# Table of Contents

EXECUTIVE SUMMARY ................................................................................................................................. 1

PROJECT DESCRIPTION/OVERVIEW ............................................................................................................. 4

    HOUSTON PILOT ........................................................................................................................................... 6
    DALLAS PILOT ............................................................................................................................................ 9

PROJECT ACTIVITIES ...................................................................................................................................... 12

    ACHIEVEMENTS IN 2007 .......................................................................................................................... 12
    JANUARY – JULY, 2008 ............................................................................................................................. 14
    INSTALLATION AND SYSTEM VERIFICATION ..................................................................................... 15
    CURTAILMENT .......................................................................................................................................... 15

DATA COLLECTION AND ANALYSIS ........................................................................................................... 16

    DATA COLLECTION ................................................................................................................................. 16
    DEMAND RESPONSE DATA ANALYSIS .................................................................................................. 16
    DEMAND RESPONSE AND LOAD PROFILES .......................................................................................... 30

EXIT SURVEY OF PROGRAM PARTICIPANTS ............................................................................................... 33

ESTIMATION OF THE MARKET-LEVEL IMPACTS ON PRICES FROM A COMMERCIAL-SCALE DEMAND RESPONSE PROGRAM .................................................................................................................. 37

CHALLENGES .................................................................................................................................................. 47

FINDINGS .......................................................................................................................................................... 51

    KW IMPACTS .......................................................................................................................................... 51
    PROVEN TECHNOLOGY ............................................................................................................................ 51
    IMPLICATIONS FOR SETTLEMENTS ........................................................................................................... 52
    DEMAND RESPONSE IN OFF-PEAK SEASONS ....................................................................................... 52
    MARKET IMPACTS ................................................................................................................................... 52

CCET DR PILOT RECOMMENDATIONS ........................................................................................................ 54

APPENDIX A: ADDITIONAL INFORMATION PERTAINING TO CONTROL TECHNOLOGIES ....................... 58

    COMVERGE .............................................................................................................................................. 58
    CORPORATE SYSTEMS ENGINEERING .................................................................................................. 62
Table of Figures

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Figure 1</td>
<td>Houston and Dallas Program Overview Diagrams</td>
<td>5</td>
</tr>
<tr>
<td>Figure 2</td>
<td>Converge System Architecture Diagram</td>
<td>7</td>
</tr>
<tr>
<td>Figure 3</td>
<td>Customer Web Portal</td>
<td>8</td>
</tr>
<tr>
<td>Figure 4</td>
<td>Utility Web Portal</td>
<td>8</td>
</tr>
<tr>
<td>Figure 5</td>
<td>Sample CSE Customer Thermostat Web Interface</td>
<td>10</td>
</tr>
<tr>
<td>Figure 6</td>
<td>Downstream BPL Communications, CSE/Current Group</td>
<td>11</td>
</tr>
<tr>
<td>Figure 7</td>
<td>August 27 Curtailment Event – Air Conditioner Cycling from 3 PM to 7 PM</td>
<td>20</td>
</tr>
<tr>
<td>Figure 8</td>
<td>October 3 Curtailment Event – Thermostat Offset from 3 PM to 5 PM</td>
<td>21</td>
</tr>
<tr>
<td>Figure 9</td>
<td>Participant Household kW Impacts in Dallas: All Curtailment Events, BPL Area Participants</td>
<td>23</td>
</tr>
<tr>
<td>Figure 10</td>
<td>Histogram of Thermostat Offset kW Impacts</td>
<td>25</td>
</tr>
<tr>
<td>Figure 11</td>
<td>Histogram of 50 percent Cycling kW Impacts</td>
<td>25</td>
</tr>
<tr>
<td>Figure 12</td>
<td>Histogram of kW Impacts of the August 27 Curtailment Event</td>
<td>27</td>
</tr>
<tr>
<td>Figure 13</td>
<td>Predicted Event Day Household Demand Response</td>
<td>30</td>
</tr>
<tr>
<td>Figure 14</td>
<td>Scaled Load Profiles and Average Customer Energy Use – Res Hi Participants on October 3rd</td>
<td>31</td>
</tr>
<tr>
<td>Figure 15</td>
<td>Scaled Load Profiles and Average Customer Energy Use – Res Lo Participants on October 3rd</td>
<td>31</td>
</tr>
<tr>
<td>Figure 16</td>
<td>Overall, how satisfied are you with the demand response program?</td>
<td>33</td>
</tr>
<tr>
<td>Figure 17</td>
<td>How satisfied are you with your new thermostat?</td>
<td>34</td>
</tr>
<tr>
<td>Figure 18</td>
<td>How could the program be improved?</td>
<td>34</td>
</tr>
<tr>
<td>Figure 19</td>
<td>Since the program started, have you noticed any specific occasions on which your thermostat was being externally controlled by your retail electric provider?</td>
<td>35</td>
</tr>
<tr>
<td>Figure 20</td>
<td>Did you experience any discomfort due to your thermostat being controlled by your retail electric provider?</td>
<td>35</td>
</tr>
<tr>
<td>Figure 21</td>
<td>How would you classify your discomfort?</td>
<td>36</td>
</tr>
<tr>
<td>Figure 22</td>
<td>What was the primary reason that you agreed to participate in the pilot program?</td>
<td>36</td>
</tr>
<tr>
<td>Figure 23</td>
<td>Typical Balancing Energy Supply Curve</td>
<td>38</td>
</tr>
<tr>
<td>Figure 24</td>
<td>Effects of Demand Response on the Market-Clearing Price of Balancing Energy</td>
<td>39</td>
</tr>
<tr>
<td>Figure 25</td>
<td>Close Up View of Effects of Demand Response on the Market-Clearing Price of Balancing Energy</td>
<td>40</td>
</tr>
<tr>
<td>Figure 26</td>
<td>Effects of Demand Response on Market-Clearing Price of Balancing Energy: 500 MW Needed to Resolve a Constraint (Case 1)</td>
<td>41</td>
</tr>
<tr>
<td>Figure 27</td>
<td>Effects of Demand Response on Market-Clearing Price of Balancing Energy: 250 MW of Demand Reduction Needed to Resolve Constraint (Case 2)</td>
<td>41</td>
</tr>
<tr>
<td>Figure 28</td>
<td>Changes in Price due to Curtailment</td>
<td>43</td>
</tr>
<tr>
<td>Figure 29</td>
<td>Curtailment Effect</td>
<td>44</td>
</tr>
<tr>
<td>Figure 30</td>
<td>Percent Change in Daily Average Balancing Energy Prices</td>
<td>44</td>
</tr>
<tr>
<td>Figure 31</td>
<td>Converge System Architecture Diagram</td>
<td>59</td>
</tr>
<tr>
<td>Figure 32</td>
<td>ZigBee Configuration Diagram</td>
<td>60</td>
</tr>
<tr>
<td>Figure 33</td>
<td>Customer Web Portal</td>
<td>61</td>
</tr>
<tr>
<td>Figure 34</td>
<td>Utility Web Portal</td>
<td>62</td>
</tr>
<tr>
<td>Figure 35</td>
<td>Sample CSE Customer Thermostat Web Interface</td>
<td>63</td>
</tr>
</tbody>
</table>
Table of Tables

Table 1. Summary of Contractual Relationships .......................................................... 13
Table 2. Summary of Progress in 2007 ......................................................................... 14
Table 3. Schedule of Implemented Curtailment Events ................................................ 15
Table 4. Baseline Method Savings Estimates – Average of Curtained Intervals ............. 19
Table 5. Estimated Savings by Event ............................................................................. 19
Table 6. Overall kW Impacts of Curtailment ................................................................. 22
Table 7. Regression Results – Curtailment Strategy ...................................................... 24
Table 8. Regression Results – Hourly kW Impacts of Regression Events by Date .......... 26
Table 9. Regression Results – Hourly kW Impacts of Curtailment Events by Date: Fixed Effects Model .................................................................................................................. 28
Table 10. Summary of Results ..................................................................................... 42
Table 11. Curtailment Impacts on Balancing Energy Expenditures ............................. 45
Executive Summary

The Demand Response (DR) Pilot Program of the Center for the Commercialization of Electric Technologies ("CCET") was a collaboration between three Retail Electric Providers (REPs Direct Energy, Reliant Energy, and TXU Energy), three Transmission and Distribution Service Providers (TDSPs American Electric Power, CenterPoint Energy – Houston Electric, and Oncor Electric Delivery), and demand response-enabling technology providers (Converge and Corporate Systems Engineering) that began in early 2007. It was undertaken in order to explore the opportunities and challenges associated with implementing residential demand response programs in the restructured Electric Reliability Council of Texas (ERCOT) market. The ERCOT market structure, as well as the use and integration of the latest technologies for advanced metering, intelligent grid operation, and in-home controls, make this pilot program unique.

Residents of the Dallas and Houston service areas living within the broadband over power line (BPL) footprints of Oncor Electric Delivery (OED) and CenterPoint Energy – Houston Electric (CEHE) – the areas in which BPL communications capacity were in place - were recruited for participation in the pilot by the REPs from among their existing customers. The Pilot involved the participation of 213 households in the OED service territory and 133 households in the CEHE service area. In addition to bill rebates or similar incentives offered by the REPs, customers were given free programmable, communicating thermostats in exchange for their participation in the program, which involved allowing their air conditioners (and, where applicable, pool pumps and electric water heaters) to be controlled remotely for a limited number of test curtailment events. While a number of challenges (from technological and legal holdups to hurricanes) limited the success of the CCET DR Pilot in terms of measured demand reduction, overall the Pilot accomplished its objectives of demonstrating the technical and operational feasibility of residential demand response in Texas's deregulated market. The major findings of the CCET DR Pilot are summarized in the following paragraphs.

Proven Technology. It is possible to successfully integrate many of today's most advanced technologies for monitoring electricity usage, communicating with thermostats controlling air conditioner operation at homes, networking devices within homes, and controlling customer appliances through a voluntary residential demand response program. This pilot program has also demonstrated that demand response programs may be successfully implemented in an "unbundled" competitive electricity market where separate organizations are responsible for the various activities that must be coordinated in order to operate a voluntary demand response program.

kW Impacts. In curtailments called in the late summer and fall of 2008, an average demand reduction of 0.6 kW was estimated for participating homes in Dallas. The demand reduction that was achieved varied depending upon the curtailment strategy employed and customer-specific factors. Had Hurricane Ike and some equipment delays not prevented the deployment of the program during the hottest period of the summer, and had more effective curtailment strategies been employed, we believe that an average demand reduction closer to 1 kW per home would have been attained.

Settlement Implications. Despite the fact that not all curtailment events for this pilot were timed to coincide with daily or seasonal demand peaks, comparison of averaged participant load shapes to the ERCOT load profiles for curtailment events showed that, during modeled curtailment events, participant energy use averaged between 1 and 2 kWh less than that predicted by the load profile. As load control and DR programs are brought to scale, the potential savings on marginal purchases on the balancing energy services market may become significant, particularly when curtailments are timed to coincide with periods of peak prices.

Demand Response in Off-peak Seasons. Given the importance of timing curtailment to periods of peak prices, it is important to note that many of the significant price spikes that have occurred in recent years...
in the ERCOT market have been due to constraints occurring in the fall and spring “shoulder” months. Because curtailments were called for this project in September and October, including some of the more successful curtailment events (in terms of estimated load reduction), the findings of this study indicate that DR programs in Texas could provide additional value if market participants contract with participant customers not only for a certain number of summer peak hours, but also for additional hours in the shoulder months. For shoulder month curtailments to be successful, curtailment strategies will need to be adapted to the ambient conditions (e.g. cycling strategies must be more aggressive on cooler days for load reduction to occur).

**Market Effects.** Had a “commercial-scale” demand response program been in effect during spikes in the price of balancing energy during the summer of 2008, wholesale prices could have been reduced by over 60% during the period of the spikes. This calculation assumes that reduced demand would have enabled ERCOT to “slide down the bid stack,” thus permitting a much lower supply side offer to set the market clearing price of balancing energy (MCPE) during those periods. Under some plausible assumptions, the total value of the reductions in the MCPE during peak periods that could be provided by demand response is estimated to be $160 million.

While this pilot program demonstrated that the technology works and the necessary coordination is possible, many of the challenges inherent in reaching a successful program were underestimated when this pilot was originally designed. Some of the brand-new technologies selected for this pilot had not yet been fully tested in the field, resulting in significant equipment-related delays. Coordination among all the entities involved in this project required the negotiation of numerous contracts to address many issues that had never previously been addressed. Many activities required “manual” efforts, since meter data management systems and procedures for the sharing of data were still under development at the time the pilot was undertaken. Fortunately, many of the problems that this pilot experienced are now being resolved through various projects at the Public Utilities Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), and through implementation of systems at the respective utilities.

**Recommendations:**
The findings described above led the project team to the following recommendations. Processes are in place to address the issues raised in some of these recommendations; however, the experience of the CCET DR Pilot team reinforces their importance and may help elucidate the directions these processes should take.

1. **Settle ERCOT Wholesale Prices on 15-Minute Intervals.** Market participants’ level of interest in aggressively pursuing demand response may be determined by whether and how ERCOT decides to use 15-minute interval data for wholesale settlements. Rule 25.130 (h) established for ERCOT the objective of being able to use 15-minute interval data for this purpose by January 31, 2010, and ERCOT has been working for some time to establish the procedures that will allow them to accomplish this objective.

2. **Deemed Savings or Stipulated Values for Use in ERCOT Settlement.** A cost-effective and viable “interim solution” is needed while ERCOT’s settlement system is being enhanced, so that DR program participants’ load shed during curtailment events may be better recognized. Such a solution could facilitate the development of residential demand response programs in the ERCOT market in the short term.

3. **Establish a Preferred Method for Quantifying Savings.** Even with advanced metering, quantifying savings requires a method to establish the counterfactual – what would have been consumed absent the curtailment event. In this pilot, savings were estimated according to two general methods: day-matching techniques and regression analysis. While each method has its advantages, in this pilot regression techniques were preferred, in part because this pilot was interested not only in estimating savings, but also in explaining the estimates. The inclusion of additional explanatory variables (e.g. temperature, hour of day) provides a greater level of
understanding of the estimated results than are available with day-matching methods. For future DR implementations, establishing clear guidelines for the methods to be employed to estimate savings would help simplify the process, driving down M&V costs. It may also be appropriate to specify different methods for different purposes.

4. **Plan to Provide REPs and Curtailment Services Providers better information on market prices and appropriate times for deploying demand-side resources in the future.** To maximize the value of investments in residential DR-enabling technology, market participants must be able to anticipate periods of peak prices. In the planned nodal wholesale market system, 15-minute advance price signals will not be provided. Any steps that could be taken to provide advanced notice of wholesale prices in the nodal market would increase the future effectiveness of demand response efforts.

5. **Expand Opportunities for Residential Demand Response.** The value of residential demand response is not limited to the annual value of reduced generation purchases on the balancing energy services market. Currently, residential direct load control can participate in some programs, such as the Emergency Interruptible Load Service (EILS) program, but has limited ability to provide ancillary service, such as non-spinning reserves. Technological challenges would have to be overcome and revisions to protocols made, for residential DR resources to provide non-spinning reserves.

6. **Promote “smart appliances” in Texas.** Future opportunities for Residential Demand Response are likely to include direct load control programs like the CCET DR Pilot, but will also include the introduction of information (e.g. prices, real time power use) to households via the “Smart Grid,” with the advanced meter providing a gateway into the home and using home area networks for communication between appliances and devices in the home. Promotion of smart appliances that can communicate on a HAN will increase consumers’ ability to manage their energy use and increase the loads available to DR programs.

7. **Address the “Stranded Investment” Problem.** Investments in customer-sited DR technology may be “lost” to the market (as well as to the market participant who made the investment) when a customer changes retail provider or moves out. Changes in retail providers and customer move-outs present two types of challenges: 1) informational – the subsequent provider may not be aware that the resource exists, and 2) technological – the subsequent provider may not be able to communicate with the resource. PUCT Project #34610 is establishing business rules for access to home area network (HAN) devices, which should address the information issue. Technological issues are also being addressed via continued development of standards in the communications protocols, including requirements that devices be tested by 3rd parties for interoperability. It should also be noted that the potential loss of the DR resource presents a disincentive for market participants to make the initial investment to put the resource in place.
Project Description/Overview

The Demand Response (DR) Pilot Program of the Center for the Commercialization of Electric Technologies (“CCET”) was undertaken in order to explore the opportunities and challenges associated with implementing residential demand response programs in the restructured Electric Reliability Council of Texas (ERCOT) market. The ERCOT market structure, as well as the use and integration of the latest technologies for advanced metering, intelligent grid operation, and in-home controls, makes this pilot program unique.

The CCET DR Pilot had the following specific objectives:

- Demonstrate that demand response technology solutions can be cost-effectively implemented for residential customers in Texas by leveraging advanced meter and intelligent grid technology.
- Provide insight into the specific challenges of implementing demand response in Texas’s largely-deregulated market.
- Demonstrate that market participants in different segments of the unbundled competitive market can work together to achieve mutual benefits.
- Measure and verify demand response data to determine energy and demand impacts of demand response offerings and allow estimates of the potential market size.
- Recommend appropriate changes to the Substantive Rules of the Public Utility Commission of Texas (“PUCT”) and to ERCOT’s Protocols that would enable the ERCOT market to better recognize the value of demand response programs involving energy consumers who are presently settled\(^1\) based upon profiles of customer load that represent averages across the entire residential class.
- Examine the economic market effects of hypothetical large-scale demand response programs in ERCOT to inform policy-makers and market stakeholders of the benefits associated with pursuing the recommendations resulting from this study.

This report recounts the success of this pilot program in meeting these objectives.

In the CCET Board Meeting on January 11, 2007, the Demand Response Pilot was approved and a schedule proposed. In part, this pilot program was a response to House Bill (HB) 2129 from the 79th Legislature, Regular Session. Governor Perry signed HB 2129 on June 18, 2005, and the bill went into effect on September 1, 2005. HB 2129 requires the PUCT to establish a non-bypassable surcharge for an electric utility or transmission and distribution utility to use to recover reasonable and necessary costs incurred in deploying advanced metering and meter information networks to residential customers and nonresidential customers other than those required by the independent system operator to have an interval data recorder meter. By September 30, 2010, the PUCT is required to evaluate whether advances in technology, changes in the market, or other unanticipated factors would allow meters or various meter-related products or services to be provided more efficiently or more effectively through competition, and make recommendations for legislation the PUCT considers appropriate. It is hoped that the results of this pilot will assist the PUCT in the evaluation that it is required to undertake.

The program was operated in neighborhoods served by Oncor Electric Delivery (OED) in Dallas and CenterPoint Energy – Houston Electric (CEHE) in Houston in which broadband over power line (BPL) networks were in place. These two Transmission and Distribution Service Providers (TDSPs) provided access to their advanced metering infrastructure, including interval data, and much of the project funding. AEP-Texas also provided some funding and participated in the program's development. Three Retail Electric Providers (“REPs”) participated in the CCET Demand Response Pilot Program: Reliant Energy (Reliant), TXU Energy (TXU), and Direct Energy (Direct). Their roles included recruitment of

---

\(^1\) Settlement refers to the process whereby the quantities of electricity sold by generators and purchased by load-serving entities each 15 minutes is estimated, and the value of power involved in transactions is determined, thereby facilitating payments from sellers to purchasers.
customers for the program and oversight of the calling of curtailments. Various technology providers contributed the control equipment and systems necessary to curtail the electricity purchases of contributing residential energy consumers in Houston and Dallas.

Figure 1. Houston and Dallas Program Overview Diagrams

Although the same three REPs were involved in program activities in Houston and Dallas, different TDSPs, technology providers, and metering and communications infrastructure were used in the two cities. This arrangement produced some differences between program activities in the two cities; the remainder of this section describes the pilot programs in each city, highlighting these differences.
Houston Pilot

Prior to the restructuring of the ERCOT electricity market, the electric utility serving Houston operated a large and successful residential load control program which relied upon radio frequency signals to curtail air conditioners at the utility’s request. While residential load control is not new to the Houston market, the use of intelligent grid technologies and advanced meters to control loads and monitor changes in usage in response to curtailment requests is new.

In 2006, CEHE worked with Itron and IBM to restructure a pilot program for a limited deployment of advanced meters. By the end of the year, 10,000 meters had been installed, as well as a basic testing platform for back office support of the pilot. Plans at that time included migrating the test environment into an operating back office system that would be integrated with legacy systems to support billing requirements. The CCET Demand Response Pilot team was informed early in January 2007 that customer data could be available on an end-of-month basis as early as July 2007, and validated, edited, and estimated (VEE’ed) data could be available as early as October 2007 assuming PUCT approval of CEHE’s meter deployment plan by May. However, the PUCT did not approve changes to their Substantive Rules under Project No. 31418 until the May 10, 2007 PUCT Open Hearing Meeting, and did not formally adopt them until May 25, 2007 (with an effective date of May 30, 2007). This delayed some CEHE implementation activities.

In early 2007, CEHE opened its Technology Center at its South Houston Service Center, which demonstrates within a lab environment the proposed advanced metering infrastructure (AMI) and future grid technologies. The center includes a display that features the selected Itron advanced meters and associated advanced metering system. In June 2007, CEHE also installed advanced meters within its broadband over power line (BPL) footprint at the Inverness Apartments and demonstrated the following PUCT-mandated basic functionalities:

- Move in and Move Out with Meter Read: Connect and Disconnect remotely through the portal in a apartment complex
- Receive Usage Value: The interval read and register read (usage data) were retrieved from the database and displayed on the Portal
- On Demand Read (ODR) on Request: The portal also allows the user to request an ODR if the usage data is not sufficient (an ODR is sometimes referred to as an interactive read).
- Energy Consumption Data (Hourly, Daily, and Monthly): Displays a consumer’s energy consumption in a graphical interface.
- Demand Response and Load Management (ZigBee): The end user can control the apartment’s temperature settings through Programmable Thermostats.

In Houston, thermostats for the CCET DR pilot were provided by Comverge. The Comverge SuperStat III is a ZigBee-enabled programmable communicating thermostat (PCT) manufactured through a partnership between Comverge and White Rodgers. The thermostat is fully programmable either locally or over the Internet, supports a wide variety of system configurations, is a one-piece design for easy installation, and can be controlled by the utility company over an AMI network. Equipment installation began in November 2007 and continued through June 2008. System testing occurred from June 2008 to October 2008.

The dispatch system architecture uses CEHE’s BPL network as the wide area network (WAN) for communicating with Itron cell relays in the field. The cell relays act as the “collector” and can communicate with up to 1,000 individual meters located at customers’ homes. The system also utilizes a “mesh network” whereby individual meters can communicate with each other and with equipment inside the home including the PCT thermostat and load control switch for pool pumps and electric water heaters. The mesh network acts as a communications path back to the cell relay. The meter management software platform, called the Itron Collection Engine, manages the communications with cell relays and individual meters and passes data back to a meter data management (MDM) system. Comverge’s load...
management software (LMS) communicates with the collection engine through a secure Virtual Private Network (VPN) tunnel. A system architecture diagram is shown in Figure 2.

**Figure 2. Comverge System Architecture Diagram**

Comverge provided a web portal for customers to access and program their thermostats over the Internet. A screen shot from the portal is shown in Figure 3. The web portal’s capabilities include secure log-in with a user name and password assigned to each account with the ability to change the password online, programming of both cooling and heating for all periods, vacation mode whereby customers could set a “hold” temperature for specific dates and times and override functions for control events.

Each of the REPs also had access to a web portal for scheduling DR control events. A screen shot from the portal is shown in Figure 4. The REP’s web portal assigned a secure login with user name and password to each REP, allowed for advance scheduling of control events using online calendars and pull-down control strategies, and provided the ability to cancel or reschedule events if necessary. The web portal also provided a system log showing all control event information including type, date, duration, and number of devices controlled.

Key issues for Comverge in their interactions with the TDSPs included security, REP access to the system, tracking the REP of record, connection of the load management software to the Itron Data Collection Engine (DCE), and developing a technical solution that would not interfere with the overall system operation. A system access agreement was established between CEHE and Comverge that provided the necessary protection for both companies, and a similar agreement was signed between CEHE and each of the REPs. The physical connection of the LMS software (located in Comverge’s Atlanta data center) and CEHE’s CE (located in Houston) was through a secure VPN tunnel.
Figure 3. Customer Web Portal

Figure 4. Utility Web Portal
Dallas Pilot

In 2007, Oncor Electric Delivery agreed to encourage residential customers' participation, through their Retail Electric Providers (REPs), in programs allowing them to reduce their electricity consumption in response to requests by OED for load curtailment when reliability of the OED transmission and/or distribution system was threatened. The Residential Demand Response pilot program was designed to allow REPs to curtail and/or cycle select residential customers' thermostats, central air conditioner (A/C) compressors, and pool pumps by appropriate technology attached to the customers' end-use equipment. OED's goals for this pilot were threefold:

- to achieve a reduction of 1,500 kW in 2008 to prove the viability of demand response,
- to demonstrate the capability of Current Communication's broadband over power line (BPL) technology to carry two-way communications for REPs for demand response purposes, and
- to demonstrate the utilization of meters that provide 15-minute interval consumption data and the BPL system.

REPs were to be paid an incentive for demand reductions achieved.

Prior to the onset of this project, Current Communications and OED had reached an agreement whereby Current would pay OED for access to OED facilities for the installation of BPL equipment. OED, in turn, agreed to pay Current for use of BPL services associated with automated metering, distribution automation, and substation monitoring. Current's BPL technology consisted of installing fiber optic cable from an electrical substation to a point along a distribution feeder where the communication signal would be "injected" onto the primary circuit. This signal would flow down the circuit, be routed around transformers to the secondary/service, and end up at each customer's meter. Communication from the meter into the home would be over customer wiring using the HomePlug protocol. It was intended that the project would use this BPL/HomePlug communication scheme to monitor energy conditions and operate customer equipment to allow load to be shed as conditions warranted. This project would be one of the first to utilize two-way communications to verify load reduction.

At the outset of the pilot project, REPs were to contract with Current for customer communications. In May, 2007, a Texas PUC ruling concerning demand response mandated that the local TDSP provide communication for the REPs.

OED agreed to provide 15-minute interval meter data for each customer recruited to the pilot at the end of each month. This data would then be utilized to establish the actual demand reductions achieved during load shed events during the month.

Payments under the OED pilot program were to be limited to single family residential customers in the OED service area where BPL facilities were installed. The residential customer was required to have a monthly summer peak of 1,000 kWh and a central A/C system. Customers were required to sign up for the service with their respective REP. All applications were due by May 30, 2008 to be eligible for the 2008 program.

Initially, it was proposed that the pilot be offered during the Summer Peak Demand Season, June 1 through September 30, from the hours of 1 p.m. to 7 p.m. Central Daylight Time, excluding weekends and federal holidays. A customer's device was to be activated at OED's request for a total of 17 hours during a peak season. One Scheduled Curtailment event, of one hour duration, was required to be implemented by the Service Provider at the start the Summer Peak Demand Season each year of the Contract. No one unscheduled event was to exceed a four hour period, and the total duration of Unscheduled Curtailments were not to exceed 16 hours, nor be less than one hour. Ultimately, the three REPs participating in the OED project - Direct Energy, Reliant Energy, and TXU Energy - did not sign up for the above proposals due to project delays and length of commitment.
All meters deployed by OED were provided by Landis + Gyr. These meters recorded 15-minute interval readings internally, and were capable of being interrogated periodically to upload the interval readings to home-office data systems over the BPL network.

29,000 Dallas customers with meters on the BPL system were identified as available for REPs to recruit for the pilot project. Each REP recruited from their respective existing customers for this pilot. Due to slow customer recruitment and technology delays involving communications and switch development (which were inter-related issues, as some REPs preferred not to begin recruitment until they were convinced that the enabling technology was ready. By the time the project actually began, TXU Energy had reached agreement with their project customers to use the customer's personal internet access rather than BPL to enable thermostat control. By this time, OED owned the BPL system and Current operated it for them.

Thermostats installed for participant customers of two of the three participating REPs in the Dallas area were provided by Corporate Systems Engineering (CSE). Thermostats were installed between August and November of 2008, with CSE providing software and hardware and CSE Services providing installations for one REP and training and support for the other. For the third REP, Comverge provided the hardware, software, and dispatch services independent of the Oncor/Current Group infrastructure.

The thermostats installed for participating REPs using CSE's equipment were CSE/Aprilaire two-way communicating thermostats. They were installed along with a communications bridge, also developed by CSE, which was installed at the air handler. The bridge enabled BPL communications from Current/Oncor to be communicated to the thermostat using the home's electrical wiring and the HomePlug protocol, and enabled the in-home devices (thermostats and switches) to communicate via BPL to the head-end system. Once each thermostat and/or load control switch was installed, it was provisioned through Current to assign a private IP address to each device within Current's BPL network. As soon as an IP address was assigned, the device was ready to participate in load control events and, in the case of thermostats, be accessed by the homeowners over the internet. Customer installations were scheduled by CSE, and the provisioning of the devices to the network was a coordinated effort between CSE and Current (who was operating the network on behalf of OED).

**Figure 5. Sample CSE Customer Thermostat Web Interface**
CSE designed, tested, and demonstrated the successful operation of the customer web portal, an example of which is provided in Figure 5, which allowed customers to view and change settings on thermostats.

CSE also designed and implemented a fully operational dispatch program for communications from dispatch through the BPL Network to the household, whereby the REPs can control demand response events from a designated authorized computer. This dispatch program allows the user to control any or all thermostats and devices installed and operating on the Current Network, and has the ability to receive confirmation and status signals from the installed thermostats. The CSE Dispatch Software Program installed on the REPs’ computers gave them the ability to call and implement an event at any time; however, the REPs did not execute any events during the Pilot. For the Pilot, all events were initiated by CSE.

Whether commands originated with the customer or were set using the dispatch application, they were sent to a Command Processor at CSE’s Indianapolis host site where they were further processed and validated. Once successfully validated, the device directives and the list of devices to be controlled (for a given curtailment event) were sent to the CSE Point Of Presence (POP) server in Dallas. The server was located within the Current BPL footprint and was required to give the Dispatchers and homeowner access to the Private IP addresses in the Current BPL network. Once at the POP server, the IP address of the device in question was looked up, a TCP/IP connection was established with the device, and the commands were passed through to affect the appropriate device in the desired way.

Figure 6. Downstream BPL Communications, CSE/Current Group

![Diagram showing downstream BPL communications, including Thermostat Web Site, Dispatch Application, Application Server, and Customer Thermostat.]
Project Activities

The CCET demand response pilot took place over the course of a two-year period. This section outlines what was accomplished during the various phases of the project.

Achievements in 2007

This project was challenging to participants on many fronts. Many of the business relationships needed were new, and not all the technology needed was fully mature and commercially available. During 2007, the parties defined the various business relationships and negotiated and put appropriate contracts into effect, although this took longer than expected. Delays were experienced in acquiring the control devices (e.g., thermostats and control switches) necessary to curtail and control select electrical loads of program participants through home-area networks, due in part to the newness of the technology being deployed. Nonetheless, considerable progress was achieved in 2007:

- A number of meetings and conference calls were held in order to develop among the parties a shared understanding of the pilot project’s goals and activities. Some key logistical issues were successfully resolved involving:
  - Responsibilities of each party.
  - Technology analysis, including the features and availability of control equipment.
  - Access to data obtained from the TDSP’s AMI systems.
  - Establishing channels for communications and control.
  - Financial compensation to the REPs from CCET and the TDSPs.
  - Determination of the demand reduction quantities that will be used for calculation of energy efficiency payments from TDSPs to REPs.
  - Scheduling of program activities, including participant recruitment, equipment delivery, and equipment installation.

- Contractual arrangements were successfully established among the numerous parties involved in the pilot program, as noted in Table 1.
- The staff of ERCOT was invited and became actively engaged in the project.
- The project Research Plan was refined and incorporated into a revised Program Plan, which was approved by the CCET Board.
- An interim solution was established for communications, load control, and meter data access for the Houston Pilot whereby a VPN tunnel was configured to allow the Comverge Load Management System to communicate between firewalls from the Comverge’s Atlanta datacenter and CEHE’s OpenWay Data Collection Engine server down to the advanced meters to the ZigBee-enabled Comverge SuperStat Basic thermostats and Digital Control Units. Although the acquisition of 15-minute interval data from CEHE was initially a manual process, the REPs worked with CEHE’s web portal design to facilitate the automated access of meter data to at least the day after, as required by current PUCT advanced meter rules.
- New state-of-the-art control equipment (i.e., programmable thermostats and load control switches) from Comverge (for program implementation in the CEHE service area) and Corporate Systems Engineering (for program implementation in the OED service area) were ordered. Initial testing of the Comverge thermostats was performed.
- Two different technologies for in-home communications were selected to be tested as part of the pilot: ZigBee™ wireless in the CEHE area and HomePlug™ on existing 120 V ac home wiring in the OED area.
- Formats and procedures for sharing the load data of participants among the parties involved in this Pilot program were established.
- Marketing Plans were developed by the REPs.
- A project Communications Plan was established.
Members of the Project Team participated in meetings of the ERCOT Profiling Working Group, the ERCOT Demand Side Working Group, the ERCOT Demand Side Task Force, and the PUCT’s Advanced Metering Rulemaking. In each of these forums, the experiences of the CCET Demand Response Pilot Program were shared.

A preliminary Test Plan was developed.

A data collection instrument was created for the purpose of collecting basic information about participants and their air conditioning, space heating, and water heating equipment and dwelling characteristics.

A variety of approaches to measuring the impacts from a demand response program were delineated.

Customer recruitment activities were initiated.

Participant recruitments, equipment procurement, equipment testing, and initial equipment installation were initiated. Installation crews were trained.

Converge conducted tests from Atlanta using the VPN that tested the temperature hold and other features of the thermostats with good results. In previous tests the units responded in about 5 seconds. However, the initial test had limited success when it was discovered that Itron's security required that the meters be enabled to receive the Converge signals. Once this setting was changed, the system response was typically 5-10 seconds.

Corporate Systems Engineering successfully completed load shed events tests using its equipment and systems. These tests were completed for each REP. These tests represented a completed end-to-end system test, the equivalent of what a REP would execute during a load shed event.

## Table 1. Summary of Contractual Relationships

<table>
<thead>
<tr>
<th>Contracts</th>
<th>Parties</th>
</tr>
</thead>
<tbody>
<tr>
<td>TDSP Research Project Funding</td>
<td>CCET - OED &amp; CEHE</td>
</tr>
<tr>
<td>CCET management of research funds</td>
<td>CCET - Direct, Reliant &amp; TXU</td>
</tr>
<tr>
<td>Energy Efficiency Market Transformation Program Funding</td>
<td>OED - Direct, Reliant &amp; TXU</td>
</tr>
<tr>
<td></td>
<td>CEHE - Direct, Reliant &amp; TXU</td>
</tr>
<tr>
<td>Material &amp; Services</td>
<td>Comverge - Direct, Reliant &amp; TXU</td>
</tr>
<tr>
<td></td>
<td>Current - Direct, Reliant &amp; TXU</td>
</tr>
<tr>
<td>ASP (Application or Ancillary) Service Provider Agreements</td>
<td>OED - Corporate Systems</td>
</tr>
<tr>
<td></td>
<td>OED - CURRENT</td>
</tr>
<tr>
<td></td>
<td>Comverge - CEHE</td>
</tr>
<tr>
<td></td>
<td>CEHE - Direct, Reliant, TXU</td>
</tr>
<tr>
<td>License Agreement</td>
<td>Corporate Systems - Direct, Reliant, &amp; TXU</td>
</tr>
<tr>
<td></td>
<td>GridPoint and Direct</td>
</tr>
</tbody>
</table>

Meanwhile, various members of the CCET project team monitored and contributed to a number of activities at the PUCT and ERCOT that affected future prospects for demand response programs in the ERCOT market:

- The PUCT enacted rules outlining the required functionality for advanced meters through Project No. 31418 and added a requirement that TDSPs carry demand response control messaging over communications networks utilized for advanced metering.
- The Staff of the PUCT released a proposed new Energy Efficiency Rule that could facilitate demand response efforts by removing the requirement that energy efficiency measures implemented through a Standard Offer Program have a 10-year minimum life and by removing
certain incentive caps and restrictions upon load management. However, the proposed rule would also constrain a TDSP’s ability to fund future research projects.

- The PUCT approved an expanded Emergency Interruptible Load Program (“EILS”), which will require ERCOT to open opportunities for residential demand response programs to receive a payment from the market in return for agreeing to curtail usage during an ERCOT system emergency.

Table 2 summarizes the progress achieved toward each of the primary objectives of this project in 2007.

### Table 2. Summary of Progress in 2007

<table>
<thead>
<tr>
<th>Objective</th>
<th>Progress Achieved</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demonstrate that demand response technology solutions can be cost-</td>
<td>• The costs and capabilities of the necessary equipment were determined. Logistical issues involving access to AMI, communications systems, and data were resolved.</td>
</tr>
<tr>
<td>effectively implemented for residential customers leveraging advanced</td>
<td></td>
</tr>
<tr>
<td>meter and intelligent grid technology.</td>
<td></td>
</tr>
<tr>
<td>Demonstrate that market participants can work together to achieve mutual</td>
<td>• Contracts were successfully negotiated among all the key players in this project. Numerous meetings and conference calls were conducted in order to develop a shared understanding of this project’s objectives and tasks.</td>
</tr>
<tr>
<td>benefits.</td>
<td></td>
</tr>
<tr>
<td>Measure and verify demand response data to determine energy and demand</td>
<td>• A draft Test Plan was developed. Alternative approaches for quantifying the impacts of the Pilot Program were identified. The role of the ERCOT staff in quantifying the impacts was defined.</td>
</tr>
<tr>
<td>impacts of demand response offerings and allow estimates of the potential</td>
<td></td>
</tr>
<tr>
<td>market size.</td>
<td></td>
</tr>
<tr>
<td>Recommend appropriate changes to the Public Utility Commission of Texas’</td>
<td>• Members of the Project Team have participated in meetings of the ERCOT Profiling Working Group, the ERCOT Demand Side Working Group, the ERCOT Demand Side Task Force, and the PUCT's Advanced Metering Rulemaking. In each of these forums, the experiences of the CCET Demand Response Pilot Program were shared.</td>
</tr>
<tr>
<td>(“PUCT’s”) Substantive Rules and to ERCOT’s Protocols that would enable</td>
<td></td>
</tr>
<tr>
<td>the ERCOT market to better recognize the value of demand response</td>
<td></td>
</tr>
<tr>
<td>programs involving energy consumers who are presently settled based on</td>
<td></td>
</tr>
<tr>
<td>profiles.</td>
<td></td>
</tr>
<tr>
<td>Examine the economic market effects of hypothetical large-scale demand</td>
<td>• Insights were gained into the challenges and benefits associated with implementing demand response programs on a much larger scale.</td>
</tr>
<tr>
<td>response programs in ERCOT to inform policymakers and market stakeholders</td>
<td></td>
</tr>
<tr>
<td>of the benefits associated with pursuing the recommendations resulting</td>
<td></td>
</tr>
<tr>
<td>from this study.</td>
<td></td>
</tr>
</tbody>
</table>

**January – July, 2008**

In the first half of 2008, the primary responsibility of the REPs was to recruit participants from their respective customer bases within the BPL footprints in Dallas and Houston. The pilot guidelines required that the REPs only market to their existing customers. Before recruitment could begin, a number of contractual agreements had to be arranged. Table 1 provides a summary of those contracts.
REPs used different forms of direct marketing, combined with healthy incentives, to encourage their customers in the BPL footprint to participate in the program. Due to the compressed schedule and relatively small number of potential participants within each TDSP’s AMI footprint, REPs focused these efforts on maximizing signups, and provided greater incentives than would be considered economical for a large-scale program. Even so, recruitment proved challenging and the REPs were not able to provide sufficient customers to meet the original project objectives of having 500 participants in each city.

**Installation and System Verification**

Installation of enabling technology began in late 2007 and continued into the late summer of 2008. By early August, sufficient installations had been completed that the team was able to perform the first system verification test on August 8th for all Houston customers and for TXU’s Dallas customers. System verification testing for households at which the CSE/Current Group technologies were installed began in Dallas on September 19th.

**Curtailment**

The curtailment verification testing event on August 8th was followed by additional curtailments beginning August 22nd. Subsequent curtailment events for the purpose of shedding load and collecting the associated data were carried out as shown in Table 3.

**Table 3. Schedule of Implemented Curtailment Events**

<table>
<thead>
<tr>
<th>Date</th>
<th>Time of Day (Hour Ending)</th>
<th># of Hours</th>
<th>Dallas A/C Curtailment Strategy</th>
<th>Temperature (°F) Ave/High</th>
<th>Houston A/C Curtailment Strategy</th>
<th>Temperature (°F) Ave/High</th>
<th>Proprietary Algorithms Used?</th>
</tr>
</thead>
<tbody>
<tr>
<td>8/8/2008</td>
<td>5 pm</td>
<td>1</td>
<td>50% Cycling</td>
<td>87/96</td>
<td>50% Cycling</td>
<td>85/96</td>
<td>No</td>
</tr>
<tr>
<td>8/22/2008</td>
<td>4 pm</td>
<td>1</td>
<td>50% Cycling</td>
<td>87/97</td>
<td>50% Cycling</td>
<td>82/90</td>
<td>No</td>
</tr>
<tr>
<td>8/27/2008</td>
<td>4 pm - 7 pm</td>
<td>4</td>
<td>33% Cycling</td>
<td>87/97</td>
<td>33% Cycling</td>
<td>83/93</td>
<td>No</td>
</tr>
<tr>
<td>9/4/2008</td>
<td>4 pm - 5 pm</td>
<td>2</td>
<td>50% Cycling</td>
<td>78/89</td>
<td>50% Cycling</td>
<td>80/90</td>
<td>No</td>
</tr>
<tr>
<td>9/11/2008</td>
<td>4 pm - 5 pm</td>
<td>2</td>
<td>33% Cycling</td>
<td>84/93</td>
<td></td>
<td></td>
<td>Yes</td>
</tr>
<tr>
<td>9/19/2008</td>
<td>5:10 pm</td>
<td>1</td>
<td>3 degree Tstat offset</td>
<td>74/85</td>
<td></td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>9/25/2008</td>
<td>4 pm</td>
<td>1</td>
<td>3 degree Tstat offset</td>
<td>79/89</td>
<td></td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>10/3/2008</td>
<td>4 pm - 5 pm</td>
<td>2</td>
<td>3 degree Tstat offset</td>
<td>78/93</td>
<td></td>
<td></td>
<td>No</td>
</tr>
<tr>
<td>10/21/2008</td>
<td>3 pm - 4 pm</td>
<td>2</td>
<td>33% Cycling/3 degree Tstat offset</td>
<td>71/82</td>
<td>50% Cycling</td>
<td>69/81</td>
<td>No</td>
</tr>
<tr>
<td>11/5/2008</td>
<td>3 pm - 6 pm</td>
<td>4</td>
<td>33% Cycling/3 degree Tstat offset</td>
<td>76/84</td>
<td>33% Cycling</td>
<td>72/84</td>
<td>No</td>
</tr>
</tbody>
</table>
Data Collection and Analysis

The TDSPs were responsible for compiling data from the advanced meters installed at participant households and providing these data to the M&V contractor (Frontier Associates LLC, herein, “Frontier”). Upon receipt of these data, the M&V contractor performed a number of analyses, as described in this section.

Data Collection

Estimation of the impacts of residential load control requires the recording and analysis of significant volumes of data. Data collection proved a challenge for the CCET Pilot, as the TDSPs were in the process of upgrading their automated data collection systems to handle the significantly higher volume of data that the advanced meters produce as compared to the meters they replaced (2,880 data points per meter for a 30-day month, which previously generated only 1 data point). Because this was a pilot program, ad hoc systems had to be put in place for the transmission and extraction of these data. Data were eventually compiled and provided to Frontier for analysis.

The data that the M&V consultant received were not Validated, Edited, or Estimated (VEE’ed) by the TDSPs. For both Dallas and Houston data, the M&V contractor (Frontier) had to develop and implement procedures by which to fill in certain gaps in the received data. To do this, Frontier took advantage of the additional data provided by the advanced meters; both OED and CEHE provide daily or sub-daily register read information that could be used to estimate missing 15-minute intervals based on (a) subtracting the sum of the 15-minute interval reads that had been made between register reads from the cumulative register read for that time period, and (b) distributing the remaining energy consumption among the intervals with missing data according to consumption patterns from surrounding days.

Additionally, some demographic data about participating customers were provided by the REPs, although the data obtained during the installations were limited. Weather data, including dry bulb temperature, cloud cover, dew point, and wind speed were obtained from NWS monitoring stations at DFW and IAH airports for the period during which testing occurred.

Houston Data

Interval data collection for Houston was compromised by a meter change out that occurred toward the end of August. CEHE discovered that the signal emitted by the ZigBee chip in its meters was not sufficiently powerful, and had to upgrade to one with greater power. Technicians in the field changed out the meters, taking with them data that had not been interrogated from those meters. These meters were later reset, and data for events prior to the change out were lost. The change out affected data for all August curtailment events, leaving only data for the September 4 event prior to the onset of Hurricane Ike, which suspended testing in Houston until the 21st of October. Data from participant households were provided to Frontier in text files.

Dallas Data

OED provided data for the Dallas-area at the end of 2008. Like CEHE, OED’s ability to automate the transmittal and storage of data was complicated by the switch to 15-minute interval meters. Data were developed through a series of manual interrogations of their data systems, and provided to Frontier in text files. OED also provided hourly data from a number of customers on a PLC network. These customers were brought into the pilot by one of the REPs.

Demand Response Data Analysis

A number of methods are available for analyzing demand response data. Generally, methods are broken into two categories: day-matching algorithm or the use of regression techniques. The CCET pilot set two objectives for analyzing the curtailment event data from this project:
• ("Ex-post") To develop an accurate estimate of the demand reduction achieved through project curtailments, and
• ("Ex-ante") To predict demand savings that could be expected from a production level deployment of residential direct load control in Texas.

Furthermore, the M&V team set out to compare demand response estimates produced according to a number of the day-matching algorithms currently used by system operators around the country (including the NYISO, ISO-NE, PJM, and ERCOT). The objective of this exercise was to identify which method might be best for estimating demand savings from a direct load control program in Texas.

The estimation of curtailment impacts was complicated by the difficulty the M&V consultant had in obtaining curtailment event logs. Ideally, had it been known exactly which customers were curtailed, and, in the case of air conditioner cycling, at what time the air conditioners were turned off and back on, this information could have been paired with the 15-minute interval data collected from the TDSPs to demonstrate more precisely the demand impacts of curtailment.

Comparison of Day-Matching Methods
Day-matching techniques are generally considered useful for ex post estimates of curtailment impacts; they are good for estimating the demand and energy impacts of a given curtailment event. However, they are less useful for predicting the impacts of future events, because they are specific to the conditions surrounding that event.

Day-matching involves the establishment of a baseline demand against which to compare the actual amount of energy consumed during a curtailment event; the difference between the baseline use and the measured (interval) use is the estimated savings. While establishing the baseline for day matching techniques may be as simple as prior day averaging, the techniques implemented by the major system operators around the country are generally more complex.

For this pilot, the project team estimated the baseline demand according to the methods employed by three independent system operators (ISOs): the New York ISO (NYISO), ISO New England (ISO-NE), and PJM. The following descriptions demonstrate an important characteristic of these methods: they are generally designed so that the most important days for establishing the baseline demand during a curtailment event are the hotter days preceding the event (not including weekends or holidays, which are generally thrown out). The underlying assumption is that demand-side resources are typically called upon on the days in which demand is projected to be highest, which tend to be the hottest days.

NYISO Baseline:
The NYISO’s Customer Baseline Load (CBL) is identified by taking the hourly average load (the average load in a given hour) across a 5 day “CBL Basis” period. The CBL Basis is identified by taking the highest 5 of the 10 days making up the “CBL Window.” The 10 days making up the CBL Window are identified by criteria similar to the other methods, with some minor differences. It begins two days prior (days of similar type – e.g. non-holiday weekdays) to the day of the curtailment, and excludes days for which the average daily event period usage was less than 25% of the average of the other days. An elective weather-sensitive CBL method is also provided by NYISO, but this was not pursued.

The following data are required for calculation of the CBL:
• Hourly load data for non-holiday, non-curtailment weekdays preceding each curtailment event, with a minimum of 10 days prior to the first curtailment.
• Load data for the 2 hours preceding each curtailment event
**PJM Baseline:**

The PJM baseline calculation methodology does not differ greatly from that of the NYISO method. Ten days are selected by the same criteria (including only non-holiday weekdays), and daily usage is averaged (called the ADEPU, or average daily event period usage). The 10 days' usage is averaged as well, to create the ADEPL (average daily event period level). Each day's ADEPU is compared to the ADEPL, and if any day's ADEPU is less than 75 percent of the ADEPL, that day is thrown out, the next most-recent eligible day is selected, and each of the 10 days' ADEPU is again compared to the ADEPL. This process is repeated until 10 valid days have been identified. Then, like the NY ISO, the five highest of those 10 days are selected, and hourly usage for those 5 days is averaged to establish the hourly baseline. PJM adjusts the baseline for day-of event weather effects on customer load using two methods. The average of hour method compares the ratio of usage in the two hours prior to the event to the baseline usage in those same two hours.

The following data are required for calculation of the PJM baseline:

- Hourly load data for non-holiday, non-curtailment weekdays preceding each curtailment event, with a minimum of 10 days prior to the first curtailment.
- Load data for the 2 hours preceding each curtailment event.

In theory, the PJM baseline should only be the same as, or higher than the NYISO baseline, as the criteria for inclusion in the ADEPL (corollary to NYISO's CBL Basis Period) is much higher than NYISO's. In this pilot, the general finding was that the PJM baseline and the NYISO baseline were generally the same, so findings are presented for both under the heading of the NYISO baseline.

**ISO-NE Baseline:**

ISO-NE refers to its baseline as the Customer Baseline (CB). Under ISO-NE's protocol, the CB is estimated based on the average hourly load, rounded to the nearest kWh, for each of the 24 hours in a day. ISO-NE's protocol differs from other protocols in that it is essentially a weighted moving average. It is updated each day according to this formula:

\[ CB_d = 0.9 * CB_{d-1} + 0.1 * \text{MeterReading}_d \]

At the end of each day, the baseline for each hour is updated by multiplying the previous day's baseline for that hour by 0.9, and adding it to one-tenth of the day's meter read for that same hour. The ISO-NE also provides for adjustments to the baseline used for a curtailment day based on the load in the hours prior to a curtailment, but is only applied if the adjustment would increase the baseline.

Data Required:

- Hourly load data for non-holiday, non-curtailment weekdays preceding each curtailment event, with a minimum of 5 days prior to the first curtailment. Load data for the 2 hours preceding each curtailment event.

**Baseline Calculation**

Estimation of the various baselines was hindered by a variety of complications. The baseline methods proved to be:

- Difficult to implement: the determination of a baseline for home for one event was a fairly straightforward task, but dealing with the many events and many customers in this study required additional computational structure.
- Computationally burdensome: the additional computational structure that was created led to long run-times for calculations of baseline for large sets of data. One enhancement was made that allowed for shorter run-times, but it did not come until late in the analysis.
• Problematic when data gaps occurred: ranking methods used ranking algorithms that could not handle days with identical values. Methods of gap-filling were designed in an attempt to overcome this, but data gaps of multiple days continued to present problems.
• Unreliable for single home predictions, particularly when using 15-minute interval data.
• Designed for situations that differed from those encountered in the current project.
• Used weather normalization methods that did capture short-term weather fluctuations.

Other key points:
• The NY-ISO and PJM methods produced very similar results, so the PJM method was abandoned for the sake of computational load reduction.
• The NE-ISO method uses a weather-adjustment that is biased toward over-estimating energy usage. Baseline values are only adjusted when the baseline value is less than the actual customer load at the start of an event. A modified NE-ISO method was implemented that corrected for this upward bias in the baseline, but the full consequences of using this modified method for the analysis were not investigated.

Estimated Demand Reduction using Day-matching Methods

Initial analysis indicated that the calculated savings using the ISO-NE and NY ISO baseline methods would be low. This preliminary conclusion was drawn by combining all calculated savings estimates for each 15-minute interval (the difference between the calculated baseline estimate and the actual measured usage) in which a curtailment occurred. The average of calculated savings estimates is presented by curtailment type in Table 4.

The NY ISO method produced savings estimates that ranged from negative savings for cycling events (more energy use with curtailment) to 0.3 kW for temperature offset events.

Table 4. Baseline Method Savings Estimates – Average of Curtailed Intervals

<table>
<thead>
<tr>
<th></th>
<th>Average of Calculated Savings Estimates (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ISO-NE</td>
</tr>
<tr>
<td>All Curtailments</td>
<td>0.373</td>
</tr>
<tr>
<td>Temperature Offset</td>
<td>0.825</td>
</tr>
<tr>
<td>Events</td>
<td>0.072</td>
</tr>
</tbody>
</table>

The ISO-NE method produced greater estimates of savings, averaging a little less than 0.4 kW across curtailment strategies. Differences between curtailment strategies as executed in this pilot are discussed in more detail in the conclusions section at the end of the section describing the regression-based analyses performed for this study.

Savings estimates are presented according to the ISO-NE and NY ISO baseline methods by event in Table 5. Similar to the results provided in Table 4, the estimates are quite low, and include estimates that energy usage was greater during the curtailment events than it would have been absent curtailment (negative savings).

Table 5. Estimated Savings by Event

<table>
<thead>
<tr>
<th></th>
<th>ISO-NE</th>
<th>NY ISO</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 27</td>
<td>-0.04</td>
<td>N/A</td>
</tr>
<tr>
<td>September 4</td>
<td>0.65</td>
<td>-0.05</td>
</tr>
<tr>
<td>September 11</td>
<td>-0.33</td>
<td>-0.70</td>
</tr>
<tr>
<td>September 19</td>
<td>0.87</td>
<td>0.03</td>
</tr>
</tbody>
</table>
In both Table 4 and Table 5, the ISO-NE method produces greater estimates of savings than the NY ISO method. However, this difference can be attributed to a peculiarity of the ISO-NE method; a weather adjustment is applied based on the consumption in hours prior to a curtailment event, but only if that adjustment serves to increase the baseline estimate. This produces an upward bias on the estimated savings, which is its desired effect, as the method is used to calculate payments made to participants, and it is unlikely that ISO-NE would have success recruiting participants if they stood to owe money when curtailment events are called. However, such a bias is undesirable when the objective is to obtain an unbiased estimate of savings.

Subsequently, effort was made to eliminate the upward bias in the ISO-NE method and obtain a more objective estimate of savings. A comparison of the modified ISO-NE baseline, the NY ISO baseline, and actual consumption on August 27th is depicted in Figure 7. On that day, participants were curtailed for four hours according to a 33 percent cycling strategy (ACs controlled 10 minutes per half hour – as for all other events, a limited number of water heaters and pool pumps were shut off for 100% of the curtailment period). The figure shows the aggregate results for all households curtailed on that day (average values), and clearly demonstrates the strategy pursued in the pilot – all participant air conditioners were cycled for the same 10 minutes of each half hour, resulting in the consistent up/down pattern in participant usage.

Additionally, Figure 7 helps demonstrate the particular difficulty in achieving net load reduction given the cycling strategy pursued. Because the cycling strategy was set as a percentage of time, rather than as a percentage of expected AC run time, there is no guarantee that the strategy will actually cause ACs to operate less than they would have absent the curtailment. Throughout the curtailment period on August 27, the general trend in consumption is increasing; in the periods in which the ACs were not controlled, they appear to have compensated for any load shed that might have occurred.
It does not appear, in comparing the baselines with the actual consumption levels in Figure 7, that the baselines predict greater energy use than the actual curtailed use. Indeed, the average demand reduction estimated using the NY ISO method is less than 0.1 kW, and the modified ISO-NE method produces an estimate of essentially zero (-0.06 kW). The inconclusive result is consistent with the conclusion, discussed above, that no net demand reduction occurred due to the inadequacy of the selected cycling strategy.

In the 15-minute intervals in which the ACs were curtailed, typical load shed was about 0.2 kWh, which translates to demand reduction of 0.8 kW.

Finally, the NY ISO and modified ISO-NE methods were applied to the October 3rd curtailment event, a 2-hour thermostat offset event occurring between the hours of 3 and 5 PM. Figure 8 shows that during the curtailment window, actual demand falls well below both the NY ISO and modified ISO-NE baselines. Immediately after the curtailment period ends, a significant bounceback effect can also be observed; actual usage in the first 15-minute interval after the curtailment spikes almost 0.3 kWh above the baseline levels (1.2 kW), and exceeds the usage predicted by both baselines for the remainder of the day. However, during the curtailment usage averages between 0.1 and 0.12 kWh less than the baseline levels, producing an estimated average demand reduction of between 0.4 and 0.5 kW.

Figure 8. October 3 Curtailment Event –Thermostat Offset from 3 PM to 5 PM

Conclusions

The analysis of demand reduction according to existing baseline methods produced low estimates of the demand reduction achieved through the CCET DR Pilot. While the low estimates of net savings associated with cycling strategies (as shown in Table 4) may be at least partially explained by the way in which cycling was performed, the overall demand reduction estimates for temperature offset curtailment events are also relatively low. These results may also have some basis in the physical reality of the tests – they were not timed to the hottest days (due to delays), and in some cases were not even timed to the hottest part of the day – but they may also be due to some difficulties in applying the baseline estimation methods. While Table 4 and Table 5 appear to show some sizable savings estimates according to the ISO-NE method, to some extent those results are due to the inherent upward bias of the method. The more moderate result obtained for the October 3rd event using the modified ISO-NE baseline method (about 0.4 kW, as seen in Figure 8 as compared to the 1.0 kW in Table 5) demonstrates the effect of the ISO-NE methods upward bias.
Regression-Based Analysis

Regression estimates are presented for two reasons. First, given the difficulties encountered in applying day-matching techniques to the load control events called during this pilot, regression provides a useful alternative for arriving at the ex-post estimates of demand response and energy impacts. Second, results of regression analysis can be extended to develop estimates of the demand reduction that can be expected for future residential load control programs in Texas.

Four regression analyses are presented. The first provides an estimate of the demand response produced in an hour of curtailment during this pilot. The second regression compares the demand response observed on the different days in which curtailment events were called, and provides insights into the effects of temperature, although it does not control for the type of curtailment called (33% cycling, 50% cycling, or temperature offset). The third analysis presented compares curtailment event types, but does not control for differences in the dates on which the events were called (and therefore does not take into account the effects of temperature). The final regression analysis presents a fixed effects model in which all participants are modeled in a single regression. Differences among participants are captured with a participant-specific factor variable, and a single estimate of the impacts of each curtailment event is produced.

Regression analysis has been performed using data from the Dallas pilot only. As explained in the above section on data collection, between Hurricane Ike, which caused the loss of a number of test dates in Houston, and the loss of meter data associated with the change out of meters that occurred immediately before the hurricane, the limited amount of data available for analysis from the Houston pilot greatly complicates the ability to draw robust conclusions from analysis of those data.

Regression 1: Simple OLS Regression

The first task undertaken the M&V team was to establish the extent to which demand reduction had, in fact, occurred when the curtailment events were called. Regression analysis was run on each participant for each interval using the following regression formula:

\[ kW = \alpha + \beta_1 CDH + \beta_2 (CDH)^2 + \gamma_i CRTLD_{Y/N} \]

where:
- \( kW \) = hourly demand for electricity,
- \( CDH \) = cooling degree hours,
- \( CRTLD_{Y/N} \) = dummy variable for whether or not the participant household was curtailed during the interval,
- \( i \) is the interval, which in this case is an hour.

The regression was estimated for each participant household. The formulation of this regression is such that the estimated coefficients on the curtailment interval dummy variables represent the impacts of curtailment on a given household (they are multiplied by one when the curtailment strategy is enacted, and by zero at all other times). Figure 9 provides a histogram of the per-household kW reductions associated with curtailing 146 of the 213 households participating in the Dallas pilot.

The model estimates that the called curtailment events produced, on average, just under 6/10ths of a kW of demand reduction, as shown in Table 6.

<table>
<thead>
<tr>
<th>Response Variable</th>
<th>Mean</th>
<th>Median</th>
<th>Std. Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Curtailment Interval Y/N</td>
<td>-0.575</td>
<td>-0.461</td>
<td>0.89</td>
</tr>
</tbody>
</table>
A histogram of the estimated values of the coefficients on the CurtailedY/N variable – the estimated demand reduction associated with curtailment of a given household’s demand is presented in Figure 9. More than 50 participants are estimated to have provided between 0 and 0.5 kW of demand response across the curtailment events called in the pilot (note that demand reduction corresponds to negative values in this and subsequent histograms).

Figure 9. Participant Household kW Impacts in Dallas: All Curtailment Events, BPL Area Participants

While at least one participant household is estimated to have shed over 3 kW, on average, across the called curtailment events, it should be pointed out that this number does not represent the maximum kW reduction observed in that household, but rather represents the typical kW reduction for that participant across all the curtailment events called during this pilot. Also, a number of households (about 30) show a negative relationship between curtailment and load reduction. The cause of this outcome was difficult to investigate, as the M&V contractor was not able to obtain records of which participants’ equipment received and responded to curtailment signals for each event. Possible causes may include thermostats not receiving curtailment signals and dependence on whole-house metering (participants adding non-air conditioning loads during curtailment events), among other factors.

Regression 2: Curtailment Types

In this pilot, two different types of curtailments were used: thermostat offsets and air conditioner cycling. Thermostat offsets (alternately called “setbacks” and “set-ups”), involve simply changing the setting on a participants’ thermostat: in this pilot, the providers turned them up 3 degrees. In cycling, customers’ air conditioners are controlled for a set period of time, typically guided by contracts in place with customers, which typically limit the amount of any hour the utility can control a customer’s thermostat. For this pilot, the project team performed 33 and 50 percent cycling (10 and 15 minutes per half hour, respectively).

In this regression, the three strategies (33 percent cycling, 50 percent cycling, and 3-degree thermostat offset) are compared. Similar to the 2nd regression, a fixed effects approach is used with respect to individual participants. The demand reduction associated with the different types of curtailment events is
reflected by the coefficients on the factor variables for the curtailment strategy, as shown in the following regression equation:

\[ kW = \alpha_0 + \beta_1 CDH + \beta_2 (CDH)^2 + \gamma_i CRTL_STRATEGY_{ij} \]

Eqtn. 2

where:
- \( kW \) = hourly demand for electricity,
- \( CDH \) = cooling degree hours (defined as the maximum of zero or the hourly ambient temperature - 70),
- \( CRTL_STRATEGY \) = dummy variable set to “1” for the intervals in which the participant household was curtailed according to curtailment strategy \( i \),
- \( i \) represents one of three curtailment strategies: 33 percent cycling, 50 percent cycling, and thermostat offset
- \( j \) indexes the curtailment strategies, of which there were 3 (33 percent cycling, 50 percent cycling, and thermostat temperature offsets).

The regression was estimated for each participant household. Only the relevant curtailment strategies were included in the regression equations for a given house; for those households curtailed by cycling, there were two curtailment strategy variables, but for those curtailed with thermostat offsets, a single dummy variable was included. The formulation of this regression is such that the estimated coefficients on the curtailment strategy dummy variables represent the impacts of that curtailment strategy on a given household (they are multiplied by one when the curtailment strategy is enacted, and by zero at all other times). The estimated coefficients on the CRTL_STRATEGY\(_{ij}\) variables for each of the 213 regressions (one for each participant household) were collected and analyzed to draw conclusions about typical savings by each curtailment strategy.

A summary of the regression output is provided in Table 7. The results indicate that thermostat offset curtailment strategies provided more measurable demand response as measured on an hourly basis over the course of this pilot.

<table>
<thead>
<tr>
<th>CRTL_STRATEGY</th>
<th>Ave Demand Impact (kW)</th>
<th>Median</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cycling (33 Percent)</td>
<td>-0.15</td>
<td>-0.16</td>
<td>0.57</td>
</tr>
<tr>
<td>Cycling (50 Percent)</td>
<td>-0.27</td>
<td>-0.28</td>
<td>0.79</td>
</tr>
<tr>
<td>Thermostat Offset</td>
<td>-1.25</td>
<td>-1.16</td>
<td>0.74</td>
</tr>
</tbody>
</table>

The apparent relative success of the thermostat offset strategy is related to measurement at hour intervals and the simple fact that it is more likely that an AC unit will remain off for an extended period of time when curtailment is done using a thermostat temperature setup. This may also help explain the seemingly paradoxical result that demand response was more effective later in the year; when heat loads are not as high, it should take longer for the temperature to rise in a curtailed household, and therefore, for the new, higher thermostat setpoint to be reached and the AC unit triggered on. However, savings that would be gained due to this phenomenon should be offset by a lower baseline AC use on cooler days.
The most frequently occurring estimated impact for participant households curtailed with a thermostat offset is between 0.5 and 1 kW demand reduction, as shown in Figure 10, but some participants provided over 3 kW of demand reduction in response to the 3 degree increase in their thermostat temperature setpoint. The histogram also indicates that the regressions for very few participants (approximately 2) had the unexpected result of greater consumption during curtailment events.

Figure 10. Histogram of Thermostat Offset kW Impacts

Figure 11. Histogram of 50 percent Cycling kW Impacts
It is estimated that many participant households - more than 40 - experiencing 50 percent cycling provided up to 0.5 kW of demand response during the called events, as shown in Figure 11. Some participants provided up to 2 kW of demand reduction, but the models estimate that a significant number of participants (more than 30, or about 25 percent) consumed more electricity during curtailment events.

**Regression 3: Event Dates**

The third regression is an analysis of the hourly demand impacts of curtailment events called on different dates. The unit of analysis remains the household, so this regression was run for each participant household for which the collected data permitted its estimation:

\[
  kW = \alpha_0 + \beta_1 CDH + \beta_2 (CDH)^2 + \gamma_i CRTL_{MMDD_i} \tag{Eqtn. 3}
\]

where:
- \( kW \) = hourly demand for electricity,
- \( CDH \) = cooling degree hours (defined as the maximum of zero or the hourly ambient temperature - 70),
- \( CRTL_{MMDD} \) is a series of dummy variables, each set to true for the intervals in which a curtailment was called on a given combination of month (MM) and day (DD), and
- \( i = \) index for the different curtailment events called at an individual household

As in Regression 2, the model was estimated for each participant household. Only the relevant curtailment events were included in the regression equations for a given participant; for TXU participants, dummy variables for the September 25 and October 3 events were not included, as they were not curtailed on these days. Likewise, for Reliant customers, dummy variables were included for only the last 4 curtailment events. The formulation of this regression model is such that the estimated coefficients on the curtailment event dummy variables represent the impacts of that curtailment at the participant household being modeled (they are multiplied by one for the intervals in which that event was enacted, and by zero at all other times). The estimated coefficients on the \( CRTL_{MMDD_{i/N}} \) variables for each of the 213 regressions (one for each participant household) were collected and analyzed to draw conclusions about typical savings by each curtailment strategy.

A summary of the analysis results is provided in Table 8:

<table>
<thead>
<tr>
<th>Date</th>
<th>Ave Demand Impact (kW)</th>
<th>Median</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 08</td>
<td>0.21</td>
<td>0.27</td>
<td>1.35</td>
</tr>
<tr>
<td>August 22</td>
<td>-0.54</td>
<td>-0.41</td>
<td>1.38</td>
</tr>
<tr>
<td>August 27</td>
<td>0.15</td>
<td>0.03</td>
<td>1.07</td>
</tr>
<tr>
<td>September 04</td>
<td>-0.24</td>
<td>-0.34</td>
<td>1.18</td>
</tr>
<tr>
<td>September 11</td>
<td>0.24</td>
<td>0.13</td>
<td>1.19</td>
</tr>
<tr>
<td>September 19</td>
<td>-0.55</td>
<td>-0.51</td>
<td>1.14</td>
</tr>
<tr>
<td>September 25</td>
<td>-0.8</td>
<td>-0.83</td>
<td>1.29</td>
</tr>
<tr>
<td>October 3</td>
<td>-2.12</td>
<td>-2.02</td>
<td>1.2</td>
</tr>
<tr>
<td>October 21</td>
<td>-0.82</td>
<td>-0.75</td>
<td>0.79</td>
</tr>
</tbody>
</table>

For the August 8, August 27, and September 11 curtailment events, the average estimated impacts are positive, indicating that, on average, customers were estimated to use more electricity, not less, during these curtailment events. This unexpected result is highlighted in red in Table 8. It is possible that some customers' equipment simply did not receive the curtailment signals. It should also be noted that the strength of the regressions used to produce the results is weak; the overall ability of the models to explain the observed variations in demand from one interval to the next is low (generally very low \( R^2 \).
values on the regressions), and the explanatory power of the Yes/No variables for each curtailment event was also weak. There was also a wide variation in response from participant to participant, as shown in Figure 12.

*Figure 12. Histogram of kW Impacts of the August 27 Curtailment Event*

The expected effect of a curtailment is negative; Figure 6 shows that, of the customers that should have been curtailed on August 27th for whom data were available and kW impacts estimated, approximately 25 used between 0 and 1 kW less than they would have used otherwise, and a total of about 35 customers used less energy over the course of this 4-hour curtailment event. However, more than 40 customers are estimated to have been using between 0 and 1 kW more during this period, and another 22 (approximately) used between 1 and 3 kW more.

It is important to note that this analysis takes into account entire hour intervals. Cycling strategies employed on the days for which the expected demand reduction was not observed involved between 20 and 30 minutes per hour of curtailment; the AC units were free to operate in the other 30 to 40 minutes of each hour. Particularly in homes for which AC units are oversized, it is conceivable that much of the demand reduction was compensated for via additional minutes of operation in the non-curtailed portion of a given hour. This phenomenon does not indicate that demand response did not work for these homes; it still provides utilities the ability to regulate demand and shift the timing of when that demand comes online.

The models estimated measurable demand reduction for the last four curtailment events. Not coincidentally, these four are the days on which about 40 percent of the customers being curtailed were curtailed using a thermostat temperature offset strategy. This result concurs with that of the second regression, and is explained above.

**Regression 4: A Fixed Effects Model of Event Dates**

Another way of obtaining a point estimate of the impacts of individual curtailment events is to include all of the participant households in a single model. In applying a fixed effects model to this dataset, the
different base electricity usage levels in each household are incorporated into a “factor” variable for each household, which produces a level shift in the estimated kW, but does not affect the slope coefficient for each curtailment event. For this model, a series of dummy variables was also introduced to control for different levels of electricity use that might take place every hour. In effect, this means that the ability of the model to capture the difference in demand response by household is constrained; the model produces a single estimate for all households of the demand response achieved from a given event. While a single point estimate for each event may be less informative than the approach presented in the previous regressions, this model - by nature of having a much larger number of data points and a broader set of explanatory variables - is able to explain a lot more of the variation in the dependent variable (demand for electricity), as it produces a much better overall regression fit than the individual regressions performed for the above-presented regressions. The individual variables also generally have more significance. The model is presented here as a check on the other model formulations.

\[ kW = a_0 + \sum_{i=1}^{24} \beta_i CDH + \sum_{j=1}^{24} \gamma_i (CDH)^2 + \delta_j CRTL_{MMDD} + \theta_n PRTCPNT_n \]  
Eqtn. 4

where:
- \( kW \) = hourly demand for electricity,
- \( CDH \) = cooling degree hours (defined as the maximum of zero or the hourly ambient temperature - 70),
- \( CRTL_{MMDD} \) is a series of dummy variables, each set to true for the intervals in which a curtailment was called on a given month (MM) and day (DD), and
- \( PRTCPNT \) is a factor for each participant,
- \( i \) is the hourly interval,
- \( j \) indexes the curtailment events, of which there were 10,
- and \( n \) is the number of participant households.

The model includes a different estimate of the effects of temperature (CDH) for every hour of the day. As in the above-presented models, the formulation of this regression model is such that the estimated coefficients on the curtailment event dummy variables represent the impacts of that curtailment event (they are multiplied by one for the intervals in which that event was enacted, and by zero at all other times). The estimated coefficients on the \( CRTL_{MMDD} \) variables for each of the 213 regressions (one for each participant household) were collected and analyzed to draw conclusions about typical savings by each curtailment strategy.

### Table 9. Regression Results – Hourly kW Impacts of Curtailment Events by Date: Fixed Effects Model

<table>
<thead>
<tr>
<th>Curtailment Event Date</th>
<th>Ave Demand Reduction (kW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 08</td>
<td>-0.15</td>
</tr>
<tr>
<td>August 22</td>
<td>-0.32</td>
</tr>
<tr>
<td>August 27</td>
<td>-0.06</td>
</tr>
<tr>
<td>September 04</td>
<td>-0.08</td>
</tr>
<tr>
<td>September 11</td>
<td>0.35</td>
</tr>
<tr>
<td>September 19</td>
<td>-0.48</td>
</tr>
<tr>
<td>September 25</td>
<td>-0.58</td>
</tr>
<tr>
<td>October 03</td>
<td>-2.02</td>
</tr>
<tr>
<td>October 21</td>
<td>-0.46</td>
</tr>
</tbody>
</table>

The results in Table 9 are obtained by a weighted average of the results of three regressions for subsets of the entire data set, due to computational limitations on the computer and software used to perform these analyses. The \( R^2 \) values for these 3 models range from 0.48 to 0.58, meaning that these models explain from just under half to almost 60 percent of the variation in the underlying data. Interestingly, the results of this model are more favorable for two of the three cycling events called prior to September.
19; however, this model still estimates positive kW impacts (greater demand) during the September 11 curtailment event. For the later events, the fixed effects model provides a similar result on October 3rd (2.02 kW reduction vs. an average reduction of 2.12 kW in Regression 3), but provides smaller results - between 0.46 and 0.58 kW - for the September 25 and October 21 events, for which the average results in Regression 3 were about 0.8.

**Conclusions**

Regression analysis provides insights into the demand reduction available through direct load control programs in Texas. Some counter-intuitive results were obtained; greater demand reduction was achieved in events called in mid-September and mid-October than in events called in August; however, this result appears to be closely related to the type of curtailment strategy called. While the results of the modeling analysis presented in regressions 2 and 3 did not provide much evidence of demand reduction for the enacted cycling programs, the fixed effects model indicated that a limited amount of demand reduction did occur for all events except the September 11th curtailment.

There are a number of important explanations for the limited demonstrable reduction in demand associated with the cycling strategies employed in this study, as compared with those observed for temperature offsets. The cycling strategies employed in this study were designed with the objective of performing measurement on 15-minute intervals; the curtailment effects were to be estimated knowing in which intervals the unit would be controlled (forced off), and in which intervals it would not be (unit may or may not run for the entirety of these periods). As such, the cycling strategies were not “intelligent,” in that there was no effort made to adapt them to the actual duty cycles of the equipment being controlled. While AC duty cycles vary depending on a number of factors, such as whether equipment is properly sized, it can be expected that, even absent curtailment, air conditioners operate for much less than 100 percent of the time when temperatures are below the hottest temperatures of the cooling season. The September 4 curtailment event, a 50 percent curtailment\(^2\) on a day in which the maximum temperature was only 89 degrees, provides a good example. According to the regression analysis, this event provided somewhere between 0.8 and 0.24 kW of demand reduction, on average. It is highly likely that this result reflects the reality that, in many participant households, the air conditioning units were capable of cooling the homes to the desired temperature while running 50 percent (or less) of the time during the curtailment interval. Had the curtailment strategy allowed for curtailments such that the air conditioning units were shut down for 33 or 50 percent of the time they would have been running absent curtailment, a more measurable reduction in demand would likely have been observed.

The constraints on the cycling strategies are contrasted by the lack of constraints on a thermostat offset strategy. Under this strategy, the air conditioning unit shuts off from the time the event is called until such time as the participant household has warmed to the new thermostat setting (in this pilot, 3 degrees). Under cooler ambient temperatures (lower heat loads on homes), the house might not reach the new target temperature for the duration of a two hour curtailment.

While there is not a clear relationship between temperature on the days for which curtailment events were called and the demand reduction achieved, it is reasonable to surmise that weather conditions played an important role in reducing the general impact of curtailment events. Figure 13 shows kW reductions by household according to two of the regression models described in this section. The green columns represent the average value of the demand reduction estimate produced regressing each household’s demand individually (Regression 3); the blue columns represent the estimate of typical demand response according to the fixed effects model performed in Regression 4, above.

---

\(^2\) Except where proprietary “adaptive” algorithms were employed, in this study 50 percent cycling meant 15 minutes per half hour (33% = 10 minutes per half hour).
The effects of temperature are most clearly observed by focusing on the results obtained during the three events between September 19 and October 3, the three curtailment event dates on which only thermostat offsets were performed. For these dates, the curtailment impacts increase with temperature. On the last curtailment event date for which data were obtained (on which both curtailment strategies were employed), the temperature had fallen significantly, and the estimated demand response also falls.

There are many reasons besides the low temperatures at which curtailments were called in this pilot to believe that residential DR should be able to achieve 1 kW, or more, per household, despite the overall estimated average of 0.6 kW of demand reduction achieved in this pilot. One reason is noted in the day-matching analysis of the cycling event on August 27th. In the 15-minute intervals in which participants’ ACs were curtailed 10 minutes (every other interval during the curtailment period), demand reduction of 0.8 kW was observed; it is reasonable to assume that 1.2 kW could have been shed during those intervals if the strategy on that day had been 50 percent cycling (15 minutes per half hour) rather than 33 percent. With more aggressive cycling, greater demand reduction can be achieved; at some point, the demand reduction becomes more than the AC unit can compensate for in the time within the curtailment window that it is allowed to run. Had such strategies been applied in this pilot, the overall average estimates of demand reduction would have likely reached and even exceeded 1 kW.

**Demand Response and Load Profiles**

Among the challenges that the deregulated market has faced in providing proper incentives for demand response is the need for REPs to be able to receive recognition for peak load reductions in the settlement process. In practice, REPs will install DR capacity so they can call on it to reduce the amount of power they purchase in periods of high prices. However, up to the time of this report, as all residential customers have been settled according to load profiles developed by ERCOT, there has not been a mechanism in place by which the shed load can be recognized. The PUCT, in concert with the TDSPs, ERCOT, and other stakeholders, is working to address this issue through the Implementation Project.
Relating to Advanced Meters (PUCT Project # 34610). It is expected that the data storage, sharing, and transmission capabilities will be put in place to enable customer settlement on 15-minute interval data. As such, this section is presented for informational purposes, to demonstrate the value of residential DR for reducing on-peak consumption as compared with the on-peak customer energy usage for which REPs currently pay according to ERCOT load profiles.

On, October 3rd, a two hour curtailment was called in Dallas between the hours of 3 and 5 PM. The following two figures compare the average consumption of participant households to the two relevant ERCOT residential load profiles.

**Figure 14. Scaled Load Profiles and Average Customer Energy Use – Res Hi Participants on October 3rd**

![Scaled Load Profiles and Average Customer Energy Use – Res Hi Participants on October 3rd](image)

**Figure 15. Scaled Load Profiles and Average Customer Energy Use – Res Lo Participants on October 3rd**

![Scaled Load Profiles and Average Customer Energy Use – Res Lo Participants on October 3rd](image)

The load profiles shown in Figure 14 and Figure 15 are the North Central region Residential High and Residential Low profiles for October 3rd. The profiles have been scaled, such that the total estimated usage in a given day matches the average usage of participant customers classified as “Res Hi” or “Res Lo,” respectively. The blue boxes represent the curtailment window.

During the curtailment period, the average energy usage during each 15-minute interval by the Res Hi participants was 0.13 kWh less than the profile on which they were settled, translating to 0.5 kWh over an hour, and 1 kWh over the 2-hour curtailment window); that of Res Lo participants was 0.22 kWh...
lower than the relevant profile for each 15 minute interval, or about 0.9 kWh for each hour of curtailment.

When curtailment events are called during peak hours and in peak season, greater reduction can be achieved, so the difference between measured usage and the load profiles can be expected to exceed the 0.5 to 1.0 kW range observed in the example provided. Market providers, such as REPs, implementing DR programs on a large scale stand to benefit from being settled on 15-minute intervals as compared to the current system of settling on load profiles.
Exit Survey of Program Participants

Telephone interviews were conducted with pilot program participants following the August - October (2008) test curtailments to gauge their level of satisfaction with the program, determine the extent to which the participants were able to detect curtailments, and solicit any other feedback that might contribute to the establishment of successful residential demand response programs in the future.

Overall, program participants were satisfied with the program. Consumers tended to be very satisfied with the new thermostats provided through the program. Consumers seldom noticed curtailments; however, respondents who experienced “temperature offsets” - curtailments in which thermostat setpoints were raised 3 degrees - were much more likely to notice these events than customers whose air conditioners were cycled on and off (under both 33 percent and 50 percent strategies).

Responses were obtained from 217 program participants in Houston and Dallas, including customers of both Reliant Energy and TXU Energy, with slightly more respondents from Dallas than from Houston. Survey results are described in greater detail below.

Figure 16. Overall, how satisfied are you with the demand response program?

![Pie chart showing satisfaction levels]

When asked: “How satisfied are you with the demand response program?” over half reported being either very satisfied or somewhat satisfied, as reported in Figure 16. In addition, less than 4 percent reported a high level of dissatisfaction.
Overall satisfaction with the programmable thermostats was high among survey respondents, as noted in Figure 17. Of the participants who offered suggestions for improvement of the demand response program, most sought increased equipment reliability, better website design, and more technical support, as shown in Figure 18.
Figure 19. Since the program started, have you noticed any specific occasions on which your thermostat was being externally controlled by your retail electric provider?

The majority of respondents (78%) were not aware of any specific curtailment events, as reported in Figure 19. Of the respondents that noticed a given curtailment event, 25 percent experienced some discomfort as noted in Figure 20; however, the majority of those respondents experienced only mild discomfort, per Figure 21.

Figure 20. Did you experience any discomfort due to your thermostat being controlled by your retail electric provider?
Figure 21. How would you classify your discomfort?

Figure 22. What was the primary reason that you agreed to participate in the pilot program?

Program participants were motivated to participate in the demand response program primarily due to the prospects of saving money on their electric bills, conserving energy, and to take advantage of the programmability features of the new thermostat technology, as noted in Figure 22.
Estimation of the Market-Level Impacts on Prices from a Commercial-Scale Demand Response Program

This chapter estimates the possible impact of a commercial-scale demand response program on wholesale and retail prices in the ERCOT market. It is assumed that the program is deployed during periods of high wholesale balancing energy prices by a REP in order to reduce the REP’s exposure to the high prices. The REP’s actions are likely to reduce the balancing energy costs faced by other purchasers of wholesale power, as well, if the demand response is sufficient to enable a lower-price supply-side offer to set the market clearing price of balancing energy.

Introduction

While we focus here on the potential for a residential demand response program to dampen price spikes in the market for balancing energy, there may be other potential roles for residential demand response programs in the ERCOT market. A demand response program may provide Emergency Interruptible Load Service (EILS). In the future nodal market, it may be possible for a load-serving entity to submit a demand curve into the Day-Ahead Market, which would provide a power purchaser a means of reducing electricity wholesale purchases at high prices. ERCOT’s Protocols make it difficult to use a residential demand response program as an ancillary service, due to telemetry and size requirements.

To analyze the potential impact of a large-scale residential demand response program upon prices in the balancing energy market, we take the following steps:

- Specify the features of a commercial-scale demand response program.
- Develop a supply curve representing the offers typically provided by generators to supply balancing energy to ERCOT’s wholesale market during periods of high prices.
- Identify points on the supply curve corresponding to high price periods (of four hours in duration). The distribution of these “starting point prices” is based on high price periods experienced in the ERCOT market in the summer of 2008 (May 1 to July 22).
- Examine how a large-scale demand response program would affect market prices by “moving down the supply curve” by the quantity of demand reduction that would be provided by the hypothetical demand response program.
- Calculate the change in market prices associated with the hypothetical demand reduction.
- Multiply the change in market price by an aggregate volume of balancing energy during each 15 minute interval to calculate the savings to load serving entities (or loss of revenue to generators) associated with the demand reduction.
- Estimate the savings in retail prices to consumers in the ERCOT market based on the reduction in wholesale prices.

This analysis demonstrates that had a “commercial-grade” demand response program been in effect during spikes in the price of balancing energy during the summer of 2008, wholesale prices could have been reduced by over 60% during the period of the spikes. Under some plausible assumptions, a large-scale residential demand response program could reduce the electricity costs of residential consumers by over $11 per year.

Characteristics of the Hypothetical Production-Scale Program

Here we assume that the hypothetical program will provide either 250 MW of demand reduction or 500 MW of demand reduction in the entire ERCOT system. The hypothetical program is based on an assumed savings of 1 KW per participant representing 250,000 participants in the entire ERCOT market for a 250 MW program. We further assume that curtailments will be 4 hours in duration, and that there will not be
more than 50 hours of curtailment during the year. No assumptions were made with respect to curtailment strategy.

The analysis also assumes that the administrator of the program correctly forecasts the periods of high prices. Historically, balancing energy prices have not been set more than 10 to 15 minutes in advance of settlement intervals, and forecast prices have not always proven accurate. Consequently, this assumption may be somewhat optimistic. However, this assumption greatly simplifies the analysis.

All curtailments or deployments of the program are assumed to occur during summer afternoons (May 1 to September 30 between the hours of 12 pm and 10 pm). Since load control programs in Texas have historically focused on air conditioning equipment, curtailments during non-summer periods were not considered.

Our data are based upon today’s wholesale market design. It is difficult to forecast how the implementation of a nodal market design in ERCOT will affect these calculations. However, we presently expect that the implementation of a nodal market will make it much more difficult for REPs to know “when to pull the trigger” and deploy a curtailment, since there is unlikely to be any advanced notice of locational marginal prices under this future market design.

Estimation of Supply Curves

A typical supply curve was developed to assist in the analysis of how demand reduction would change the intersection of the supply and demand curves in the balancing energy market on high demand days. The catalyst for this model is the “hockey stick” nature of the bid stack or supply curve. The typical scenario for supply-side bidders is that they put in bids according to what they can provide at any price level. Usually there is a point at which the supply curve becomes vertical and producers no longer bid in extra power. Wholesale market offer caps have been gradually increasing, per PUCT Subst. R. §25.505(g)(6). For this analysis, we shall adopt the cap of $2,250 offer cap and apply it as if it were a price cap. Thus, bidders may put in a bid at $2,250 for a small amount of extra power. The effect of this is that when demand reaches the maximum quantity the balancing energy market can supply, the marginal clearing price becomes the price cap. Figure 23 is an illustration of a typical bid curve; note the “hockey stick” appearance.

Figure 23. Typical Balancing Energy Supply Curve

![Typical Balancing Energy Supply Curve](image)

It may not be visible at the scale of Figure 23, but at the $2,250 price cap level, there is a small amount of extra power bid in by generators. The figure suggests that at a high market price, a very modest amount of demand reduction can greatly reduce market prices.
Market Effects of Large-Scale Demand Response

The effects of large scale implementation of demand response in Texas have been estimated under two scenarios: (1) the unconstrained case, in which we make the simplifying assumption that a price spike affects the entire market equally, and (2) the constrained case, where we attempt to identify the sub-market effects of constraints between zones. Often price spikes in ERCOT are a consequence of binding transmission constraints among zones, resulting in high prices in certain zones while more-normal prices may persist in others.

System Wide Market with No Constraints between Zones

Figure 24 is a simple model of the effect of a load curtailment program on a 15-minute interval of a high demand day for the entire balancing energy market. This model assumes that there are no inter-zonal constraints (the prices in all zones are equal). Consequently, the offers to provide balancing energy during this period were selected simply to illustrate a typical aggregated bid stack or supply curve for the entire balancing energy market. D = 7450, D-250 = 7200 and D-500 = 6950. The value of D was chosen to be the intersection of maximum demand and the (aggregated) bid curve: D represents an elevated price due to high demand. “D – 250” and “D – 500” are two demand curves representing the potential effects of possible demand response scenarios on total demand for balancing energy. Figure 24 provides a graphical representation of the model. So, under this case, reducing demand by 250 MW reduces market prices from the cap of $2,250 to $225 per MWh. Reducing demand by an additional 250 MW (for a total reduction of 500 MW) has little incremental impact on market prices (an additional reduction of $22 per MWh).

Figure 24. Effects of Demand Response on the Market-Clearing Price of Balancing Energy

If we zoom in on the relevant section of the graph, we can see the price effects more clearly:
**Zonal Market with Constraints between Zones**

The following is another simple model of the effect of a load curtailment program on a 15-minute interval of a high demand day for the entire balancing market, but here we assume that there are constraints between zones so that the prices among zones are not equal. This scenario is being examined because most price spikes in ERCOT in recent years have been, at least in part, a result of inter-zonal congestion. When congestion occurs, the amount of supply potentially available in a given zone may be limited as a result of the constraint.

Two cases are examined here. In the first hypothetical case, 250 MW of demand reduction (in the right place) provided through a residential demand response program is required in order to relieve an inter-zonal transmission constraint. In the second case, 500 MW of demand response can fully resolve the constraint.

The offers to provide balancing energy during this period were selected simply to illustrate a typical aggregated bid stack or supply curve for the entire balancing energy market, just as in the previous scenario. However, the constraint curve was chosen to represent what the bid curve would look like with a constraint. In this case, the aggregated bid curve would be ignored when the constraint is binding and the market clearing price of energy would be calculated by the intersection of the constrained bid curve, representing offers in the zone(s) on the relevant size of the constraint, and demand on the relevant side of the constraint.

There are an infinite number of possible combinations of zonal offer curves and constraints, so just one plausible case is presented here for illustrative purposes. The hypothetical constrained curve has a slope of 11 beyond the constraint. The slope was chosen arbitrarily in order to line up the first constrained MW and a high example accepted price (in this example $3000 per MW, which may be a future wholesale offer cap in ERCOT). The constraint is purposely placed at 6950 MWs. D = 7450, D-250 = 7200 and D-500 = 6950. The value of D is set at the intersection of maximum demand and the constrained (aggregated) bid curve, and represents an elevated price due to high demand. D-250 and D-500 are possible demand response scenarios chosen to illustrate the price effect of demand reduction. Figure 26 is a graphical representation of the model (Case 1):
In this scenario, the constraint was intentionally placed within 250 MW of the highest offer to illustrate how a demand response could eliminate a constraint. In some cases a 250 MW reduction will not be
enough to eliminate a constraint (Case 2), but it may be enough to bring down the market clearing price of balancing energy, as shown in Figure 27.

In this scenario, a 250 MW curtailment is not enough to eliminate the constraint, but it is enough to cut the market price almost in half.

One other aspect of the examples with inter-zonal constraints is the vertical price jump occurring with the first constrained MW. There will typically be a vertical price jump associated with the first constrained MW, however, calculating a model to depict the exact price jump associated with the first constrained MW is beyond difficult due to the multitude of possibilities that may affect the price jump.

**Theoretical Results**

Table 10 is a recap of the results of what a demand response program would theoretically accomplish in three scenarios.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>No Constraints</th>
<th>Constrained Case 1: 500 MW of Demand Reduction Needed to Resolve Constraint</th>
<th>Constrained Case 2: 250 MW of Demand Reduction is Sufficient to Resolve Constraint</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original Market Clearing Price of Energy</td>
<td>$2,250</td>
<td>$3,000</td>
<td>$3,000</td>
</tr>
<tr>
<td>Market Clearing Price Assuming lower demand due to a 250 MW Curtailment</td>
<td>$225</td>
<td>$1647</td>
<td>$225</td>
</tr>
<tr>
<td>Reduction in Price (for 250 MW reduction)</td>
<td>$2,025 (90%)</td>
<td>$1,353 (45%)</td>
<td>$2,775 (92.5%)</td>
</tr>
<tr>
<td>Market Clearing Price of Energy Assuming a lower demand due to a 500 MW Curtailment</td>
<td>$203</td>
<td>$203</td>
<td>$203</td>
</tr>
<tr>
<td>Reduction in Price from original MCPE</td>
<td>$2,047 (91%)</td>
<td>$2,797 (93.2%)</td>
<td>$2,797 (93.2%)</td>
</tr>
</tbody>
</table>
Figure 28. Changes in Price due to Curtailment

Figure 28 shows little difference between a 250 MW and 500 MW in the unconstrained case and the second constrained case, because of the hockey stick nature of the bid curve (or the elimination of the constraint in the second case). Once the vertical portion is overcome, the marginal effects of additional savings are small. The challenge is that the amount of demand reduction required to slide all the way down the “blade” of the hockey stick may vary, such that having the additional DR capacity may be important, even if not all of it is required to overcome a given constraint.

**Empirical Data**

To estimate the effects of a hypothetical curtailment program on historical prices, we identified the five days with the highest daily weighted average market clearing price for balancing energy between May 1\textsuperscript{st} and July 22\textsuperscript{nd} of 2008. These high price days occurred on 5/19/08, 5/20/08, 5/21/08, 5/23/08, and 6/2/08. For these days, we selected the highest four-hour price window between the hours of 12 pm and 10 pm to simulate a four-hour curtailment program. The earliest the program could start was 12 pm and the latest start was 6 pm. Here a total of 20 hours of curtailment were examined. During every hour there were four 15-minute price intervals, giving the program a total of 80 curtailed intervals (20 hours times 4, 15 minute, intervals). Of the 80 curtailed intervals, 8 (10\%) did not have constraints between zones. Of the 8 unconstrained intervals, 3 (3.75\%) were at the offer cap of $2,250. The presence of constraints in 72 of the 80 curtailed intervals suggests that there is a high correlation between constraints and high prices; however, the model ignores whether or not the original price was constrained and simply shows what the prices should theoretically be with a curtailment and without constraints. The following chart shows the impact of curtailment programs on daily weighted average balancing energy prices:
The results of the previous charts may suggest that the value of going from a 250 MW reduction to a 500 MW reduction is very small; however, this may not always be true. A 250 MW reduction may not be enough to eliminate constraints, in which case a 500 MW reduction would have far more value than a 250 MW reduction.
Table 11 shows the impact of a curtailment program on balancing energy expenditures by load-serving entities. This was obtained by multiplying the price reduction calculated from sliding down the supply curve by the actual amount of balancing energy procured during the curtailment period.

Table 11. Curtailment Impacts on Balancing Energy Expenditures

<table>
<thead>
<tr>
<th>Date</th>
<th>5/19/08</th>
<th>5/20/08</th>
<th>5/21/08</th>
<th>5/23/08</th>
<th>6/02/08</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Original</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day Weighted Avg. MCPE</td>
<td>$371.82</td>
<td>$571.88</td>
<td>$391.18</td>
<td>$588.67</td>
<td>$337.44</td>
<td></td>
</tr>
<tr>
<td>Day UBES Requirement</td>
<td>41,257</td>
<td>56,027</td>
<td>44,686</td>
<td>69,411</td>
<td>57,799</td>
<td>269,180</td>
</tr>
<tr>
<td>Day UBES Expenditure</td>
<td>$15,340,164</td>
<td>$32,040,699</td>
<td>$17,479,966</td>
<td>$40,860,096</td>
<td>$19,504,001</td>
<td>$125,224,925</td>
</tr>
<tr>
<td><strong>250MW Curtailment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day Weighted Avg. MCPE</td>
<td>$141.20</td>
<td>$216.02</td>
<td>$146.46</td>
<td>$173.25</td>
<td>$116.18</td>
<td></td>
</tr>
<tr>
<td>Day UBES Requirement</td>
<td>40,257</td>
<td>55,027</td>
<td>43,686</td>
<td>68,411</td>
<td>56,799</td>
<td>264,180</td>
</tr>
<tr>
<td>Day UBES Expenditure</td>
<td>$5,684,275</td>
<td>$11,886,904</td>
<td>$6,398,221</td>
<td>$11,852,498</td>
<td>$6,599,160</td>
<td>$42,421,057</td>
</tr>
<tr>
<td>Savings</td>
<td>$9,655,889</td>
<td>$20,153,795</td>
<td>$11,081,746</td>
<td>$29,007,598</td>
<td>$12,904,841</td>
<td>$82,803,868</td>
</tr>
<tr>
<td><strong>500MW Curtailment</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Day Weighted Avg. MCPE</td>
<td>$138.06</td>
<td>$216.76</td>
<td>$147.07</td>
<td>$169.04</td>
<td>$115.30</td>
<td></td>
</tr>
<tr>
<td>Day UBES Requirement</td>
<td>39,257</td>
<td>54,027</td>
<td>42,686</td>
<td>67,411</td>
<td>55,799</td>
<td>259,180</td>
</tr>
<tr>
<td>Day UBES Expenditure</td>
<td>$5,419,721</td>
<td>$11,710,578</td>
<td>$6,277,775</td>
<td>$11,395,125</td>
<td>$6,433,824</td>
<td>$41,237,024</td>
</tr>
<tr>
<td>Savings</td>
<td>$9,920,443</td>
<td>$20,330,121</td>
<td>$11,202,190</td>
<td>$29,464,971</td>
<td>$13,070,177</td>
<td>$83,987,901</td>
</tr>
</tbody>
</table>

A curtailment program will have a significant impact on prices and expenditures if it is assumed that a curtailment program will be used to eliminate congestion. If a demand response program can overcome a constraint, then there is potential to save over $80 million in balancing energy expenditures with just 20 hours of curtailment across the ERCOT system. However, it is unclear what size of a demand response program is necessary to overcome a constraint for the entire system, because the amount of DR required will vary as constraints shift. Sometimes, 1 MW may be enough to remove a constraint, whereas other times even 500 MW would be insufficient. In the cases of natural disasters or transmission line outages, it may be impossible to remove a constraint.

If a demand response program is capable of removing a constraint, this will permit power from low-price zones to flow into high-price zones. This tends to equalize prices across zones and should always lead to lower overall prices. If demand reduction is achieved in a zone that is isolated from the rest of the system due to constraints, a given amount of demand reduction will have a greater impact on prices in that zone than had the constraint not been present. The applicable market is now just the zone, not all of ERCOT.

**Impact**

The hypothetical program would save approximately $80 million during a three month period. We believe that it may be reasonable to double this savings figure to reflect the potential savings from a program which could be operated throughout the summer. On the wholesale side, in 2008 the UBES market had expenditures of approximately $700 million. Thus a $160 million reduction in balancing energy costs would represent a savings of about 23%. The balancing energy market satisfies about 5% of the total generation requirements in ERCOT, putting the total value of generation sold in the market in the neighborhood of $14 billion. Thus, savings of $160 million in a market of $14 billion would represent savings of about 1.1%. Assuming an average residential consumer purchases 12,000 kWh per year and
the generation component of a residential consumer's electricity price is about 8 cents per kWh, a typical residential energy consumer would save nearly $11 per year in energy costs (12,000 kWh * $0.08 * 1.14%) as a result of a successful large-scale demand response program.

**Conclusion**

A large, commercial scale demand response program has the potential to save large amounts of BES expenditures. The critical factors for success for a demand response program would be to make the program large enough and strategically located so as to overcome likely constraints, although there is still value in reducing overall costs even if constraints are not overcome, particularly for a REP who could reduce high-priced purchases as a result of implementing such a program. With 20 hours of curtailment and 500 MW of demand reduction per curtailment (if 500MW is large enough to eliminate constraints) there is potential to save over $160 million in balancing energy expenditures. This translates to annual savings of 23% in balancing energy expenditures and 1.1% in retail cost savings for load-serving entities across the ERCOT market. There is also a positive externality of making the ERCOT system more reliable by adding demand response to ERCOT’s toolkit.
Challenges

Implementation of this pilot program proved challenging for a variety of reasons, including:

- the new types of business relationships required among the pilot program participants;
- the challenges inherent in being an early user of new technologies and systems; and
- Hurricane Ike.

The challenges were typical of the development of new business relationships and the implementation of new technologies, and no insurmountable hurdles were identified. Nevertheless, these challenges were significant to the project and are discussed below.

Coordination within the ERCOT Market Structure

When a vertically-integrated electric utility administers a demand response program, the need for coordination is relatively small. The same entity (or its contractors) manages the relationship with the customer or participant, reads the meter, deploys curtailment signals through its communications infrastructure, and determines the value that the customer’s response to curtailment requests provides to the utility. In a restructured market with retail competition, such as ERCOT, different entities are responsible for the various functions necessary to administer a demand response program. REPs manage the relationship with consumers, are responsible for marketing and customer recruitment, and provide incentives to program participants. TDSPs are responsible for metering and intelligent grid technologies, which have the capability to communicate curtailment requests to program participants and monitor their usage. The ERCOT market’s settlement procedures dictate how (and whether) the changes in consumption induced by the program shall be recognized in the power costs borne by REPs. As demonstrated by the comparisons of participant customer usage to the scaled load profiles in Figure 14 and Figure 15, these avoided power costs can be significant.

Coordination among these entities, as well as with the technology providers, necessitates the complex contractual arrangements earlier identified in Table 1. Contracts were required in order to safeguard the confidentiality of customer electricity usage data, define liability and indemnity, determine insurance requirements, provide for the security of data stored behind computer firewalls, and coordinate the actions of various entities in different market sectors. Since there were no standardized terms and conditions for these agreements, numerous contracts had to be prepared between the pilot participants which caused numerous delays to the pilot.

ERCOT’s unbundled market structure presents challenges for demand response. In a vertically-integrated utility setting, the same entity can derive value from a demand response program’s impact on reducing generation requirements during high-cost periods, avoiding or delaying power plant additions, and potentially delaying transmission investments. In an unbundled market, different segments of the market can derives various benefits from demand response. REPs can benefit from avoided generation requirements. TDSPs can benefit from deferred transmission system investments and by using demand response achievement toward meeting energy efficiency goals. The ERCOT system operator could benefit from the availability of an additional tool to reduce demand during periods of impaired system reliability. Providing value and assigning costs among different entities involves coordination and contractual agreements.

3 It should be noted that REPs may, but are not required to, use the TDSP intelligent grid capabilities to communicate with customers. Some REPs may prefer to use non-TDSP systems in deploying DR technology, particularly if they want to offer DR programs to all their customers before TDSPs complete their rollout of AMI.
As a result of this pilot program, these challenges have been defined and largely resolved. Through the PUCT’s Advanced Metering Implementation Project, many of the needed procedures and legal agreements are becoming more refined and standardized.

One area which requires additional attention is the ERCOT settlement system. REPs remain very interested in seeing settlements done on 15-minute interval data so that the market value of curtailments may be properly recognized.

**Technology-Related Challenges**

The fast-moving nature of change in enabling technologies posed numerous challenges. These ranged from issues with the meters and load control devices at homes to the substantially increased volume of meter data being handled. For example, many of CEHE’s original advanced meters had to be upgraded in the middle of the 2008 curtailment season in order to enable on-premise communication between the meters and the Comverge thermostats. System upgrades had to be made to Itron’s metering network in the CEHE service area during the pilot. CEHE reported potential Itron OpenWay and BPL communication issues associated with system software compatibility with hardware/firmware upgrades, and ZigBee chip interface issues with customer load control devices resulting from binding problems with advanced meters.

Home area network (HAN) protocols were being developed while the pilot program was underway. The ZigBee Smart Energy protocol, which was eventually adopted and used in the Houston pilot, was under development and not publicly available at the start of the project, so Itron and Comverge initially worked together on a proprietary communications profile, which they used to start the project rather than waiting for the ZigBee Smart Energy profile to come available. The ZigBee Alliance did not introduce its Smart Energy public application profile, which supported load shed/restore through one-way communications, until January 2008, at which point they were made available to the public. The unavailability of the public application profile until this time delayed delivery of the enabling technologies.

Given the vast amount of data collected through CEHE’s and OED’s new advanced metering systems, the TDSP’s meter data management systems must now accommodate 15-minute interval data for the residential premises metered with new AMI systems.

Significant gaps are evident in much of the data collected and analyzed, as discussed in the previous section on project data. Many intervals had missing values. This is indicative of the intermediate step in transitioning to new meter data management systems that will, when fully mature, provide the quality of data desired.

**Hurricane Ike**

Ike presented CEHE and the Houston Pilot with a whole new set of priorities for the month of September. CEHE spent a lot of time, and deployed a lot of personnel to disaster-related activities, including project team members, to handle the myriad issues they faced. Once electric transmission and distribution systems were restored, trouble-shooting and repairing of damaged BPL communications infrastructure had to be addressed.

**Other Challenges Faced**

A major obstacle for the CCET Demand Response Pilot within CEHE’s service area was the large number of multi-family dwellings compared to the desired single family dwellings. In an effort to correct this market barrier CEHE filed the AMIN project (See Appendix A: CenterPoint Energy – Background), whereby the REP would be the driver in the selection and location of AMS equipment. The CEHE
advanced meter mass deployment filing identifies the strategy and maps for installations which are cited within the settlement stipulation to be “not unreasonably discriminatory, prejudicial, preferential, or anticompetitive.” However, the REPs will continue to be restricted within the service areas selected by the TDSP. As noted above, factors considered in developing the Deployment Plan were: (1) existing automatic meter reading equipment in the district; (2) the number of field activities required in that district (e.g., number of disconnects/reconnects, move-in/move-out readings, and difficulty to manually read); and (3) the proximity to deployment staging areas.

Weather-related issues whereby air conditioner operational thresholds were below load cycling requirements. Several customers participating in the pilot program had very low energy usage levels during the test periods.

Providers of the control technologies report the following additional challenges:

1. Small pilot footprint limited market size in Houston (less than 3,000 single-family customers were eligible, making it virtually impossible to get 500 customers signed up)
2. Overall project delays which resulted in significantly extending the project implementation
3. Scheduling of equipment installations (customers had to be home for install)

**CEHE Primary Challenges**

The following summarizes the significant challenges CEHE faced during this pilot and that may limit the success of future efforts to implement DR programs:

**Regulatory Risk** - Ongoing PUCT rulemaking discussed above will have significant impact on key system functional requirements, such as (1) common data repository and web portal access for market participants (including customer) to secured data, (2) near-real time access to meter data via advanced meter or TDSP communications interface, (3) load control / demand response capabilities to be supplied by TDSP, (4) VEE interval data requirements, (5) HAN functionality support requirements, (6) end-to-end connectivity testing capability for load command, control and monitoring signals, (7) settlement of 15 minute interval data, (8) REP of Record tracking requirements, etc.

**System/Product Acceptance Testing Methodologies and Structured Pilot Test Plans** - As market systems evolve and new energy management/efficient products are introduced into the market, the need to establish system/product acceptance testing standards becomes more critical.

**Troubleshooting** of operational or data collection problems could have been more easily addressed if 15 minute interval data was made available the day after testing. Ideally, near-real time data would have provided the most accurate monitoring and measurement of the expected curtailment cycles.

**Demand Response Program Data Retention Requirements** - Unique data requirements outside the current CEHE systems will need to be addressed. Since customers will switch REPs, the TDSP may be the only logical location for storing, maintaining and managing this data, outside perhaps the proposed Texas Common Repository. This includes the identification of customers that have demand response equipment installed, and customer-specific information not maintained by TDSP legacy billing systems such as customer name, mailing address, phone number(s), emergency number(s), etc. Also, premise-specific data associated with the types of load control devices, device manufacturer information, communications interfaces, device MAC addresses, etc. will need to be stored within a common data repository location. Lastly, DR programs may require customer usage data that is more granular than billing consumption data or even that captured in the Meter Data Management system (15-minute
(interval data) to allow accurate measurement and verification of required load curtailments (e.g. one or five minute interval data recordings may be required for a subset of program participants).

All of these issues could be overcome with proper planning and execution. The lessons learned from the CCET Demand Response Pilot were very valuable and would be utilized in developing a larger scale program.
Findings
The CCET Demand Response Pilot Project presents findings in five key areas:

- kW Impacts
- Proven Technology
- Implications for Settlements
- Demand Response in Off-peak Seasons
- Market Impacts

**kW Impacts**
The project has demonstrated that residential loads respond to direct load control. Generally, analysis of the interval data show that, for this pilot, typical participant demand reduction was on the order of 0.6 kW. This result is lower than that observed in other studies in the literature, and is likely due, at least in part, to the relatively mild weather conditions on the control days. Because the M&V consultant did not have access to communication records between devices confirming participation in control events, it is also possible that the demand reduction estimates produced in this report underestimate the demand response achieved because the estimate includes households that did not, for one reason or another, actually participate in the curtailment event.

- Thermostat setbacks proved more measurably effective at driving down demand during the control period than cycling strategies.
- In defiance of the expected increasing relationship between temperature and demand response, the most effective curtailment events were called between September 25th and October 21st. The highest average demand reduction observed was associated with the October 3rd curtailment, and was about 1.2 kW.
- Fixed effects modeling, which attempts to account for a number of household specific characteristics affecting base electricity use with a single factor variable, provided a more favorable estimate of demand response associated with the earlier curtailment events (cycling events) than the aggregated results of the simpler regression techniques employed, and produced similar results to those estimated for the later dates, at least in terms of the average impacts.

**Proven Technology**
Residential Direct Load Control (DLC) is a proven concept. Load switches, thermostats, and the associated remote enabling technology (radio communications, etc) have been in use for some time, even since the 1970’s. However, most previous efforts to implement DLC relied on one-way communication from a central dispatch via radio to the load controlling devices (switches, thermostats), and typically used radio communications. This pilot was concerned with testing the capabilities of a number of new technologies - 2-way communicating thermostats, advanced meters, broadband over power line (BPL) and Power Line Carrier (PLC) for communications, and Smart Home technologies such as HomePlug and ZigBee protocol devices. While postponement of the release of communication protocols like ZigBee’s smart energy public application profile may have contributed to delays in the project, the process of preparing coordinating development, testing, and manufacturing new technologies among vendors to be able to provide functional equipment to caused delays, particularly in the project’s first year.

Significant advances in technology, development tools, testing, certification, manufacturing and communications protocols have been made since the pilot began. Several utilities have joined forces with the ZigBee Alliance and the HomePlug Powerline Alliance to develop two-way communications protocols for the integration of a common application layer across HAN technologies that will allow a common
certification process for plug and play interoperability of consumer energy management and efficiency devices. The continued advancement of standards, and collaboration between these major alliances, will only improve the array of available technologies, their capabilities, and their costs.

**Implications for Settlements**

In this report, we provide a comparison of curtailed customers and ERCOT load profiles scaled to the average daily use of those customers (under the heading Demand Response and Load Profiles, see Figure 14 and Figure 15). The analysis shows that, even under the curtailment events called on off-peak hours of off-peak days, the per-household difference between usage of curtailed customers and the estimated usage for which the REP would pay according to the load profile can be significant. Furthermore, to the extent that residential DR is a substitute for purchasing power on the BES market, the value of each shed MW can be as high as $2,250. If REPs were able to receive recognition for peak load reductions associated with residential DR programs in the settlement process, they would have a much larger incentive than they currently have to invest in deploying DR programs. The deployment of AMI infrastructure across the state over the next several years presents the opportunity for settlement of residential customers’ accounts, and particularly DR program participants’ accounts, on interval data in the not too distant future.

TDSPs have been required by the PUCT to submit AMI deployment plans; the TDSPs participating in this pilot have already done so. However, up to the time of this report, as all residential customers have been settled according to load profiles developed by ERCOT, there has not been a mechanism in place by which the shed load can be recognized. The PUCT, in concert with the TDSPs, ERCOT, and other stakeholders, is working to address this issue through the Implementation Project Relating to Advanced Meters (PUCT Project # 34610). It is expected that the data storage, sharing, and transmission capabilities will be put in place to enable customer settlement on 15-minute interval data. As such, this section is presented for informational purposes, to demonstrate the value of residential DR for reducing on-peak consumption as compared with the on-peak customer energy usage for which REPs currently pay according to ERCOT load profiles.

**Demand Response in Off-peak Seasons**

The typical season for calling demand response events, when temperatures are highest and A/C use is at its peak, are the summer months of July, August, and September. The project team had limited opportunities to call curtailment events during these months, because of the numerous challenges enumerated above. However, the project team opted to move forward with calling curtailment events in October and as late as November 5, with the objective of being able to achieve some measurable savings. While the demand impacts of calling a curtailment in cooler weather can be expected to be lower, there may be value to Texas utilities in being able to call them. There have been a number of off-season price spikes in the ERCOT market in the past couple years (e.g. market clearing prices approaching $600 on May 20th and 23rd in 2008). Typically, these peaks are caused by unanticipated demand spikes, combined with decreased capacity for the grid to respond (plants offline for maintenance in “shoulder” months).

One of the challenges presented by attempting off-season curtailment events is that the baseline estimation methods are designed based, in some part, on an assumption that curtailments will be called on a day in which demand is expected to be at least as great as, if not greater than, demand on the preceding days. A different method for establishing baseline consumption may be required when factors other than demand lead utilities to call a curtailment event.

**Market Impacts**

A large, commercial scale demand response program has the potential to save large amounts in balancing energy expenditures. The critical factors for success for a demand response program would be to make the program large enough and strategically located so as to overcome likely constraints. The hypothetical scenarios evaluated in this report demonstrate that, with 40 hours per season of curtailment...
with sufficient demand reduction per curtailment to eliminate the effects of constraints, there is potential to save over $160 million in balancing energy expenditures. This would translate into annual savings of 23% in balancing energy expenditures, retail cost savings of 1.1% for load-serving entities across the ERCOT market, and an estimated $11 per household to Texas consumers.
CCET DR Pilot Recommendations

Through this pilot, the participating CCET members have endeavored to demonstrate the applicability of new technologies to the accomplishment of a relatively old task – demand response. This pilot has demonstrated that providers of the latest technologies can dispatch curtailments via BPL and other networks, thermostats can be controlled, and information may be provided back to the dispatcher. It has also provided an example of how the required parties for implementing demand response in the Texas market can work together. However, this pilot has also shed light on significant challenges that must be addressed if residential direct load control and other demand-side peak load management programs are to be implemented on a large scale in Texas.

Demand Response at the residential level has not, to date, been a significant factor in the Texas electric market, due to a number of complicating factors. These factors have included difficulties in metering and verifying the actions of residential energy consumers; reliance upon a market settlement system that uses average load profiles to estimate the temporal usage of smaller energy consumers; coordinating the actions of curtailment services providers, distribution utilities, and retail electric providers; and the “severed value chain” associated with the structure of the market - in which distribution utilities, retail electric providers, and ERCOT system operators all recognize some value from demand response, but the value enjoyed by any single entity may be insufficient to justify the sponsorship of a demand response program. The deployment of advanced meters that has already begun presents an opportunity to address some of these challenges. 4

Based on its experiences over the two-year course of this pilot, the project team submits the following recommendations. The recommendations in this section have implications for various parties with a stake in the Texas electricity market, from the TDSPs and REPs to regulators to consumers, and are designed to help the ERCOT market address, at least partially, the above-identified challenges to broad deployment of residential demand-side resources:

1. **Settle ERCOT Wholesale Prices on 15-Minute Intervals.** Market participants' level of interest in aggressively pursuing demand response (and particularly that of the REPs), may be determined by whether and how ERCOT decides to use 15-minute interval data for wholesale settlements. Rule 25.130 (h) established for ERCOT the objective of being able to use 15-minute interval data for this purpose by January 31, 2010, and ERCOT has been working for some time to establish the procedures that will allow them to accomplish this objective.

   This pilot has demonstrated that there are challenges for all parties in the collection, storage, and provision of 15-minute interval data for residential customers, but that these challenges can be overcome. While the 15-minute interval data records provided by the TDSPs were not 100% complete, missing values were limited, and reliable routines can be run to estimate missing values. The existence of multiple data channels on the advanced meters allows for cumulative reads over longer periods (e.g. 8 – 24 hours), which can be used to fill the gaps in an individual customer's 15-minute interval record.

2. **Deemed Savings or Stipulated Values for Use in ERCOT Settlement.** The process of estimating the demand reduction obtained through a demand response program requires a means of estimating and verifying the drop in power purchases resulting from a curtailment event. This information can be obtained by combining measured use according to advanced meters with estimation procedures (for the counterfactual – what would have been consumed absent a curtailment event), or stipulated values may be employed. Clearly, the use of actual metered data

---

4 The PUCT is making great strides in preparing the state to take full advantage of this opportunity through Project #34610, the Implementation Project Relating to Advanced Metering.
is the preferred approach. However, the metering equipment necessary to measure and verify curtailments is not yet fully available throughout ERCOT. In the OED and CEHE service areas, advanced metering systems will not be fully deployed on a service area basis for a number of years, and deployment in the AEP-Texas Central, AEP-Texas North, and Texas-New Mexico Power Company is presently being planned, with implementation yet to begin. Until these systems are deployed, an interim solution must be adopted. The approach that is presently permitted by the ERCOT Protocols to recognize the impacts of residential load control programs in the ERCOT settlement system – lagged dynamic sampling using representative interval data recorders – has proven too expensive to be viable. A much simpler reliance upon a set of deemed or stipulated "engineering estimates" was proposed in 2007, but failed to receive Commission endorsement. Consequently, there remains no effective means of recognizing the value of a load control program within the ERCOT settlement process.

3. **Establish a Preferred Method for Quantifying Savings.** Generally, two methods are used for estimating load shed during curtailment events: day-matching and regression. Each method has its advantages: day-matching techniques are conceptually simpler to understand and formulaic in their implementation, while regression analysis allows the effects of specific factors to be explicitly analyzed and provides results that are more extensible. For this Pilot, regression techniques were preferred.

For day-matching, three methods for establishing baseline consumption were compared, including those used by the New York ISO, ISO-New England, and PJM. In this project, while producing reasonable estimates of savings for some events, the three methods produced results that varied significantly by household; furthermore, the methods tended to underestimate the baseline, and in a significant percentage of cases, produced baseline estimates (the load for a given interval in the absence of a curtailment event) that were less than the observed curtailed load (implying increased usage during curtailment events). While day-matching methods are considered less complex than regression, the M&V contractor found that it took almost as much time to set up and implement the different methods as it did to set up and run regressions, particularly with respect to handling missing values in the raw data.

The best method for quantifying savings may depend on the purpose for which the estimate is being developed: day-matching is generally useful for quantifying savings for a single event, while regression methods are more useful when the purpose is also to predict savings for events called under different conditions, as those conditions can be modeled and their impacts on savings estimated. However, in this project we found little if any advantage to employing day-matching methods. Regression methods similar to those used for this project shall be specified as the preferred method for establishing savings for demand response events associated with future projects and pilots in Texas. Alternatively, if simpler baseline methods could be established that provide reliable estimates of baseline demand, then day-matching methods could also be employed for quantifying the savings from a single event.

4. **Promote “smart appliances” in Texas.** Increasing the numbers and types of appliances that are (for example) ZigBee- or HomePlug-enabled at the time of purchase or equipment installation shall provide curtailment services providers and the market with a larger base of loads that could potentially be curtailed through a program. This would improve the cost-effectiveness of demand response actions and could provide opportunities to achieve demand reductions during periods when air conditioners (the primary source of demand reduction in this pilot program) are not operated. Such technology would also improve the viability of real time pricing programs, as smart

---

5 While it is understandable that estimated baselines would occasionally underestimate household energy use for a given interval, and the ISO methods implemented in this pilot have methods for handling this outcome (such as simply rejecting estimates of negative savings), the incidence of negative savings observed in this pilot - around 50% - was simply too high to consider these methods reliable.
appliances could be programmed to shut off or power down in response to price signals using automated demand response (auto-DR) technologies.

There is a wide array of parties that should be interested in seeing more smart appliances installed in homes, ranging from the obvious – appliance manufacturers and retailers – to other stakeholders, including builders & contractors, energy service companies, consumers themselves, advocacy groups, and state government offices, such as the State Energy Conservation Office.

5. **Plan to Provide REPs and Curtailment Services Providers better information on market prices and appropriate times for deploying demand-side resources in the future.** When ERCOT transitions to a nodal wholesale market system, the advance notice of wholesale balancing energy prices that ERCOT presently provides will no longer be provided. Greater information about system conditions will be provided to the market, but there will be considerable uncertainty regarding how to translate this technical information into an estimate of the zonal locational marginal prices upon which energy consumers shall be settled and the benefits that would be realized from a curtailment. While participation in the Day Ahead Market would provide some price certainty, real-time locational marginal costs are expected to be more volatile than day-ahead prices and are likely to prove to be more-appropriate “triggers” for curtailment actions. Any steps that could be taken to provide advanced notice of wholesale prices would increase the effectiveness of demand response efforts.

6. **Expand Opportunities for Residential Demand Response, including both Direct Load Control and other customer choice-based strategies.** Residential direct load control programs are presently eligible to participate in the Emergency Interruptible Load Service (EILS) program, can participate in the energy efficiency programs offered by some of the transmission and distribution utilities, and can engage in voluntary load response (although there may be some difficulties in recognizing the impacts of such programs through ERCOT’s settlement process as noted elsewhere in this report). The ability of residential load control programs to provide an ancillary service, such as non-spinning reserves, is limited. True ancillary services must have telemetry (so that ERCOT can monitor the availability of the resource in near-real-time). In the future nodal market, there may also be difficulties in assigning these distributed resources to individual nodes in sufficient sizes (at least 0.1 MW) to be recognized by ERCOT’s operational systems. Refinements to ERCOT’s protocols may be necessary to introduce these types of programs into ERCOT’s ancillary services markets.

7. **Address the “Stranded Investment” Problem.** The PUCT Project #34610 is attempting to address a number of the issues related to stranded devices through establishment of business rules surrounding access to home area network (HAN) devices (Task 157). In particular, they are addressing the question of whether to provide information about customer owned devices to REPs besides the REP of Record, particularly when occupants move. However, there are additional challenges that will have to be addressed; if the original REP uses a certain set of equipment designed by a given technology provider, would another REP providing service at that address be able to communicate with the proprietary hardware installed at that location?

Many of these concerns may be addressed naturally through the continued development of standards, such as the ZigBee HomePlug Smart Energy Profile 2.0, which is to be deployed to advanced meters when it becomes available. As manufacturers begin making equipment designed to this protocol, portability should become much easier. Interoperability concerns may also be addressed via standards development, as 3rd party interoperability testing becomes part of the certification process for devices wishing to market themselves as ZigBee and/or HomePlug-enabled.

On a more fundamental level, the question of what information must be shared and whether REPs will lose assets when customers move out of homes must be addressed in such a way that the REPs have sufficient incentive to make the initial investment of installing the enabling technology in customers’ homes. However, information about the existence of those assets must be maintained.
by additional parties, and made available at appropriate times, to reduce the incidence of stranded assets.
Appendix A: Additional Information Pertaining to Control Technologies

For the Houston pilot, Comverge provided the programmable communicating thermostats and control switches that were installed in participating customers homes. Comverge also provided curtailment-enabling equipment in the Dallas pilot for TXU’s participating customers. Corporate Systems Engineering (CSE) provided the communicating thermostats and devices for the other REPs (Reliant and Direct Energy) in the Dallas pilot. This appendix includes information explaining in greater detail their respective roles in the project.

**Comverge**

**Thermostat Technology**
The Comverge SuperStat III is a ZigBee enabled programmable communicating thermostat (PCT) which is manufactured through a partnership between Comverge and White Rodgers. The thermostat is fully programmable either locally or over the Internet, supports a wide variety of system configurations, is a one-piece design for easy installation, and can be controlled by the utility company over an AMI network.

**CCET Pilot Control Event Dispatch Procedures**

*Source of curtailment signals*
Load control (or curtailment) signals were sent out by the participating REPs using a web based interface. The web interface allows the REPs to schedule events in advance and also provides tracking and reporting of events.

*Architecture of communications from dispatch to thermostat and back, including use of BPL and PLC networks, and additional devices (bridges, gateways) that had to be installed to create communication link between dispatch and thermostat*

The system architecture uses CEHE’s BPL network as the wide area network (WAN) for communicating with Itron cell relays in the field. The cell relays act as the “collector” and can communicate with up to 1,000 individual meters located at the customer’s home. The system also utilizes a “mesh network” whereby individual meters can communicate with each other and use this mesh as a path back to the cell relay. The meter management software platform, called the Itron Collection Engine, manages the communications with cell relays and individual meters and passes data back to a meter data management (MDM) system. Comverge’s load management software (LMS) communicates with the collection engine through a secure VPN tunnel. A system architecture diagram is shown in Figure 31.
In the Dallas market, Comverge provided TXU with ZigBee enabled thermostats (same units used in Houston) and an Ethernet-ZigBee gateway that allowed TXU to use a customer's high speed Internet connection as the communication path. In this configuration, control signals were sent from Comverge's LMS software to Digi's Connectware software (which manages the gateway devices) over the Internet to the gateway, and then the gateway communicated to the thermostat over the wireless ZigBee connection. A diagram is shown in Figure 32.
**Web portals for customers to access/modify their thermostat settings**

Comverge provided a web portal for customers to access and program their thermostats over the Internet. The web portal includes the following capabilities listed below. A screen shot is shown in Figure 33.

1. Secure log-in with user name and password assigned to each account
2. Programming of both cooling and heating for all periods
3. Vacation mode whereby customers could set a “hold” temperature for specific dates and times
4. Override capabilities for control events
5. The ability to change password on-line
Web portals for utilities to access participant information

Each of the REPs had access to a web based control portal for scheduling control events. The web portal includes the following capabilities listed below. A screen shot is shown in Figure 34.

1. Secure log-in with user name and password assigned to each REP
2. Ability to schedule control events in advance using on-line calendars and pull-down control strategies
3. System log showing all control events including type of control, date and duration of control, and number of devices that were controlled.
4. Ability to cancel or reschedule event if necessary
Timeline for installation and testing of equipment

Corporate Systems Engineering

Description of In-Home Technology Used

Thermostat
CSE/Aprilaire two way communicating thermostats with resident web access and dispatch control. The thermostats are installed along with a bridge at the air handler to provide the BPL communications via Current Group/Oncor. This allowed the standard 4 wires to the thermostat to be utilized. This provided easy at-the-wall thermostat upgrade. The Bridge is installed at the air handler to communicate via BPL to the head-end system and to the thermostat/load control receiver. Once each thermostat/LCR was installed, it was provisioned through Current to assign a private IP address to each device within Current’s BPL network. As soon as an IP address was assigned, the device was ready to participate in load control events and, in the case of a thermostat, be accessed by the homeowner via the Internet.
Downstream Communications (from BPL Network to Thermostat)

All communication is initiated in one of two ways - either a demand response event initiated from the dispatch application or thermostat query/set command directive from the homeowner via the internet. From the dispatch application, a set of thermostats and/or load control receivers (LCRs) are selected to receive the appropriate cycling strategies (LCRs) or temperature setback directives (thermostats). Once the appropriate commands for each type of device were selected from Dispatch, the commands were encoded.

From the thermostat web-portal, a homeowner would decide the changes to the settings they wished to make to their thermostat(s) and submitted the commands.

Figure 35. Sample CSE Customer Thermostat Web Interface

In either of the above cases, the commands were sent to a Command Processor at the Indianapolis (CSE) host site where they were further processed and validated. Once successfully validated, the device directives and the devices to be controlled were sent to the CSE POP (Point Of Presence) server in Dallas. The server was located within the Current BPL footprint and was required to give the dispatchers and homeowner access to the private IP addresses in the Current BPL network. Once at the POP server, the IP address of the device in question was looked up, a TCP/IP connection was established with the device and the commands passed through to affect the appropriate device in the desired way. Intelligence in both types of device allowed the device to then perform its desired function for the specified time with no further interaction from the Dispatcher/homeowner. Communication to the LCRs was one-way while communication to the thermostat was one-way from the Dispatcher’s viewpoint and two-way from the homeowner’s viewpoint.

CSE Load Control Switches with BPL enabled technology were chosen to control pool pumps, electric water heaters and AC units, where replacing the thermostat was not an option.

2-way communications – CSE thermostats were controlled over the Current Communication Network. The CSE equipment can send and receive real time data of the thermostats set points, space temperature, operational settings and seven day programmed features.

Dispatch

CSE designed and implemented a fully operational dispatch program for communications from dispatch through the BPL Network to the household, whereby the REPs can control demand response events from a designated authorized computer. This dispatch program allows the user to control any or all thermostats and devices installed and operating on the Current Network, and has the ability to receive
confirmation and status signals from the installed thermostats. The CSE Dispatch Software Program installed on the REPs’ computers gave them the ability to call and implement an event at any time; however, the REPs did not execute any events during the Pilot. For the Pilot, all events were initiated by CSE.

Figure 36. Load Control Dispatch Application

![Image of Load Control Dispatch Application](image)

Whether commands originated with the customer or were set using the dispatch application, they were sent to a Command Processor at CSE’s Indianapolis host site where they were further processed and validated. Once successfully validated, the device directives and the list of devices to be controlled (for a given curtailment event) were sent to the CSE Point Of Presence (POP) server in Dallas. The server was located within the Current BPL footprint and was required to give the Dispatchers and homeowner access to the Private IP addresses in the Current BPL network. Once at the POP server, the IP address of the device in question was looked up, a TCP/IP connection was established with the device, and the commands were passed through to affect the appropriate device in the desired way.
Figure 37. Downstream BPL Communications, CSE/Current Group

Figure 38. System Diagram – CSE System Architecture