Arnold Schwarzenegger
Governor

INTELLIGENT SOFTWARE AGENTS – EFFECTIVE INTEGRATION OF DISTRIBUTED ENERGY RESOURCES INTO THE CALIFORNIA ENERGY MARKETPLACE

PIER FINAL PROJECT REPORT

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program, initiated in 1998, supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program annually awards up to $62 million to conduct the most promising public interest energy research by partnering with research, development, and demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following 10 RD&D program areas:

- Buildings End-Use Energy Efficiency
- Climate Change Program
- Energy Innovations Small Grant Program
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Natural Gas Research
- Renewable Energy Technologies
- Transportation Research

What follows is the final report for the Demonstration of Intelligent Software Agents for Control and Scheduling of Distributed Energy Resources Project, Project: 500-00-016, conducted by Alternative Energy Systems Consulting, Incorporated.

The final report is titled "Intelligent Software Agents – Effective Integration of Distributed Energy Resources into the California Energy Marketplace." This project contributes to the Distributed Energy Resources Program in the Energy Systems Integration Program Area. For more information on the PIER Program, please visit the Commission's website at: http://www.energy.ca.gov/research/index.html or contact the Commission's Publications Unit at 916-654-5200.

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Abstract

Intelligent agent technology represents a fundamentally different way of addressing the distributed energy resources (DER) asset-scheduling problem. Use of intelligent agent technology provides for a distributed decision-making solution where centralized decision making processes are currently being applied. The overall goal of this project was to build on the success of an earlier project, which had shown agents as a viable solution for distributed energy resources scheduling. This subsequent effort provided for updating the product requirements to match the changed California energy market and then testing this new technology in a "real-world" environment.

During the project, the project team was able to:

- Develop and deploy a *Smart**DER™* agent-based control at the Calabasas Landfill.
- Integrate *Smart**DER operation with Connected Energy's commercially available gateway device.
- Demonstrate that agents are robust.
- Demonstrate that *Smart**DER generated operating schedules capable of responding to changing site conditions were able to achieve up to 40 percent more costs savings under either the existing time-of-use or the critical peak pricing electric tariffs.
- Show that *Smart**DER savings extend beyond critical peak pricing event days, providing value on a daily basis.

Ultimately this demonstration was very successful in showing how deployment of *Smart**DER can facilitate participation in emerging demand response programs such as critical peak pricing since *Smart**DER:

- <u>Automates site response</u> to the demand response signal while eliminating the need for daily and hourly monitoring of market or demand response signals by site staff.
- <u>Provides daily benefits</u> by continuously monitoring and predicting site energy use and maximizing the benefits of distributed energy resources asset use on a daily basis. The critical peak pricing event is just another input, not the only input for consideration.
- <u>Retains local control</u> of site distributed energy resources assets thus further facilitating customer acceptance and participation in demand response programs.

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Keywords: Distributed generation, smartgrid, agents, software agents, resource scheduling, intelligent software agents, control, dispatch, renewables, demand response, intelligent agents, dispatchable loads, curtailable loads, distributed energy resources, grid automation.

Executive Summary

The California Energy Commission (Commission) has long recognized both the need for and difficulty associated with integrating distributed energy resources into the California marketplace. Distributed energy resources (DER) include small generation (or distributed generation), storage and curtailable load assets where distributed generation (DG) are small generation assets (that is, renewables, microturbines, and so forth.) located at or near the point of use. The Commission began exploring the possible use of intelligent software agents for distributed energy resource scheduling in a Phase 1 project (PIER 500-98-040) that was concluded in March 2001. In this Phase 1 effort, Alternative Energy Systems Consulting, Inc. (AESC) successfully demonstrated the viability of using *Smart**DER™ intelligent software agents for distributed energy resource scheduling via simulation software. This project is a subsequent project that builds on the success of the Phase 1 effort. The primary objective of this subsequent project was to demonstrate in a real-world environment how distributed energy resource scheduling in response to market pricing or demand response signals can be accomplished using *Smart**DER intelligent software agent technology.

Background

The problem, simply stated, is that the vast majority of electric utility customers do not have the ability to respond to market signals. These market signals can be in the form of variable energy and demand charges or demand response signals that indicate an impending system problem. This inability to respond was identified as a fundamental flaw in the failed California electric utility industry "deregulation" experiment. Customers either didn't have the resources with which to respond, such as distributed generation or curtailable loads, or customers with these distributed energy resources did not have the ability to routinely monitor the relevant market signals and make the needed decisions.

Deregulation of the California electricity industry has since been replaced by a newly regulated market with a strong emphasis on customer demand response. Customer demand response has been identified by the California Public Utilities Commission (CPUC) as an important element in the newly regulated marketplace. Demand response programs provide financial incentives, typically in the form of special electric tariffs, to customers that modify their load (that is load curtailment, use of storage, local generation, and so forth.) when called upon by the electric utility. These programs have been mandated by the CPUC and implemented by the California utilities and have had trouble attracting participants. One such program, critical peak pricing provides for sharply increased energy rates during brief critical peak pricing periods to entice customers to reduce their site load. The reluctance of customers to participate in critical peak pricing and other demand response programs stems from the following:

- Other than very large customers with on-site personnel devoted to energy management, most customers do not have the local expertise to continuously deal with a dynamic decision-making environment.
- Customers without local staff can minimize the decision-making process by committing to a fixed response in advance. However, even a fixed response must be implemented, and customers have little incentive to install the needed equipment or personnel when the demand response signal comes so seldom (critical peak pricing is limited to a maximum of 15 events per year).

The Smart*DER Solution

*Smart**DER employs intelligent agent technology at the local site level to automatically maximize the benefits of distributed energy resources asset operation. Intelligent agent technology is a distributed decision-making approach in contrast to the centralized decision and control approach typically used in the energy industry. Distributed decision making process is inherently more robust and scalable since it eliminates dependence on a central control and avoids the communication bottlenecks that can occur when large numbers of sites are dispatched centrally.

The intelligent *Smart**DER agent is basically a piece of software code that operates continuously to determine how best to use the distributed energy resources assets. The software agent monitors local site loads and develops an internal load model for use in predicting site load on an hourly and daily basis. Local weather and relevant pricing signals (such as market prices) are automatically collected via the Internet and used along with basic user inputs (such as asset availability, site occupancy schedules, and so forth.) to develop daily distributed energy resources operating schedules. A demand response signal, if and when it comes in, is just another routine input that must be considered by the *Smart**DER agent when developing the schedule for that day or hour of operation. Thus *Smart**DER agent technology:

- <u>Automates site response</u> to the demand response signal while eliminating the need for daily and hourly monitoring of market or demand response signals by site staff.
- <u>Provides daily benefits</u> by continuously monitoring and predicting site energy use and maximizing the benefits of distributed energy resources asset use on a daily basis.
- <u>Retains local control</u> of site distributed energy resources assets thus further facilitating customer acceptance and participation in demand response programs.

The Calabasas Demonstration Site

The Calabasas landfill was selected for demonstration of *Smart**DER technology. The Calabasas landfill is operated by the Los Angeles County Sanitation District and is located north of Los Angeles in Calabasas. The landfill is served by Southern California Edison (SCE) under a conventional time-of-user electric tariff.

Figure 1. Calabasas Landfill - Microturbine Enclosures
Alternative Energy Systems Consulting Inc.

Since 2002 this landfill has operated 10 Capstone 30 kW microturbines (see Figure 1) using a small portion of the low-Btu gas that is generated as part of the landfill process. Los Angeles County Sanitation District contracts with a third-party operation and maintenance contractor to maintain and operate the microturbines as well as the flare system used to dispose of the remainder of the landfill gas.

The turbines are controlled via control software developed by the operation and maintenance contractor. This control software is comprised of a Wonderware® (commercial control software) user interface application that serves as a "front-end" to underlying ModBus® control software. As a landfill, the electric loads are limited to the parasitic loads associated with treating and compressing the landfill gas, minimal office loads (that is , lighting, and so forth.) and two 75 HP water pumps. Each microturbine has a nominal output capacity of 30 kW, which varies significantly with ambient temperature.

Additionally, Los Angeles County Sanitation District and SCE were participating in a U.S. DOE funded effort that involved installation and demonstration of a secure Web-based communications infrastructure (hardware and software) developed by Connected Energy Corporation (Connected Energy). Connected Energy's Internet capable gateway device, the *CENTRY*WCC™* could serve as the communications gateway for both the U.S. DOE and PIER projects. A demonstration project involving the use of the Calabasas

* Trademark of Connected Energy Corporation

landfill site was subsequently proposed and accepted by the Commission in October 2005.

Field Test Description

A feasibility field test plan was developed for the Calabasas site that called for operation of a *Smart**DER agency on a commercial grade personal computer located in an on-site enclosure. These agents would provide data analysis, data storage/access, and data collection functions. Access to *Smart**DER-generated schedules and site information would be accomplished via *Smart**DER Graphical User Interface software located remotely at Alternative Energy System Consulting Inc., Los Angeles County Sanitation District, and others. The Connected Energy gateway device would provide the *Smart**DER agency with site data as well as electric rate and weather information supplied by a server located at Connected Energy's offices. Site real-time data would be provided by the existing control via specialized software provided by the operation and maintenance contractor. SCE's critical peak pricing program uses an e-mail based notification. The e-mail message transmitted by SCE to notify customers of critical peak pricing events would be translated into hourly energy rates and provided via a Web service hosted by Infotility Incorporated. The Connected Energy server would collect weather along with the electric rate information and transmit this information to the site agency hourly using the secure communications infrastructure developed by Connected Energy under the existing U.S. DOE-sponsored project.

Field Test Results

Installation of AESC and Connected Energy equipment was completed in February 2006. Communication between the site and Alternative Energy System Consulting Inc's and Connected Energy's offices using Connected Energy's secure communications infrastructure was also confirmed at that time. The third-party software used to transmit real-time data from the existing Wonderware control was installed in April 2006, and the Web service providing the hourly electric rates became operational in May 2006. All of the "pieces" were therefore in place by the end of May 2006.

A number of issues/problems arose that hampered researchers' efforts to begin normal operation. These issues/problems included connectivity issues between the gateway device and the existing controls, cell modem (used for Internet connection) reliability problems, inconsistent content of critical peak pricing notifications, and unreliable transmittal of real-time site data from the existing control. The project team was able to resolve all of these issues with one exception. The operation and maintenance contractor was unable to establish reliable real-time transfer of site data from the existing control, which prevented normal operation of the *Smart**DER control.

It was for this reason that the Commission contract manager agreed to modify the field test to allow use of the archived site data. To preserve the integrity of the demonstration the operation and maintenance contractor provided these data to Connected Energy personnel, who then "streamed" the data to a *Smart**DER agency in the same manner as would have occurred during normal operation. The *Smart**DER agency then processed and stored the data into 15 minute records. During normal operation each day of data would have been processed and schedules generated over a 24-hour period. To accelerate this process, special routines were developed that caused the agency to develop a single "day-end" schedule using the stored data along with the weather and electric rate information already collected and processed during the summer. In this way, the *Smart**DER agency was able to process all of the available data and generate suggested operating schedules for the period spanning June 1, 2006, to September 13, 2006.

Smart*DER Schedule Performance

During normal operation the user has the ability to update critical inputs using the *Smart**DER GUI. These input data are then used by the *Smart**DER agency to adjust the operating schedules accordingly. This ability to automatically adjust to changing conditions is an important and powerful feature of the *Smart**DER approach. Compare this flexible approach with the existing control, which employs a fixed operating strategy to minimize or eliminate site load during all hours of the day.

To demonstrate the benefits of this flexibility, the data were processed using four user input configurations. The *Smart**DER graphical user interface was used to specify two levels of microturbine operating costs and two different electric tariffs. The two electric tariffs selected represent the time-of-use tariff currently in effect at the site and the associated critical peak pricing tariff (GS2-TOU-CPPV1). Microturbine operating cost values were selected based on feedback from Los Angeles County Sanitation District. The lower value, $0.40 per hour of operation, corresponds to the operating costs when the microturbines were initially installed and covered by manufacturer's warranties. The higher value, $1.90 per hour of operation is the more current operating cost. Using these input variations we were able to explore how *Smart**DER operation, would compare against the existing control using both the critical peak pricing tariff as well as the time-of-use-tariff currently in effect at the site. In both cases the researchers were also able to observe how changes to unit operating costs affected scheduled operation and overall savings.

Critical Peak Pricing (CPP) Electric Tariff

A total of 11 critical peak pricing events occurred during the test period. Critical peak pricing events began at either 12 noon or at 3 p.m. and lasted from 2 – 5 hours. The maximum energy rate occurring on non-event days was $0.132 / kilowatt-hr and occurred during the on-peak period. The minimum rate is $0.0374 per kilowatt-hr, which occurs during all other hours. On critical peak pricing event days the energy rate increases to $0.769 per kilowatt-hr beginning at the designated time and lasting the prescribed number of hours. The critical peak pricing tariff employs a non-coincident demand charge that is not dependent on the time of day.

As noted previously the existing control attempts to minimize site demand during all periods of the day without regard to cost. This strategy resulted in base-loading of all operational microturbines during the test period. The *Smart**DER provided very similar results when the operating costs are set to the lower value of $0.40 per hour of operation. The distributed generation operating hours, associated costs and savings were essentially the same for both the *Smart**DER and existing controls. The *Smart**DER based control was able to achieve an additional 8 percent or $1,289 of savings by curtailing load during critical peak pricing events. Note that unit outages on July 10 and on August 23 reduced the possible critical peak pricing-related savings since these outages coincided with critical peak pricing event days.

The difference between the two control strategies becomes more pronounced with increased distributed generation operating costs. Increasing the distributed generation operating costs to the higher $1.9-per-hour value causes the *Smart**DER control to drastically reduce the distributed generation operating hours to less than 30 percent of the previous value. In this case the high operating costs makes operation of the microturbines during off-peak hours uneconomical unless a demand reduction can be achieved. The existing control, with its static operating strategy, was unable to achieve a net savings during the test period whereas the *Smart**DER control was able to achieve overall savings during all three months, representing a $10,000 increase in overall savings. It is interesting to note that the demand savings achieved by both the existing and *Smart**DER controls were the same even though the *Smart**DER control operated the microturbines far fewer hours.

Figures 2 and 3 show *Smart**DER graphical user interface screen shots displaying the gross and net site load on July 3, 2006, with both the existing (actual) and *Smart**DER control (planned). The existing control minimizes the site net load to near zero during off-peak hours. The net site load under *Smart**DER control is significantly higher during the same period (Figure 3). However note that the daytime peak demand under both control strategies remains the same and is in excess of 125 kW. The *Smart**DER control correctly deduced that it was not cost-effective to maintain off-peak site electric demand below daytime levels. Instead, the *Smart**DER control maintains a more constant site load.

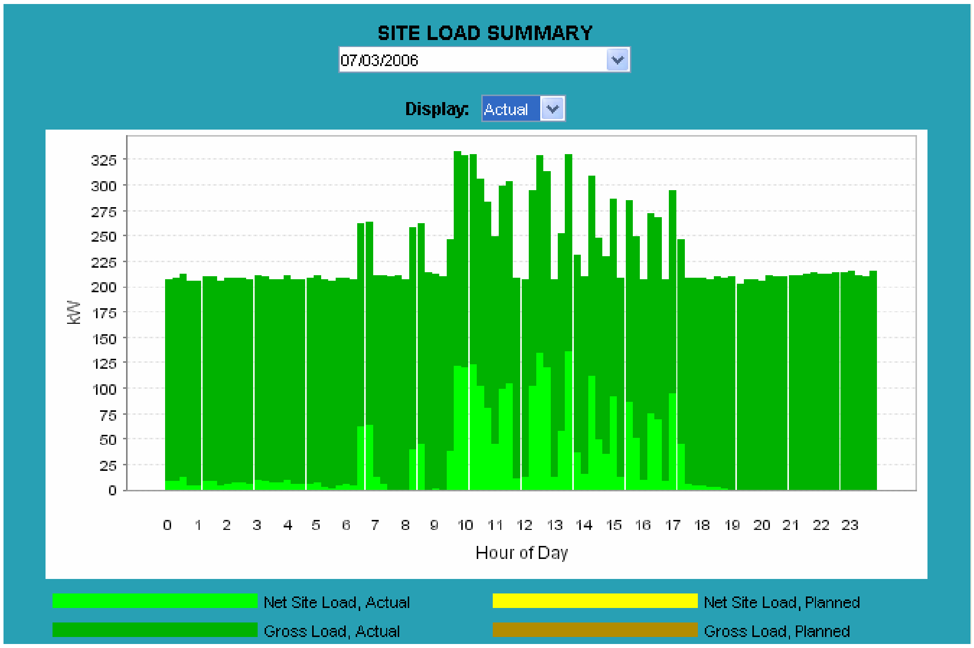

Figure 2. Site load for 7/3/06 using the existing control

Alternative Energy Systems Consulting Inc.

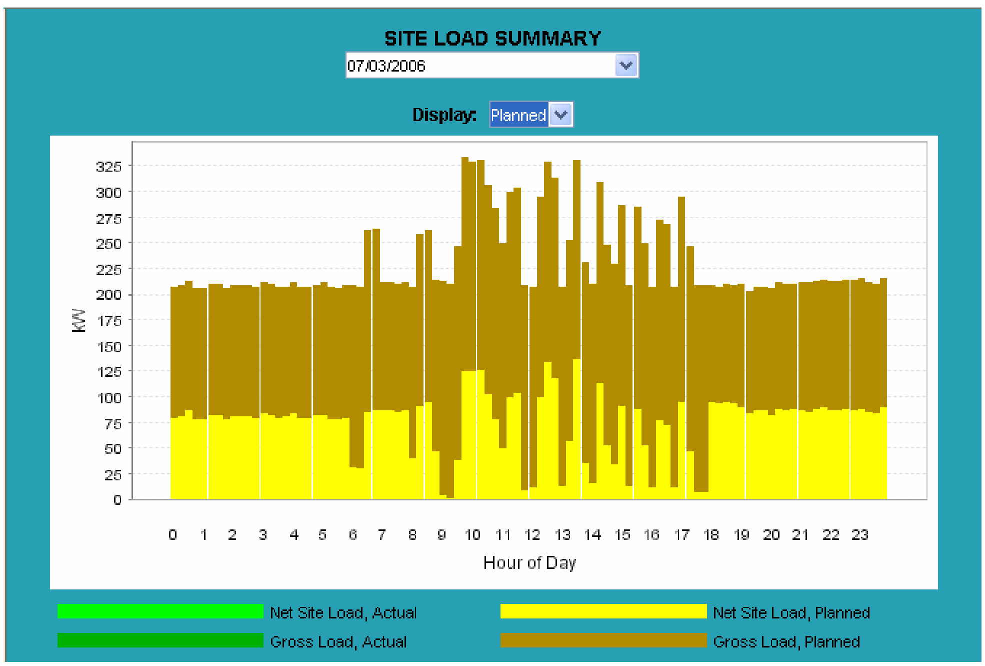

Figure 3. Site load for 7/3/06 using *SmartDER**

Alternative Energy Systems Consulting Inc.

Time of Use (TOU) Electric Tariff

A time-of-use tariff was in use at the Calabasas site during the test period. Unlike the critical peak pricing tariff, which does not have a time-related demand charge, the time-of-use tariff is a conventional time-of-use tariff with three billing demand periods: on-peak, mid-peak, and off-peak. Compared to the critical peak pricing tariff, the conventional tariff has higher energy charges during all periods when compared with non-critical peak pricing event rates but has lower overall demand charges.

*Smart**DER schedule performance when operating under the conventional time-of-use tariff was similar to the critical peak pricing results in that the existing and *Smart**DER controls achieved very similar results when the lower operating cost was used. As with the critical peak pricing tariff results *Smart**DER control achieved the same or higher overall savings under all scenarios. As expected, increasing the distributed generation operating costs caused the *Smart**DER control to reduce microturbine operating hours. Overall, the *Smart**DER control achieved $3,917 or 40 percent greater overall savings during the test period.

Field Test Accomplishments

While an inability to transmit complete real-time site data to the *Smart**DER agency prevented the system from becoming fully functional, the project team was still able to successfully demonstrate the various *Smart**DER control elements. Specifically the project team was able to:

- Demonstrate that agents are robust; the agents operated continuously during the test period. The agents automatically restarted and resumed activities when the system was shutdown (simulating site power failure).
- Develop and deploy a *Smart**DER agent/agency with Connected Energy's commercially available gateway device.
- Demonstrate that *Smart**DER generated operating schedules capable of responding to changing site conditions (that is , unit outages, changing operating costs, billing demands, and so forth.), were able to achieve up to 40 percent more costs savings relative to the existing control under either time-of-use or critical peak pricing electric tariffs.
- Show that *Smart**DER savings extend beyond critical peak pricing event days providing value on a daily basis.

The *Smart**DER approach is inherently compatible with a variety of potential dynamic tariffs since it does not respond to a program specific trigger/notification. Instead the *Smart**DER agency evaluates hourly rates along with site data and customer inputs to develop the appropriate response. Thus the *Smart**DER approach involves routine evaluation of hourly rates and site conditions to develop operating schedules. It is not a fixed response to an "event notification" signal but rather an intelligent response to changing site conditions. This approach makes *Smart**DER readily compatible with other, potentially more complex dynamic tariffs/programs such as real-time-pricing (RTP) and customer demand bidding (CDB). For instance, only minor user interface modifications would be needed to enable system operation under an hourly pricing tariff such as real-time-pricing. Contrast this with the existing control that employs inflexible control software requiring modification to implement any changes.

Ultimately this demonstration was very successful in showing how deployment of *Smart**DER can facilitate participation in emerging demand response (DR) programs such as critical peak pricing since *Smart**DER:

- Automates site response to the demand response signal while eliminating the need for daily and hourly monitoring of market or demand response signals by site staff.
- Provides daily benefits by continuously monitoring and predicting site energy use and maximizing the benefits of distributed energy resources asset use daily. The critical peak pricing event is just another input, not the only input for consideration.
- Retains local control of site distributed energy resource assets thus further facilitating customer acceptance and participation in demand response programs.

Alternative Energy Systems Consulting Inc., working with the Environmental Business Cluster of San Jose University State developed a *Smart**DER commercialization plan. Alternative Energy Systems Consulting Inc. is moving forward with commercialization of this important technology and is actively looking for commercialization opportunities.

1.0 Introduction

The California Energy Commission (Energy Commission) has long recognized both the need for, and difficulty associated with integrating distributed energy resources into the California marketplace. The primary objective of this project was to demonstrate how scheduling of these disparate resources in response to market pricing or demand response signals can be accomplished using a *Smart**DER™ intelligent software agent technology.

1.1. The Problem

The problem, is that the vast majority of electric utility customers do not have the ability to respond to market signals. These market signals can be in the form of variable energy rates or demand charges (real-time pricing, customer demand bidding, critical peak pricing) or demand response signals (CAISO alerts and emergency notifications)that indicate an impending system problem. This inability to respond was identified as a fundamental flaw in the failed California electric utility industry "deregulation" experiment. Customers either didn't have the resources with which to respond, such as distributed generation (that is , renewables, microturbines) storage or curtailable loads or customers with these distributed energy resources did not have the ability to routinely monitor the relevant market signals and make the needed decisions. Deregulation of the California electricity industry has since been replaced by a newly regulated market with a strong emphasis on customer demand response programs. Demand response programs provide financial incentives, typically in the form of special electric tariffs, to customers that modify their load (load curtailment, use of storage, local generation) when called upon by the electric utility.

Customer demand response has been identified by the California Public Utilities Commission (CPUC) as an important element in the newly regulated marketplace. Demand response programs, mandated by the CPUC and implemented by the California utilities have had trouble attracting participants. One such program, Critical Peak Pricing (CPP) provides day-ahead notification of sharply increased energy rates during brief CPP periods in order to entice customers to shed load and/or increase local generation. In exchange for agreeing to CPP, customers receive a more favorable rate during non-CPP periods. Customer response to this program has been virtually non-existent forcing the CPUC to push for mandatory participation. Other programs that involve aggregation of loads or generators for demand response purposes have experienced varying but similar results.

The reluctance of customers to participate in demand response programs stems from the following:

- Other than very large customers with on-site personnel devoted to energy management, most customers do not have the local expertise to deal with a dynamic decision making environment. Somebody or something has to respond

- Customers without local staff can minimize the decision process by committing to a fixed response in advance. However, even a fixed response must be implemented and customers have little incentive to install the needed equipment or staff when the demand response signal comes so seldom (CPP is limited to 15 times per year maximum). Why install equipment or train staff to respond to a signal that may never, or seldom comes?
- Customers are reluctant or unwilling to cede control of a local asset to a third-party aggregator since the third-party aggregator doesn't have any responsibility for the local impacts and therefore won't account for the local impact when deciding how to operate the local DER asset. Customers that do decide to participate often utilize assets that have little to no impact on their daily operation, thus limiting the potential market response.

1.2. The *Smart**DER Solution

*Smart**DER employs intelligent agent technology at the local site level to maximize the benefits of DER asset operation. Intelligent agent technology is a distributed decision making approach in contrast to the centralized decision and control approach typically used in the energy industry. The Distributed decision making process is inherently more robust and scalable since it eliminates dependency on a central control and avoids the communication bottlenecks that can occur when large numbers of sites are dispatched centrally.

The intelligent *Smart**DER agent is essentially a piece of software code that operates continuously to determine how best to utilize the DER assets. The software agent monitors local site loads and develops an internal load model for predicting site load on an hourly and daily basis. Local weather and relevant pricing signals (such as market prices) are automatically collected via Internet and used in conjunction with basic user inputs (such as asset availability, site occupancy schedules) to develop daily DER operating schedules. A demand response signal, upon arrival, is just another routine input that must be considered by the *Smart**DER agent when developing the schedule for that day or hour of operation. Thus *Smart**DER agent technology:

- <u>Automates site response</u> to the demand response signal while eliminating the need for daily and hourly monitoring of market or demand response signals by site staff.
- <u>Provides daily benefits</u> by continuously monitoring and predicting site energy use and maximizing the benefits of DER asset use on a daily basis. For instance, the *Smart**DER agent(s) may determine that temporary load curtailment or increased local generation, even in the absence of a demand response signal, can achieve significant cost savings by minimizing or eliminating the monthly peak demand charge (if applicable).

- Retains local control of site DER assets thus further facilitating customer acceptance and participation in demand response programs.

1.3. Agent Technology

At its most basic level, an "agent" is simply an entity that acts on behalf of its user. More specifically, a "software agent" is a software construct that can act on behalf of the user. Of course, under this definition virtually any software program that performs a useful function could conceivably be cast as a "software agent". Thus the definition must be refined further to include critical functionality. For purposes of this discussion it is assumed that an intelligent software agent:

- Executes autonomously & operates in real-time
- Communicates with other agents or users
- Is able to exploit domain knowledge
- Exhibits goal-oriented behavior

Software agents can be used in a wide variety of applications. An intelligent software agent can contain significant amounts of expertise and can be applied in systems requiring planning or learning capabilities. One popular use of agents is information seeking and cataloging on the Internet. Agents can be used in applications where they learn about an individual user and modify their own behavior to suit the information-seeking needs of the user. Agents are also useful in applications where multiple agents can communicate and cooperate with other agents for solving a given problem. They can be physically located on the same computer or distributed in a variety of locations.

Multiple agents operating in conjunction, as an agency, can achieve goals/objectives that would not be otherwise achievable by a single agent. Use of intelligent software agents with their ability to communicate and collaborate thus distributing the decision process, is well-suited to the task of scheduling and coordinating the activities of large numbers of DER assets. Use of agents in this fashion reduces the level of expertise needed to own and operate distributed energy resources, which in turn, allows greater participation by owners of distributed energy resources in California's competitive energy industry.

1.4. PIER Project History

This project is a follow-on project to a highly successful Phase 1 effort (PIER 500-98-040) that demonstrated the basic viability of the intelligent agent based scheduling approach. The Phase I effort, which officially began in May1999, confirmed the functionality of the various agents while operating in response to pricing and weather conditions for dates in 1999. Single and multiple agency testing confirmed that *Smart**DER agents, acting on behalf of individual sites could collaborate via Internet-based communications to schedule DER asset operation. Testing indicated that *Smart**DER operation enabled sites with excess generating capacity to collaborate for purposes of aggregating this capacity and subsequently participating in the Ancillary Services markets operated by the California Independent System Operator (California ISO). Essentially, testing showed that *Smart**DER technology could bring generating capacity to the California marketplace that would not otherwise have been able to participate. AESC demonstrated the *Smart**DER intelligent agent software at the Energy Commission's Sacramento offices on March 13, 2001.

The Phase I project successfully moved this technology to a Stage 3 (Bench testing/proof of concept) level of development. In 1998, when the Phase I project was first proposed there were four basic avenues for DER interaction in the deregulated marketplace. First, DER assets could be used to offset site loads to provide cost savings associated with utility bill reduction. Secondly, DER assets could be used in conjunction with electric utility sponsored interruptible rates. Third, DER assets, if aggregated in sufficient numbers, could bid into the energy spot market run by the California Power Exchange (CalPX). And fourth, aggregated DER assets could participate in the AS markets operated by the California ISO. By the end of the project, in 2001 the California marketplace had changed dramatically.

The elimination of the CalPX and "re-regulation" of the market eliminated the need for direct market interaction of DER assets but did not diminish the importance of DER. Use of demand response and distributed generation to help meet California's growing need for energy has continued to gain regulatory acceptance to the extent that the resource loading order established in 2003 elevated these resources (along with renewables and energy efficiency) above use of fossil-fired generation. There is little question that integration of DER assets into the marketplace, the overriding premise behind this PIER project, continues to be of paramount importance.

1.5. Project Objectives

Intelligent agent technology represents a fundamentally different way of addressing the DER asset-scheduling problem. Use of intelligent agent technology provides for a distributed decision-making solution where centralized decision making processes are currently being applied. This fundamental shift in thinking makes the job of transferring this technology into the private sector more challenging since it requires that potential users change the way that they view the problem, and solution.

The overall goal of this follow-on effort was to build on the success of the preceding project in such a way as to facilitate market acceptance of the agent based approach. Updating the product requirements to match the changed California energy market and then testing this new technology in a "real-world" environment to schedule and control DER assets (for example, distributed generation, curtailable loads, and so forth.) were identified as the key project objectives. The technical performance objectives of this project that support these overall objectives were to:

1. Update the *Smart**DER product specification based on feedback received during the Phase I effort as well as changes that have occurred in the California energy marketplace.

2. Identify and enlist participation by one or more potential commercialization partners that will integrate *Smart**DER into their technology for field test.
3. Refine *Smart**DER technology to reflect changes in the product specification and to provide interfaces with field tested software/products.
4. Complete a successful feasibility test assessment of *Smart**DER technology scheduling/controlling DER assets in the "real world" California marketplace.

2.0 Project Approach

The project approach can be divided into three basic task areas. Two areas, Project Start-up Tasks and Project Reporting Task pertain to the project management and reporting efforts required of all PIER projects while the third area, technical tasks deals with the effort to develop and test the *Smart**DER agent based technology.

2.1. Project Technical Tasks

2.1.1. Task 2.1 Update Smart*DER Product Requirements

During the Phase 1 effort we enlisted the support of a virtual evaluation group of individuals and companies working in the energy industry. At the end of the Phase I effort this group was given the opportunity to review and use the demonstration software that was developed during the Phase 1 effort. The purpose of this task was to collect and summarize feedback on the software as well as update *Smart**DER product requirements to reflect changes in the California marketplace that had occurred since the Phase 1 project inception in 1998.

Technical transfer activities that promoted agent technology in the energy industry were also included in this task. These efforts included:

- Contractor support for the *Smart**DER website (www.SmartDER.com).
- Providing the *Smart**DER demonstration software by potential end-users or potential commercialization partners.
- Supporting use of the *Smart**DER demonstration software by potential end-users or potential commercialization partners.
- Summarizing activities associated with *Smart**DER demonstration software in the project Monthly Progress Reports.
- Presenting *Smart**DER technology at two nationally recognized relevant energy industry conferences.

2.1.2. Task 2.2 Prepare a Test Plan for the Feasibility Field Test

The purpose of this project task was to define and document the Feasibility Field test requirements including:

- Field test objectives,
- Field test participant requirements,
- Field test site requirements, and
- Data collection requirements.

A draft and final test plan documents were the task deliverables, which were reviewed and discussed as part of both the 1st and 2nd Critical Project reviews.

2.1.3. Task 2.3 Enlist Field Test Participation

The purpose of this task was to engage potential field test participants and enlist their participation. The following activities are included in this task:

- Identify potential field test participants using the field test participant characteristics identified in 2.1.
- Contact potential field test participants to enlist participation.
- Work with field test participants to identify test sites that meet the field test site requirements.

2.1.4. Task 2.4 Technology Refinement & Integration

The purpose of this task was to refine the *Smart**DER software in preparation for integration and field testing. This effort required modification of both the *Smart**DER software (by AESC) and modification of third-party software in order to integrate *Smart**DER agent technology with communications infrastructure software and energy management system (EMS) or remote terminal unit (RTU) equipment employed at the demonstration field test site.

2.1.5. Task 2.5 Feasibility Field Test for Scheduling of DER Assets

The purpose of this task was to conduct a 9-12 month Feasibility Field Test of *Smart**DER technology operating at one or more sites to schedule DER assets in a "real-world" dynamic environment. This task included:

Installation and Start-up Activities

- Work with the Field Test Participant to install *Smart**DER software and associated hardware at the Field Test Site.
- Conduct on-site integration testing in conjunction to confirm that site systems, the *Smart**DER software and communication equipment are operating properly.
- Observe *Smart**DER software operation for a one-week start-up period to insure proper operation.
- Confirm that data gathering and processing is functioning to insure that field test objectives can be met.

Field Test Monitoring and Data Collection

During the field test the following activities were planned:

- Monitor and support *Smart**DER operations at the Field Test Site(s),
- Collect and process data from the test site for the duration of the test period,
- Describe and summarize operations in the Monthly Progress Report.
- Analyze the data taken during the field test and include the analysis and the results in the Final Report.

2.1.6. Task 3.4 Business Plan Development

To facilitate transference of *Smart**DER technology into the marketplace AESC was tasked with development of a business plan. AESC was to work closely with the Environmental Business Cluster Group of San Jose State to formalize a plan for market utilization of *Smart**DER agent technology. The resulting business plan would be summarized for the Commission Contract Manager during the Final Meeting.

3.0 Results

Project results are summarized by task in the following subsections.

3.1. Update *Smart**DER Product Requirements

Changes in the California energy marketplace since the inception of the original Phase 1 effort necessitated a rethinking of how these changes impacted the utility of *Smart**DER technology. The California energy landscape has changed significantly since the *Smart**DER product requirements were established in 1999. The most significant events affecting the marketplace since that time include:

- Financial insolvency of major California utilities and subsequent emergence of the California Department of Water Resources (CDWR) as the energy purchaser for California IOUs,
- Elimination of the CalPX and the energy spot market,
- CPUC reversal of direct access in California, and
- Creation of state sponsored programs emphasizing energy conservation and demand side management.

These events eliminated some California market opportunities for application of *Smart**DER agent technology while at the same time creating new market players and associated opportunities.

To briefly summarize, the original need for aggregation of distributed generation units to facilitate their participation in deregulated markets such as the California ISO ancillary services market was no longer relevant. While this potential application was no longer a viable application the emergence of demand response programs such as Critical Peak Pricing and dynamic bidding programs such as the Customer Demand Bidding (CDB) program offered by the investor-owned utilities appeared to provide alternative applications for *Smart**DER technology. In addition, load shaping across multiple facilities in a campus environment (multiple buildings served by a single utility meter) in response to a conventional time-of-use electric tariff also appeared to be a viable application for agent technology. The usefulness of scheduling curtailable loads in addition to DG was reiterated in that curtailable loads had always been identified as a distributed energy resource (DER) that should be integrated with DG operation.

Based on marketplace changes as well as well as feedback received from market participants it was concluded that a number of changes and refinements were needed to the *Smart**DER product requirements. The results of this task were summarized in the ***Smart**DER Product Requirements Update** document (issued November 2001) with the most significant changes briefly described in Table 1. It is important to note that a number of product requirements are site and application specific and product requirements therefore continued to be reviewed and modified during the course of the project.

Table 1. Updated *SmartDER Product Requirements**

Requirement Area	Description
DER Asset Scheduling	• Scheduling algorithms should be updated to accommodate requirements of DR programs such as Critical Peak Pricing or Customer Demand Bidding (CDB) programs administered by utilities in their individual service territories. • Future *Smart**DER scheduling algorithms should be refined to include additional inputs related to unit emissions. The scheduling algorithm must consider both the financial and the operational constraints associated with unit air emissions.
Forecasting / Prediction	***Site Load Prediction*** • For applications where the primary objective is to reduce site utility costs and DER assets such as curtailable loads or unconstrained DG assets are involved then the site load prediction time horizon should coincide with the applicable site billing period or approximately one month in most cases. • *Smart**DER equipped sites that participate in a utility administered CDB or other DR programs should calculate and forecast site load using the same methodology used by the applicable utility program (moving average approach used by these programs).
	Relevant Market Pricing • Forecasting of California energy spot market and AS prices has been eliminated.
Graphical User Interface	• Update inputs to include currently relevant markets (TOU, CPP) and remove inputs for programs not currently in use (CalPX). • Add screens for display of relevant market prices and add pull-downs for specific utility electric tariffs. • Modify GUI screens to increase the number and types of inputs (costs, operating constraints) associated with curtailable loads • Enable operation of multiple GUI's in conjunction with a single site agency. This will allow multiple interested parties to view site activities.

Table 1 continued. Updated *SmartDER Product Requirements**

Requirement Area	Description
Data Storage / Retrieval	• Integration of *Smart**DER technology with third party commercialization partner software or integration with existing legacy systems will require that other databases eventually be accommodated (SQL Server, Oracle, DB2, MySQL, and others).

Communications	• Provisions for CalPX and CAISO communications were eliminated. • Internet based communication with utility administered demand response programs should be accommodated, • Secure communications routines that employ authentication and encryption should be implemented, and • Additional data transfer protocols such as XML should be supported.
Hardware / Platform Requirements	• No changes to the basic hardware requirements. • Individual agents operating on a variety of platforms should be supported.

3.1.1. Tech Transfer Activities

Technical transfer activities that promoted agent technology in the energy industry were also included in this task. During the course of the project we maintained the *Smart**DER website (www.smartder.com) and presented papers at, nine technical conferences and attended workshops (see Table 2).

3.2. Enlist Field Test Participation

Efforts to enlist field test participation began shortly after the start of the project in August 2001. Early efforts were directly intended to educate the energy industry on agent technology and its potential benefits. The technical transfer activities, specifically presentations at workshops and conferences that occurred in 2001 and 2002 were part of this educational effort. While workshop attendance and presentation of the agent technology educational materials was successful in sparking interest, a demonstration site was not implemented in this early effort.

Table 2. Technical Conference/Workshop Attendance

Conference/Workshop Name	Sponsor	Date	Presenter ?
International Distributed Power Conference	InterTech	September 2001	X
POWER-GEN International	Power Engineering	December 2001	X
Microgrid Workshop	CERTS	May 2002	
ASHRAE Annual Conference	ASHRAE	June 2002	X
CADER-USCHPA Annual Conference	CADER	November 2002	X
FY '04 Annual Program and Peer Review Meeting	DOE-EDT	October 2003	X
Collaborative DER Pilot Project Stakeholder Workshop	E2I	October 2004	
FY '05 Annual Program and Peer Review Meeting	DOE-EDT	April 2005	
San Diego Smart Grid Summit	EPIC	October 2006	

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In addition to the educational or indirect approach to enlist participation two ways of enlisting were implemented . First, companies or organizations with access to, or knowledge of potential demonstration sites were targeted. This group included electric utilities, research organizations, energy service companies and energy equipment providers. A secondary objective of contacting this first group was also to identify potential commercialization partners for *Smart**DER technology. Secondly, companies or organizations that consisted of site owners or operators who could benefit directly from use of *Smart**DER technology at their sites were targeted.

The California energy industry was experiencing significant changes during this time. Uncertainty in the marketplace hampered the initial efforts at locating a demonstration site. It is difficult to promote the use of a technology that facilitates the local decision making process when it is no longer clear what decisions are necessary. The uncertainty in California and lack of a dynamic market in which to participate necessitated that the search effort for the demonstration website should be broader.

Two potential demonstrations were subsequently proposed and then rejected. The first involved multiple sites in the vicinity of Fort Collins, Colorado. The local municipal utility employed an electric tariff that involved a dynamic demand charge. This tariff provided for a single monthly peak demand charge that occurred on the hour coinciding with the peak monthly load of the municipality. The specific date and time of this peak load was determined at the end of each month and customer's bills were adjusted accordingly. The regional energy supplier, Platte River Power Authority (PRPA) employed a prediction algorithm that was effective in predicting this monthly peak on a day-ahead basis, which accessible via the Internet. The proposed demonstration provided for *Smart**DER automated retrieval and processing of weather forecast and PRPA load forecast data with S*mart**DER generating day-ahead and hour-ahead operating schedules to minimize potential demand charges. We were able to solicit the support of the Fort Collins municipal utility as well as engage the local university (Colorado State University) as both a potential demonstration site and as a provider of on-site local support. The proposed demonstration was rejected by the Commission because the electric tariff, while dynamic, was removed too far from tariffs likely to be employed in California.

A second demonstration was subsequently identified. This demonstration involved *Smart**DER control of a 30 kW Capstone microturbine located on the campus of the California Polytechnic Institute in San Luis Obispo. This microturbine was fueled by biogas generated at the university's dairy education facility. Biogas, generated in a covered pond located adjacent to the facility fueled the microturbine. The amount of available gas varied based on a variety of factors with total daily gas production insufficient to support continuous microturbine operation.

The proposed demonstration involved *Smart**DER retrieval of local weather forecast information and monitoring of the electric load of the education facility. *Smart**DER would then analyze the potential cost savings of running the microturbine during different times of the day to offset site load and then generate daily operating schedules maximizing the economic benefit of microturbine operation using the limited fuel supply. The *Smart**DER generated operating schedules would provide savings based on the conventional TOU tariff in use at the university. Additionally, testing was proposed to assess the ability of *Smart**DER to generate savings under the Critical Peak Pricing tariff that was being proposed for implementation in California. The proposed demonstration was rejected by the Commission based on the belief that the potential application involving biogas fueled microturbines did not apply to a sufficiently large market in California.

In May 2004 the Commission directed AESC to focus the demonstration site search on commercial or industrial sites with access to the newly emerging CPP tariff. During the site enlistment effort a large number of contacts were made and pursued. Table 3 summarizes the most significant of the organizations that were contacted. Many of the organizations listed were contacted multiple times during the course of the project as conditions within the organization or conditions in the California energy industry changed.

In July 2005 AESC personnel met with representatives of the Los Angeles County Sanitation district to discuss their potential participation in the CEC-PIER demonstration project. The Calabasas landfill is operated by the LA County Sanitation District (LACSD) and is located north of Los Angeles in Calabasas. Since 2002 this landfill has operated ten Capstone 30 kW microturbines (see Figure 4) using a portion of the low-BTU gas that is generated as part of the landfill process. A third-party O&M contractor is under contract to LACSD to maintain and operate the microturbines as well as the flare system used to dispose of the remainder of the landfill gas.

Table 3. Field Test Participant Meetings and Significant Contacts

Organization Name
Air Quality Management District (AQMD)
California Department of Water Resources (CDWR)
California Polytechnic Institute, San Luis Obispo
California State University, Dominguez Hills
California State University, Long Beach
California State University, Northridge
City of Fort Collins, Colorado
CMS Viron
Colorado State University, Boulder
Connected Energy Corporation
East Bay Municipal Utility District (EBMUD)
Encorp Inc.
Enflex Inc.
Engage Networks, Inc.
Envenergy Inc.
Electric Power Research Institute (EPRI)
Lawrence Berkeley National Laboratory (LBNL)
Los Angeles County Sanitation District (LACSD)
Pacific Gas & Electric (PG&E)
PurEnergy LLC
San Diego Gas & Electric (SDG&E0
Siemens Building Technologies, Inc.
Sixth Dimension Inc.
Solar Turbines Inc.
Sonoma State University
Southern California Edison (SCE)
University of California, Irvine (UCI)
University of California, San Diego (UCSD)

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The turbines are controlled via a control comprised of Wonderware (commercial control software) application that serves as a "front-end" to underlying ModBus control software. As a landfill, the electric loads are limited to the parasitic loads associated with treating and compressing the landfill gas (Figure 5), minimal office loads (i.e., lighting, etc.) and two 75 HP water pumps (Figure 6) that operate during the day to irrigate the hillsides within the landfill property. Each microturbine has an output capacity of 30 kW, which varies significantly with ambient temperature. Typically the microturbine output is capable of meeting or exceeding the site load.

Figure 4. Microturbine Enclosures
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Figure 5. Gas Treatment Skid

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Figure 6. Irrigation Pumps

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LACSD has the ability to export excess power to the local electric utility, Southern California Edison (SCE) but does not receive any compensation for doing so. LACSD perceived that the control strategy employed by the O&M contractor did not adequately match site load and generation resulting in periods when the site is purchasing electricity that it could otherwise generate on-site and periods when the microturbine output is being exported to the grid (with no compensation). LACSD expressed an interest in using *Smart**DER agent technology to investigate how locally intelligent agents could be used to match site generation to load as a means of minimizing electricity purchases and reducing periods of uncompensated power export. While providing this benefit on a daily basis, the agents would also be available to formulate a response to an incoming demand response signal such as that provided by the SCE CPP program.

Additionally, LACSD and SCE were participating in a DOE funded effort that involved installation and demonstration of a secure web-based communications infrastructure (hardware and software) developed by Connected Energy Corporation (Connected Energy). Connected Energy's Internet capable gateway device could serve as the communications gateway for both the DOE and CEC-PIER projects. A demonstration project involving the use of their Calabasas landfill site was subsequently proposed and accepted by the Commission in October 2005.

Upon approval of the Calabasas demonstration site the Field Test Plan was updated to include a new site summary along with requirements specific to the Calabasas site.

3.2.1. Calabasas System Configuration

A description of the basic system design for the Calabasas site was developed and included in the test plan document (see Figure 7).

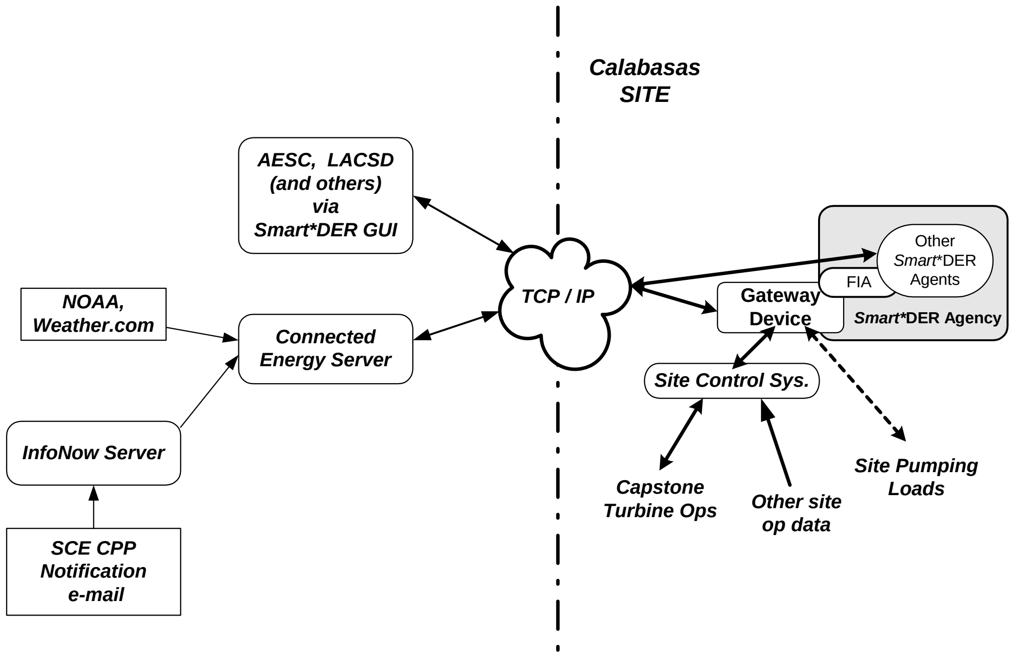

Figure 7. Calabasas *SmartDER System Configuration**

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The plan called for the *Smart**DER agency to operate on a commercial grade personal computer located in an enclosure adjacent to the gas treatment skid and Capstone microturbines. These agents would provide data analysis, data storage/access and data collection functions. Multiple instances of the *Smart**DER GUI user interface would be located remotely at AESC, LACSD and others to permit access to the *Smart**DER agency located on-site. The GUI would communicate with the site via an Internet connection using username and password security. Additionally, all inter-agent communications would utilize authentication and encryption security methods for added security.

Within the *Smart**DER agency the Facility Interface agent (FIA) would handle data collection and transmittal of operating commands and communicate directly with the Connected Energy *CENTRY*wcc™. The *CENTRY*wcc™ is a commercially available gateway device, providing site data via communications with the existing controls. It gateway device would also serve as the link to the Connected Energy server to provide weather and rate information to the *Smart**DER agency. The e-mail message transmitted by SCE to notify customers of CPP events would be translated into hourly energy rates and provided via a web-service hosted by Infotility using XML/SOAP communication protocol. The Connected Energy server would collect weather along with the electric rate information and transmit this information to the site agency on an hourly basis.

All communications between the Connected Energy server and the site would be accomplished using the secure communications infrastructure developed by Connected Energy under the existing DOE sponsored project. Communications between the FIA and the gateway device would utilize Connected Energy's XML-based communications protocol. At the same time communications between the gateway device and the existing controls would utilize ModBus protocols. A cellular modem, located on site provides the needed Internet connection.

System Operation & Testing

During normal operation, the *Smart**DER agency would operate autonomously on a continuous basis to develop suggested schedules for operation of the on-site distributed generation assets. It also distributed curtailable loads in response to local site conditions/constraints and the SCE pricing/CPP information provided via the Connected Energy server. The suggested plans are then compared against actual operation to compute the potential savings. During the test, AESC would monitor agency operations from its San Diego offices on a daily basis and collect data directly from the on-site agency for preparation of project reports.

*Smart**DER operation was planned to proceed in three phases. After initial installation and start-up the system would operate in "monitor only" mode. During this time it would collect and analyze site information and update the site load and equipment performance forecasting algorithms. AESC, using remote data collection would monitor operation during this phase and determine when the system could be moved to the next phase of operation. The next phase, "Monitor/Schedule" provides for generation of suggested operating plans but does not allow transmittal of operating instructions to the site equipment. During this phase, site operators can gain confidence in the suggested schedules and may implement them at their discretion. Special tests would be scheduled to confirm that the suggested schedules can be implemented by *Smart**DER. Based on the outcome of these tests the system may be permitted to advance to the last testing phase. In the last phase, "Monitor/Schedule/Implement" the system would be allowed to transmit and implement the suggested operating schedules via the gateway device.

3.3. Technology Refinement & Integration

All of the technology refinements to the *Smart**DER and Connected Energy technologies were successfully completed during this task. Technology refinement efforts were carried out by various team members and were concluded at different times. Table 4 summarizes the various efforts and their completion dates. As the table shows, all of the refinements were initially completed and all of the "pieces" appeared to be in place and ready for the start of field testing by the end of May 2006.

Table 4. Technology Refinement Responsibilities and Completion Dates

Description	Responsible	Initially Completed*
*Smart**DER agent & GUI updates	AESC	February 2006
Implementation of XML based communication protocols in the *Smart**DER FIA	AESC	February 2006
Internal and external site communications network (hardware and software)	Connected Energy	February 2006
Implementation of ModBus communications from the existing control	Connected Energy / O&M Contractor	April 2006**
Webservice for collection, processing and transmittal of CPP rate information	Infotility	May 2006
Implementation of server retrieval/transmittal of weather and rate information	Connected Energy	May 2006

* - Additional refinements and testing occurred during the field test period.

** - O&M contractor installed software at the site but its operation was not confirmed due to connectivity issues.

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3.4. Feasibility Field Test

As noted in the previous section, the refinement activities were completed at various times and this allowed some field test activities to commence early while some occurred later. Installation of AESC and Connected Energy equipment was completed in February, 2006. Two electrical equipment boxes containing the needed equipment were installed adjacent to the gas treatment skid and the existing control equipment (see Figures 8 and 9). The box housing the Connected Energy equipment also contained an ambient temperature sensor. This was directly connected to the gateway device and did not therefore require communications with the existing control. On February 15, 2006 AESC personnel completed installation of the *Smart**DER agency and confirmed that the agency was successfully receiving and processing the ambient temperature sensor data. Communication between the site and AESC's and Connected Energy's offices was also confirmed on this date.

Figure 8. ***Smart**DER and Connected Energy Installation**

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Figure 9. ***Smart**DER Computer Installation**

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3.4.1. Smart*DER GUI

The *Smart**DER GUI was modified to incorporate the product enhancements identified earlier and information specific to the Calabasas site was entered into the various input screens to configure the system for field testing. Figures 10 - 12 show representative input screens for the Calabasas demonstration site. Each of the screens is arranged into three basic areas. The various GUI functions are accessed via a folder type menu located at the left side of the screen above the AESC logo. The primary display for the *Smart**DER GUI area is located to the right of the menu area and comprises the majority of the screen. Below the primary display area is the runtime message display area that shows real-time significant message traffic between the various *Smart**DER agents. Additional information on *Smart**DER system status is displayed along the bottom edge of the screen.

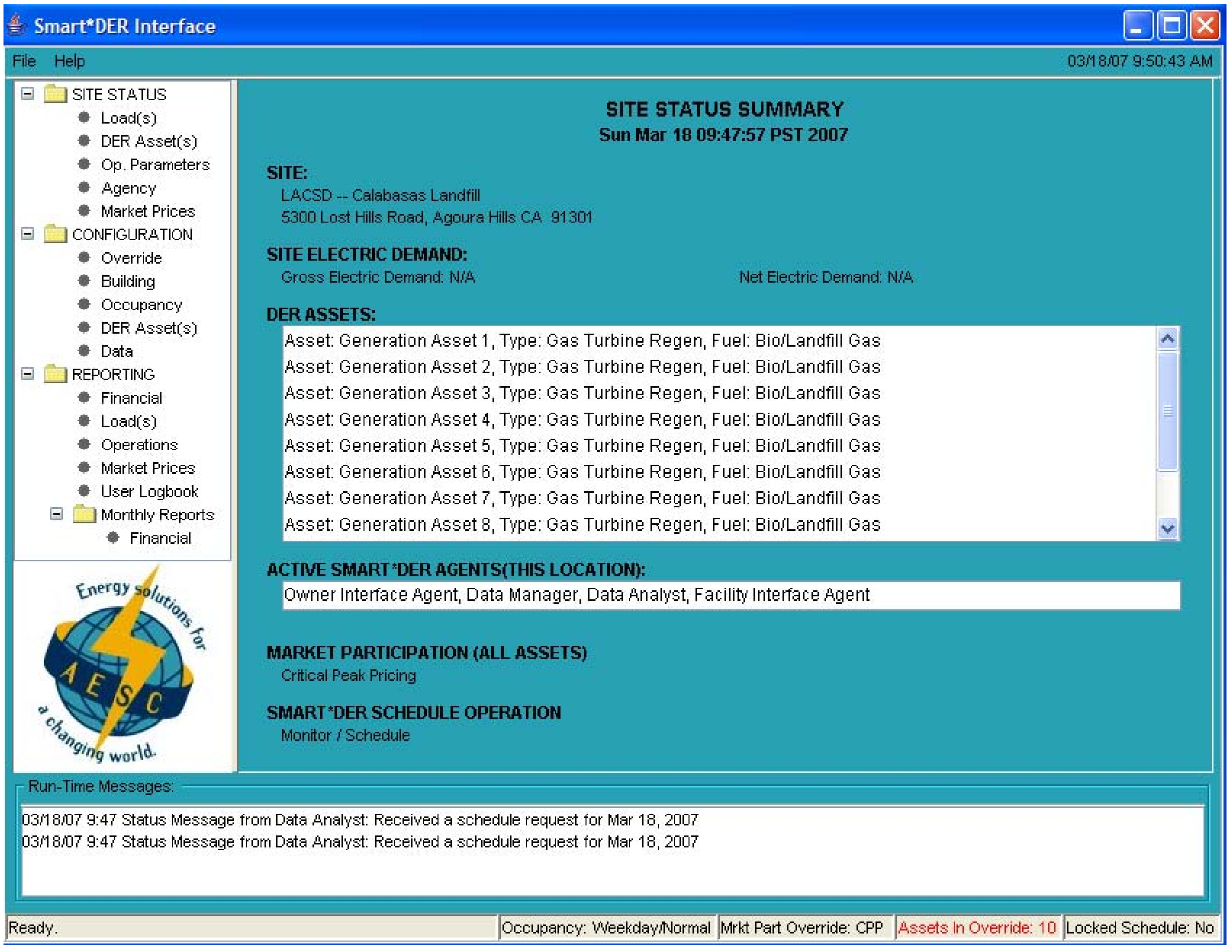

Figure 10. *SmartDER Interface Site Summary Screen**

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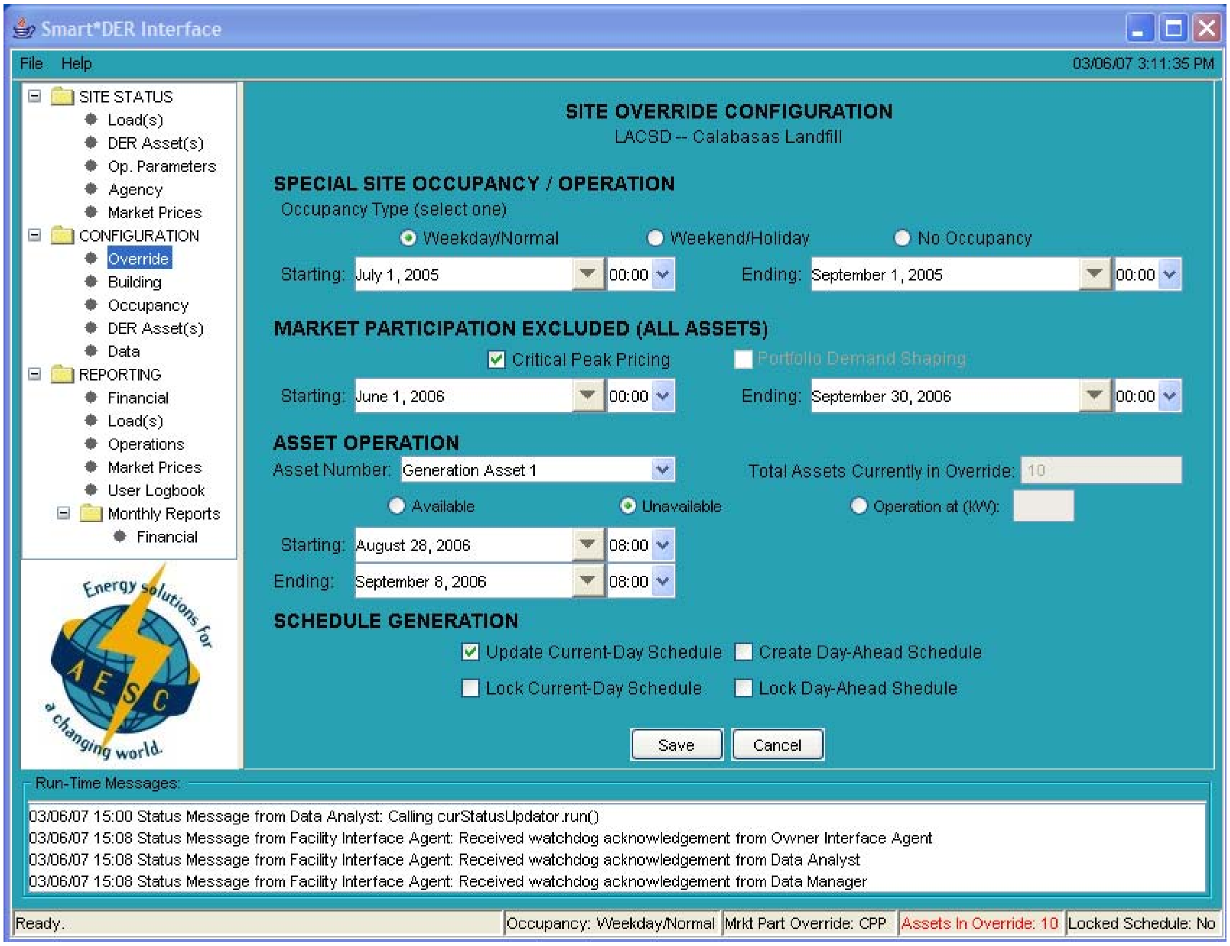

Figure 11. Site Override Configuration Screen
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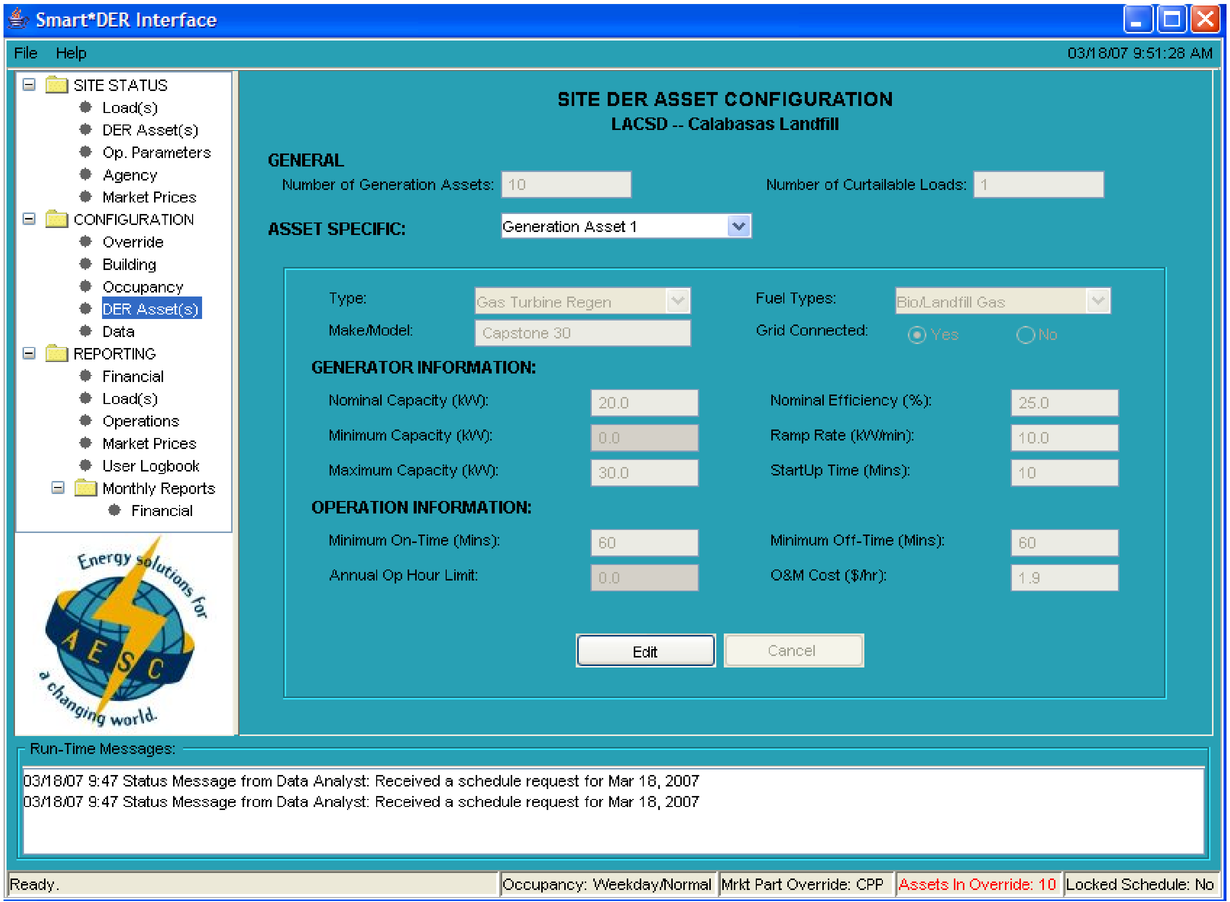

Figure 12. DER Asset Configuration Screen

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3.4.2. Field Test Activities

Field test activities were carried out by the various project team members with varying levels of success. Table 5 briefly summarizes the field test activities and significant milestones. As noted previously, the software refinement activities were initially completed in May 2006. While all of the "pieces were in place" at that time it was still not possible to bring all of the various systems on-line and begin normal operation. Two issues; one associated with the cell modem and another with the software supplied by the O&M contractor for real-time transmittal of site data proved difficult to resolve.

<u>Cell Modem Reliability</u>

The Calabasas landfill is located in Rolling Hills with obstructed lines of sight between the demonstration site and the main landfill office complex. The distance (1/2 mile or more) between the main office and the lack of a line of sight made use of a wireless network impractical since it would have involved installation of repeater stations. A Sprint™ cell repeater site is located on the landfill property and Sprint is the only cell phone service that provides reliable service. For this reason, a Sprint cell phone modem was selected for use at the site.

Cell modem operation, proved to be problematic, resulted in unreliable connectivity to the site. Personnel from Connected Energy worked with the cell modem manufacturer to identify and resolve the problem. The problem was traced to an undersized modem power supply. The problem was remedied with installation of a new larger power supply in August 2006.

Table 5. Field Test Activities

Date	Activity Description
December 2006	• Site selection confirmed
January - February 2006	• AESC and Connected Energy complete site physical installation • *Smart**DER agency begins operation, receiving site ambient temperature readings directly from the gateway device • Site connectivity issues surface
March 2006	• Site connectivity issues involving communication protocols resolved enabling web-based communications between AESC, Connected Energy and the site.
April 2006	• O&M contractor installs application for real-time transmittal of site data. (site hardware issues prevent operation)
May 2006	• InfoNow webservice for transmittal of CPP rates becomes operational. Issues associated with interpreting CPP e-mail notification surface.
June 2006	• Infotility web-service becomes fully operational. • AESC and Connected Energy confirm that *Smart**DER agency is receiving, processing and storing weather, electric rate and site ambient temperature information • Connected Energy and O&M contractor work to resolve site hardware issues.
July 2006	• O&M contractor and Connected Energy resolve site hardware connectivity issue but cell modem failure prevents final testing.
August – September 2006	• Cell modem problem is resolved (August) • O&M contractor supplied software operates sporadically (fails after short periods of operation and requires site visit to restart); real-time data remains unavailable
October 2006	• AESC/CE/O&M contractor meet to resolve real-time data problem • Archived data (1 minute) is requested from O&M contractor
November 2006	• Archived data received (through September)

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It is important to note that cell modem troubleshooting required powering down and restarting the site equipment on multiple occasions. In each instance, the *Smart**DER agency successfully restarted and resumed operation without external intervention.

<u>Real-time Site Data Transfer</u>

The existing control system that monitors and controls the microturbines and associated auxiliary equipment was developed and is maintained by an operation and maintenance contractor under contract to LACSD. As envisioned, a "typical" *Smart**DER installation would have involved connecting all of the site equipment directly to the gateway device. However this was not possible given the contractual arrangements that were already in place. Instead, this arrangement necessitated the use operation and maintenance contractor supplied software for transmittal of the real-time site data. This arrangement proved to be very problematic.

The data transfer software application was installed by the operation and maintenance contractor in April 2006. Equipment connectivity issues at the site initially prevented confirmation of software operation. The site's remote location combined with the cell modem reliability problem described above made troubleshooting difficult and time consuming. In July 2006 all of the site equipment connectivity issues were resolved but continuing cell modem problems hampered final integration testing. Final resolution of the cell modem problem in August allowed Connected Energy to resume integration testing of site transfer. It became apparent at that time that the data transfer software could not operate for more than a few hours without failing. Lacking remote access to the site, the operation and maintenance contractor had to travel to the site to restart the software and troubleshoot the problem. This arrangement proved to be cumbersome and ultimately impractical since real-time data transfer remained unavailable throughout the summer.

While real-time data transfer was not possible the existing Wonderware software had archived 1 minute data on-site during most of this time. The operation and maintenance contractor indicated that these data could be made available in lieu of the real-time data stream.

3.4.3. Field Test Modification

On-site equipment including the *Smart**DER agency and Connected Energy equipment became operational in February, 2006. The Infotility webservice supplying electric rate information became fully operational in early June and sporadic cell modem operation was corrected in July. However, lacking access to real-time site data; the *Smart**DER agency was unable to begin normal operation. With the exception of the operation and maintenance contractor supplied data transfer software all elements were operating normally. Field test objectives requiring demonstration of dependable operation were being met but without *Smart**DER generating operating schedules, there was little to prove that dependable operation would result in economic benefits.

It was for this reason that the Commission Contract Manager agreed to modify the field test to allow use of the archived site data. To preserve the integrity of the demonstration the data was provided to Connected Energy personnel who then "streamed" the data to a *Smart**DER agency in the same manner as would have occurred during normal operation. The *Smart**DER agency then processed and stored the data into 15 minute records. During normal operation each day's worth of data would have been processed and schedules generated over a 24 hour period. In order to accelerate this process, special routines were developed that caused the agency to develop a single "day-end" schedule using the stored data in conjunction with the weather and electric rate information already collected and processed during the summer. Subsequently, the *Smart**DER agency was able to process all of the available data and generate suggested operating schedules for the time period spanning June 1, 2006 to September 13, 2006.

3.4.4. Smart*DER Schedule Performance

During normal operation the user has the ability to update critical inputs using the *Smart**DER GUI. These input data are then used by the *Smart**DER agency to adjust the operating schedules accordingly. This ability to automatically adjust to changing conditions is an important and powerful feature of the *Smart**DER approach. In order to demonstrate this flexibility, the data were processed using the *Smart**DER agency with four different input configurations, the summary of the data can be seen in Table 6.

Table 6. User Input Configurations

Configuration	SCE Electric Rate Tariff	Microturbine Operating Costs
1	GS2-TOU-CPPV-1	$0.40 / hour
2	GS2-TOU-CPPV-1	$1.90 / hour
3	GS2-TOU	$0.40 / hour
4	GS2-TOU	$1.90 / hour

Alternative Energy Systems Consulting Inc. The two electric tariffs selected represent the time-of-use tariff currently in effect at the site (GS2-TOU) and the associated CPP tariff (GS2-TOU-CPPV1). Microturbine operating cost values were selected based on feedback from LACSD. The lower value, $0.40 per hour of operation corresponds to the operating costs when the microturbines were initially installed and covered by manufacturer's warranties. The higher value, $1.90 per hour of operation is the more current operating cost. Using these input variations we were able to explore how *Smart**DER operation would compare against the existing control using both the CPP tariff as well as the TOU tariff currently in effect at the site. In both cases we were also able to observe how changes to unit operating costs impacted scheduled operation and overall savings.

<u>GS2-TOU CPPV-1 Electric Tariff</u>

A total of eleven CPP events occurred during the test period on the following dates: July 10, 13, 14, 17, 19, 25, 26, 27 and August 23, 24, and 25. The CPP tariff has a fixed non-coincident demand charge of $26.48 per kilowatt with energy rates that vary based on time of day as well as during CPP events. Characteristics of the eleven CPP events that occurred during the test period are shown in Table 7.

As the table shows, CPP events began at either12 noon or at 3 p.m. and lasted from 2 – 5 hours. Figure 13 shows the rates that occurred during the July 10, 2006 CPP event, which began at 3 p.m. and lasted for two hours. The maximum energy rate that occurs on non-event days is $0.132 / kilowatt-hr, which occurs during the on-peak period. The minimum rate is $0.0374 per kilowatt-hr, which occurs during all other hours. On CPP event days the energy rate increases to $0.769 per kilowatt-hr beginning at the designated time and lasting the prescribed number of hours. It is important to note that both the timing and duration of CPP events can vary thus complicating the decision process.

Table 7. CPP Event Description

Event Date	Start Time	Duration hrs
7/10/2006	15:00	2
7/13/2006	15:00	2
7/14/2006	15:00	2
7/17/2006	12:00	4
7/19/2006	12:00	4
7/25/2006	12:00	5
7/26/2006	12:00	5
7/27/2006	12:00	5
8/23/2006	15:00	2
8/24/2006	15:00	2
8/25/2006	15:00	2

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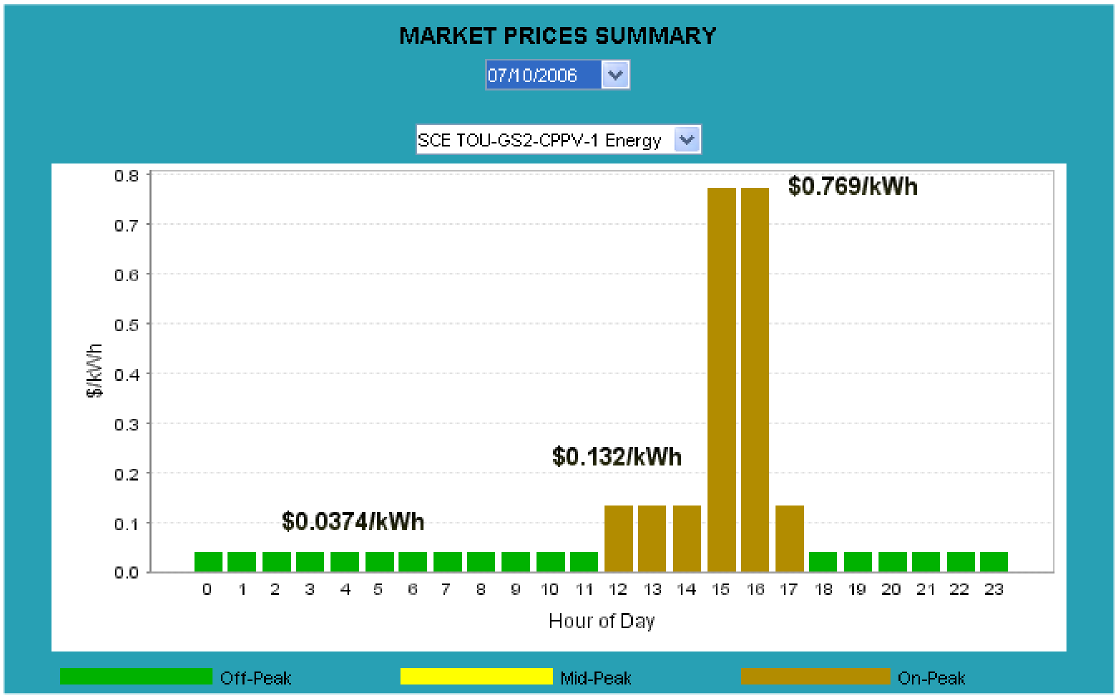

Figure 13. CPP Event Energy Charges for 7/10/2006

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Schedule Performance - CPP Electric Tariff

Monthly and total *Smart**DER performance schedule when operating under the CPPV-1 tariff is summarized in Tables 8 and 9. The performance values include system operation during all of the CPP events days with one exception. The CPP event date of July 19, 2006 corresponds to a period of time when no archived site data were available for processing. The *Smart**DER system successfully retrieved the CPP event rates but lacking site data it was not possible to generate operating schedules and estimate the associated savings for this date.

Table 8. Monthly Summary for CPP Operation & $0.40 /hr Operating Cost

	$0.40/hr Op Cost w/o *Smart**DER				$0.40/hr Op Cost w/ *Smart**DER			
	July	August	Sept*	Totals	July	August	Sept*	Totals
DG Op Hours	4,113	5,628	2,808	**12,549**	4,040	5,419	2,972	**12,431**
DG Op Costs	$1,645	$2,251	$1,123	**$5,020**	$1,616	$2,168	$1,189	**$4,972**
DG Energy Income	$7,734	$7,587	$3,526	**$18,847**	$7,525	$7,484	$3,775	**$18,784**
Curtailable Load Income	$0	$0	$0	**$0**	$1,057	$248	$0	**$1,305**
Net Energy Income	$6,089	$5,335	$2,403	**$13,828**	$6,966	$5,565	$2,586	**$15,117**
Demand Income	$1,425	$813	$0	**$2,238**	$1,425	$813	$0	**$2,238**
Net Total Savings	$7,514	$6,149	$2,403	**$16,066**	$8,391	$6,378	$2,586	**$17,355**

** - September results are through the 13th.*

Table 9. Monthly Summary for CPP Operation & $1.90 /hr Operating Cost

	$1.90/hr Op Cost w/o *Smart**DER				$1.90/hr Op Cost w/ *Smart**DER			
	July	August	Sept*	Totals	July	August	Sept*	Totals
DG Op Hours	4,113	5,629	2,808	**12,549**	1,538	1,170	783	**3,491**
DG Op Costs	$7,815	$10,694	$5,335	**$23,844**	$2,922	$2,223	$1,488	**$6,633**
DG Energy Income	$7,734	$7,587	$3,526	**$18,847**	$5,296	$3,541	$1,618	**$10,455**
Curtailable Load Income	$0	$0	$0	**$0**	$1,054	$248	$0	**$1,302**
Net Energy Income	($80)	($3,107)	($1,808)	**($4,996)**	$3,429	$1,566	$130	**$5,125**
Demand Income	$1,425	$813	$0	**$2,238**	$1,425	$813	$0	**$2,238**
Net Total Savings	$1,344	($2,294)	($1,808)	**($2,758)**	$4,854	$2,379	$130	**$7,363**

** - September results are through the 13th.*

As noted previously the existing control attempts to minimize site demand during all periods of the day without regard to cost. This strategy resulted in base-loading of all operational microturbines during the test period[1]. The *Smart**DER and existing controls provide very similar results when the operating costs are set to the lower value of $0.40 per hour of operation. The DG operating hours, associated costs and savings are essentially the same for both the *Smart**DER and existing controls. The *Smart**DER based control is able to achieve an additional 8% or $1,289 of savings by curtailing load during the ten CPP events for which data were available.[2] Note that unit outages on July 10th and on August 23rd reduced the possible savings since these outages coincided with CPP event days.

The difference between the two control strategies becomes more pronounced with increased DG operating costs. Figure 14 shows the monthly and total DG operating hours for the existing and *Smart**DER controls with varying operating costs. As the figure shows the *Smart**DER control responds to increased operating costs by drastically reducing the DG operating hours to less than 30% of the previous value. In this case the high operating costs makes operation of the microturbines during off-peak hours uneconomical unless a demand reduction can be achieved. The existing control, with its static operating strategy, is unable to achieve a net savings in two of the three months, which results in a net loss for the test period. The *Smart**DER control is able to achieve overall savings during all three months representing a $10,000 increase in overall savings. Note that the demand savings achieved by both the existing and *Smart**DER controls were the same even though the *Smart**DER control operated the microturbines far fewer hours.

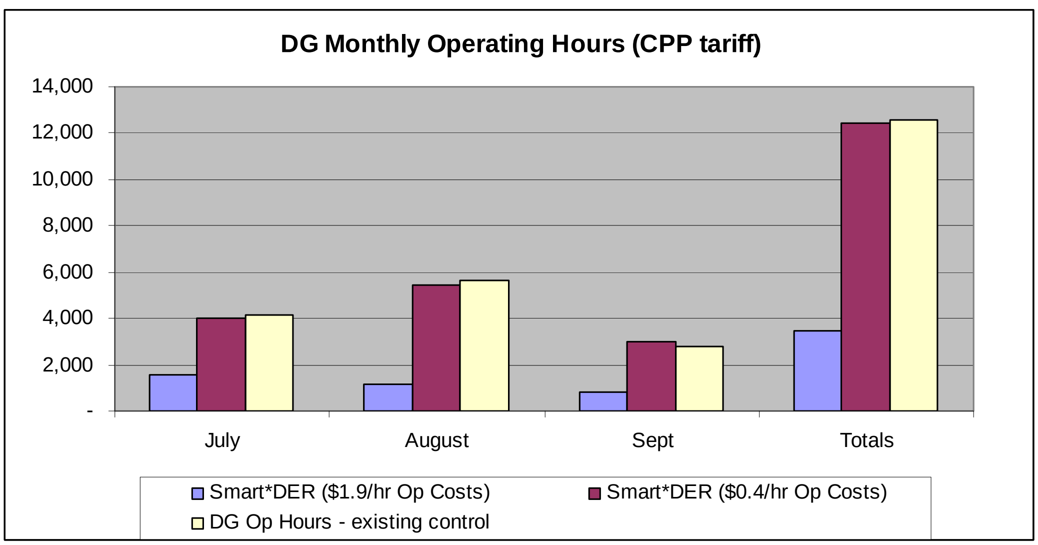

Figure 14. DG Operating Hours (CPP Tariff)

[1] Note that one of the microturbines was out of service during the entire test period (Unit 5) and outages caused some or all of the other units to be out of service during other periods.
[2] Note that a single irrigation pump (60 kW) was used as the curtailable load during CPP events.

Figures 15 and 16 show *Smart**DER GUI screen shots displaying the gross and net site load on July 3, 2006 with both the existing (actual) and *Smart**DER control (planned), respectively.

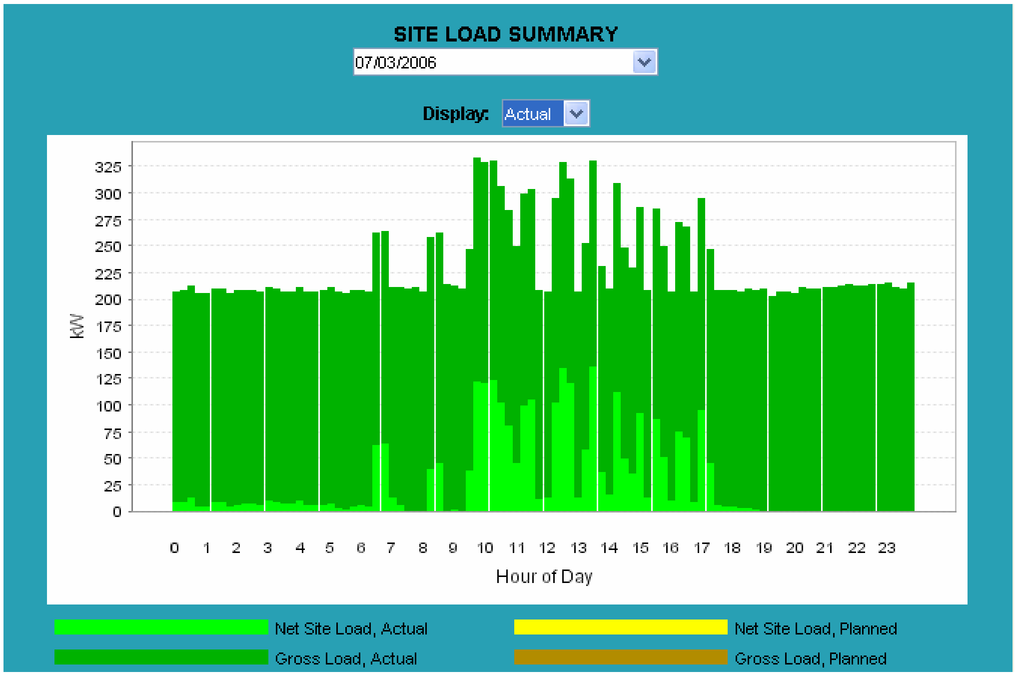

Figure 15. Site load for 7/3/06 using the existing control

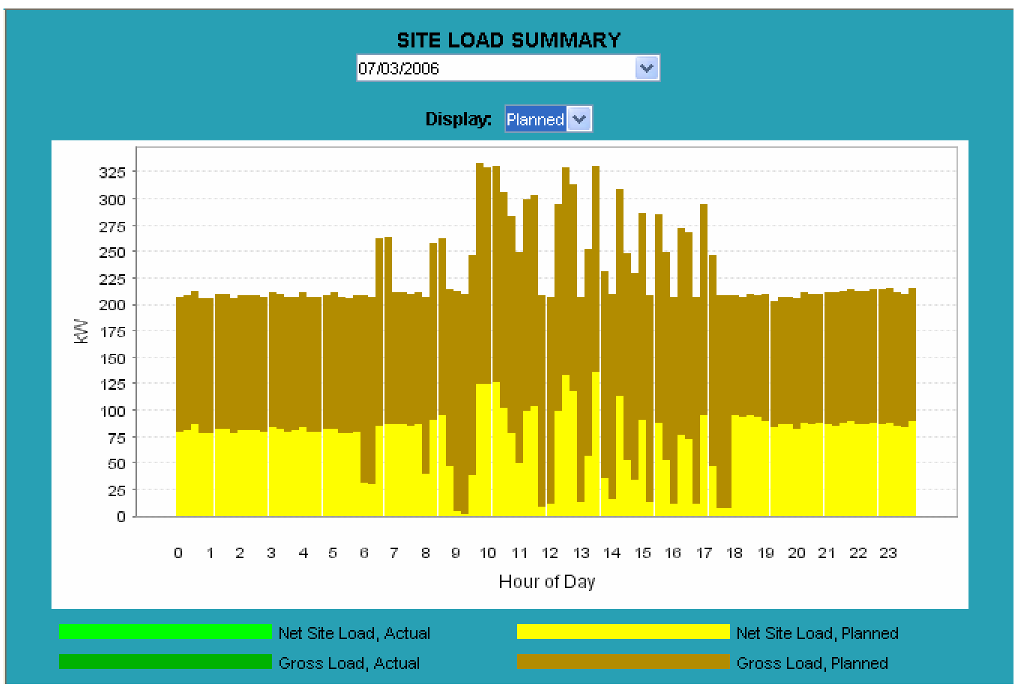

Figure 16. Site load for 7/3/06 using *SmartDER ($1.9/hr, CPP)**

The existing control minimizes the site net load to near zero during off-peak hours. The net site load under *Smart**DER control is significantly higher during the same time period (Figure 16). However, note that the daytime peak demand under both control strategies remains the same and is in excess of 125 kilowatt. The *Smart**DER control has correctly determined that it is too costly to maintain a site electric demand below which is occurring during the daytime hours. The site load is maintained at a more constant level under *Smart**DER control and is able to achieve higher overall savings.

GS2-TOU Electric Tariff

The GS2-TOU tariff is the tariff that is currently in use at the Calabasas site. Unlike the CPPV1 tariff, which does not have a time related demand charge, the TOU tariff is a conventional time-of-use tariff with three billing demand periods: on-peak, mid-peak and off-peak. Table 10 summarizes the applicable energy and demand charges for the TOU tariff during the test period (summer months). Compared to the CPPV tariff the conventional tariff has higher energy charges during all periods when compared with non-CPP event rates; however' the tariff but has lower overall demand charges.

Table 10. GS2-TOU Tariff Description (summer)

Description	Applicable Time Period	Energy Charge* ($/kWh)	Demand Charge ($/kW)
On-peak	1200 – 1800 (weekdays)	0.27463	7.24
Mid-peak	0800 – 1200 (weekdays) 1800 – 2300 (weekdays)	0.07407	2.76
Off-Peak	2300 – 0800 (weekdays) all other hours	0.04215	0.00
Non-coincident	All Hours	NA	4.86

** -- Energy charge is a composite based on contribution of DWR power during the month.*

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Schedule Performance - TOU Electric Tariff

*Smart**DER schedule performance when operating under the conventional TOU tariff is summarized in Tables 11 and 12. Results when operating under the conventional TOU tariff are similar to the CPP results described above in that the existing and *Smart**DER controls achieved very similar results when the lower operating cost is used. As noted previously, the *Smart**DER control was only allowed to curtail load during CPP events, thus the income associated with load curtailment is zero and the overall savings for the *Smart**DER and existing control are essentially the same. It is interesting to note that the savings values are significantly higher under the conventional TOU tariff in all instances. The higher energy charges associated with the TOU tariff make it more profitable to operate the microturbines during all hours of the day.

Table 11. Monthly Summary for CPP Operation & $0.40 /hr Operating Cost

	$0.40/hr Op Cost w/o *Smart**DER				$0.40/hr Op Cost w/ *Smart**DER			
	July	August	Sept*	Totals	July	August	Sept*	Totals
DG Op Hours	4,113	5,628	2,808	**12,549**	4,149	5,462	2,809	**12,420**
DG Op Costs	$1,645	$2,251	$1,123	**$5,020**	$1,660	$2,185	$1,124	**$4,968**
DG Energy Income	$10,150	$14,598	$7,249	**$31,998**	$10,340	$14,582	$7,303	**$32,224**
Curtailable Load Income	$0	$0	$0	**$0**	$0	$0	$0	**$0**
Net Energy Income	$8,505	$12,346	$6,126	**$26,978**	$8,680	$12,397	$6,179	**$27,256**
Demand Income	$873	$628	$0	**$1,501**	$873	$628	$0	**$1,501**
Net Total Savings	$9,378	$12,975	$6,126	**$28,479**	$9,553	$13,025	$6,179	**$28,757**

** - September results are through the 13th.*

Table 12. Monthly Summary for TOU Operation & $1.90 /hr Operating Cost

	$1.90/hr Op Cost w/o *Smart**DER				$1.90/hr Op Cost w/ *Smart**DER			
	July	August	Sept*	Totals	July	August	Sept*	Totals
DG Op Hours	4,113	5,629	2,808	**12,549**	1,907	2,077	1,426	**5,410**
DG Op Costs	$7,815	$10,694	$5,335	**$23,844**	$3,623	$3,946	$2,709	**$10,279**
DG Energy Income	$10,150	$14,598	$7,249	**$31,998**	$7,244	$9,724	$5,381	**$22,350**
Curtailable Load Income	$0	$0	$0	**$0**	$0	$0	$0	**$0**
Net Energy Income	$2,336	$3,904	$1,915	**$8,154**	$3,621	$5,778	$2,672	**$12,071**
Demand Income	$873	$628	$0	**$1,501**	$873	$628	$0	**$1,501**
Net Total Savings	$3,208	$4,532	$1,915	**$9,655**	$4,494	$6,406	$2,672	**$13,572**

** - September results are through the 13th.*

As with the CPP tariff results; *Smart**DER control achieves the same or higher overall savings under all scenarios. As expected, increasing the DG operating costs causes the *Smart**DER control to reduce microturbine operating hours (see Figure 17) relative to the existing control while achieving $3,917 or 40% greater overall savings. However, the reduction in operating hours is less severe as compared with operation under the CPP tariff. This is due to the presence of the mid-peak billing period in the conventional TOU tariff. The higher relative energy charge during the mid-peak period has the effect of increasing the "window of opportunity" for energy savings and causes the *Smart**DER control to operate the microturbines during the both the on-peak and mid-peak periods.

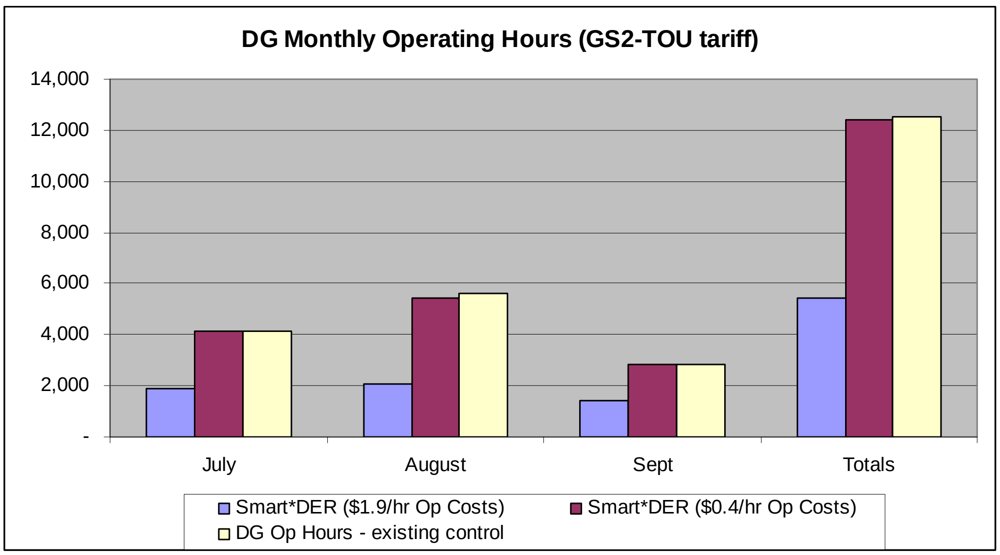

Figure 17. DG Operating Hours (TOU Tariff)

The ability to modify operating schedules in response to changing site conditions is a powerful feature of the *Smart**DER based control. This ability to adapt is illustrated in Figure 18, which shows the daily DG operating hours during the month of July. As expected, the conventional control operates all of the available microturbines throughout the month. Thus, the line depicting DG operating hours under the existing control (w/o *Smart**DER) represents the maximum possible number of operating hours for each day. Reduced or missing operating hours on days 9 -12, 22, and 23 is the result of total unit outages with partial unit outages impacting days 13 – 21. Note that data were not available for days 18, 19 and 20.

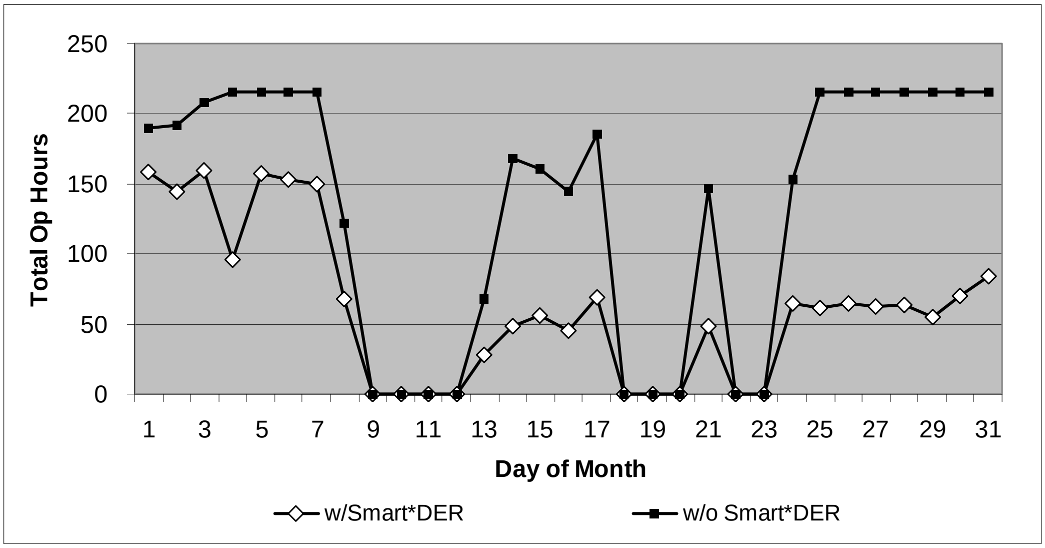

Figure 18. July DG Daily Operating Hours ($1.90 Op Costs, GS-TOU tariff)

At the beginning of the month the existing control operates all of the available units to minimize site net load during all hours of the day. As with the CPP tariff results, the *Smart**DER control calls for less operation since it has set the demand target to correspond with the historical minimum achievable demand of approximately 100 kilowatt. Following the unit outage that ended on the 12th the existing control resumes operation of all available units while the *Smart**DER control drastically reduces the DG hours of operation during the remainder of the month. The *Smart**DER control correctly deduced that the unit outage had severely reduced the potential demand savings and that it was no longer cost effective to operate as many DG units in pursuit of demand savings. The result is that the *Smart**DER control achieves the same demand savings and higher overall savings compared with the existing control; with far fewer hours of operation.

3.4.5. Providing Value on a Daily Basis

Whether operating under the CPP or TOU tariff, the *Smart**DER control was able to generate operating schedules that provided value to the customer on a daily basis. Results showed that the *Smart**DER control was able to respond to the CPP "events" but more importantly results showed that additional savings were achieved by monitoring and responding to changes in billing demand as well as incorporating operating costs into the analysis. In this way, *Smart**DER functions the same under CPP as under a conventional tariff; only the inputs differ.

3.4.6. Readily Compatible with Other Potential Tariffs

The *Smart**DER agency evaluates hourly rates in conjunction with site data and customer inputs to develop the appropriate response. That is correct; there is no mention of CPP event notification. As noted above the *Smart**DER approach involves routine evaluation of hourly rates and site conditions to develop operating schedules. It is not a fixed response to an "event notification" signal but rather an intelligent response to changing site conditions. This approach makes *Smart**DER readily compatible with other, potentially more complex dynamic tariffs/programs such as Real-Time-Pricing (RTP) and Customer Demand Bidding (CDB). For instance, only minor user interface modifications would be needed to enable system operation under an hourly pricing tariff such as RTP. Contrast this with the existing control that employs inflexible control software requiring modification to implement any changes.

3.4.7. Field Test Summary

The field test was successful in many ways. While an inability to transmit complete site data to the *Smart**DER agency in real-time prevented the system from becoming fully functional the project team was still able to successfully:

1. <u>Demonstrate operation of all of the *Smart**DER system elements</u>
2. <u>Implement Connected Energy's secure communication infrastructure</u> – for transmittal of electric rate and weather information to the site agency.
3. <u>Demonstrate robust agent operation</u> – agents operated continuously from February to November 2006; communicating continuously with the gateway device using Connected Energy's XML-based protocol to receive and store electric rates, weather forecasts and site ambient temperature data. The *Smart**DER agency automatically restarted and resumed activities on multiple occasions after power to the equipment was shutoff.
4. <u>Deploy and operate a webservice for translating the SCE CPP notification e-mail into hourly rates</u> – webservice operated successfully from June to November when it was removed from service at the end of the demonstration.
5. <u>Collect and process site data</u> – archived site data were "streamed" to the *Smart**DER agency in the same manner as if it had been received in real-time. The *Smart**DER agency subsequently generated operating schedules for all available data.
6. <u>Demonstrate that *Smart**DER generated operating schedules outperformed the existing control</u> –*Smart**DER schedule savings equaled or exceeded the savings achieved by the existing control under either the existing TOU or CPPV electric tariffs.
7. <u>Integrated load curtailment with DG operation in *Smart**DER schedules</u>
8. <u>Demonstrate that flexible operating schedules provide greater savings</u> – automatic *Smart**DER schedule modification in response to increased operating costs or increased site billing demand resulted in additional savings over the fixed operating strategy.

9.

10.

4.0 Conclusions and Recommendations

The overall goal of this follow-on effort was to build on the success of the preceding project in such a way as to facilitate market acceptance of the *Smart**DER agent-based approach. The key project objectives were updating the product requirements to match the changed California energy market and then testing this new technology in a "real-world" environment to schedule and control DER assets (e.g., distributed generation, curtailable loads, etc.).

Changes in the California energy market since the original project's inception in 1999 eliminated the original need for aggregation of distributed generation units to facilitate their participation in deregulated markets. While this potential application was no longer a viable application, the emergence of demand response programs such as Critical Peak Pricing (CPP) and dynamic bidding programs such as the Customer Demand Bidding (CDB) program offered by the investor-owned utilities appeared to provide alternative applications for *Smart**DER technology. In addition, load shaping across multiple facilities in a campus environment (multiple buildings served by a single utility meter) in response to a conventional time-of-use electric tariff also appeared to be a viable application for agent technology. These emerging programs placed added emphasis on integrating curtailable loads into the operating schedules in addition to distributed generation assets.

During the course of the field test all of the various *Smart**DER control elements were successfully demonstrated. While an inability to transmit complete site data to the *Smart**DER agency in real-time prevented the system from becoming fully functional the project team was still able to successfully:

- Demonstrate that agents are robust; the agents operated continuously during the test period. The agents automatically restarted and resumed activities when the system was shutdown (simulating site power failure).
- Deploy and operate a webservice that translates the SCE CPP notification e-mail into hourly rates for use by *Smart**DER.
- Develop and deploy a *Smart**DER agent/agency with Connected Energy's commercially available gateway device.
- Demonstrate *Smart**DER collection and processing of site data. Due to the difficulties associated with transmittal of real-time data archived site data was used in lieu of the real-time data. Archived data was transmitted and processed in the same manner as if it had been received in real-time. The *Smart**DER agency subsequently generated operating schedules for all available data.
- Demonstrate that *Smart**DER generated operating schedules that incorporate both generation and curtailable load assets were able to achieve up to 40% more

costs savings relative to the existing control. Furthermore, increased savings were achieved under either the existing TOU or CPP electric tariffs.

- Demonstrate that flexible *Smart**DER generated operating schedules, capable of responding to changing site conditions (i.e., unit outages, changing operating costs, billing demands), provide benefits on a daily basis.

Deployment of *Smart**DER will facilitate participation in emerging Demand Response (DR) programs such as CPP since it:

- Automates site response to the DR signal while eliminating the need for daily and hourly monitoring of market or demand response signals by site staff.
- Provides daily benefits by continuously monitoring and predicting site energy use and maximizing the benefits of DER asset use on a daily basis. The CPP event is just another input, not the only input for consideration.
- Retains local control of site DER assets thus further facilitating customer acceptance and participation in DR programs.

AESC, working with the Environmental Business Cluster of San Jose State University developed a *Smart**DER commercialization plan. AESC is moving forward with commercialization of this important technology and is actively looking for commercialization opportunities.

5.0 Glossary

AESC	Alternative Energy Systems Consulting, Incorporated
AS	Ancillary services markets
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
CADER	California Alliance for Distributed Energy Resources
CAISO	California Independent System Operator
CalPX	California Power Exchange
CERTS	Consortium for Electric Reliability Technology Solutions
Commission	California Energy Commission
DER	Distributed Energy Resources
DG	Distributed Generator
DOE	U.S. Department of Energy
DR	Demand Response
E2I	Electricity Innovation Institute
EM	Event Manager
EPIC	Energy Policy Initiatives Center
EPRI	Electric Power Research Institute
ESCO	Energy Service Company
FIA	Facility Interface Agent
GUI	Graphical User Interface
I/O	Input/Output

ISO	Independent System Operator
kW	kilowatt
kWh	Kilowatt-hour
MCP	Market clearing price
PBR	Performance based ratemaking
PC	Personal computer
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research
SBIR	Small Business Innovative Research
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
TCP/IP	Transmission Control Protocol/Internet Protocol
USCHPA	U.S. Combined Heat and Power Association
XML	Transfer Markup Language