
22	08/10/08 16:25	4.47	0.000	NO	6.87	0.015	NO
23	08/10/08 18:20	4.13	-0.056	NO	6.18	0.003	NO
23	08/10/08 18:25	4.10	-0.086	NO	6.09	-0.027	NO
24	08/14/08 15:25	5.09	0.046	NO	5.71	0.079	NO
25	08/24/08 16:20	5.08	0.046	NO	9.00	0.144	YES
26	08/30/08 15:20	5.69	-0.067	NO	6.84	-0.112	NO
27	09/02/08 17:20	5.13	-0.062	NO	7.70	0.074	NO
28	09/03/08 17:20	5.33	-0.058	NO	8.17	0.006	NO
29	09/04/08 17:20	5.27	0.021	NO	8.23	0.001	NO
30	09/05/08 17:20	4.96	0.019	NO	7.94	0.060	NO
31	09/16/08 15:50	3.55	-0.094	NO	5.05	0.129	NO
32	09/17/08 15:20	3.30	0.004	NO	6.09	0.010	NO
33	09/18/08 15:20	3.58	0.058	NO	6.49	0.067	NO
34	09/23/08 19:35	3.46	0.043	NO	4.77	-0.071	NO
35	09/25/08 19:20	4.26	-0.016	NO	6.93	-0.158	NO
36	09/29/08 14:20	3.46	0.020	NO	5.68	0.035	NO
37	09/29/08 17:20	4.13	-0.067	NO	7.44	0.003	NO
38	10/01/08 18:20	5.35	0.066	NO	7.27	0.069	NO
39	10/07/08 16:20	4.24	0.033	NO	5.25	-0.097	NO
40	10/10/08 15:20	2.31	-0.001	NO	2.65	0.041	NO

7.5.3 Aggregated Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Inland Empire and High Desert Combined, and All Feeders Combined

Table 7.7 shows the event estimates for the summed Inland Empire A and High Desert A feeders (IE/HD), and for the sum of all four A feeders. The load drops are much easier to pick up on the IE/HD "feeder," as indicated by the greater number of statistically significant events. As explained above, any "signal," such as drop in load, sums linearly and thus increases faster than the error because the error of the estimate sums as the root of summed squares. In this case, however, there is no additional "signal" being added in as the feeder noise increases. Effectively, instead of trying to extract a load drop the size of High Desert A's and Inland Empire A's from a feeder with a prediction error bound of 150 kW, we are trying to see the same size load drop (because Simi Valley contributes zero and Temecula less than the others) on a feeder with an error bound of 200 kW. Thus, adding High Desert A to Inland Empire A amplifies the signal relative to the error, while Simi Valley dilutes it.[17]

[17] Looking at Table 7.6 it seems that Temecula does show some response, just not as great as we would expect. It would be interesting to analyze it added to the HD/IE combination to see if its weak signal could still contribute.

Table 7.7 Aggregate Load Curtailments Estimated from the Models Based on Eight-Second Feeder Data — Inland Empire and High Desert Combined, and All Feeders Combined

		Inland Empire + High Desert			Feeders 'A' Total		
Test #	Test Event Time	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	05/22/08 18:35	5.53	-0.014	NO	11.33	0.061	NO
2	06/23/08 17:35			.			.
3	07/02/08 18:05			.			.
4	07/07/08 18:05			.			.
5	07/15/08 16:05			.			.
6	07/15/08 18:05			.			.
7	07/16/08 15:50			.			.
8	07/16/08 18:05			.			.
9	07/17/08 15:05			.			.
10	07/22/08 16:05			.			.
11	07/24/08 15:05			.			.
12	07/24/08 17:10			.			.
13	07/25/08 15:50			.			.
14	08/01/08 15:20	10.04	0.282	YES	20.69	0.573	YES
15	08/01/08 16:05	10.18	0.386	YES	21.27	0.381	YES
16	08/02/08 14:20	9.13	0.178	YES	20.18	0.177	NO
17	08/02/08 15:20	9.65	0.212	YES	21.39	0.243	YES
18	08/04/08 14:20	10.95	0.356	YES	22.63	0.511	YES
19	08/04/08 15:20	10.82	0.229	YES	23.20	0.592	YES
20	08/07/08 14:20	11.30	0.263	YES	23.04	0.358	YES
20	08/07/08 14:25	11.30	0.130	NO	23.24	0.359	YES
21	08/07/08 16:20	11.04	0.409	YES	24.27	0.330	YES
21	08/07/08 16:25	11.01	0.152	YES	24.19	0.122	NO
22	08/10/08 16:20	8.77	0.319	YES	20.08	0.371	YES
22	08/10/08 16:25	8.77	0.065	NO	20.10	0.080	NO
23	08/10/08 18:20	8.53	0.271	YES	18.82	0.189	NO
23	08/10/08 18:25	8.43	0.015	NO	18.62	-0.109	NO
24	08/14/08 15:25	11.33	0.269	YES	22.11	0.374	YES
25	08/24/08 16:20	9.39	0.191	YES	23.49	0.394	YES
26	08/30/08 15:20	9.34	0.319	YES	21.87	0.152	NO
27	09/02/08 17:20	9.71	0.193	YES	22.64	0.298	YES
28	09/03/08 17:20	10.46	0.514	YES	23.99	0.495	YES
29	09/04/08 17:20	10.45	0.377	YES	23.95	0.391	YES
30	09/05/08 17:20	10.50	0.366	YES	23.37	0.420	YES
31	09/16/08 15:50	8.35	0.281	YES	16.95	0.313	YES
32	09/17/08 15:20	9.30	0.336	YES	18.74	0.402	YES
33	09/18/08 15:20	9.51	0.255	YES	19.63	0.435	YES
34	09/23/08 19:35	7.39	0.169	YES	15.65	0.164	NO
35	09/25/08 19:20	8.27	0.069	NO	19.49	-0.086	NO
36	09/29/08 14:20	8.36	0.119	NO	17.48	0.149	NO
37	09/29/08 17:20	7.26	0.115	NO	18.84	0.059	NO
38	10/01/08 18:20	8.55	0.093	NO	21.08	0.132	NO
39	10/07/08 16:20	7.51	0.117	NO	16.97	0.010	NO
40	10/10/08 15:20	5.24	0.060	NO	10.22	0.111	NO

7.5.4 Aggregated Load Curtailments Estimated from the Models Based on Two-Minute Feeder Data

The results from the Inland Empire A and Inland Empire B feeders, shown in Table 7.8 below, are illustrative of a number of issues we faced in analyzing these data. The two-minute data on feeder A perform similarly to the eight-second data from which they are derived; there are a fair number of statistically significant event estimates, they correlate with temperature (this can be seen best in Figure 5.1), and they have a distribution comparable in deviation to our estimate of prediction error. In Section 5, we saw that while feeder A has 105 switches, Inland Empire feeder B has 225 curtailable units. It is not surprising, therefore, that feeder B exhibited almost twice the number of statistically significant events during the summer because has an error bound that is lower than feeder A's and a potential load reduction that is almost twice as large.

Figure 7.7 makes clear this difference in average magnitude of the two feeder (A and B) load responses; more switches are clearly leading to more load response. With two strongly responding feeder pairs, the combined Inland Empire feeder, shown in Figure 7.7, exhibits a very dependable load response to test events and is even more highly correlated with temperature than the individual feeders. Adding the feeders together has produced a feeder that is relatively easier to predict with events of a magnitude that leaves less room for doubt. The upshot is that as a program gets larger, having more load under control across more feeders, we get more than a linear increase in the certainty of the size of the response.

We also looked at the results from the model derived from two-minute data compared to the results from the eight-second data, as in Table 7.9. Two noteworthy observations emerged:

First, the eight-second data produce more significant responses than the two-minute data. At first glance, this might seem to because of a higher precision from having better data in the eight-second set. Figure 7.8, which graphs the two sets of event estimates against one another, shows that it is not so much differences in precision as it is that *the eight-second model predicts higher load responses than the model derived from two-minute data*.[18] Further investigation of the models would be necessary to determine whether this is a random outcome on this feeder for this summer or whether there is a systematic reason for this difference.

[18] This result is also seen in the High Desert event impact estimates.

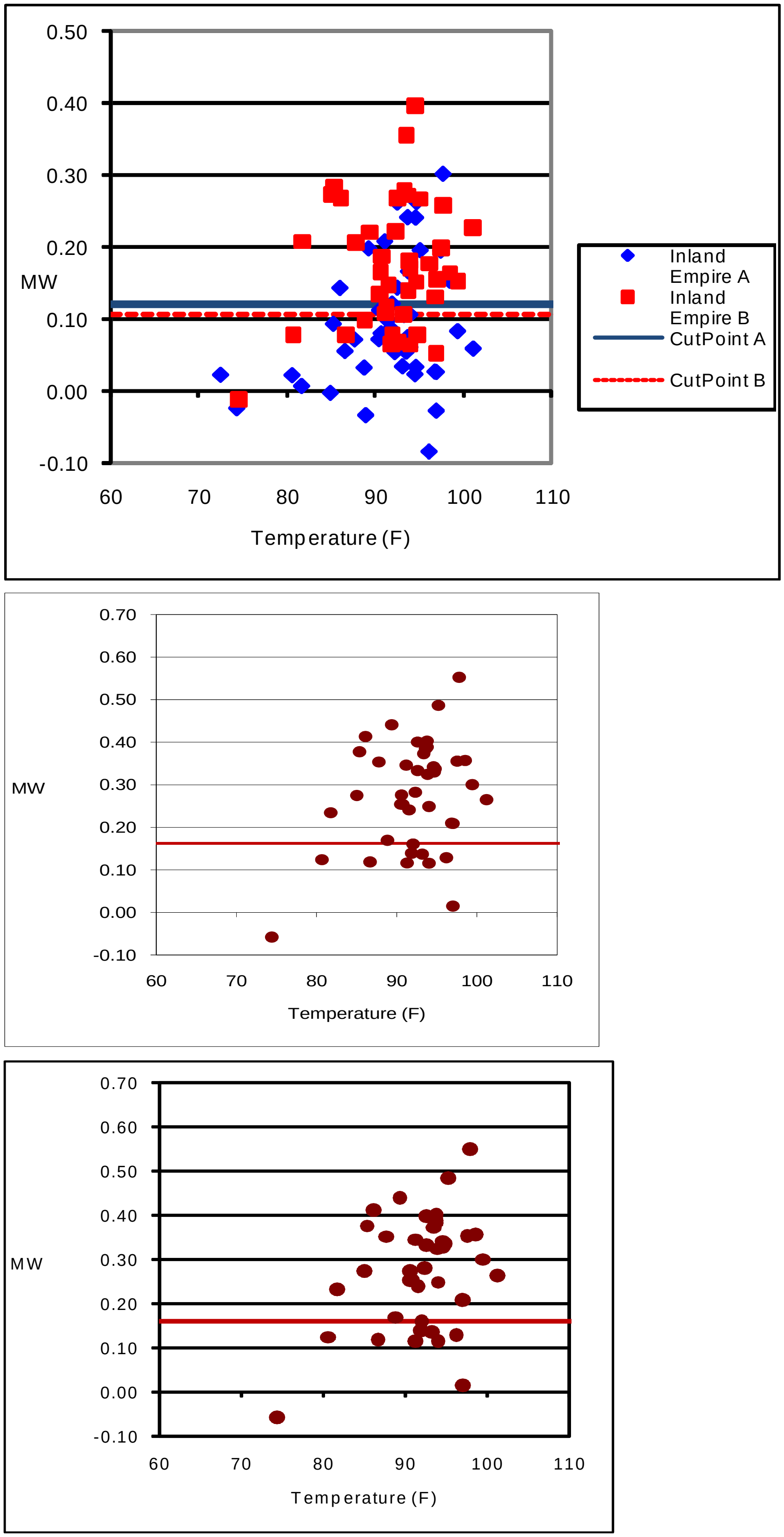

Figure 7.7 Aggregate Load Curtailed vs. Temperature for Inland Empire

Table 7.8 Comparison of Aggregated Load Curtailments Estimated from the Models Based on Eight-Second and Two-Minute Feeder Data — Inland Empire

		Inland Empire A			Inland Empire B			Inland Empire A+B		
Test #	Test Event Time	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	06/23/08 17:35	4.3683	-0.0322	NO						.
2	06/30/08 17:15	4.4262	0.0346	NO						.
3	07/02/08 18:05	4.6439	0.0551	NO	4.0813	0.2231	YES	8.7292	0.2823	YES
4	07/07/08 18:05	4.2913	-0.1110	NO	3.9947	0.1188	YES	8.3944	0.1162	NO
5	07/15/08 16:05	4.4440	0.0883	NO	3.3673	0.0665	NO	7.7988	0.1391	NO
6	07/15/08 18:05	4.1477	0.1989	YES	3.6473	0.2215	YES	7.8158	0.4412	YES
7	07/22/08 16:05	4.2503	0.0336	NO	3.0259	0.1000	NO	7.3027	0.1695	YES
8	07/24/08 15:05	4.7520	0.1070	NO	2.9183	0.1715	YES	7.6408	0.2491	YES
9	07/24/08 17:10	4.6594	0.1224	YES	3.3466	0.0788	NO	7.9654	0.1606	NO
10	07/25/08 15:50	4.8379	-0.0826	NO	3.9052	0.1778	YES	8.7699	0.1286	NO
11	08/01/08 15:20	4.6371	0.0245	NO	3.2266	0.3970	YES	7.8322	0.3422	YES
12	08/01/08 16:05	4.5497	0.1669	YES	3.3607	0.1819	YES	7.8863	0.3247	YES
13	08/02/08 14:20	3.8589	0.0618	NO	3.4985	0.0648	NO	7.3465	0.1156	NO
14	08/02/08 15:20	4.0945	0.0353	NO	3.6485	0.1076	YES	7.7370	0.1369	NO
15	08/04/08 14:20	5.6318	0.1964	YES	3.5030	0.2668	YES	9.1583	0.4867	YES
16	08/04/08 15:20	5.1187	0.0557	NO	3.7792	0.3561	YES	8.8705	0.3845	YES
17	08/07/08 14:20	5.5668	0.0282	NO	3.3654	0.1314	YES	8.9826	0.2099	YES
17	08/07/08 14:25	5.5188	-0.0260	NO	3.4205	0.0536	NO	8.9265	0.0147	NO
18	08/07/08 16:20	5.2340	0.3021	YES	4.0591	0.2576	YES	9.2863	0.5528	YES
18	08/07/08 16:25	5.2183	0.1956	YES	4.1320	0.1987	YES	9.3117	0.3556	YES
19	08/10/08 16:20	3.6266	0.1133	NO	3.5345	0.1655	YES	7.1581	0.2759	YES
19	08/10/08 16:25	3.6087	0.0730	NO	3.5020	0.1356	YES	7.1560	0.2541	YES
20	08/10/08 18:20	3.4641	0.0942	NO	3.4168	0.2847	YES	6.8797	0.3777	YES
20	08/10/08 18:25	3.4431	-0.0013	NO	3.3977	0.2734	YES	6.8436	0.2749	YES
21	08/14/08 15:25	5.4460	0.1541	YES	3.7421	0.1649	YES	9.2262	0.3571	YES
22	08/24/08 16:20	4.1473	0.0601	NO	4.2724	0.2281	YES	8.3963	0.2648	YES
23	08/30/08 15:20	4.1135	0.1444	YES	4.0774	0.2682	YES	8.1788	0.4005	YES
24	09/02/08 17:20	4.7811	0.1064	NO	4.1146	0.2782	YES	8.8843	0.3731	YES
25	09/03/08 17:20	5.0294	0.2630	YES	4.1574	0.0784	NO	9.1828	0.3375	YES
26	09/04/08 17:20	4.8242	0.2420	YES	4.0154	0.1408	YES	8.8597	0.4028	YES
27	09/05/08 17:20	4.5799	0.0759	NO	3.9755	0.2721	YES	8.5960	0.3886	YES
28	09/12/08 15:20	3.1192	-0.0225	NO	1.4288	-0.0113	NO	4.5236	-0.0583	NO
29	09/15/08 15:20	5.2708	0.0842	NO	3.4542	0.1538	YES	8.7875	0.3004	YES
30	09/16/08 15:50	4.6406	0.1441	YES	3.2753	0.2687	YES	7.9166	0.4135	YES
31	09/17/08 15:20	5.0457	0.2085	YES	3.2481	0.1082	YES	8.3230	0.3460	YES
32	09/18/08 15:20	5.1837	0.2623	YES	3.1041	0.0694	NO	8.2896	0.3335	YES
33	09/23/08 19:35	3.5888	0.0233	NO	2.8018	0.0781	NO	6.4130	0.1238	NO
34	09/25/08 19:20	3.9405	0.0727	NO	3.5017	0.2069	YES	7.5162	0.3535	YES
35	09/29/08 14:20	5.3405	0.2415	YES	3.1219	0.1522	YES	8.3990	0.3303	YES
36	09/29/08 17:20	3.9834	0.0811	NO	3.2878	0.1879	YES	7.2559	0.2536	YES
37	10/01/08 18:20	4.4565	0.0991	NO	3.9292	0.1483	YES	8.3792	0.2409	YES
38	10/02/08 15:35	4.1603	0.0566	NO	2.8842	0.0787	NO	7.0277	0.1185	NO
39	10/02/08 18:20	3.3796	0.0083	NO	2.8884	0.2083	YES	6.2857	0.2343	YES
40	10/07/08 16:20	4.2119	0.0276	NO	2.9797	0.1555	YES	7.2173	0.2088	YES
41	10/10/08 15:20	2.9815	0.0237	NO						.

Table 7.9 Comparison of Aggregated Load Curtailments Estimated from the Models Based on Eight-Second and Two-Minute Feeder Data — Inland Empire

	Inland Empire A			
	2 Minute		8 Second	
Test Event Time	Est. Drop	Stats Sig	Est. Drop	Stats Sig
05/22/08 18:35			-0.069	NO
06/23/08 17:35	-0.032	NO	0.006	NO
06/30/08 17:15	0.035	NO		
07/02/08 18:05	0.055	NO	0.047	NO
07/07/08 18:05	-0.111	NO	-0.102	NO
07/15/08 16:05	0.088	NO	0.107	NO
07/15/08 18:05	0.199	YES	0.191	YES
07/16/08 15:50			0.140	YES
07/16/08 18:05			0.068	NO
07/17/08 15:05			0.102	NO
07/22/08 16:05	0.034	NO	0.080	NO
07/24/08 15:05	0.107	NO	0.158	YES
07/24/08 17:10	0.122	YES	0.181	YES
07/25/08 15:50	-0.083	NO	-0.007	NO
08/01/08 15:20	0.025	NO	0.202	YES
08/01/08 16:05	0.167	YES	0.178	YES
08/02/08 14:20	0.062	NO	0.083	NO
08/02/08 15:20	0.035	NO	0.082	NO
08/04/08 14:20	0.196	YES	0.184	YES
08/04/08 15:20	0.056	NO	0.113	NO
08/07/08 14:20	0.028	NO	0.110	NO
08/07/08 14:25	-0.026	NO	0.120	NO
08/07/08 16:20	0.302	YES	0.273	YES
08/07/08 16:25	0.196	YES	0.135	YES
08/10/08 16:20	0.113	NO	0.187	YES
08/10/08 16:25	0.073	NO	0.056	NO
08/10/08 18:20	0.094	NO	0.097	NO
08/10/08 18:25	-0.001	NO	-0.030	NO
08/14/08 15:25	0.154	YES	0.194	YES
08/24/08 16:20	0.060	NO	0.117	NO
08/30/08 15:20	0.144	YES	0.204	YES
09/02/08 17:20	0.106	NO	0.133	YES
09/03/08 17:20	0.263	YES	0.337	YES
09/04/08 17:20	0.242	YES	0.264	YES
09/05/08 17:20	0.076	NO	0.149	YES
09/12/08 15:20	-0.023	NO		
09/15/08 15:20	0.084	NO		
09/16/08 15:50	0.144	YES	0.180	YES
09/17/08 15:20	0.208	YES	0.234	YES
09/18/08 15:20	0.262	YES	0.262	YES
09/23/08 19:35	0.023	NO	0.025	NO
09/25/08 19:20	0.073	NO	0.081	NO
09/29/08 14:20	0.241	YES	0.091	NO
09/29/08 17:20	0.081	NO	0.106	NO
10/01/08 18:20	0.099	NO	0.127	YES
10/02/08 15:35	0.057	NO		
10/02/08 18:20	0.008	NO		
10/07/08 16:20	0.028	NO	0.076	NO
10/10/08 15:20	0.024	NO	0.055	NO

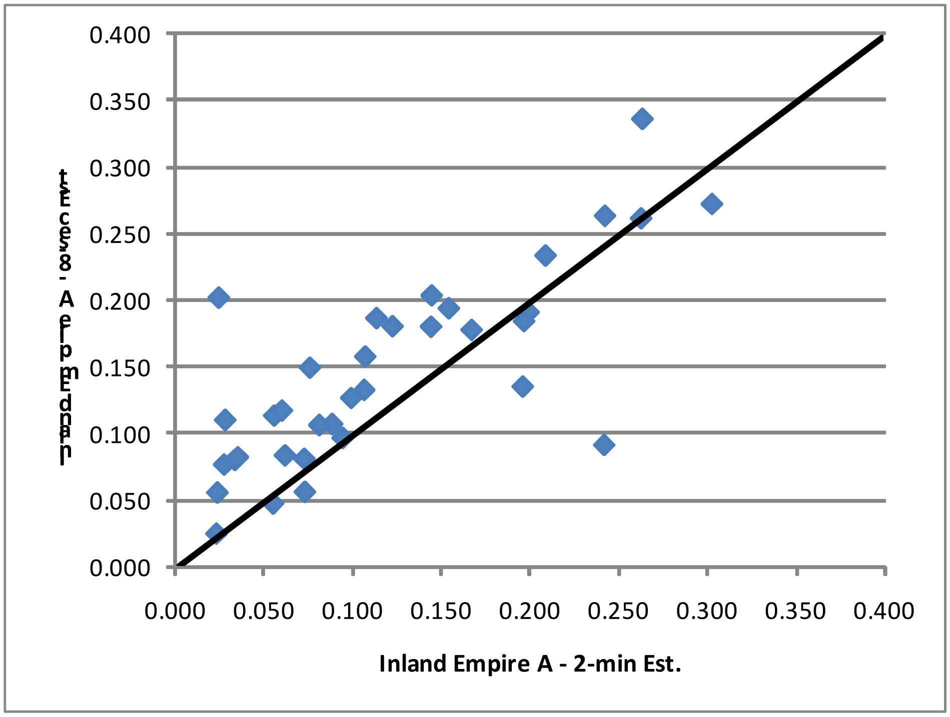

Figure 7.8 Comparison of Aggregated Load Curtailments Estimated from the Models Based on 8-Second and 2-Minute Feeder Data - Inland Empire

This relates to the second observation arising from this comparison. Although the two models' results are highly correlated, they produce difference estimates for the same tests. Most of the time, these results are within one standard deviation of each other, and only a small number are greater than 1.65 deviations apart, making them easily attributable to the error underlying both estimates. Taken with the bias identified in Figure 7.8, however, these differences speak to the need to more thoroughly investigate the differences between the two-minute data and the eight-second data from which the two-minute data are derived before committing to a study or program design based on the more readily available two-minute data.

The two-minute data models' results, shown in Table 7.10, for the High Desert feeders reflect the results from the eight-second data analysis. The High Desert feeder response is lower than the Inland Empire feeder response, but there are still a fair number of statistically significant results, partially because the predictive model has a relatively low error bound. When the High Desert feeder was split, roughly two-thirds of the 275 switches ended up on the A feeder. This is reflected in the results in Table 7.10 and Figure 7.9. Feeder A has a higher frequency of statistically significant events and a higher average load impact than the feeder B. Also as expected, feeder A shows a more consistent, stable, and steeper relationship with temperature than feeder B.

Table 7.10 Aggregated Load Curtailments Estimated from the Models Based on Two- Minute Feeder Data — High Desert

Test #	Test Event Time	High Desert A			High Desert B			High Desert A+B		
		Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	06/23/08 17:35									.
2	06/30/08 17:15									.
3	07/02/08 18:05									.
4	07/07/08 18:05									.
5	07/15/08 16:05									.
6	07/15/08 18:05									.
7	07/22/08 16:05									.
8	07/24/08 15:05									.
9	07/24/08 17:10									.
10	07/25/08 15:50									.
11	08/01/08 15:20									.
12	08/01/08 16:05									.
13	08/02/08 14:20									.
14	08/02/08 15:20									.
15	08/04/08 14:20	5.3695	0.1388	YES	6.6288	0.0194	NO	11.9942	0.1540	YES
16	08/04/08 15:20	5.7280	0.0863	NO	6.4830	-0.0202	NO	12.2780	0.1332	NO
17	08/07/08 14:20	5.6136	0.0534	NO						.
17	08/07/08 14:25	5.6459	0.0641	NO						.
18	08/07/08 16:20	5.8954	0.0567	NO						.
18	08/07/08 16:25	5.8912	0.1670	YES						.
19	08/10/08 16:20	5.2763	0.1654	YES	5.9665	0.0461	NO	11.2274	0.1961	YES
19	08/10/08 16:25	5.2531	0.1017	YES	5.9461	0.0037	NO	11.2211	0.1274	NO
20	08/10/08 18:20	5.1354	0.1300	YES	5.6033	0.0888	NO	10.7507	0.2309	YES
20	08/10/08 18:25	5.0985	0.1368	YES	5.6429	0.1341	YES	10.7790	0.3085	YES
21	08/14/08 15:25	5.8847	0.0632	NO	7.3344	0.1307	YES	13.2117	0.1865	YES
22	08/24/08 16:20	5.2301	-0.0195	NO						.
23	08/30/08 15:20	5.2295	0.0268	NO						.
24	09/02/08 17:20	4.9419	0.0127	NO						.
25	09/03/08 17:20	5.5298	0.2013	YES						.
26	09/04/08 17:20	5.6652	0.0297	NO						.
27	09/05/08 17:20	5.8526	0.1159	YES						.
28	09/12/08 15:20	4.6692	-0.0067	NO						.
29	09/15/08 15:20	5.0166	0.0519	NO	6.2687	0.1372	YES	11.2976	0.2013	YES
30	09/16/08 15:50	3.6882	0.1014	YES	4.4984	0.0431	NO	8.1493	0.1071	NO
31	09/17/08 15:20	4.3058	0.1529	YES	5.1862	-0.0518	NO	9.4565	0.0657	NO
32	09/18/08 15:20	4.3806	0.0188	NO	5.2998	-0.1516	NO	9.6514	-0.1619	NO
33	09/23/08 19:35	3.8043	0.0671	NO	4.2948	-0.0632	NO	8.0806	-0.0146	NO
34	09/25/08 19:20	4.3802	-0.0095	NO	4.8891	-0.1459	NO	9.2995	-0.1252	NO
35	09/29/08 14:20	3.1470	0.0159	NO	4.0654	0.0830	NO	7.1910	0.0774	NO
36	09/29/08 17:20	3.3268	0.0475	NO	3.8179	0.0683	NO	7.1441	0.1152	NO
37	10/01/08 18:20	4.1734	-0.0105	NO	4.8113	0.0452	NO	8.9784	0.0284	NO
38	10/02/08 15:35	3.8512	0.0286	NO	4.6541	0.0871	NO	8.4769	0.0872	NO
39	10/02/08 18:20	3.4542	0.0103	NO	3.8054	-0.0563	NO	7.2630	-0.0426	NO
40	10/07/08 16:20	3.3094	0.0571	NO	3.7082	0.0322	NO	7.0505	0.1222	NO
41	10/10/08 15:20	2.2711	0.0020	NO	2.5188	0.0191	NO	4.7798	0.0110	NO

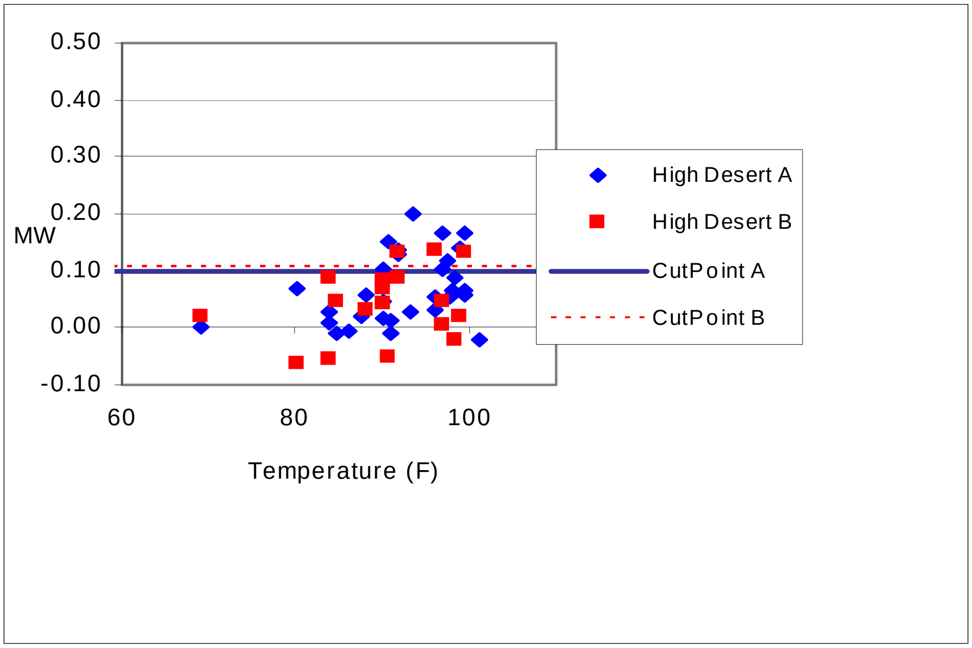

Figure 7.9 Aggregate Load Curtailed vs. Temperature for High Desert

Table 7.11 shows the results for the Simi Valley A and B feeders and then for the A and B feeders combined. Similar to the results seen for the feeder A eight-second data, there does not appear to be appreciable load drop as a result of the test events. The combined feeder shows a few more significant differences between predicted and actual load because of its smaller relative error bounds. It is possible that some of these are the result of curtailment events. For the most part, however, the magnitude of load impacts of the Simi Valley feeders is not large enough to be seen outside of the natural variation in the feeder.

Temecula A's two-minute data results, Table 7.12, are almost identical to the results seen in the eight-second data for that feeder. A few outlier events achieve statistically significant differences, and the average estimated load response is greater than zero. However, the load response does not have the magnitude necessary for us to draw definitive conclusions about the feeder's responsiveness to curtailment events.

Table 7.11 Aggregated Load Curtailments Estimated from the Models Based on Two- Minute Feeder Data — Simi Valley

Test #	Test Event Time	Simi Valley A			Simi Valley B			Simi Valley A+B		
		Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?	Load	Est. Drop	Stat Sig?
1	06/23/08 17:35									.
2	06/30/08 17:15									.
3	07/02/08 18:05									.
4	07/07/08 18:05									.
5	07/15/08 16:05	5.5265	0.1440	YES	5.6545	0.0356	NO	11.1868	0.1868	YES
6	07/15/08 18:05	5.2293	-0.0947	NO	5.6334	0.0133	NO	10.8609	-0.0831	NO
7	07/22/08 16:05	4.7976	0.0158	NO	4.4945	-0.1914	NO	9.2662	-0.2106	NO
8	07/24/08 15:05	4.1533	0.0271	NO						.
9	07/24/08 17:10	4.4931	-0.0281	NO						.
10	07/25/08 15:50	5.2123	0.0441	NO	5.0357	-0.0387	NO	10.2537	0.0125	NO
11	08/01/08 15:20	4.7453	0.0323	NO	4.6378	0.2247	YES	9.4061	0.3148	YES
12	08/01/08 16:05	5.0376	0.0660	NO	4.9734	-0.0031	NO	10.0553	0.1074	NO
13	08/02/08 14:20	5.1038	-0.0478	NO	5.4319	0.0748	NO	10.5287	0.0199	NO
14	08/02/08 15:20	5.4359	-0.0168	NO	5.8452	0.0081	NO	11.3230	0.0332	NO
15	08/04/08 14:20	5.0700	-0.0089	NO	5.4939	-0.0466	NO	10.6287	0.0096	NO
16	08/04/08 15:20	5.1712	-0.1049	NO	5.6423	-0.0580	NO	10.8982	-0.0782	NO
17	08/07/08 14:20	4.8889	0.0484	NO	6.0554	0.1748	YES	10.9309	0.2098	YES
17	08/07/08 14:25	4.9318	-0.0004	NO	6.0745	0.0726	NO	11.0299	0.0958	NO
18	08/07/08 16:20	5.3415	-0.0723	NO	6.6646	0.0862	NO	12.0026	0.0104	NO
18	08/07/08 16:25	5.3515	-0.0354	NO	6.6050	0.0338	NO	11.9853	0.0273	NO
19	08/10/08 16:20	4.4888	0.0895	NO	5.5622	-0.0725	NO	10.0411	0.0072	NO
19	08/10/08 16:25	4.4767	0.0405	NO	5.5717	-0.0169	NO	10.0330	0.0083	NO
20	08/10/08 18:20	4.1284	-0.0153	NO	5.2057	-0.2144	NO	9.3570	-0.2068	NO
20	08/10/08 18:25	4.0798	-0.1417	NO	5.1887	-0.2010	NO	9.2170	-0.3941	NO
21	08/14/08 15:25	5.0931	0.0494	NO	6.1251	-0.1139	NO	11.2009	-0.0819	NO
22	08/24/08 16:20	5.0838	0.0556	NO	6.6285	0.0497	NO	11.6748	0.0677	NO
23	08/30/08 15:20	5.7242	-0.0627	NO	7.1263	0.0108	NO	12.8169	-0.0856	NO
24	09/02/08 17:20	5.1600	-0.0755	NO	5.9580	-0.0676	NO	11.1006	-0.1605	NO
25	09/03/08 17:20	5.3386	-0.0474	NO	6.6610	-0.0706	NO	12.0492	-0.0683	NO
26	09/04/08 17:20	5.2446	-0.0378	NO	6.5510	-0.0395	NO	11.8696	-0.0033	NO
27	09/05/08 17:20	4.9704	0.0638	NO	6.5312	-0.0635	NO	11.5323	0.0311	NO
28	09/12/08 15:20	2.6617	-0.0114	NO	2.8040	-0.0223	NO	5.4652	-0.0343	NO
29	09/15/08 15:20	3.8503	0.0288	NO	5.1330	0.0931	NO	9.0165	0.1551	YES
30	09/16/08 15:50	3.5305	-0.1303	NO	4.8403	-0.0400	NO	8.3891	-0.1520	NO
31	09/17/08 15:20	3.2756	0.0053	NO	4.1487	0.0182	NO	7.4135	0.0126	NO
32	09/18/08 15:20	3.5826	0.0750	NO	4.5451	0.1365	YES	8.1049	0.1886	YES
33	09/23/08 19:35	3.4391	0.0178	NO	4.3061	0.0578	NO	7.7161	0.0465	NO
34	09/25/08 19:20	4.2642	-0.0096	NO	5.3645	0.0003	NO	9.5924	-0.0456	NO
35	09/29/08 14:20	3.4815	0.0458	NO	4.4709	-0.0050	NO	7.9628	0.0512	NO
36	09/29/08 17:20	4.1321	-0.0984	NO	5.4654	-0.0274	NO	9.6008	-0.1225	NO
37	10/01/08 18:20	5.3733	0.1172	YES	6.8583	0.1129	YES	12.2175	0.2159	YES
38	10/02/08 15:35	4.1028	0.0007	NO	5.3211	-0.0739	NO	9.4329	-0.0642	NO
39	10/02/08 18:20	3.8008	0.0297	NO	4.7988	0.0349	NO	8.6134	0.0783	NO
40	10/07/08 16:20	4.2800	0.0389	NO	5.4590	0.0118	NO	9.6954	0.0070	NO
41	10/10/08 15:20	2.3046	0.0030	NO	2.6921	0.0050	NO	5.0006	0.0119	NO

Table 7.12 Aggregated Load Curtailments Estimated from the Models Based on Two- Minute Feeder Data — Temecula Valley

Test #	Test Event Time	Temecula		
		Load	Est. Drop	Stat Sig?
1	06/23/08 17:35			
2	06/30/08 17:15	6.1188	-0.0188	NO
3	07/02/08 18:05			
4	07/07/08 18:05			
5	07/15/08 16:05			
6	07/15/08 18:05			
7	07/22/08 16:05			
8	07/24/08 15:05			
9	07/24/08 17:10			
10	07/25/08 15:50			
11	08/01/08 15:20	5.8565	0.0560	NO
12	08/01/08 16:05	6.0446	-0.0516	NO
13	08/02/08 14:20	5.9840	0.0694	NO
14	08/02/08 15:20	6.2473	-0.0098	NO
15	08/04/08 14:20	6.5338	0.1039	NO
16	08/04/08 15:20	6.9562	0.1883	YES
17	08/07/08 14:20	6.7916	-0.1362	NO
17	08/07/08 14:25	6.8098	0.0135	NO
18	08/07/08 16:20	7.8561	-0.0257	NO
18	08/07/08 16:25	7.8385	-0.0142	NO
19	08/10/08 16:20	6.8580	-0.0013	NO
19	08/10/08 16:25	6.9506	0.0970	NO
20	08/10/08 18:20	6.0989	-0.1585	NO
20	08/10/08 18:25	6.0600	-0.0323	NO
21	08/14/08 15:25	5.7104	0.1069	NO
22	08/24/08 16:20	9.0746	0.1049	NO
23	08/30/08 15:20	6.8028	-0.0755	NO
24	09/02/08 17:20	7.8034	0.0881	NO
25	09/03/08 17:20	8.1987	-0.0131	NO
26	09/04/08 17:20	8.1437	-0.0474	NO
27	09/05/08 17:20	7.9005	-0.0096	NO
28	09/12/08 15:20	2.7498	0.0298	NO
29	09/15/08 15:20	6.6906	-0.0027	NO
30	09/16/08 15:50	5.1169	0.1690	YES
31	09/17/08 15:20	5.9638	-0.0857	NO
32	09/18/08 15:20	6.4840	0.0291	NO
33	09/23/08 19:35	4.6894	-0.0517	NO
34	09/25/08 19:20	6.9050	-0.1444	NO
35	09/29/08 14:20	5.5509	-0.0877	NO
36	09/29/08 17:20	7.4532	0.0425	NO
37	10/01/08 18:20	7.2227	-0.0040	NO
38	10/02/08 15:35	5.6178	-0.0480	NO
39	10/02/08 18:20	5.2850	-0.0214	NO
40	10/07/08 16:20	5.2924	-0.1005	NO
41	10/10/08 15:20	2.6455	0.0098	NO

7.6 Summary of Findings

The aggregate impact of demand response from many individually small sources can be estimated reliably through analysis of distribution feeder loads. We developed a new analytical method to both quantify the magnitude of demand response and establish the statistical significance of this estimate. We demonstrated that the method could be applied with roughly comparable results using either high-time-resolution real time (eight-second) or low-time-resolution archived (two-minute) distribution feeder data. We also found that applying the method to data combined from multiple feeders further improved the statistical reliability of the estimates. The method was, however, unable to provide statistically significant results for two of the four distribution feeder groups (Simi Valley and Temecula Valley). In the next two sections, we explore the reasons for this unexpected finding.

8. Estimation and Analysis of Aggregate Load Curtailments Using Metering on Individual AC Units

As noted in the Phase 1 report (Eto et al., 2006) and in Section 7, determining aggregated load curtailments for this project using distribution feeder load data was challenging because of the inherent stochastic nature (or noisiness) of these loads, the amount of curtailable AC load within a distribution feeder, and the efficacy of SCE's load management dispatch system to initiate curtailments. In an effort to better understand these issues, we deployed specialized, near-real-time AC monitoring devices ("enhanced switches") within each of the distribution feeder groups. The devices recorded both the receipt of dispatch signals from the SCE load management dispatch system and changes in energy use by the individual AC unit.

This section describes our analysis of the data from the enhanced switches to: 1) assess the effectiveness of SCE's load curtailments, 2) examine aspects of energy use by AC units participating in the demonstration, and 3) develop independent estimates of the aggregate amount of load curtailed for comparison to those described in Section 7. As discussed in Section 5, we encountered a number of challenges in assembling data from the enhanced switches for use in our analyses. Consequently, we also discuss the dependence of our estimates of aggregated load curtailed on the varying amounts of data that were available to support the analysis.

8.1 Analysis of the Efficacy of SCE's Dispatch of Load Curtailments and Insights into Residential AC Usage Patterns

To better understand the performance of AC units participating in the demonstration, we first reviewed information from the enhanced switches indicating whether each switch received dispatch requests as well as whether the AC unit was operating on the day of each curtailment, and, if it was operating, how it performed during each curtailment.

We first sought to establish whether AC units were "available" to participate in a curtailment by determining whether, in fact, they were in use on the day of a curtailment. We used two measures: 1) AC was in operation during three hours prior to curtailment ("Load 3 hrs before"), and 2) AC was in operation during half-hour prior to curtailment ("Load ½ hour before").

We then sought to confirm whether the AC load control switches received a dispatch command to shed load from the SCE load management dispatch system ("Signal confirm") and then, for those switches that did receive the command, if and how AC energy use changed subsequent to the receipt of the dispatch ("Shed load," "Increased load," or "Maintain load"). We used changes in power demand greater than 0.5 kW (either up or down) as the threshold for establishing whether AC energy use increased or decreased following receipt of a command to shed load. We also calculated these same three energy use metrics for the AC units with switches that did not confirm receipt of a dispatch command.

Tables 8.1 through 8.5 summarize our findings for each distribution feeder group and then for all distribution feeder groups combined.

Table 8.1 Performance of Enhanced Switches and AC Units in the Inland Empire

	Inland Empire (N=19)										
		Received Shed Signal					Did Not Receive Shed Signal				
Test Event Time	Signal Confirm	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load
6/23/08 5:35 PM	12	6	6	4	0	0	1	1	1	0	0
6/30/08 5:15 PM	14	4	4	4	0	0	1	1	1	0	0
7/2/08 6:05 PM	13	7	7	5	0	0	1	1	1	0	0
7/7/08 6:05 PM	13	3	3	2	0	0	0	0	1	0	0
7/15/08 4:05 PM	7	2	2	2	0	0	0	0	0	0	0
7/15/08 6:05 PM	7	2	2	1	0	0	0	0	0	0	0
7/22/08 4:05 PM	7	1	1	1	0	0	0	0	0	0	0
7/24/08 3:05 PM	7	1	1	1	1	0	0	0	0	0	0
7/24/08 5:10 PM	7	1	1	1	0	0	0	0	0	0	0
7/25/08 3:50 PM	8	1	1	1	0	0	0	0	0	0	0
8/1/08 3:20 PM	8	0	0	0	0	0	1	0	0	0	0
8/1/08 4:05 PM	7	0	0	0	0	0	1	0	0	0	0
8/2/08 2:20 PM	8	0	0	0	0	0	2	1	0	0	0
8/2/08 3:20 PM	8	1	1	0	0	0	1	0	0	0	0
8/4/08 2:20 PM	7	0	0	1	0	0	1	1	0	0	1
8/4/08 3:20 PM	7	1	1	0	0	0	0	0	0	0	1
8/7/08 2:20 PM	6	2	2	0	2	0	0	0	0	0	0
8/7/08 4:20 PM	6	2	2	2	0	0	0	0	0	0	1
8/10/08 4:20 PM	7	2	2	1	0	0	0	0	0	0	0
8/10/08 6:20 PM	7	2	2	2	0	0	0	0	0	0	0
8/14/08 3:25 PM	4	2	1	1	0	0	0	0	0	0	0
8/24/08 4:20 PM	2	1	1	1	0	0	0	0	0	0	0
8/30/08 3:20 PM	3	2	2	1	0	0	0	0	0	0	0
9/2/08 5:20 PM	3	1	1	1	0	0	0	0	0	0	0
9/3/08 5:20 PM	3	2	2	2	0	0	1	1	0	0	0
9/4/08 5:20 PM	3	1	1	1	0	0	0	0	0	0	0
9/5/08 5:20 PM	3	1	1	1	0	0	1	1	0	0	0
9/12/08 3:20 PM	3	1	1	1	0	0	0	0	0	0	0
9/15/08 3:20 PM	7	1	1	1	0	0	1	1	0	1	0
9/16/08 3:50 PM	7	2	2	1	0	0	1	1	0	0	1
9/17/08 3:20 PM	7	1	1	1	0	0	1	1	0	1	1
9/18/08 3:20 PM	7	1	1	1	0	0	0	0	0	0	0
9/23/08 7:35 PM	5	0	0	0	0	0	0	0	0	0	1
9/25/08 7:20 PM	6	1	1	1	0	0	2	2	1	0	0
9/29/08 2:20 PM	6	0	0	1	0	0	0	0	0	0	0
9/29/08 5:20 PM	6	0	0	0	0	0	0	0	0	0	1
10/1/08 6:20 PM	6	0	0	0	0	0	0	0	0	0	0
10/2/08 3:35 PM	5	0	0	0	0	0	0	0	0	0	0
10/2/08 6:20 PM	5	0	0	0	0	0	0	0	0	0	0
10/7/08 4:20 PM	7	2	2	2	2	0	1	1	0	0	0
10/10/08 3:20 PM	6	0	0	0	0	0	0	0	0	0	0

Table 8.1 summarizes the performance of the enhanced switches and AC units in the Inland Empire (both A and B feeders combined). The table indicates that no more than 14 of the 19 enhanced switches confirmed receipt of dispatch signals from the SCE transmitting towers. Because the highest numbers of confirmations were recorded only during the first part of the testing, we suspect that several of these enhanced switches stopped operating shortly after installation. The number of switches confirming receipt of dispatch signals varied considerably over the course of the summer. Overall, the number confirming receipt of dispatch signals appears to hover between five and seven or only about one-third of the total number of enhanced switches installed. As few as two or three switches confirmed receipt of dispatch signals in late August and early September. Because the number of confirming switches returns to five to seven later in September, we suspect that the temporary reduction resulted from changes in the transmission of the dispatch signals, not changes in the functioning of the switches themselves. SCE confirmed that the assignments of primary and secondary transmitter towers for the Inland Empire changed during late August.

Table 8.1 also reveals that very few of the AC units were actually operating on the day of curtailments. On the day of any given curtailment, typically only one, two, or no units appear to be operating during the period prior to a curtailment. This conclusion is especially well-supported for the switches that also confirm receipt of a dispatch signal. It is less well-supported for the switches that do not confirm receipt of a dispatch signal because, as noted above in discussing the apparent drop-off in number of switches confirming receipt of dispatch signals, the monitoring and reporting functions of some enhanced switches might have stopped working.

In examining the AC energy use of the switches that confirmed receipt of a dispatch signal to shed load, there is good correspondence between the number of these switches that had appeared to have load available to shed (i.e., they recorded using AC energy either three hours or one-half hour before the curtailment) and the number that actually shed load following receipt of the command. However, the correspondence is not one to one. Often, fewer units shed load than the total number that would appear to be available to do so. We believe that this is a reflection of natural diversity in the operating performance of AC units. At any given time, some AC units are cycled off and therefore are not available to shed load in response to a dispatch signal to do so. Of potentially greater concern are the two instances when units appear to have increased load following confirmed receipt of a shed command. We do not have enough information on the performance of these units to explain this unexpected finding.

In examining the AC energy use of the switches that did not confirm receipt of a dispatch signal to shed load, we find expected behaviors among the units indicating they were in use on the day of a curtailment. Although, as noted above, few appear to be operating during the period prior to a curtailment, those that were appear to display expected cycling behaviors: some increase load, some decrease, and some maintain. (As was also noted above, some might have been operating, but the enhanced switch was not recording or communicating this information.)

Table 8.2 summarizes the performance of the enhanced switches and AC units in the High Desert (both A and B feeders combined). Although the data from this set of distribution feeders exhibit some of the same general patterns observed for the Inland Empire (notably, few AC units appear to be operating on the day of curtailments), the number of enhanced switches confirming receipt of dispatch signals is consistently higher. Nearly twice the number of enhanced switches in the High Desert (i.e., 11-14) confirm receipt of dispatch signals compared to the number in the Inland Empire for the majority of curtailment events.

The higher number of units confirming receipt of dispatch signals further reinforces the earlier observation regarding the apparent low rates of AC energy use. Rarely do four of the units (out of, say, 12 units confirming receipt of dispatch signals) appear to be using AC energy on the day of curtailments; more typically the number is two or only about 15% of the units confirming receipt of dispatch signals.

Table 8.2 Performance of Enhanced Switches and AC Units in High Desert

	High Desert (N=18)										
		Received Shed Signal					Did Not Receive Shed Signal				
Test Event Time	Signal Confirm	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load
6/23/08 5:35 PM	15	2	2	4	2	0	0	0	0	0	0
6/30/08 5:15 PM	14	1	1	0	2	0	1	1	0	1	0
7/2/08 6:05 PM	13	2	2	1	1	0	1	1	0	0	1
7/7/08 6:05 PM	12	1	1	1	0	0	0	0	0	0	1
7/15/08 4:05 PM	13	3	3	2	0	0	1	0	0	0	1
7/15/08 6:05 PM	13	3	2	2	0	0	1	1	0	0	1
7/22/08 4:05 PM	12	0	0	0	0	0	1	0	0	0	0
7/24/08 3:05 PM	12	1	0	0	0	0	1	2	0	0	0
7/24/08 5:10 PM	13	2	2	2	0	0	0	0	0	0	0
7/25/08 3:50 PM	14	4	4	3	0	0	0	0	0	0	0
8/1/08 3:20 PM	14	2	2	2	0	0	0	0	0	0	0
8/1/08 4:05 PM	14	2	2	2	0	0	0	0	0	0	0
8/2/08 2:20 PM	13	2	2	2	0	0	0	0	0	0	0
8/2/08 3:20 PM	14	0	0	0	0	0	0	0	0	0	0
8/4/08 2:20 PM	14	1	1	1	1	0	0	0	0	0	0
8/4/08 3:20 PM	14	1	1	1	0	0	0	0	0	0	0
8/7/08 2:20 PM	11	2	2	1	4	0	1	1	0	0	0
8/7/08 4:20 PM	12	3	3	2	0	0	0	0	0	0	0
8/10/08 4:20 PM	10	3	3	1	1	0	1	1	0	0	1
8/10/08 6:20 PM	11	3	3	3	0	0	1	1	0	0	0
8/14/08 3:25 PM	12	4	4	1	2	0	0	0	0	0	1
8/24/08 4:20 PM	11	5	4	3	1	0	1	1	0	0	0
8/30/08 3:20 PM	12	2	2	1	0	0	0	0	0	0	1
9/2/08 5:20 PM	11	2	2	1	0	0	1	1	0	0	1
9/3/08 5:20 PM	11	1	1	1	0	0	1	1	0	0	1
9/4/08 5:20 PM	11	1	0	1	0	0	0	0	0	0	1
9/5/08 5:20 PM	11	3	2	2	0	0	0	0	0	0	1
9/12/08 3:20 PM	11	1	1	0	0	0	0	0	0	0	0
9/15/08 3:20 PM	11	2	2	1	0	0	0	0	0	0	0
9/16/08 3:50 PM	11	0	0	0	0	0	0	0	0	0	0
9/17/08 3:20 PM	12	0	0	0	0	0	0	0	0	0	0
9/18/08 3:20 PM	12	1	1	1	0	0	0	0	0	0	0
9/23/08 7:35 PM	9	1	1	0	0	0	0	0	0	0	0
9/25/08 7:20 PM	12	1	1	1	0	0	0	0	0	0	0
9/29/08 2:20 PM	12	1	1	0	0	0	0	0	0	0	0
9/29/08 5:20 PM	12	1	1	1	0	0	1	1	0	0	0
10/1/08 6:20 PM	12	2	2	0	0	0	1	1	0	0	1
10/2/08 3:35 PM	12	0	0	0	0	0	0	0	0	0	0
10/2/08 6:20 PM	11	2	2	1	0	0	0	0	0	0	0
10/7/08 4:20 PM	13	2	2	1	0	0	0	0	0	0	0
10/10/08 3:20 PM	14	1	1	0	0	0	0	0	0	0	0

The units that appear to be available to shed load in a curtailment event (i.e., those that confirm receipt of dispatch signals and report AC energy during the either or both periods prior to the time of curtailment) generally appear to shed load consistently following receipt of a shed command. Yet, as was also observed in Inland Empire, some of these units also appear to increase load following receipt of a shed command on one or more occasions. Again, we are not able to explain this unexpected behavior based on the information we were able to analyze.

Finally, few unique conclusions can be drawn from the information available from switches that did not confirm receipt of dispatch signals both because they are comparatively fewer in number and because AC energy use among these units also appears to be very low. No more than one unit out of the group that did not confirm receipt of dispatch signals ever reports AC energy use on the day of curtailments.

Table 8.3 Performance of Enhanced Switches and AC Units in Simi Valley

	Simi Valley (N=21)										
		Received Shed Signal					Did Not Receive Shed Signal				
Test Event Time	Signal Confirm	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load
6/23/08 5:35 PM	10	3	3	3	0	0	0	0	0	0	2
6/30/08 5:15 PM	10	1	1	0	0	0	1	1	0	0	0
7/2/08 6:05 PM	9	2	2	1	0	0	1	1	0	0	1
7/7/08 6:05 PM	9	4	4	2	0	0	0	0	0	0	1
7/15/08 4:05 PM	10	2	2	3	0	0	0	0	0	0	1
7/15/08 6:05 PM	10	2	2	2	0	0	0	0	1	0	1
7/22/08 4:05 PM	0	0	0	0	0	0	0	0	0	0	0
7/24/08 3:05 PM	0	0	0	0	0	0	0	0	0	0	0
7/24/08 5:10 PM	0	0	0	0	0	0	0	0	0	0	0
7/25/08 3:50 PM	9	2	2	0	0	0	0	0	0	0	0
8/1/08 3:20 PM	10	0	0	0	0	0	0	0	0	0	0
8/1/08 4:05 PM	11	0	0	1	0	0	0	0	0	0	0
8/2/08 2:20 PM	10	0	0	1	0	0	2	1	0	0	0
8/2/08 3:20 PM	10	1	0	0	0	0	1	1	0	0	0
8/4/08 2:20 PM	10	0	0	3	0	0	3	3	0	0	1
8/4/08 3:20 PM	10	2	2	2	1	0	1	1	0	0	0
8/7/08 2:20 PM	0	0	0	0	0	0	3	2	0	1	0
8/7/08 4:20 PM	0	0	0	0	0	0	3	2	0	0	2
8/10/08 4:20 PM	0	0	0	0	0	0	0	0	0	0	0
8/10/08 6:20 PM	0	0	0	0	0	0	0	0	0	0	0
8/14/08 3:25 PM	0	0	0	0	0	0	0	2	2	0	3
8/24/08 4:20 PM	10	2	1	0	0	0	1	0	0	0	0
8/30/08 3:20 PM	8	2	1	0	0	0	0	0	0	0	0
9/2/08 5:20 PM	10	2	2	2	0	0	4	4	0	0	1
9/3/08 5:20 PM	10	4	4	3	0	0	3	3	0	2	1
9/4/08 5:20 PM	9	2	2	1	0	0	4	3	1	0	0
9/5/08 5:20 PM	9	3	3	2	0	0	5	4	0	0	1
9/12/08 3:20 PM	10	0	0	0	0	0	0	0	0	0	0
9/15/08 3:20 PM	9	2	2	1	0	0	0	0	0	0	0
9/16/08 3:50 PM	10	1	1	0	0	0	1	1	0	0	2
9/17/08 3:20 PM	9	0	0	0	0	0	2	2	1	0	1
9/18/08 3:20 PM	9	0	0	0	0	0	0	0	0	0	1
9/23/08 7:35 PM	7	0	0	0	0	0	0	0	0	0	0
9/25/08 7:20 PM	11	3	3	2	0	0	1	1	0	0	1
9/29/08 2:20 PM	11	1	1	1	0	0	2	2	0	0	0
9/29/08 5:20 PM	10	2	2	2	0	0	1	1	1	0	0
10/1/08 6:20 PM	9	4	4	2	0	0	3	3	1	0	2
10/2/08 3:35 PM	9	1	1	1	0	0	2	2	0	0	0
10/2/08 6:20 PM	9	3	3	2	1	0	0	0	0	0	0
10/7/08 4:20 PM	12	6	6	4	2	0	0	0	0	0	0
10/10/08 3:20 PM	12	0	0	0	0	0	0	0	0	0	0

Table 8.3 summarizes the performance of the enhanced switches and AC units in Simi Valley (both A and B feeders combined). As noted in Section 5, we were not able to obtain data for two periods during the summer. The data from Simi Valley are similar to the data collected from the High Desert. A consistent number of switches report receipt of dispatch signals throughout the summer though slightly fewer as a percent of the total installed (approximately one-half for Simi Valley compared to about two-thirds for the High Desert). AC energy use among units reporting receipt of dispatch signals is low for Simi Valley. It is slightly lower than for the High Desert and similar to the number reported for the Inland Empire. Changes in AC energy use following receipt of dispatch signals exhibit patterns consistent with those observed in the High Desert and Inland Empire.

8.2 Estimation of Aggregate Load Curtailed based on Individual Metered AC Units

Table 8.4 summarizes the performance of the enhanced switches and AC units in Temecula Valley (both A and B feeders combined). The most striking aspect of the enhanced switch data from this distribution feeder group is the apparent confirmation of the inability of SCE's load management dispatch system to initiate curtailments. Only one enhanced switch of the 16 installed in these feeders reports confirmation of receipt of dispatch signals.

Focusing on the enhanced switches that did not confirm receipt of dispatch signals, AC energy use patterns mirror trends observed in the other three feeders. First, as we speculated for the Inland Empire, drop-off in the number of switches reporting AC energy use over the first few curtailment events suggests a drop-off in the ability of some enhanced switches to record or communicate energy use data, not a change in energy use. Second, as observed for the other three feeder groups, AC energy use is low; rarely do more than two or three units report energy use during the periods prior to a curtailment. Third, for the majority of units that do not confirm

Table 8.4 Performance of Enhanced Switches and AC Units in Temecula Valley

	Temecula (N=16)										
		Received Shed Signal					Did Not Receive Shed Signal				
Test Event Time	Signal Confirm	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load	Load 3 Hrs before	Load 1/2 Hr Before	Shed load	Increase load	Maintain load
6/23/08 5:35 PM	0	0	0	0	0	0	6	4	0	0	5
6/30/08 5:15 PM	1	1	1	1	0	0	4	4	1	3	3
7/2/08 6:05 PM	1	1	1	1	0	0	4	4	2	0	2
7/7/08 6:05 PM	1	0	0	0	0	0	1	1	1	0	1
7/15/08 4:05 PM	1	0	0	0	0	0	2	2	0	0	1
7/15/08 6:05 PM	1	0	0	0	0	0	2	2	0	0	4
7/22/08 4:05 PM	1	0	0	0	0	0	0	0	0	0	3
7/24/08 3:05 PM	1	1	1	1	0	0	2	2	0	0	1
7/24/08 5:10 PM	1	0	0	0	0	0	3	3	0	0	3
7/25/08 3:50 PM	1	0	0	0	0	0	2	2	0	0	3
8/1/08 3:20 PM	1	0	0	0	0	0	3	1	0	1	1
8/1/08 4:05 PM	1	0	0	0	0	0	3	1	0	1	0
8/2/08 2:20 PM	1	0	0	0	0	0	2	2	1	1	1
8/2/08 3:20 PM	1	0	0	0	0	0	2	2	0	0	2
8/4/08 2:20 PM	1	0	0	0	0	0	1	1	0	1	0
8/4/08 3:20 PM	1	0	0	0	0	0	1	1	0	0	1
8/7/08 2:20 PM	1	0	0	0	0	0	2	2	0	0	0
8/7/08 4:20 PM	1	0	0	0	0	0	2	2	1	1	1
8/10/08 4:20 PM	1	0	0	0	0	0	1	1	1	1	1
8/10/08 6:20 PM	1	0	0	0	0	0	1	1	0	0	0
8/14/08 3:25 PM	1	0	0	0	0	0	0	2	0	0	0
8/24/08 4:20 PM	1	1	1	1	0	0	0	0	0	0	1
8/30/08 3:20 PM	1	1	1	1	0	0	0	0	0	0	0
9/2/08 5:20 PM	1	0	0	0	0	0	3	3	0	0	3
9/3/08 5:20 PM	1	1	1	1	0	0	5	4	2	0	3
9/4/08 5:20 PM	1	1	1	1	0	0	2	2	0	1	2
9/5/08 5:20 PM	1	1	1	1	0	0	0	0	0	0	2
9/12/08 3:20 PM	1	0	0	0	0	0	0	0	0	0	0
9/15/08 3:20 PM	1	1	1	1	0	0	1	1	1	0	0
9/16/08 3:50 PM	1	1	1	1	0	0	1	1	0	1	0
9/17/08 3:20 PM	1	0	0	0	0	0	2	2	1	1	2
9/18/08 3:20 PM	1	1	1	1	0	0	2	2	0	1	1
9/23/08 7:35 PM	1	0	0	0	0	0	1	1	0	0	1
9/25/08 7:20 PM	1	1	1	1	0	0	2	2	1	0	2
9/29/08 2:20 PM	1	0	0	0	0	0	0	0	0	0	0
9/29/08 5:20 PM	1	0	0	0	0	0	2	1	1	0	0
10/1/08 6:20 PM	1	1	1	1	0	0	1	0	0	0	2
10/2/08 3:35 PM	1	1	1	1	0	0	1	1	0	0	1
10/2/08 6:20 PM	1	1	1	0	0	0	1	1	1	0	1
10/7/08 4:20 PM	1	1	1	0	0	0	0	0	0	0	0
10/10/08 3:20 PM	1	0	0	0	0	0	0	0	0	0	0

receipt of a dispatch command to shed load, AC energy use following the time a dispatch signal to shed load is sent exhibits the expected pattern of diversity with some units increasing load, some shedding load, and some maintaining load. The number of units in each case is to low to discern specific trends in the patterns of this behavior.

Next, we used the information from the enhanced switches to develop an independent estimate of the aggregate amount of load curtailed on each distribution feeder group and compared these estimates to those presented in Section 7.

Table 8.5 provides a side-by-side comparison, for each distribution feeder group and curtailment event, of the estimates developed using the two methods. To facilitate the comparisons and lay the groundwork for the discussion following in Section 8.3, the estimates are normalized by the

Table 8.5 Estimates of Load Curtailed Using Data from Distribution Feeders and from Enhanced Switches

	Inland Empire				High Desert				Simi Valley				Temecula	
Test Event Time	Feeder	Stat Sig?	Switch	% of Feeder	Feeder	Stat Sig?	Switch	% of Feeder	Feeder	Stat Sig?	Switch	% of Feeder	Feeder	Switch
6/23/08 5:35 PM	N/A		1.340		N/A		0.381		N/A		0.325		N/A	-0.001
6/30/08 5:15 PM	N/A		1.241		N/A		-0.476		N/A		0.014		N/A	0.176
7/2/08 6:05 PM	0.855	YES	0.814	95.2%	N/A		0.469		N/A		0.117		N/A	0.805
7/7/08 6:05 PM	0.352	NO	0.582	165.4%	N/A		0.456		N/A		0.183		N/A	0.538
7/15/08 4:05 PM	0.422	NO	0.359	85.2%	N/A		0.716		0.877	YES	0.335	38.2%	N/A	0.000
7/15/08 6:05 PM	1.337	YES	0.154	11.5%	N/A		0.693		-0.390	NO	0.202	-51.8%	N/A	0.006
7/22/08 4:05 PM	0.514	YES	0.121	23.6%	N/A		0.025		-0.989	NO	0.000	0.0%	N/A	0.001
7/24/08 3:05 PM	0.755	YES	-0.006	-0.7%	N/A		0.023		N/A		0.000		N/A	0.238
7/24/08 5:10 PM	0.487	NO	0.128	26.4%	N/A		0.497		N/A		0.000		N/A	0.246
7/25/08 3:50 PM	0.390	NO	0.141	36.2%	N/A		1.025		0.059	NO	0.001	1.0%	N/A	0.000
8/1/08 3:20 PM	1.037	YES	0.005	0.5%	N/A		0.849		1.478	YES	-0.005	-0.3%	N/A	-0.160
8/1/08 4:05 PM	0.984	YES	0.004	0.4%	N/A		0.790		0.504	NO	0.060	11.9%	N/A	-0.252
8/2/08 2:20 PM	0.350	NO	-0.002	-0.5%	N/A		0.734		0.093	NO	0.140	150.1%	N/A	0.034
8/2/08 3:20 PM	0.415	NO	-0.002	-0.5%	N/A		0.043		0.156	NO	0.030	19.3%	N/A	0.006
8/4/08 2:20 PM	1.475	YES	0.277	18.8%	0.558	YES	0.379	67.9%	0.045	NO	0.326	722.9%	N/A	-0.303
8/4/08 3:20 PM	1.165	YES	-0.024	-2.1%	0.483	NO	0.469	97.2%	-0.367	NO	0.204	-55.5%	N/A	0.000
8/7/08 2:20 PM	0.636	YES	-0.250	-39.3%	N/A		-0.234		0.985	YES	-0.145	-14.7%	N/A	0.013
8/7/08 4:20 PM	1.675	YES	0.304	18.1%	N/A		0.695		0.049	NO	0.000	0.0%	N/A	0.141
8/10/08 4:20 PM	0.836	YES	0.177	21.2%	0.711	YES	0.259	36.5%	0.034	NO	0.000	0.0%	N/A	0.160
8/10/08 6:20 PM	1.145	YES	0.293	25.6%	0.837	YES	0.948	113.3%	-0.971	NO	0.000	0.0%	N/A	0.002
8/14/08 3:25 PM	1.082	YES	0.134	12.4%	0.676	YES	0.232	34.4%	-0.385	NO	0.131	-34.0%	N/A	0.000
8/24/08 4:20 PM	0.802	YES	0.126	15.7%	N/A		0.671		0.318	NO	0.051	16.1%	N/A	0.202
8/30/08 3:20 PM	1.214	YES	0.149	12.3%	N/A		0.289		-0.402	NO	0.058	-14.4%	N/A	0.261
9/2/08 5:20 PM	1.131	YES	0.130	11.5%	N/A		0.303		-0.754	NO	0.199	-26.3%	N/A	0.124
9/3/08 5:20 PM	1.023	YES	0.209	20.4%	N/A		0.329		-0.321	NO	0.360	-112.3%	N/A	0.827
9/4/08 5:20 PM	1.221	YES	0.142	11.6%	N/A		0.282		-0.015	NO	0.445	-2913.3%	N/A	-0.348
9/5/08 5:20 PM	1.178	YES	0.129	11.0%	N/A		0.691		0.146	NO	0.343	234.6%	N/A	0.199
9/12/08 3:20 PM	-0.177	NO	0.135	-76.6%	N/A		-0.014		-0.161	NO	0.007	-4.1%	N/A	-0.002
9/15/08 3:20 PM	0.910	YES	0.091	9.9%	0.729	YES	0.348	47.7%	0.728	YES	0.171	23.5%	N/A	0.261
9/16/08 3:50 PM	1.253	YES	0.123	9.8%	0.388	NO	0.029	7.5%	-0.714	NO	0.008	-1.2%	N/A	-0.008
9/17/08 3:20 PM	1.048	YES	0.013	1.2%	0.238	NO	0.016	6.7%	0.059	NO	0.133	224.0%	N/A	-0.017
9/18/08 3:20 PM	1.011	YES	0.123	12.2%	-0.587	NO	0.056	-9.6%	0.885	YES	0.001	0.1%	N/A	0.106
9/23/08 7:35 PM	0.375	NO	0.001	0.2%	-0.053	NO	0.000	0.9%	0.219	NO	0.000	-0.2%	N/A	0.000
9/25/08 7:20 PM	1.071	YES	0.253	23.6%	-0.454	NO	0.071	-15.8%	-0.214	NO	0.241	-112.4%	N/A	0.337
9/29/08 2:20 PM	1.001	YES	0.054	5.4%	0.280	NO	0.020	7.2%	0.240	NO	0.201	83.7%	N/A	0.011
9/29/08 5:20 PM	0.768	YES	0.003	0.4%	0.417	NO	0.052	12.5%	-0.575	NO	0.231	-40.1%	N/A	0.133
10/1/08 6:20 PM	0.730	YES	0.014	2.0%	0.103	NO	0.003	3.0%	1.013	YES	0.375	37.0%	N/A	0.213
10/2/08 3:35 PM	0.359	NO	-0.002	-0.6%	0.316	NO	0.023	7.4%	-0.301	NO	0.095	-31.5%	N/A	0.104
10/2/08 6:20 PM	0.710	YES	0.003	0.4%	-0.154	NO	0.173	-111.8%	0.368	NO	0.193	52.4%	N/A	0.081
10/7/08 4:20 PM	0.633	YES	-0.132	-20.9%	0.443	NO	0.386	87.1%	0.033	NO	0.155	469.3%	N/A	0.013
10/10/08 3:20 PM	N/A		-0.005		0.040		0.003	6.4%	0.056	NO	0.038		N/A	0.002

number of switches to yield estimates in kW/switch. The table also reports whether the estimates based on distribution feeder load data were found to be statistically significant (as discussed in Section 7).

The comparison of load curtailed on a per-switch basis highlights several important trends. First, we find a degree of consistency between the two methods for estimating the amount of load curtailed. Focusing on the events for which the distribution-feeder-data estimates of load curtailed were found to be statistically insignificant, we see that the same events yield very low or negative values when the estimates are based on enhanced switch data.

Second, we find corroboration for the earlier speculation that there were systematic problems with the SCE dispatch system initiating load curtailments in Temecula Valley. In Section 7, we found, by analyzing distribution feeder data, that very few estimates of load curtailments in Temecula Valley were statistically significant. In Section 8.1, we found that only one enhanced switch in Temecula Valley confirmed receipt of dispatch signals. We speculate that neither method should be expected to yield reliable estimates if in fact few or no loads were ever curtailed because of problems with the SCE load management dispatch system.

Third, we find evidence of possible systematic bias in the estimates based on analysis of enhanced switch data, which we will explore further in the next subsection. Focusing on the results for the Inland Empire, the estimates of load curtailed developed through analysis of enhanced switch data appear to be consistently lower than those estimated through analysis of distribution feeder data. This trend is especially pronounced for the estimates of distribution feeder load curtailment that were found to be statistically significant in Section 7.

8.3 Sample Size Effects on Estimates of Aggregate Load Curtailed based on Individual Metered AC Units

The normalization of estimated load curtailed using data from the enhanced switches presented in Section 8.2 was based on the entire population of enhanced switches installed in each distribution feeder group. Yet, in section 8.1, we found that many of the enhanced switches never confirmed receipt of dispatch signals. If these switches were defective (as appeared to be the case when there was a drop-off in the number of switches confirming receipt of dispatch signals shortly after the start of the summer) or if for whatever reason they never confirmed receipt of a dispatch signal (and, in many cases, also never recorded AC energy use), then the inclusion of these switches in the normalization of estimated loads would lead to systematic underestimates of load curtailed, expressed on a per-switch basis, as is suggested by the comparison just described.

We explored this issue by recalculating the estimates of load curtailed per switch from the enhanced switch data by renormalizing these estimates so that they are based on only switches that confirmed receipt of dispatch signals.[19] We focus this inquiry solely on the estimates developed for the Inland Empire and the High Desert.

[19] It is important to acknowledge that the line of inquiry presented in this subsection leaves unaddressed the issue of whether the same bias may be present in our normalization of distribution feeder data by the total number of switches installed.

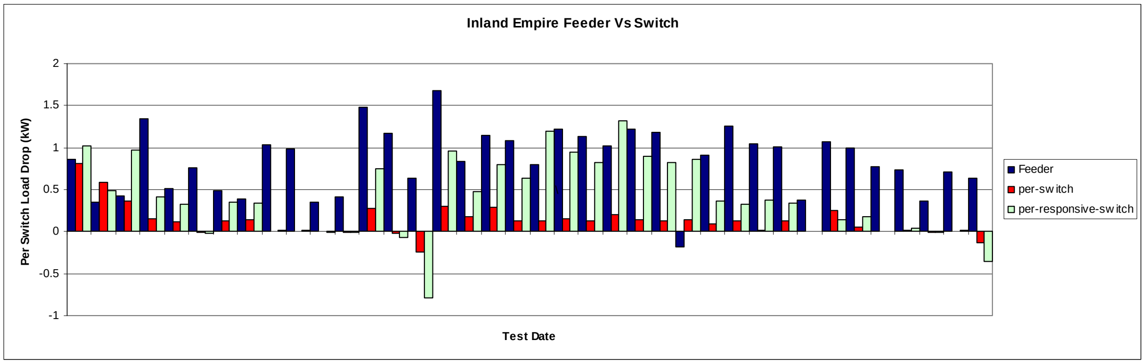

Figure 8.1 Load Curtailment Estimates based on Distribution Feeder and Enhanced Switch Data — Inland Empire

Figure 8.1 compares the load-curtailed-per-switch estimates based on distribution feeder data, enhanced switch data (using all installed enhanced switches), and enhanced switch data (using only enhanced switches that confirmed receipt of dispatch signals) for the Inland Empire. Predictably, the enhanced switch estimates using only switches that confirmed receipt of dispatch signals are always larger than those using all installed switches (because n is smaller). Of greater interest, these estimates are now much closer in magnitude to those estimated based on distribution feeder data.

This is a reassuring finding. There appears to be reasonable consistency between the two methods for estimating the amount of load curtailed.

However, Figure 8.1 also reveals that the consistency is neither exact nor uniform. So we examine next the small number of enhanced switches contributing usable data to the estimates of aggregated load curtailed.

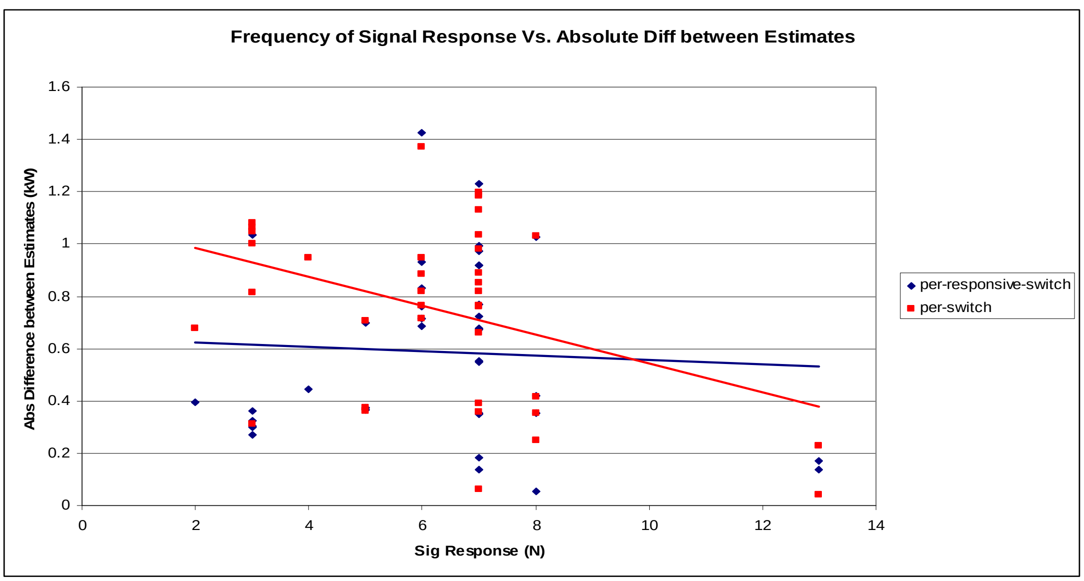

Figure 8.2 Difference Between Estimates from Enhanced Switch Data and Distribution Feeder Data — Inland Empire

Figure 8.2 highlights the effect of sample size on both estimates of load curtailment from enhanced switch data when compared to the estimate based on distribution feeder data. Figure 8.2 compares the differences between both enhanced switch data estimates compared to the distribution feeder data estimates as a function of the number of switches that confirmed receipt of the dispatch signal. When the number of switches confirming receipt of the dispatch signal is small, the resulting estimates show the greatest difference from the estimate based on distribution feeder data. As the number of switches confirming receipt of the dispatch signal increases, these differences decrease. The decrease in differences is much more dramatic for the enhanced switch estimates based on all installed switches.

Table 8.6 compares the estimated load curtailed from the two enhanced switch estimates to the feeder-level estimates for Inland Empire. While the per-responsive-switch method yields estimates that are closer to those estimated using distribution feeder data, the difference from the estimate using distribution feeder data is still significant (47%).

Table 8.6 Load Curtailment Estimates based on Distribution Feeder and Enhanced Switch Data — Inland Empire

Load Drop Estimate Type	Average Load Drop (kw)	% of Feeder Level
Feeder Lever	0.85	
per-switch	0.13	15%
per-responsive switch	0.39	47%

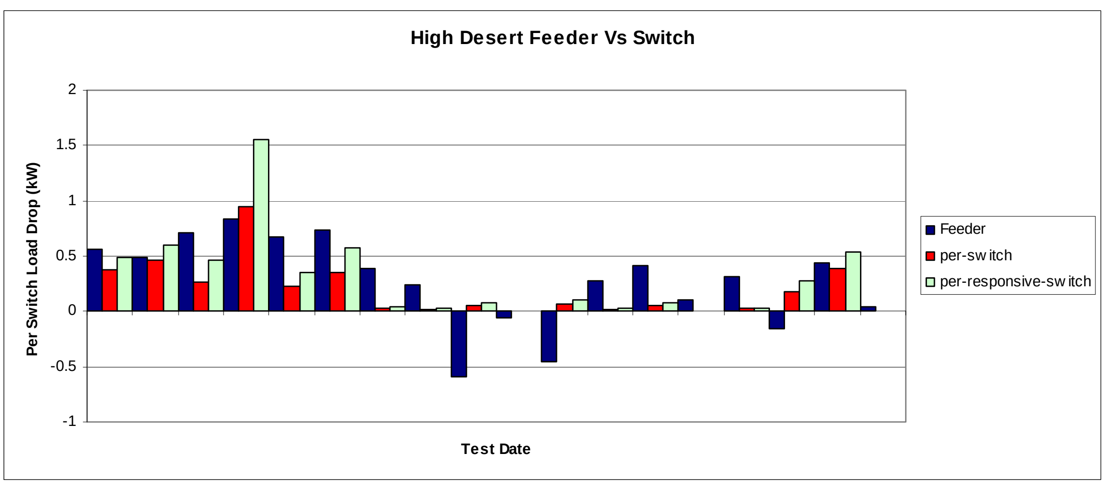

Figure 8.3 Load Curtailed Estimates based on Distribution Feeder and Enhanced Switch Data — High Desert

Figure 8.3 compares the load-curtailed-per-switch estimates based on distribution feeder data, enhanced switch data (using all installed enhanced switches), and enhanced switch data (using only enhanced switches that confirmed receipt of dispatch signals) for the High Desert. As with

Figure 8.1, the estimates based on enhanced switches that confirmed receipt of dispatch signals is again by definition higher than those based on all enhanced switches; however, the differences are smaller. As discussed in Section 8.1, the High Desert consistently had the highest percentage of enhanced switches confirming receipt of dispatch signals.

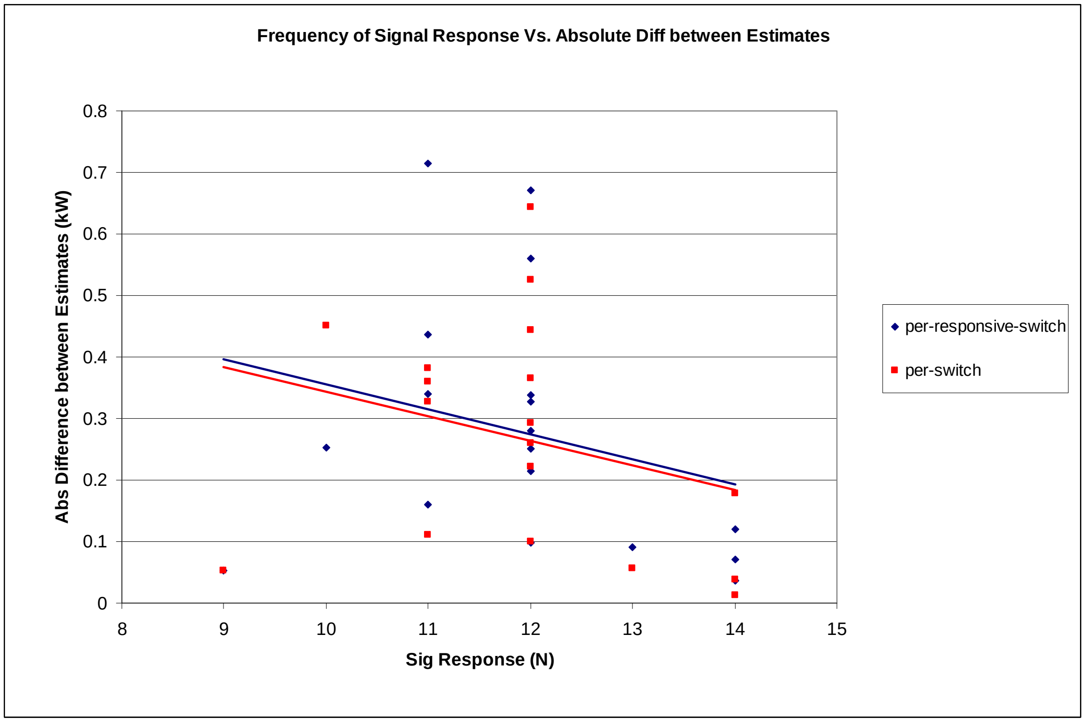

Figure 8.4 Difference Between Estimates from Enhanced Switch Data and Distribution Feeder Data — High Desert

Consequently, the comparison of absolute differences in Figure 8.4 also shows much greater similarity between the two estimates. Notably, the same trend first observed in Figure 8.2 is also present in Figure 8.4. The differences between the enhanced switch estimates and the distribution feeder estimates diminish as the number of enhanced switches confirming receipt of dispatch signals increases.

Table 8.7 compares the estimated load curtailed from the two enhanced switch estimates to the feeder level estimates for the High Desert. In comparison to the results for the Inland Empire in Table 8.6, the estimates based on enhanced switches that confirmed receipt of dispatch signals are essentially the same as those based on the distribution feeder data.

Table 8.8 is a final summary of our investigation of the effects of normalization based on the numbers of enhanced switches used in the estimation process. As shown in the table, the enhanced switches installed in each of the two distribution feeder groups are comparable both in absolute number and as a percentage of the population of switches installed. However, the percentages are modest; they represent sample sizes of less than 10% of the total population within each distribution feeder group. Moreover, the effective sample size diminishes further when we consider only the enhanced switches that confirmed receipt of dispatch signals. This percentage is higher for the High Desert than it is for the Inland Empire.

Table 8.7 Load Curtailed Estimates based on Distribution Feeder and Enhanced Switch Data — High Desert

Load Drop Estimate Type	Average Load Drop (kw)	% of Feeder Level
Feeder Lever	0.28	
per-switch	0.19	67%
per-responsive switch	0.29	106%

Table 8.8 Comparison of Enhanced Switch Installations and Performance for Inland Empire and High Desert

Circuit	All Switches	Enhanced Switches	% of All	Average Confirming Receipt Of Dispatch	% of All	% of Enhanced
Inland Empire	330	19	6%	6.5	2%	34%
High Desert	276	18	7%	12.2	4%	68%
Difference			1%	5.7	2%	34%

8.4 Summary of Findings

Monitoring individual AC units is an extremely useful diagnostic tool for evaluating the efficacy of the load management dispatch system as well as for understanding AC energy use behavior. Monitoring also provided an independent means for estimating the magnitude of aggregate load curtailments as well as giving us insights into the results developed using estimation methods that rely solely on distribution feeder data.

We found that a significant number of installed monitoring devices were not able to confirm receipt of dispatch signals from the SCE load management dispatch system. This finding was indicative, in many instances, of monitoring devices that did not record or communicate information properly. It also helped explain why the analysis of distribution feeder data for Temecula Valley did not yield statistically significant results for the majority of curtailments; it appears that dispatch signals from the SCE load management dispatch system were simply not received by the majority of participating AC units in this region.

We also found very modest levels of AC energy use by the monitored units on the days when curtailments were conducted. Rarely were more than one-quarter to one-third of the units actually in operation (and thus able to provide load relief). This was a surprising finding as the curtailments were scheduled to take place during the hottest periods of the day. More analysis with larger numbers of monitored units is required to better understand this finding.

By treating the monitored units as a statistically representative sample, we derived independent estimates of the aggregate load curtailed within each distribution feeder group. We found reasonable correlation between these estimates and those developed through analysis of distribution feeder data when those developed from distribution feeder data were also found to be statistically significant. This finding suggests that the estimates produced by the two methods were fairly consistent with one another.

We were able to further close the gap between the absolute value of the two sources of estimates by adjusting the monitored unit sample size to include data from only monitored units that confirmed receipt of dispatch signals. We also explored the limitation imposed by the small numbers of monitored units available to support our estimation methods and concluded that greater numbers of monitored units would likely have led to more robust results.

9. Review, Assessment, and Recommendations for Next Steps

This final section reviews critical program design and evaluation issues that should be considered in moving the demonstration concepts toward a full-scale utility program.

9.1 Target Marketing Demand Response Programs

As discussed in Section 2, target marketing has been demonstrated as successful in increasing enrollment in demand response programs beyond levels achievable solely through mass marketing approaches. However, to have maximum effect, target marketing requires coordination among multiple groups within a utility and among contractors supporting the utility.

To increase enrollment within the four distribution feeder groups in our demonstration, a sequential marketing campaign was undertaken involving letters to potential participants followed by telemarketing. The letters and telemarketing had to carefully explain the relationship between the standard SDP and the research-oriented Demand Response Spinning Reserve Demonstration program. The timing and sequencing of the letter and telemarketing efforts had to be coordinated, which was complicated because different parts of the SCE organization (and its contractors) were responsible for each effort.

9.2 Documenting the Time Required for Full Response from Aggregated Demand Response

As discussed in Section 6, documenting the initiation of load curtailments is straightforward because the utility systems that manage the dispatch process are largely automated and already have the capability to record the time when each step in the process is executed. However, in a demand response program, the ultimate confirmation of dispatch can only come from the end-use devices that are supposed to respond.

To obtain confirmation of dispatch, we installed monitoring devices on individual AC units within each distribution feeder group. Section 6 describes how we used the data from these devices to confirm the time when they received signals to either shed or restore load. By and large, the times recorded were very consistent across the many curtailments. However, Section 8 reports our finding that the vast majority of monitoring devices in one distribution feeder group never confirmed receipt of dispatch signals. This finding, which was corroborated by the absence of statistically significant load curtailments in the data from that distribution feeder, led us to conclude that dispatch signals were, in fact, not being transmitted properly to the participating AC units on that feeder.

We conclude from this experience that monitoring of individual end-use devices is highly warranted to track performance and identify problems in the dispatch system. If the sole purpose of monitoring is to document the time to respond to commands, this monitoring need not be ongoing.

Based on the information we gathered, it appears that the time required to dispatch is reasonably constant as long as the dispatch system performs reliably. Periodic spot monitoring may be adequate for documenting time to respond.

9.3 Estimating the Magnitude of Short-Duration Demand Response

We explored two independent methods for estimating the magnitude of short-duration demand response. One is based on analysis of distribution feeder data; the other is based on analysis of monitoring data for a sample of individual AC units. These two methods produced estimates that were reasonably consistent with one another though each was subject to limitations resulting from related but distinct statistical sampling issues.

9.3.1 Estimates Based on Distribution Feeder Data

As discussed in Section 7, estimating the magnitude of load curtailments based on distribution feeder data requires analysis methods that can reliably extract the "signal" created by the aggregate response of AC units from the background "noise" that is ever-present in (i.e., the stochastic nature of) the loads on distribution feeders. This task is easiest when the signal is strong compared the noise. Formalizing the conceptual framework for this analysis provides insight into the results we reported in Section 7 for distribution feeder data for the Inland Empire, High Desert, and Simi Valley.[20]

The strength of the signal from responding AC units can be broken down into two elements: 1) the number of responding AC units, and 2) the load relief provided by each responding AC unit. The strength of the background noise on a distribution feeder is expressed by a direct measure of the variability of the loads on the feeder.

Table 9.1 expresses the relationship between these concepts analytically for the Inland Empire and High Desert using concepts from statistical sampling theory. For purposes of this discussion, two elements are held fixed. The inherent noise or error bound (MW) of each feeder, feeder group, or combination of feeders is taken from the analysis presented in Section 7. The load relief provided by each responding AC unit (1.0 kW) is taken from the analysis presented in Section 8 (see Table 8.5). Thus, the only element allowed to vary is the number of responding AC units.

Table 9.1 Relationships Between Distribution Feeder "Noise" and Aggregate Curtailed Load "Signal"

Feeder	Error Bound (MW)	Est. Per unit Impact (kW)	Curtailed Units	Units for Relative Precisions (RP) of: 100%	50%	25%	10%	% of Pop to get 10% RP
HD A	0.097	1.0	174	97	194	388	971	
HD B	0.108	1.0	102	108	215	431	1,077	
HD A&B	0.146	1.0	276	146	292	585	1,462	58%
IE A	0.121	1.0	105	121	243	486	1,214	
IE B	0.107	1.0	225	107	214	427	1,068	
IE A&B	0.162	1.0	330	162	324	648	1,621	78%
IE/HD A	0.152	1.0	606	152	305	610	1,524	33%

[20] In Section 8, we concluded that our inability to develop estimates of load curtailment for Temecula Valley is likely due to problems with the SCE load management dispatch system. These problems appear to have resulted in few participating AC units ever receiving dispatch signals.

Statistical sampling theory gives an exact relationship among these quantities that is a function of the level of precision sought in the final estimate: $LoadNecessary = \frac{errorbound}{RP}$.

For example, for Inland Empire feeders A and B, a sample size (or number of responding AC units) of 1,621 is required to achieve a relative precision of 10% in the resulting estimate. A 10% relative precision means that the resulting estimate would be expected to be within 10% of the true value. The basic intuition here is that relative precision increases as sample size increases, up to the point where the precision becomes exact (0% relative precision) when the sample size is the entire population.

It is useful now to recall that the actual sample size (i.e., number of participating AC units) for Inland Desert feeders A and B is 330, which means that the relative precision of our estimates is only about 50%. Note that 330 is the number of participants. If some participants do not respond (because they do not receive dispatch signals), then the number of responding AC units is even lower, and the relative precision gets worse because the sample (i.e., number of responding units) has been decreased.

The final column of Table 9.1 expresses the number of responding AC units required to obtain relative precision of 10% as a percentage of the eligible population on each feeder or feeder group. The relationships expressed in Table 9.1 lead us to conclude that the relative precision for the majority of the estimates presented in Section 6 is rarely less than 50%. This gives us means for understanding the findings from Section 6, which led us to conclude that many estimates of load curtailed were not statistically significant.

Table 9.1 also highlights the potential for improving relative precision by combining data from multiple feeders, a conclusion we also drew in Section 6. That is, when data from multiple feeders are combined, the error bounds for each feeder are not additive; some of the stochastic variation (i.e., the noise) is reduced. Yet, the strength of the signal is strictly additive. Hence, the signal is stronger compared to the noise. This can be seen by smaller number of responding AC units required to achieve a given level of precision for combined feeders compared to the number required for the same level of precision for individual feeders.

Finally, the linear relationship between number of responding units and load relief per unit on the one hand, and signal strength on the other hand, gives us a key to understanding differences among the results presented in Section 7 for the Inland Empire, High Desert, and Simi Valley.

Analysis of distribution feeder data for the Inland Empire yielded the greatest number of statistically significant results. Reviewing the per-unit estimates in Section 8 (Table 8.5), we see that, compared to the per-unit estimates for the High Desert and Simi Valley, the per-unit estimates for the Inland Empire are generally very close to the 1.0 kW per unit used to develop the information presented in Table 9.1. With respect to the findings on relative precision presented on Table 9.1, lower per-unit estimates (as exhibited in the findings for the High Desert and Simi Valley, see Tables 8.2 and 8.3, and 8.5) lead to even higher estimates of relative precision for a given number of responding AC units. In other words, lower per-unit energy use by AC units in the High Desert and Simi Valley are part of the explanation for our inability to develop statistically significant estimates from analysis of distribution feeder data.

The implication of this analysis is very clear for future efforts that rely on distribution feeder data to estimate the magnitude of load curtailments from aggregated demand response: The strength of the demand response signal must be strong relative to the inherent noise in distribution feeder data.

The strength of the signal depends on the number of participants within a feeder as well as the load relief provided by each participant. In this regard, it will be important to understand the relationship between program recruitment methods and the energy use behavior of program participants.

The relative amount of noise in distribution feeder data compared to the strength of the signal provided by responding participants diminishes as feeders are combined. Thus, although low participation on any given feeder may present estimation problems, combining data from multiple feeders will likely improve relative precision, other things (such as the amount of load provided by each participant) being equal.

9.3.2 Estimates Based on Monitoring Individual AC Units

As discussed in Section 8, monitoring individual AC units provided both an independent estimate of load curtailments and insight into the efficacy of SCE's load management dispatch system and participants' AC use (and thereby insight into the findings from analysis of distribution feeder data). For the latter reasons alone, inclusion of individual AC unit monitoring is warranted in future efforts to examine AC demand response.

This discussion turns now to the use of individual AC unit monitoring to provide an independent estimate of load curtailment. This issue can also be assessed from the perspective of statistical sampling. As Section 8.3 illustrated, increasing the number of individually monitored AC units used in the estimation process reduced the discrepancies between the resulting estimates and those obtained from analysis of distribution feeder data. In this case, the question is to determine how many AC units to monitor within a distribution feeder group to estimate the aggregated demand response of all units. As above, precision increases as the number sampled approaches the total population.

However, in this example, the relationship between sample size and relative precision is more straightforward. As demonstrated by political polling techniques, comparatively small samples (100's or less) can provide reliable information on very large populations (1,000,000's or more). On our distribution feeders, it is reasonable to expect that samples of 20 to 30 individually monitored AC units will be adequate to characterize populations of 200 to 400 or even 600 participants.

Appendix A. Project Rationale

In this appendix, we reproduce the rationale for using demand-side resources as system reliability resources, which was originally presented in the Phase 1 technical report for this project (Eto, et. al 2006).

We begin with a technical description of the role and function of the system reliability resource known as spinning reserve, focusing on the difference between the technical requirements of the service as specified in reliability rules, which require that it be available for up to two hours, and the way in which it is actually used by system operators, which is often for 10 minutes or less. This discussion illustrates why air-conditioning load and other demand-side resources that have some form of storage or inertia are well matched to the short time periods during which spinning reserve is actually utilized in practice. Compared to the very long curtailments (two to six hours) typically experienced by customers on traditional utility load-cycling programs, the far shorter curtailments associated with providing spinning reserve may be indistinguishable to these customers from the routine operation of their air conditioners.

We build from this basic insight to discuss other technical advantages that might accrue from use of demand-side resources to provide spinning reserve.

A.1 What is Spinning Reserve?

To assure reliable provision of electricity service, power system operators must have resources continuously poised, ready to respond immediately if a generator or transmission line fails. Without reserves to replace the lost generation (or the generation that the lost transmission was delivering), load would exceed generation, and the power system would rapidly collapse.

Figure 2-1 shows a plot of power system frequency during a major loss-of-generation contingency. In this case the reserve responded well, and system balance was successfully restored within 10 minutes.

Contingency response is not obtained from a single resource or even from a single service. Instead, a series of services (shown in figure 2-2) is coordinated to provide the required response speed and duration: spinning reserve is the “first responder” service, followed by non-spinning reserve and replacement reserve.

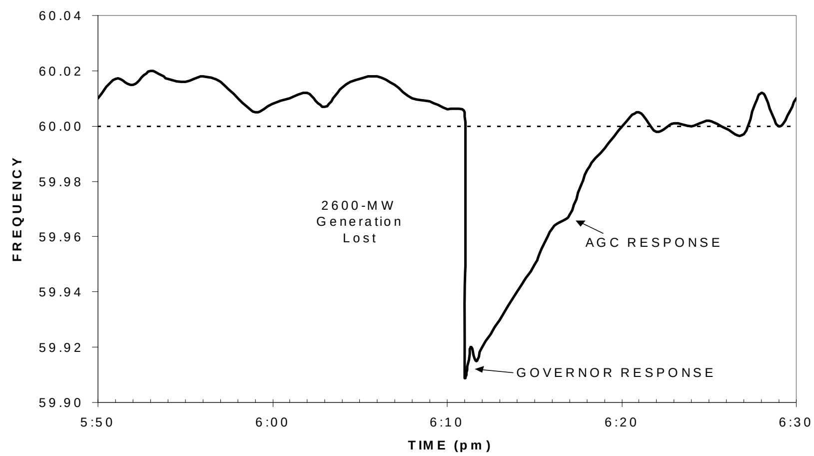

Figure 2-1. Power System Frequency During a Major Contingency. Reserves successfully restored generation/load balance within 10 minutes after sudden failure of two generators in Texas.

Spinning reserve must begin to respond immediately and be fully responsive within 10 minutes. To provide this service, spinning reserve must be already synchronized with the grid. *Non-spinning reserve* must also respond fully within 10 minutes but does not need to begin responding immediately. As a result, it does not need to be synchronized with the grid initially. *Replacement reserve* must respond fully within 30 minutes. California's real-time energy market, with its five-minute dispatch interval, can also be used by system operators to obtain response to contingency events.

Spinning reserve is the fastest-responding contingency reserve and thus the most critical for maintaining power system reliability. Spinning reserve is the service that arrests the dangerous frequency drop seen in Figure 2-1. WECC does not currently allow responsive loads to provide spinning reserve. Only generators that are on line and synchronized to the grid can supply spinning reserve.

A.2 Why Use Controllable Air-Conditioning Units For Spinning Reserve?

Advances in communications and control technology now make it possible to use aggregated groups of curtailable loads, such as air-conditioning units already equipped with load-cycling controls, as a spinning reserve resource that is potentially superior to relying on generators for this service. The natural response capabilities of these loads match the response speed, duration, and frequency required to support spinning reserve. The appropriateness of this match has been recognized by the Electric Reliability Council of Texas (ERCOT), which allows load curtailment to supply half of ERCOT's 2,300 MW spinning reserve requirement. The PJM Interconnection also recently changed its reliability rules to allow loads to supply spinning reserve.

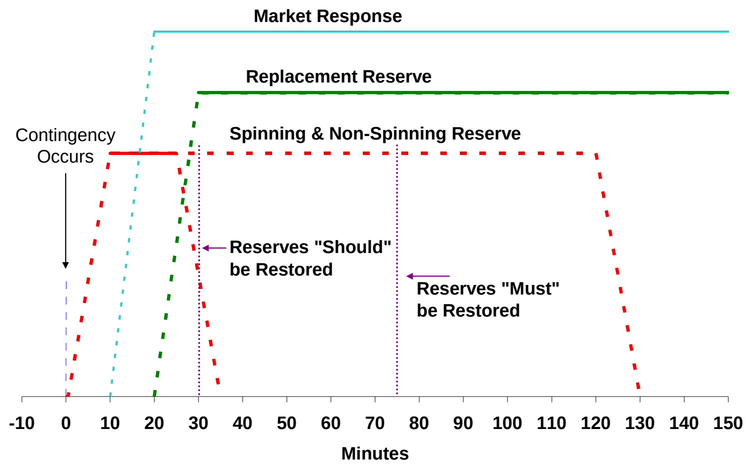

Figure 2-2. Coordinated Contingency Response. A series of reserve services provide coordinated contingency response.

In California, air conditioning is one type of curtailable load that has the capability to respond faster to system disturbances than generators can. Data gathered in the tests described in this report show that air-conditioning load can be dropped nearly instantaneously (in tens of seconds or less) in response to commands from a system operator. The rapid response possible from using air-conditioning load as spinning reserve could improve power system reliability; using air-conditioning load as demonstrated in this study would allow load response to be in place much more quickly than the 10 minutes currently allowed for generators who provide spinning reserve.

Spinning reserve is a good match to air-conditioning load-response capabilities for several reasons:

- *Deployment of spinning reserve is typically brief*: Total air-conditioning load can therefore be curtailed for the event duration; because the event is likely to be brief, customers are not likely to notice the curtailment.

- *Spinning reserve deployment is relatively infrequent*: Response is only required when a contingency occurs as opposed to, for example, being required every afternoon during a heat wave for peak reduction.

- *Air-conditioning response is reliable and robust*: Meaningful response is spread over thousands of small, independent units, so failure of a single unit to respond has no impact on power system reliability. In contrast, failure of a large generator to provide spinning reserve is a serious reliability event.

- *Air-conditioning response is generally available when needed*: Hourly spinning reserve market price history confirms that spinning reserve is in short supply (prices rise) when system load is high, which is the same time that air conditioning is loading the system.

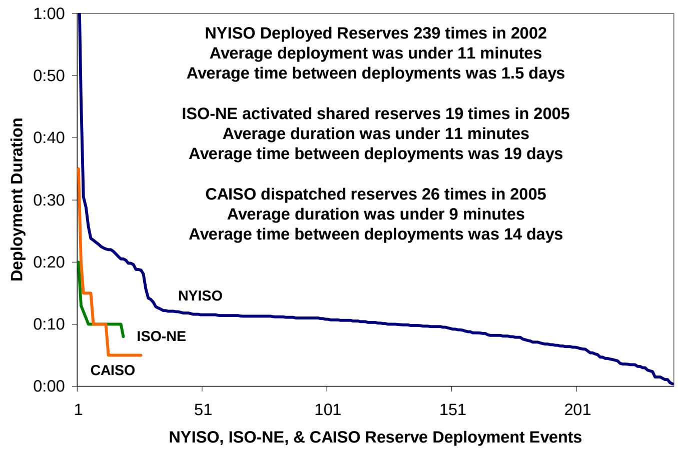

Figure 2-3. Duration of Spinning Reserve Deployment. ISOs differ in frequency of use of spinning reserve, but most deployments of spinning reserve are short in duration.

A.2.1 Spinning Reserve Deployment Duration

As shown in Figure 2-3, spinning reserve events are typically quite short. The figure shows data for the ISO New England (ISO NE) and New York Independent System Operators (NYISO) and CA ISO. Longer reserve deployments are occasionally required and are extremely important for reliability, but, as shown in Figure 2-3, they are rare. Brief event duration is a perfect match for air-conditioning load curtailment because air-conditioning units can easily be curtailed for short periods, likely, with little or no comfort impact on occupants. Longer duration curtailments, too, are also possible. However, the comfort impacts would become more noticeable.

A.2.2 Load and Spinning Reserve Cycles

The daily and seasonal load cycles of air conditioning mean that it can supply spinning reserve when generator-supplied spinning reserve is most costly. Spinning reserve prices in California are shown in Figure 2-4 along with a typical air-conditioning load profile. The spinning reserve price is low overnight because there is ample partially loaded generation available to supply spinning reserve. The spinning reserve price rises near the load peak because generation is needed to serve load and is thus not available as reserve. So, although air-conditioning load is available at certain times and the power system need for spinning reserve is constant, there are low-cost alternative supplies available when air-conditioning load is not.

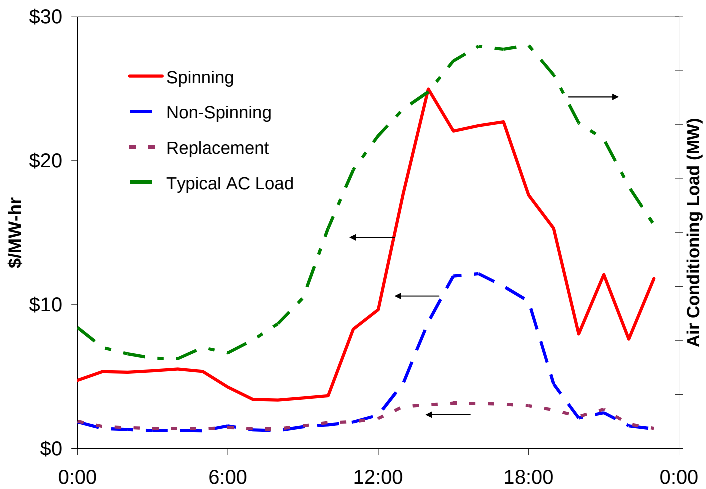

Figure 2-4. Correlation Between Air Conditioning Load Availability and Cost of Spinning Reserve. Hourly prices show that the power system values spinning reserve the most at the same time that this service is available from air conditioning.

Figure 2-4 also shows why load should be used to supply spinning reserve if possible rather than restricting load to supplying only non-spinning and replacement reserves: spinning reserve prices are typically three times higher than non-spinning and five times higher than replacement reserves. These numbers quantify the higher reliability value of spinning reserve to the power system. Expanding spinning reserve supply will both increase reliability and lower costs for all customers.

A.2.3 Load Response Reliability

Figure 2-5 shows that the response reliability of aggregations of small loads can be greater than the response reliability of a small number of large generators. This simple example compares the provision of contingency reserves from two sources.

First, we assume contingency reserves are supplied by six generators that can each provide 100 megawatts (MW) of response with 95-percent reliability. These assumptions produce a 74-percent chance that all six generators will respond to a contingency event and a 97-percent probability that at least five will respond. That probability indicates a significant risk that fewer than five generators will respond.

Second, we assume that contingency reserves are provided by many (1,200) smaller loads that, for illustrative purposes, are assumed to be individually less reliable (90-percent reliability) than the large generators.[21] This aggregation typically delivers 540 MW (out of the total possible 600 MW) of reserves but never delivers less than 520 MW (or 120 MW more than the large generators). This example illustrates that the aggregate load response is much more predictable

[21] There would be many more (and smaller) air conditioners in a typical aggregation. This example used only 1,200 because of the limitations of the software program (Microsoft Excel) used to create the example. Larger numbers of smaller loads simply result in a more vertical aggregate response curve.

and the response that the system operator can "count on" is actually greater than is the case with the traditional strategy of relying on a few small generators for spinning reserve.

It is worth noting that this statistical analysis of response reliability may indicate that, if load response provides spinning reserve service, system operators would not have to conduct the detailed monitoring currently required when spinning reserve service is provided by a few large generators. System operators monitor large generators providing spinning reserve at the four- to 10-second Supervisory Control and Data Acquisition (SCADA) rate at least partially because there is some probability that the generator will not respond when required. The system operator can watch the response in real time and take alternative action in the rare (but important) event that a generator fails to move. With a large aggregation of independent loads, the system operator might only have to monitor the common communications system to make sure that the signal has been sent because the response reliability is sufficiently high to make continued monitoring unnecessary.

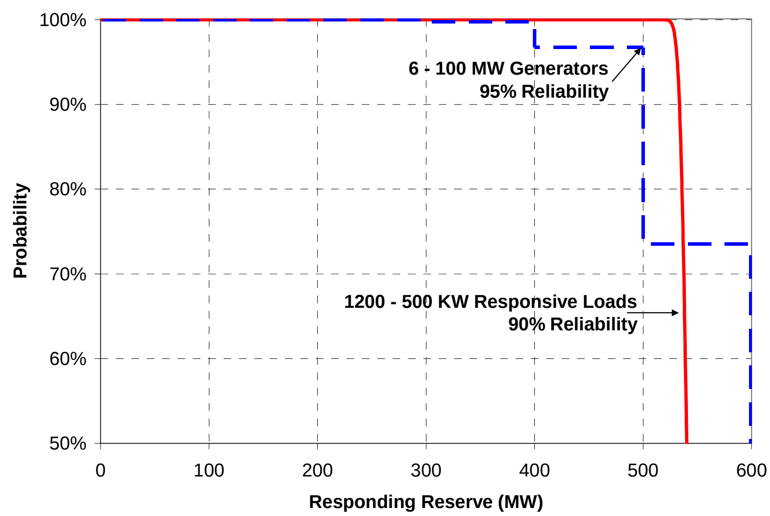

Figure 2-5. Reliability Comparison. Large numbers of individually less-reliable responsive loads can provide greater aggregate reliability than fewer large generators.

Appendix B. Southern California Edison Emergency Management Research Plan (EMRP) Post Program Research

Southern California Edison

EMRP Post Program Research

Tom Wheat
Customer Experience Management
Market Research

Conducted by
Market Decisions Corporation
www.mdcresearch.com

Table of Contents

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Methodology

- Three hundred two (n=302) telephone surveys were conducted by Market Decisions Corporation between December 4 and December 22, 2008.
- Three customer segments were surveyed among SCE customers living on the Kiowa, Pourroy, Catawba and Sinoloa circuits.
  - Emergency Management Research Plan (EMRP)
    - Two types of EMRP Participants were interviewed: "special" (2-way communication device installed on AC units) and "standard" (standard communication device installed on AC units)
  - Summer Discount Plan Program Participants (SDP)
  - Non-Participants
- All respondents were screened to meet the following criteria:
  - Decision-maker regarding monthly electricity usage and bill payment
  - Confirm Southern California Edison customer address
  - If Participants, aware of enrollment in SCE's Summer Discount Plan Program
  - If Non-Participants, have at least one centralized air conditioning system.
- A total sample size of 302 yields a maximum sample variable of 5.6% at the 95% confidence level. Variability within circuits and programs is presented below:

• Kiowa:	n=84 → ±10.7%	• Non-Participant:	n=100 → ±9.8%
• Pourroy:	n=108 → ±9.4%	• SDP:	n=90 → ±10.3%
• Catawba:	n=47 → ±14.3%	• EMRP (total):	n=112 → ±9.3%
• Sinola:	n=63 → ±12.4%	• EMRP (standard):	n=103 → ±9.7%
		• EMRP (special – 2-way):	n=9 → qualitative

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Key Findings

Program Perceptions

- **SDP/EMRP Program Participants do not clearly understand which programs they selected.**
  - Half of SDP Participants believe they are enrolled in EMRP, and 38% of EMRP Participants are not aware they are enrolled in EMRP.
  - In addition, the primary barriers to participation in EMRP are a lack of familiarity and lack of awareness about the program.
- **More than eight in ten Participants (SDP & EMRP) did not notice any AC interruptions during the past summer. No Special EMRP Participants (2-way communication devices) noticed an interruption.**
- **Among those who noticed an interruption:**
  - Only one participant considered leaving the program.
  - The average interruption was perceived to last an average of 26 minutes, with the longest interruptions averaging 29 minutes.
  - Nearly half felt it was uncomfortably warm or hot during the interruption, but only 4% felt it was an inconvenience. This suggests that, although uncomfortably warm, the AC cycling off for a few minutes does not interrupt or interfere with daily activities.
  - Customers say they would wait more than 90 minutes before considering complaining to SCE.
- **Eight in ten feel they understand the program when asked to rate their level of understanding on a 5-point scale. Despite their perceived high level of understanding, customers are not aware of their level of program involvement, or the effects of program participation (i.e., length/duration of outages, etc.)**
- **A majority feels that the SDP Program exceeds their expectations.**

Recommendations

- Opportunity exists to expand program participation levels.
  - Moving customers to the SDP or EMRP programs is likely to have a positive impact on overall satisfaction with SCE. As customers become more engaged, they have higher levels of satisfaction and loyalty.
  - Little "downside" risk since less than ten percent of participants contact SCE customer service.
- Marketing materials need to address the "Fear Factor" surrounding these programs and educate customers with clear, concise, easy-to-understand language.
  - Although Participants and Non-Participants both perceive they understand the SDP program, most are unable to articulate program details when probed, or differentiate between the two programs. This emphasizes the need for easily comprehended marketing materials.
  - Educate customers about the potential for cost savings by enrolling in the programs.
    - A reduced energy bill is most commonly mentioned as the way the programs exceed Participants' expectations.
  - Telemarketing needs to be used judiciously since it tends to "polarize" customers.
- Help customers understand the difference between SDP and EMRP, including the frequency of and reason for AC interruptions.
  - Promote the infrequency and short duration of interruptions; there tends to be a perception that the programs are likely to more intrusive than they typically are.
  - Communicate with customers after interruptions occur to let them know the actual duration.

Key Findings

Awareness & Barriers

- Awareness of SDP is high among Non-Participants (85% aided awareness). The most common source of awareness is a direct mailing.
  - Direct mailings are also the preferred source for information about programs offered by SCE.
  - Telemarketing calls from SCE tend to be polarizing, with almost a quarter of respondents indicating they are completely willing to take calls from SCE and about a third saying they are not at all willing to take SCE calls.
- Among Non-Participants aware of the program, 71% recall being offered the opportunity to participate.
  - Primary reasons for choosing not to participate include wanting the ability to use their air conditioner at any time, and concern over allowing SCE to control their AC. Yet only slightly more than 10% of participants noticed any interruption, suggesting that the program is perceived as being more disruptive than it really is.

Satisfaction & Loyalty

- Among Participants, eight in ten are "very satisfied" with the SDP and EMRP programs, nearly nine in ten would be "very likely" to recommend the programs to a friend, family member or colleague and nine in ten are "very likely" to participate in the future.
  - Three quarters of Participants can be considered "secure" (very satisfied, very likely to recommend and very likely to participate in the future).
- Overall, two thirds are "very satisfied" with SCE.
  - EMRP Participants (78% "very satisfied") are significantly more likely than SDP Participants (63%) and Non-Participants (51%) to be "very satisfied" with SCE.
- Forty percent of Non-Participants state that they would consider enrolling in future programs, indicating that significant "upside" potential exists for future program participation.

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Program Perceptions

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SCE MARKET RESEARCH

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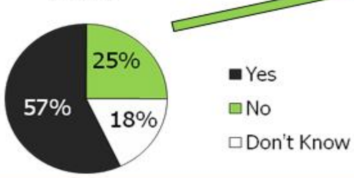
Customers Tend to be Confused About Their Participation in the Programs

- There is some confusion among participants regarding program participation.
  - One in five of all Participants are not sure in which programs they are enrolled.
  - Half of Summer Discount Plan Program (SDP) Participants incorrectly believe they are also in the Emergency Management Research Program (EMRP).
  - One in five EMRP Participants are not aware they are currently enrolled in the program.

Perceived EMRP Enrollment Among EMRP/SDP Participants
(n=201)



Primary Barrier to EMRP Participation (n=87)	
Not familiar with EMRP	33%
EMRP was not offered	13%
Only interested in discounts	8%
Interested in conservation	5%
More familiar with SDP	5%

Perceived EMRP Enrollment Among EMRP/SDP Participants

	Participants (n=201)	SDP (n=89)	EMRP (n=112)
Yes	57%	49%	62%
No	25%	35%	17%
Don't Know	18%	16%	21%

Q1. Did you participate in the Electricity Management Research Program, in addition to the Summer Discount Plan Program?
Q2. Why did you choose to participate in the Summer Discount Plan Program, but not the Electricity Management Research Program?

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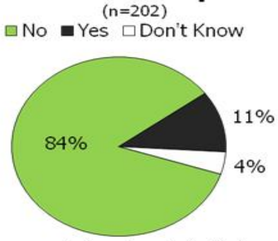
SCE MARKET RESEARCH

AC Interruptions During Past Summer Perceived as Minimal

- More than eight in ten Participants did not notice any power interruptions during the past summer. Of the 23 who did, only one person considered dropping out of the program.
  - None of the Special EMRP Participants (2-way devices) noticed an interruption during the past summer.
- Although SDP Participants perceived longer interruptions than EMRP Participants, none felt inconvenienced by the interruptions.
- SDP and EMRP participants are highly likely satisfied with the programs (SDP: 94% satisfied; EMRP: 99%).
- On average, customers report they would complain to SCE after a 92 minute interruption.

Noticed Interruptions
(n=202)



	Total (n=24)	SDP (n=14)	EMRP (n=10)
Average number of interruptions	2.2	2.1	2.4
Average length of interruptions	25.7 min	31.2 min	19.3 min
Longest interruption	28.7 min	31.4 min	25.7 min
Uncomfortable	46% Yes	43% Yes	50% Yes
Inconvenienced	4% Yes	0% Yes	10% Yes

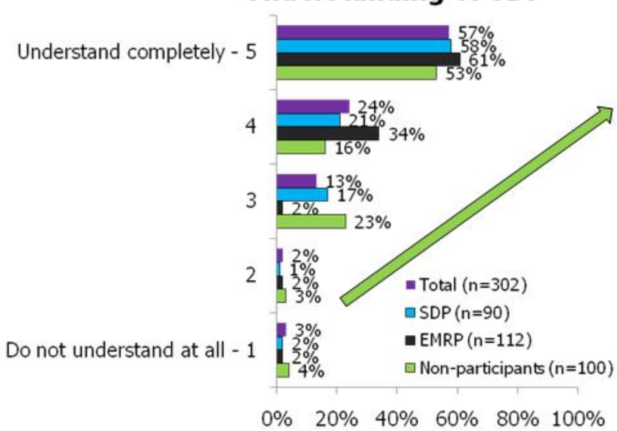
Caution: small sample sizes

Q17. Did you or anyone else in your household notice if your air conditioning was shut off or interrupted by the program any time this past summer?
Q18. How many times did someone notice it being shut off?
Q19. On average, in minutes, how long would you estimate that your AC remained off each time when it was shut off?
Q20. In minutes, how long would you estimate that your AC remained off during the longest interruption over the summer?
Q21. During those times when you noticed the AC being shut off, did it ever get uncomfortably warm or hot in your home?
Q23. Have you felt inconvenienced by the interruptions this past summer?
Q25. In minutes, how long would your AC have to be turned off before you would complain to SCE, friends or family members?
Q26. Have you considered leaving the program as a result of the interruptions this past summer?

Customers Claim High Levels of Comprehension, Yet are Confused about Their Level of Participation, Suggesting a Need for Clear, Easy to Understand Marketing Materials.

- Over half claim to completely understand the SDP program (5 rating), and another fourth rate their program comprehension a "4" on the 1-5 scale.
  - The main reason cited for confusion is a "lack of program information."
  - Even Non-Participants perceive that they understand the SDP program "completely."

Understanding of SDP

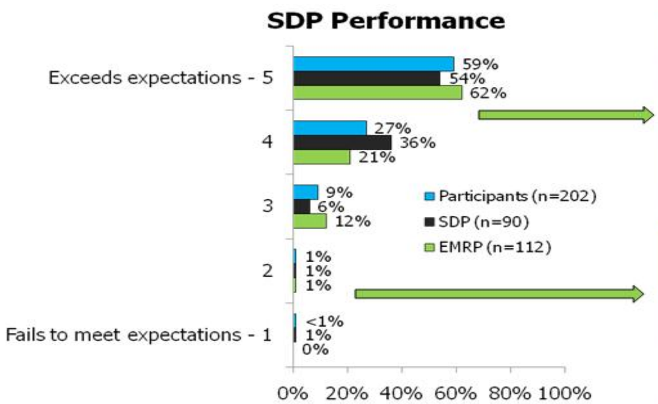


What is confusing or difficult to understand? (n=14)	
Lacked program information	64%
Did not sign up for program	14%
Everything	14%
Unsure of shut off times	7%
Illness in household ineligible	7%
Discount not believable	7%

Q28. How would you rate your level of understanding of the Summer Discount Plan Program?
Q29. Specifically, what about the program is confusing or difficult to understand?

SDP Expectations Tend to be Exceeded

- Six in ten report that the SDP exceeds their expectations.
  - The main reason for exceeding expectations is a lower utility bill.



How did it exceed your expectations? (n=174)	
Lower bills	34%
Didn't notice when off	31%
Few interruptions	15%
Pleased with service	15%
No inconvenience/problems	13%
Did exactly what expected	8%
Received credit/rebate	7%

How did it fail to exceed your expectations? (n=3)
"I didn't get a discount. My electric bill is still too high."
"The bill was higher than I expected. I expected the bill to be lower."
"Right now, I do not know."

Q30. How would you rate your perception of the Summer Discount Plan Program compared to your expectation
Q31. In what ways did the program exceed your expectations?
Q32. In what ways did the program fail to meet your expectations?

Awareness & Barriers

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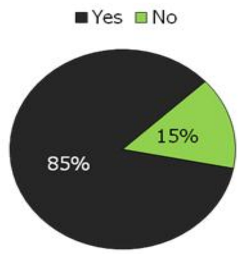
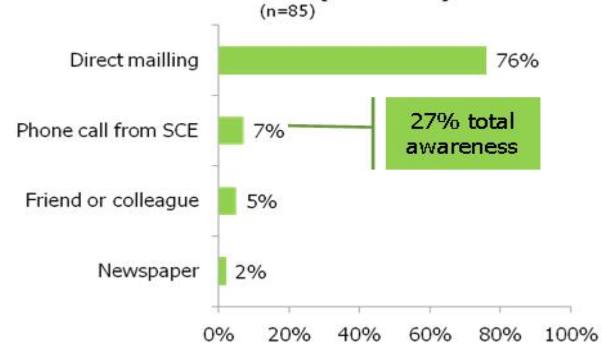
SDP Awareness is Quite High Among Non-Participants

- More than eight in ten Non-Participants are aware of the SDP.
  - Three fourths of those aware of SDP found out through a direct mailing.
  - When asked if they received a phone call about the program, 27% of non-participants report receiving a phone call from an SCE representative.

SDP Awareness Among Non-Participants
(n=100)



Aware of SDP (Unaided)
(n=85)



Q8.Have you heard of SCE's Summer Discount Plan Program...?
Q9. How did you hear about this program?
Q10. Did you receive a telephone call from an SCE representative to tell you about the program?

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SCE MARKET RESEARCH

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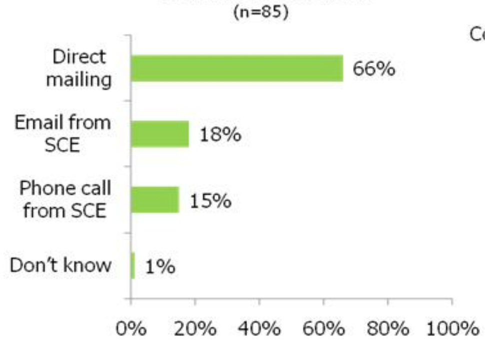
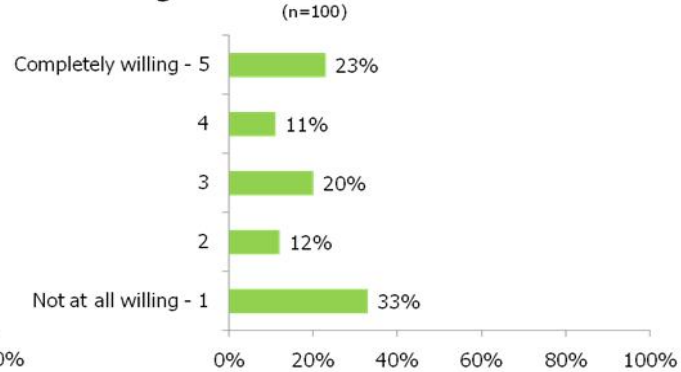
Telemarketing Tends to "Polarize" Customers

- Among Non-Participants, the preferred method of communication is direct mail.
- One third of Non-Participants are willing (4-5 ratings) to receive phone calls about programs like SDP. However, this is a polarizing concept for customers, with 45% not willing (1-2 ratings) to take calls from SCE.

Preferred Method of Communication
(n=85)



Willingness to Take Calls from SCE
(n=100)



Q11. How would you rate your willingness to take calls from SCE representatives about programs like the Summer Discount Plan Program?
Q16. What is your preferred method of receiving communications from SCE about new programs and services?

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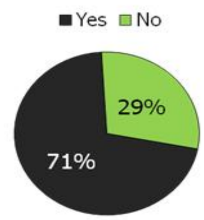
SCE MARKET RESEARCH

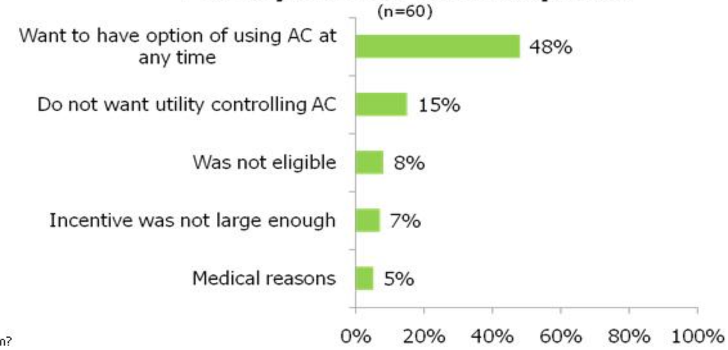
Barriers to Participation Focus on Issues of Control

- Most Non-Participants aware of SDP recall being offered the opportunity to participate.
  - The main barrier to participating is a desire to be able to use the AC at any time.
  - Of those offered a chance to participate, half (48%) say the would enroll if SCE guaranteed not to interrupt AC service for more than 10 minutes.
  - Among those not offered a chance to participate, one in five (20%) are interested in the program.

Non-Participants Offered Participation
(n=85)



Primary Barriers to Participation
(n=60)

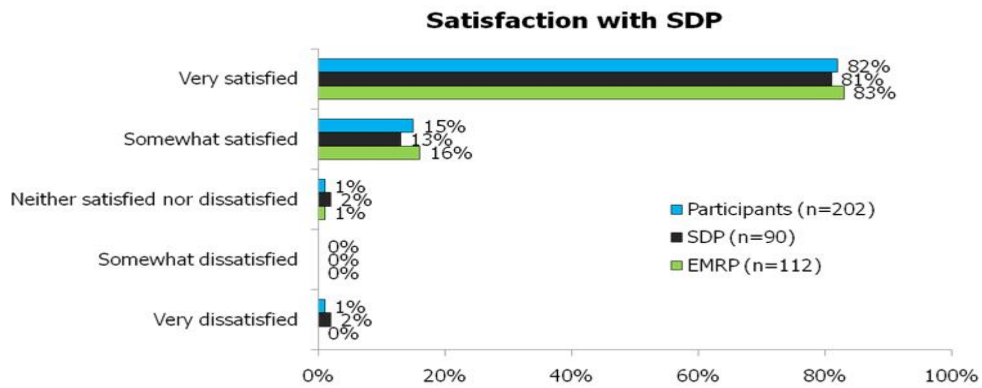


Q12. Were you ever offered the chance to participate in the program?
Q13. Why did you choose not to participate?
Q14. Would you have been willing to participate if SCE guaranteed not to interrupt your AC service for more than 10 minutes?
Q15. Does that sound like the sort of program you would be interested in?

Satisfaction & Loyalty

Satisfaction with SDP/EMRP is High

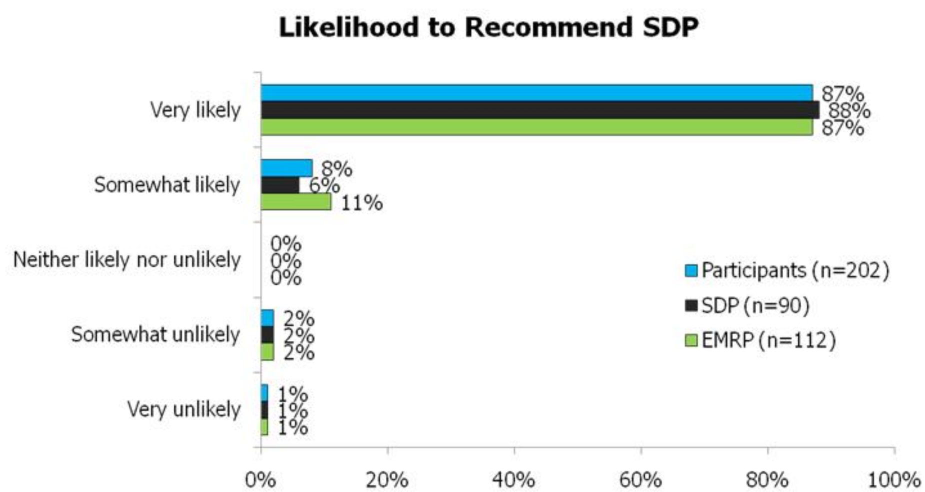
- Eight in ten Participants are satisfied with the SDP/EMRP programs.



Q33. Thinking more specifically of you experience with the Summer Discount Plan Program, how satisfied are you with program?

Participants Are Likely to Advocate SDP

- Nearly all Participants are somewhat or very likely to recommend the SDP to a friend, family member or colleague.

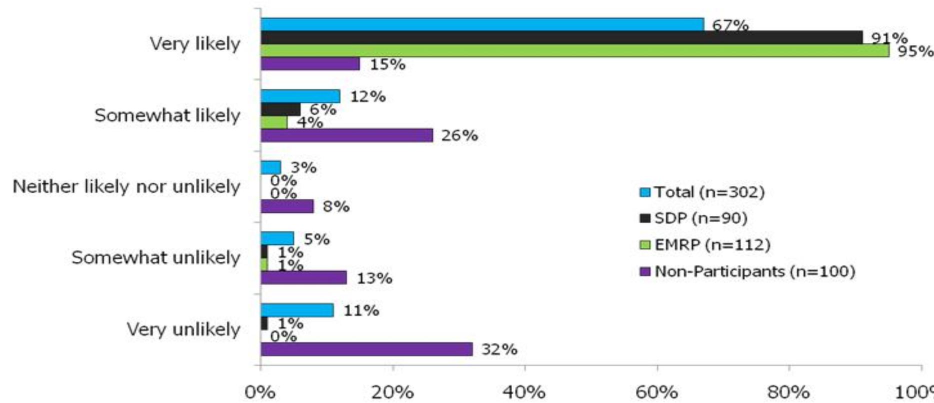


Q34. How likely would you be to recommend the Summer Discount Plan Program to a friend, family member or colleague?

Customers Have a High Likelihood of Participating in Future Programs

- Nearly all Participants and four in ten Non-Participants are likely ("very + somewhat likely") to participate in the SDP program in the future.
  - The high percentage of Non-Participants (41%) somewhat or very likely to participate in the future indicates a strong opportunity for SCE to grow the SDP program.

Likelihood to Participate in the Future



Q35. How likely would you be to participate in the Summer Discount Plan Program in the future?

EMRP Participants are "Secure" in Program

- Secure Customer Index (SCI) is used to classify customers as "Secure," "Favorable," "Indifferent," and "At Risk."
  - Overall, three fourths of Participants can be considered "secure."
- Increased levels of program participation appear to improve overall perceptions of SCE.
  - EMRP Participants are significantly more likely than SDP Participants to be "Favorable".

	Participants (n=202)	Circuits				Programs	
		Kiowa (n=61)	Pourroy (n=81)	Catawba (n=28)	Sinoloa (n=32)	SDP (n=90)	EMRP (n=112)
Secure	77%	79%	77%	75%	75%	77%	77%
Favorable	17%	16%	14%	21%	22%	12%	21%
Indifferent	5%	3%	7%	4%	3%	9%	2%
At Risk	1%	2%	2%	0%	0%	2%	1%

Secure = very satisfied AND definitely would recommend AND definitely would participate in the future

Favorable = very/somewhat satisfied AND definitely/probably would recommend AND definitely/probably would participate in the future (excluding Secure Customers)

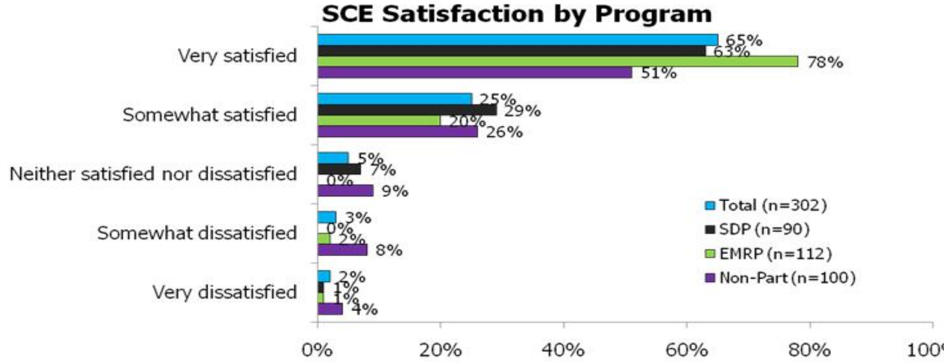
Indifferent = all other combinations of ratings

At Risk = very dissatisfied OR definitely would not recommend OR definitely would not participate in the future

Program Participation Leads to Higher Satisfaction Levels

- Program participants are significantly more likely than Non-Participants to be satisfied with SCE. Additionally, EMRP Participants are significantly more likely to be satisfied than SDP participants.
  - On average, Participants give significantly higher satisfaction ratings than Non-Participants (4.5 vs. 4.1 average satisfaction scores on a 1-5 scale).
  - EMRP Participants give significantly higher average satisfaction ratings than Non-Participants and SDP Participants (4.7 vs. 4.5 and 4.1, respectively).

SCE Satisfaction by Program

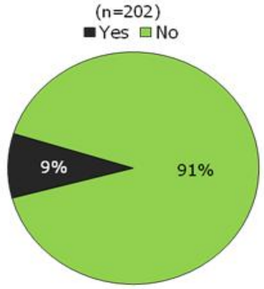


Q36. Thinking of your experience overall as a customer, how satisfied are you with Southern California Edison?

Customer Service Infrequently Used

- One in ten Participants contacted customer service regarding the SDP program.
  - EMRP Participants are significantly more likely than SDP Participants to report calling customer service during the past summer (15% vs. 2%).
  - The most common reason for calling was to sign up for the program.
- Of those who called, 18 out of 19 reported that customer service was able to resolve their problem.
  - All 19 people who contacted customer service rated their experience as "very satisfying."

Contacted Customer Service
(n=202)



Reason for Customer Service Call (n=19)	
To sign up for program	9 mentions
General question	4
General repairs	4
AC specific repair	2
Leave feedback	1
Senior discount	1
Billing question	1

Q37. Did you contact SCE customer service at any point this summer regarding the Summer Discount Plan Program?
Q38. What was the reason for your call?
Q39. Was customer service able to resolve your problem?
Q40. How satisfied are you with that customer service experience?

Year First Enrolled

– One fourth (24%) of SDP Participants report enrolling in 2002 or earlier; 23% of EMRP Participants first enrolled in 2008.

Year First Enrolled in SDP

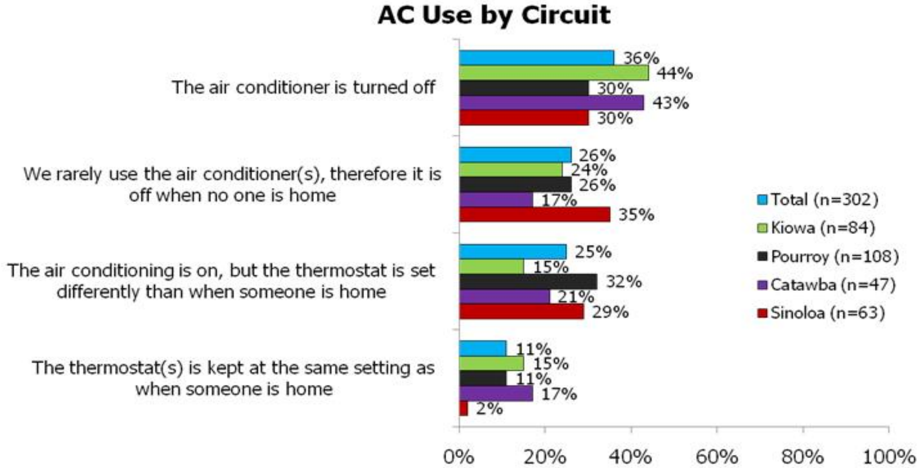
	Participants (n=201)	SDP (n=89)	EMRP (n=112)
2008	15%	4%	23%
2007	18%	16%	21%
2006	15%	16%	14%
2005	8%	8%	9%
2004	5%	6%	4%
2003	6%	7%	5%
2002 or earlier	13%	24%	4%
Don't know	19%	20%	19%

Q3. Do you recall the year that you first enrolled in the summer Discount Plan Program?

AC Use When No One is Home

– Two thirds of all respondents either always turn their air conditioner off, or turn it off when no one is home.
  - Customers on the Sinoloa circuit are significantly less likely than those on all other circuits to leave the AC at the same setting as when people are at home.

AC Use by Circuit

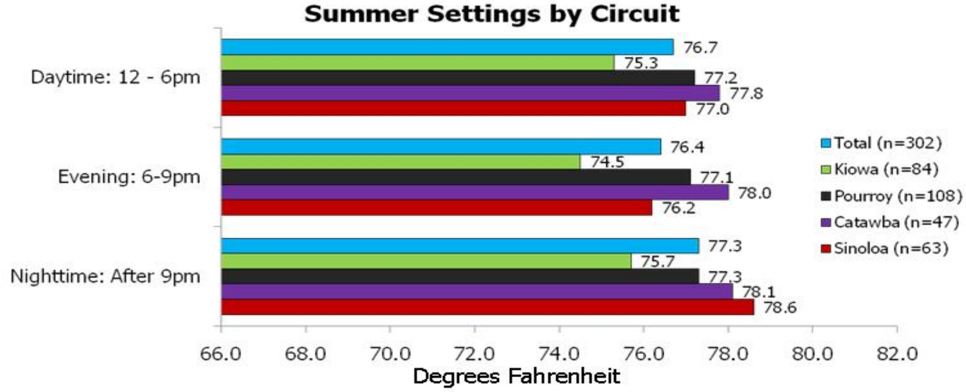


Q41. Which of the following statements best describes how your home is cooled when **no one** is home?

Summer Thermostat Settings

- Two thirds (66%) of all respondents have at least 1 programmable thermostat.
- Overall, the average summer thermostat setting is 76.9 degrees.
  - During the daytime, those on the Kiowa circuit are significantly more likely than those on other circuits to set their thermostat for 70 degrees or less (25% Kiowa, 10% Sinoloa, 6% Pourroy, 2% Catawba).

Summer Settings by Circuit

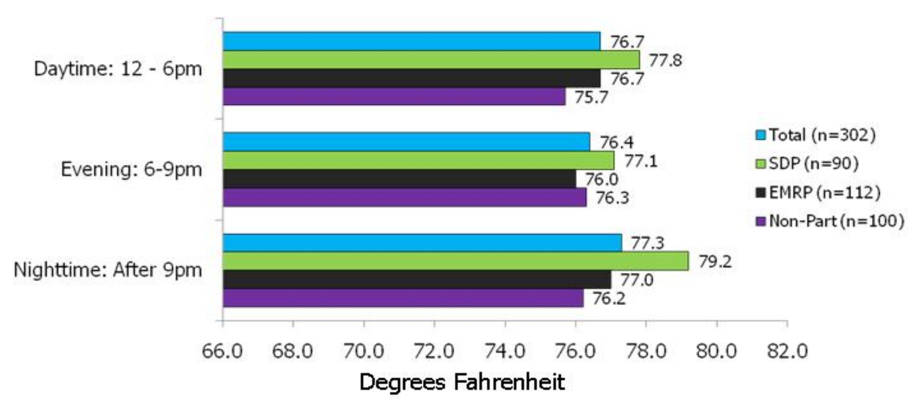


Q42. How many of each of the following thermostats do you have in your home?
Q43. Please indicate your usual thermostat cooling settings during the months of July through September : Daytime/Evening/Night .

Summer Thermostat Settings (Cont...)

- During the daytime, program participants have significantly higher average thermostat settings than Non-Participants (77.2 vs. 75.7 degrees).
  - Participants also have significantly higher nighttime thermostat settings than Non-Participants (79.2 vs. 76.2 degrees).

Summer Settings by Program

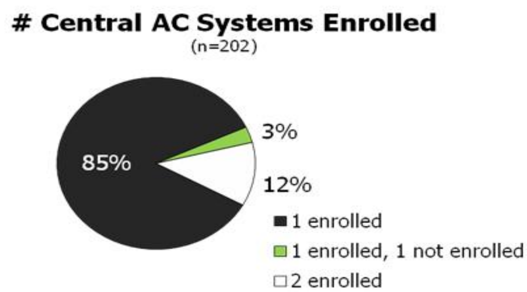


Q43. Please indicate your usual thermostat cooling settings during the months of July through September : Daytime/Evening/Night .

Research Insights Solutions

Number of Central Air Conditioners Enrolled

- More than eight in ten Participants have one central air conditioning system in their home.
  - Of those with two systems, three fourths have enrolled both in the SDP program.



Q4. Do you have more than one centralized air conditioning system in your home?
Q5. How many do you have?
Q6. How many of those central air conditioners are not signed up for the Summer Discount Plan Program?
Q7. Why is that air conditioner not signed up for the program?

Research Insights Solutions

Demographics

EMRP Participants' Income Skews Lower Than Non-Participants'

Rent / Own Home

	Total (n=302)	Non Part (n=100)	SDP (n=90)	EMRP std. (n=103)	EMRP sp. (n=9)
Own	91%	85%	92%	95%	89%
Rent	7%	13%	3%	4%	0%

Employment

	Total (n=302)	Non-Part (n=100)	SDP (n=90)	EMRP std. (n=103)	EMRP sp. (n=9)
Full Time	1.0	0.9	1.2	1.0	1.1
Part Time	0.4	0.4	0.4	0.3	1.2
From Home	0.4	0.3	0.5	0.4	0.9
Retired	0.5	0.4	0.4	0.6	0.4
Disabled / Unemployed	0.2	0.2	0.2	0.3	0.0

Primary Household Language

	Total (n=302)	Non-Part (n=100)	SDP (n=90)	EMRP std. (n=103)	EMRP sp. (n=9)
English	90%	91%	91%	87%	89%
Spanish	3%	4%	--	5%	--
Other	2%	1%	1%	4%	--
Refused	5%	4%	8%	4%	11%

Household Occupants

	Total (n=302)	Non Part (n=100)	SDP (n=90)	EMRP std. (n=103)	EMRP sp. (n=9)
Under 18	0.8	0.7	0.7	0.9	0.6
18 to 49	1.2	1.3	1.2	1.1	1.2
50 to 64	0.7	0.6	0.6	0.7	0.9
65 or more	0.4	0.4	0.3	0.4	0.3

Income

	Total (n=302)	Non Part (n=100)	SDP (n=90)	EMRP std. (n=103)	EMRP sp. (n=9)
$0-$25K	12%	13%	11%	11%	11%
$25-$50K	17%	14%	14%	23%	11%
$51-$75K	14%	12%	9%	20%	11%
$75-$100K	12%	11%	16%	10%	22%
$100-$150K	13%	14%	13%	12%	22%
$150-$200K	7%	9%	9%	4%	11%

Appendix C. Data Platform

This appendix describes the changes made to the data platform and its configuration for this phase of the project.

C.1 Phase 1 Overview and Key Platform Changes for Phase 2

A demand response spinning reserve system needs to have a real-time and secure data acquisition and presentation platform that gives the operator the same types of system views as are available for traditional spinning reserve resources. The key issue is that the operator must be able to see, in real time, that all of the subsystems are properly responding and that the desired level of load reduction is being achieved.

During Phase 1 of the project, we built a data platform that provided web-based monitoring and analysis, integrating data from the following sources:

SCE Feeder Level Data (Load data) – SCE SCADA system
SCE Operator Data (Shed/Restore information, e.g.: when a curtailment started)
Weather Data – National Weather Service (Current Observations, Forecasts)
Weather Data – SCE SCADA system (Current Observations)
Air-Conditioner Load and Timing Data

The web-based platform provided two data views tailored to the stakeholders in the project: 1) a private web page for use by project team members, and 2) a public web page for use by homeowners and business owners participating in the pilot program.

The private web page gave access to all of the data collected by the system as well as a set of tools for real-time data analysis. This included on-demand and scheduled reporting and data trending. This page allowed access to both real-time data and data collected during previous tests.

The public web page provided a high-level view showing the aggregated load drop in real-time of curtailments as well as an aggregated total power load on the test feeders. This site only displayed data from the current test and provided no tools for analysis.

In addition to the web portals, an automated data export system was set up to transmit data to statisticians for daily analysis.

During Phase 2 of this project, several key changes were made to the platform.

During Phase 1 of the project, data were collected from the enhanced switches deployed in the field by querying a third-party web service periodically to check for new information. This approach was not scalable, added latency to the system, and increased the overall complexity of the platform. As a result, during Phase 2, we integrated the enhanced switches directly with the BPL Global data center.

During a curtailment in Phase 2, the deployed enhanced switches would send air-conditioner load data as well as timing data on the "shed" and "restore" commands to the data center automatically. This allowed data to be available immediately for display and analysis on the public and private web portals. In addition, the enhanced switches could be queried to download data collected outside of the curtailment time periods. This feature was used to construct a load profile for each air conditioner.

C.2 **SCE Shed/Restore Signal Integration**

To perform complete timing analyses of the curtailments as well as to display in real time the state of any curtailment in progress, changes were made to the SCE Dispatch Application to communicate directly with the BPL Global data center. Whenever the SCE operator issued a "shed" or "restore" command, the dispatch application would send a message to the data center with a timestamp indicating when the command was sent out.

Unfortunately, logistical issues with the SCE corporate firewall prevented this communication from working correctly for a large number of the Phase 2 curtailments. As a result, timing data for these missing events were entered manually into the system. Because the timestamp was still automatically collected and logged by the application, the only implication of this issue was an additional delay in this timing data being available for analysis.

C.3 **CA ISO Automated Dispatching System Integration**

During Phase 2 of the project, we developed a software application that directly communicated with the CA ISO Automated Dispatch System (ADS). This software application utilized the notification framework provided by the data platform to send out pages, e-mails, and phone messages to the SCE Operator indicating the time at which a curtailment should be started or finished. It also logged these timestamps in the data platform database for post-curtailment analysis.

The BPL Global web presentation platform can provide different data views tailored to each market stakeholder. During Phase 2 of the project, we discussed setting up a separate presentation screen that would give the ISO real-time visibility into the curtailment through data aggregations and calculations based on all elements being integrated into the platform. This screen would also be able to prevent the ISO from viewing protected data such as low-level SCADA data being collected from SCE. These screens were not deployed during Phase 2, however, because of the time required to complete the primary integration of the CA ISO dispatching system.

Figure C.1 depicts a high-level architecture diagram of the secure data platform.

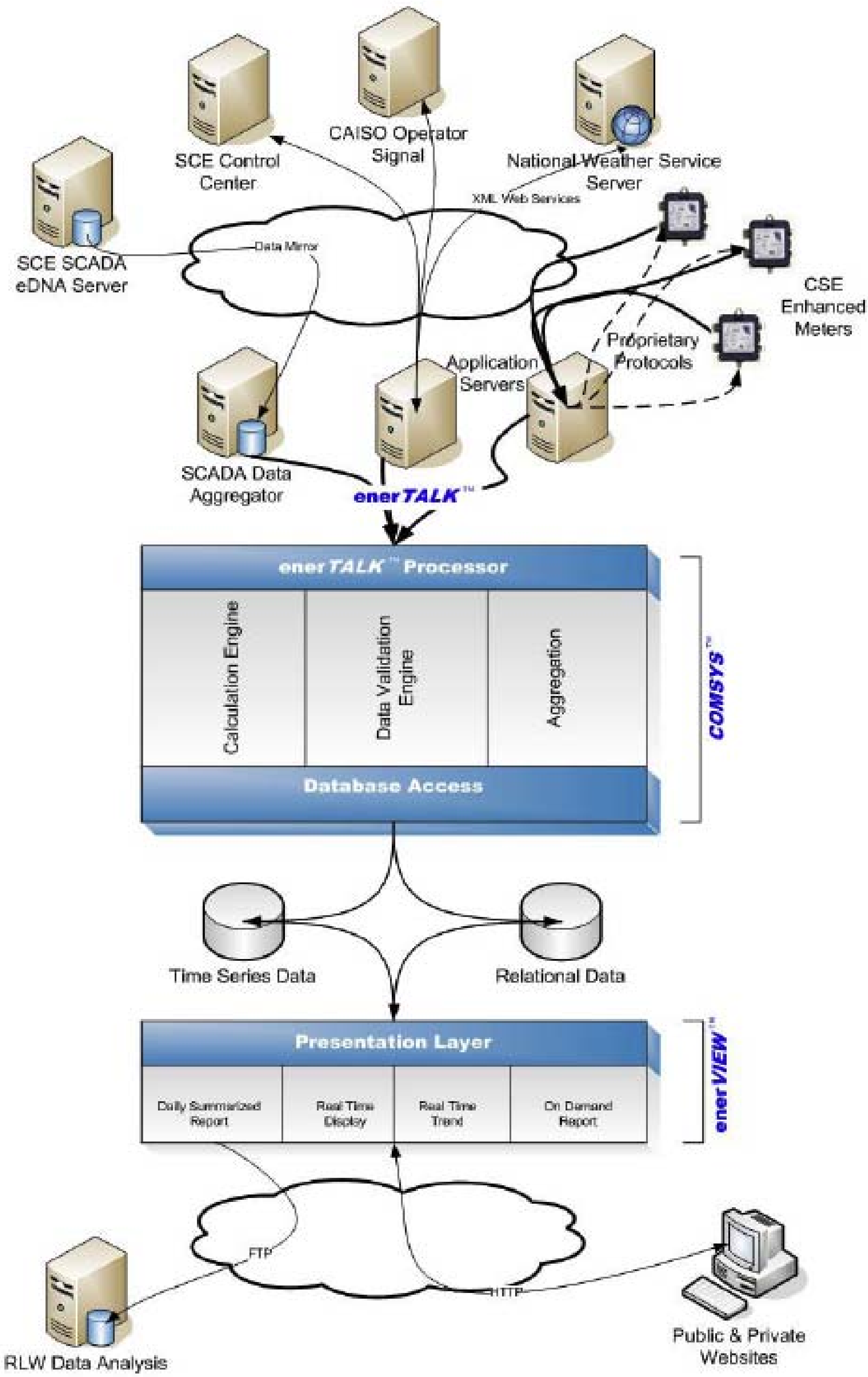


Figure C.1 Secure Data Platform Architecture and Technology Stack

The top portion of the diagram shows all of the external interfaces to other data systems used in the project. This includes data sources such as the enhanced switches as well as outbound data transmissions such as sending a "shed" or "restore" notification to the SCE operator. The bottom portion of the diagram shows the human users of the system. The center portion depicts the features and capabilities of the data platform that provide a variety of services in addition to raw data.

C.4 **Public Web Portal Changes**

During Phase 2 of the project, the public web portal was refreshed and enhanced substantially.

The data overview page shows live trends that display real-time feeder load data from each of the test circuits as well as an aggregated load for the entire test territory. These live trends show a 24-hour and 30-minute load profile. A status indicator is also available showing whether a curtailment is currently in progress.

The third live trend shows a 30-minute load profile from the air conditioners controlled by the enhanced switches. A live trend is a visual graph of data displayed on the web page that automatically updates and refreshes when new data is received by the system.

The following data parameters are also displayed and refreshed automatically:
CA ISO Curtailment Dispatch Time
Enhanced Switch Dispatch Time
Number of Enhanced Switches Participating in the Event
Length of the Event
Feeder Temperature
Feeder Humidity

Figure C.2 below shows an example of the public web page data overview screen. The page refreshes in real time as data are collected from the various systems.

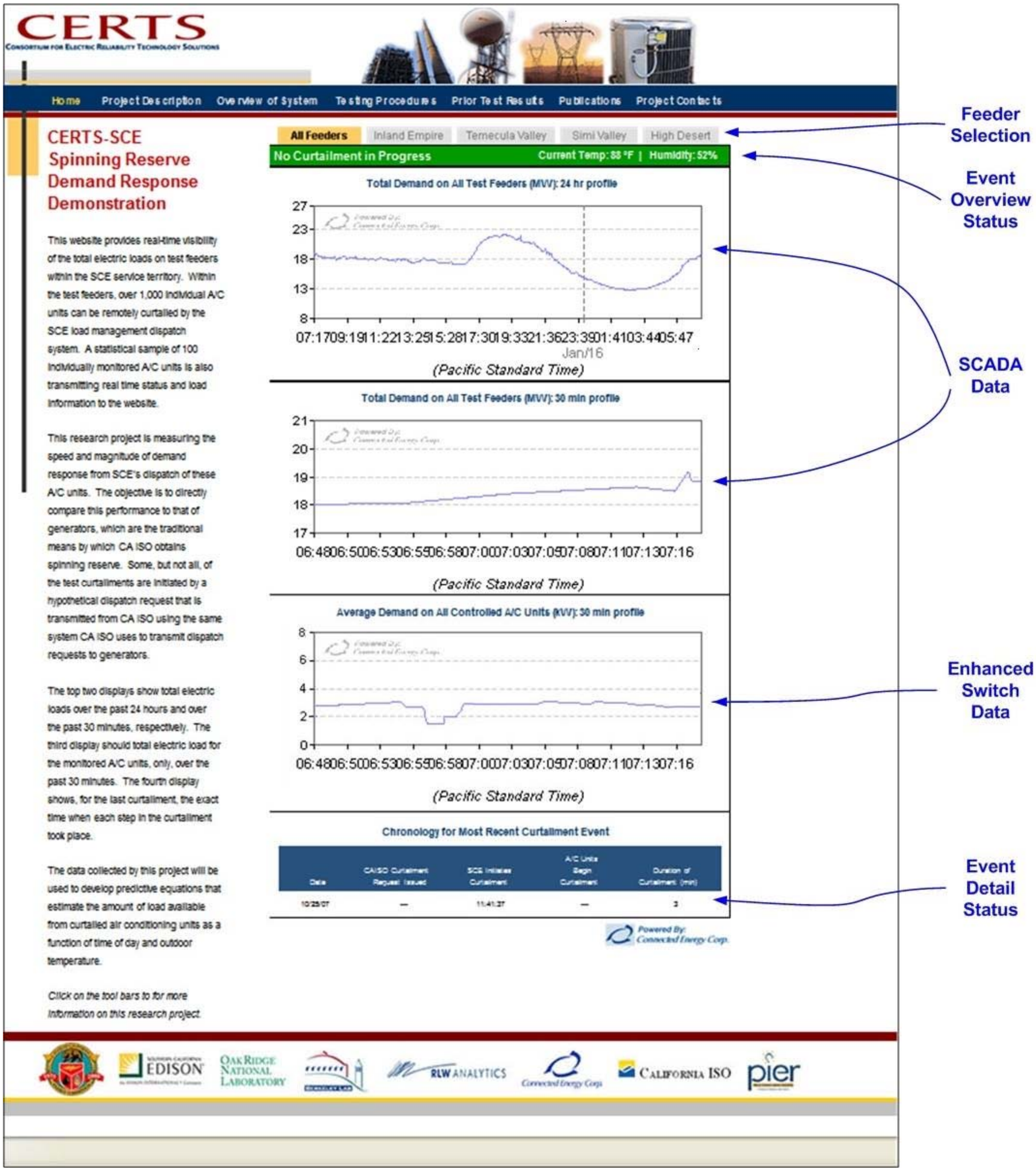
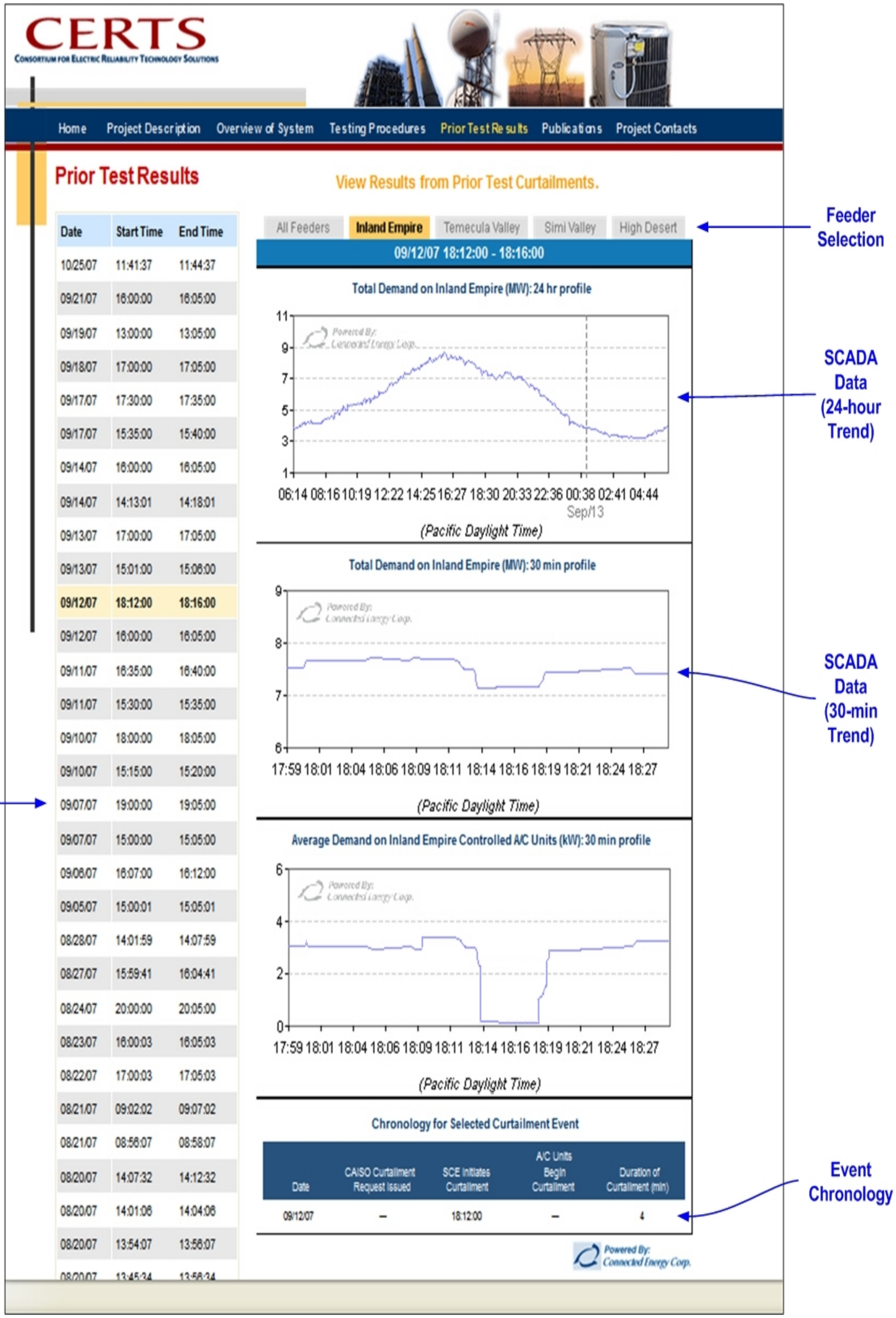


Figure C.2 Public Website Real-Time System Data Page

The public website also displays the results from previous events. Figure C.3 below shows this page. A listing of previous events is available on the left; by selecting an event, the user can see the same data set that is available on the real-time current view page.



Date	Start Time	End Time
10/25/07	11:41:37	11:44:37
09/21/07	16:00:00	16:05:00
09/19/07	13:00:00	13:05:00
09/18/07	17:00:00	17:05:00
09/17/07	17:30:00	17:35:00
09/17/07	15:35:00	15:40:00
09/14/07	16:00:00	16:05:00
09/14/07	14:13:01	14:18:01
09/13/07	17:00:00	17:05:00
09/13/07	15:01:00	15:06:00
09/12/07	18:12:00	18:16:00
09/12/07	16:00:00	16:05:00
09/11/07	16:35:00	16:40:00
09/11/07	15:30:00	15:35:00
09/10/07	18:00:00	18:05:00
09/10/07	15:15:00	15:20:00
09/07/07	19:00:00	19:05:00
09/07/07	15:00:00	15:05:00
09/06/07	16:07:00	16:12:00
09/05/07	15:00:01	15:05:01
08/28/07	14:01:59	14:07:59
08/27/07	15:59:41	16:04:41
08/24/07	20:00:00	20:05:00
08/23/07	16:00:03	16:05:03
08/22/07	17:00:03	17:05:03
08/21/07	09:02:02	09:07:02
08/21/07	08:56:07	08:58:07
08/20/07	14:07:32	14:12:32
08/20/07	14:01:06	14:04:06
08/20/07	13:54:07	13:56:07
08/20/07	13:45:34	13:56:34

Date	CAISO Curtailment Request Issued	SCE Initiates Curtailment	A/C Units Begin Curtailment	Duration of Curtailment (min)
09/12/07	–	18:12:00	–	4

Figure C.3 Public Website Prior Test Results Page

C.5 **Private Web Portal Changes**

Because of the increased number of data sources being integrated into the data platform during this phase of the project, the private web portal was modified to display all of these data points. In addition, several new reports were defined to aid in the real-time analysis of the curtailment data.

C.6 **Data Alarming Modification**

Throughout this phase of the pilot program, the SCADA data bridge responsible for pushing data in real time to the BPL Global data platform from the SCE data center went out of service periodically, during which time SCADA data were not available for real-time display and analysis. To detect these situations rapidly, the BPL Global alarm system was configured to continuously monitor these data streams and send e-mail notifications whenever problems were detected.

C.7 **Feeder Data Configuration**

As a result of additional feeders being included in this phase, we made configuration changes to the data bridge linking the SCE and BPL Global data centers. These changes also allowed additional weather data points from SCE to be integrated into the data platform for analysis.

During the latter portion of this phase of the project, the original four feeders had been split into eight feeders, which required further configuration changes to collect these data in real time. Because of SCE SCADA system updates, it was not possible to automatically integrate these feeder splits into the data platform. As a result, we collected data in real time for the four original feeders (A feeders) and manually imported the data for the four additional feeders (B feeders).

Appendix D. Comparison of Distribution Feeder Data Load Curtailment Estimation Methods

In Phase 1, we used a simple method to estimate the impact of each event. Working from the assumption that the best indicator of load over a short (five- or 10-minute) interval was the load immediately preceding or following it, we used regression models created using data from the 10-minute period preceding the test as well as the 10-minute period after the test.[22] Figure D.1 illustrates graphically the derivation of this estimate. Note that the snap-back period in B, excluded from the regression analysis, does not influence the estimate line plotted through the test period.

This differs from the analysis described in Phase 2 in two key regards:

First, the previous method only used information for the day of an event to predict the load during that event. While more computationally efficient than the newer methods, this does not allow the model to respond to inflection points (such as the system peak or the transition from ramping-up to the peak period). For example, the 20 minutes before a peak will be less than the peak itself, as will the 20 minutes following the peak. If a test event straddles the peak perfectly, therefore, a regression line drawn through the "before" and "after" periods will significantly understate the load reduction from the event. This is, in part, reflected in the fact that the old model estimates the load on the Inland Empire feeder during event hours with an error bound of about 150kW (out of a five-MW peak), as compared to the 125kW precision of the newer model.

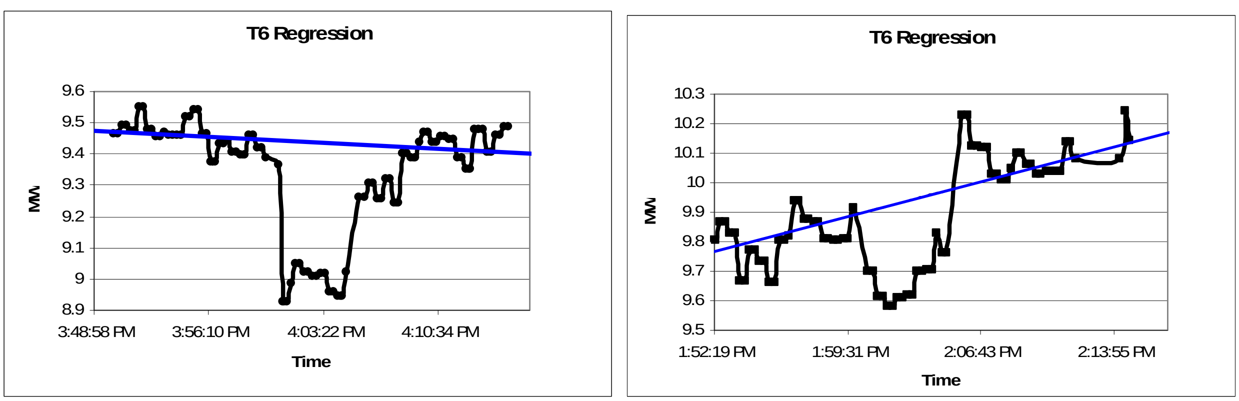


Figure D.1 Two examples of the 2007 methodology applied to the Inland Empire feeder for a test event

The second difference was that the older model used information following an event to inform the estimate of the load during the event. This helped to stabilize the model in the absence of other days' load information, but it was ultimately deemed inappropriate to include when we

[22] The two minutes of data immediately following the test was removed from the analysis because it was determined that the snap-back response was too variable to be accurately characterized in the regression models. Thus, the 10-minute interval immediately following the test actually consisted of eight minutes' worth of data.

investigated the multi-day comparison model used in this report. First, the snap-back time was not always long enough to avoid the direct impacts of load returning on line. Secondly, even if the directly observable snap-back were accounted for, to include load information that has been altered by the test we are trying to quantify would undermine the assumption that there is no causation from the dependent variable of the regression to the independent variables of the regression.

D.1 **Comparison of Method's Results**

We ran the 2007 feeder load data through the refined estimation methods used in this year's study to see what impact the methodological change had on estimated load impacts for test events. The feeders in 2007 had not been split into the A and B feeders seen in the 2008 study.

RMSE Lower for the Same Methods on the 2007 Data

Root mean squared error (RMSE), as described in the main methods section of this study, is the measure used in evaluating the error associated with the predictive models employed in this study. Multiplied by 1.645, the RMSE yields the error bound of the predictions of the model. The 2008 multi-day comparison model yielded error bounds of 162 kW for the combined Inland Empire feeder and 146 kW for the combined High Desert feeder, both of which had peak loads near 9 MW. When the same methods were used on the September and October 2007 load data from these two feeders, the error bounds of the estimates were 127 kW and 102 kW respectively. More investigation would be necessary to explain this difference, but the key differences between the 2007 and 2008 feeders raise a few potential hypotheses: the homogeneity of the loads in a shorter study period yield better predictions; removing the largest peaks from the study period brings the RMSE down by removing what would otherwise be outliers; or, when the feeders were split into A and B, other loads were added to each sub feeder that made them more heterogeneous and thus less predictable. Preliminary tests indicate, however, that the most likely explanation is that the lower feeder loads seen in the fall allow for less variation in the predictions and thus a better RMSE.

High Desert

Figure D.2 shows the recomputed results for the 2007 High Desert feeder using the 2008 estimation method. Three tests were estimated as above the level of statistical significance, but most of the tests yielded inconclusive results. These results are similar to what we saw in 2008 on the Simi Valley feeders; some indication of impact, i.e., an average impact greater than zero, but only a few events statistically significant and certainly no more than would be expected by chance. It appears that between the delayed enrollment of High Desert participants and the late-season testing, the impacts were just not large enough to consistently show up.

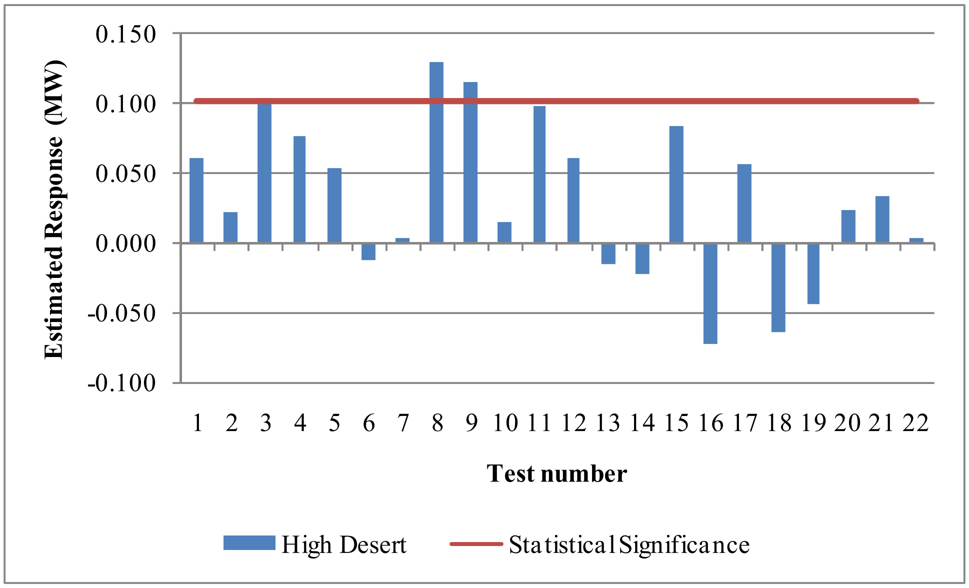


Figure D.2 Estimates of the High Desert 2007 Test Events using the 2008 Study Multi-Day Comparison Methodology

Inland Empire

Applying the new methods to the 2007 data for the Inland Empire feeder (which was, at the time, the A and B feeders combined) was very successful, and highlights a few differences between the two approaches. Figure D.3 shows the 37 test events estimated first using the 2007 linear regression method and then using the 2008 multi-day comparison method. They track one another very closely with a correlation coefficient of 0.92. This indicates that, given the same event data, the two methods yield very similar conclusions about the size of impacts.

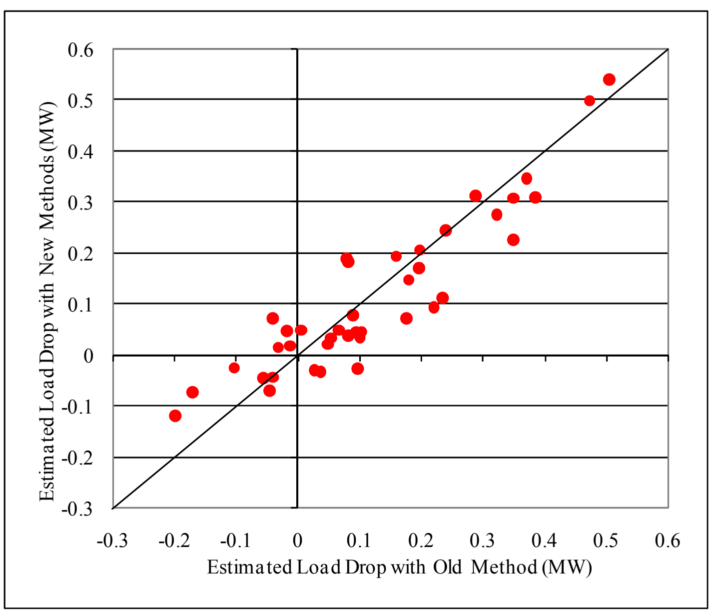


Figure D.3 Comparison of Inland Empire Impact Estimates using the 2008 Multi-day Comparison Method and the 2007 Regression Method

However, the graph also indicates that the newer methods tend to produce lower estimates, on average, than the old linear regression method; more of the data fall below the y=x line than above it. This result is, in part, a limitation of using the multi-day comparison method on data that straddle the cooling and non-cooling seasons. The multi-day method incorporates the general load shape of the most similar other days in estimating the test day's load. When looking at September and October data, this means that more cooler days, which tend to have flatter load shapes, are incorporated into the mix. If these are the closest fits for some of the warmer days with test events, then it is possible that the estimated loads during tests are similarly flattened. The graph indicates that the effect is minor; the predictions from the 2008 method are not significantly lower than the 2007 predictions. However, the result means that a more careful investigation of the impact of seasonality on the 2008 multi-day comparison method would be necessary before using it for any future tests.

D.2 **Conclusions and Assessment**

RMSE Lower for the Same Methods on the 2007 Data

The take-away from both of these is that seasonality seems to be playing a role, and we may need to investigate some sort of "day classification" that separates out das into AC-intensity categories (no usage, low usage, high usage) in doing the estimation techniques.

References

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