Technology Performance Report #1

Irvine Smart Grid Demonstration, a Regional Smart Grid Demonstration Project

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Table of Contents

Table of Figures

TABLE OF TABLES

1. Executive Summary

With a vision of safely providing a more reliable and affordable electric system, Southern California Edison Company (SCE) has been awarded up to $39.6 million in matching funds from the U.S. Department of Energy (DOE) to conduct the Irvine Smart Grid Demonstration (ISGD). This demonstration is testing the interoperability and effectiveness of key elements of the electric grid – from the transmission level through the distribution system and into the customer premises. This end-to-end demonstration of smart grid technologies is helping SCE address several profound changes impacting the electric grid's operation, including increased use of renewable resources, more intermittent generation connecting to the distribution system, the ability of customers to actively manage the way they use electricity, and policies and mandates focused on improving the environment and promoting energy security.

Project Overview

ISGD operates primarily in the City of Irvine (Irvine) in Orange County, California, and many of the project components are located on or near the University of California, Irvine (UCI) campus. Key project participants include UCI, General Electric, SunPower Corporation, LG Chem, Space-Time Insight, and the Electric Power Research Institute.

ISGD's evaluation approach includes four distinct types of testing: simulations, laboratory tests, commissioning tests, and field experiments. ISGD uses simulations and laboratory testing to validate a technology's performance capabilities prior to field installation. The purpose of the field experiments is to evaluate the physical impacts of the various technologies on the electric grid and to quantify the associated benefits.

The project includes four domains. Each domain includes one or more sub-projects with distinct objectives, technical approaches, and research plans. There are eight sub-projects within these four domains.

1. Interoperability & Cybersecurity
2. Next Generation Distribution System
3. Smart Energy Customer Solutions
4. Workforce of the Future

Interoperability & Cybersecurity

The electric grid is evolving to include an increasing number of distributed and interconnected grid resources, both utility and customer owned. The need for plug-and-play interoperability within a secure environment is therefore of critical importance. The project is using SCE's MacArthur Substation to pilot its next generation of substation automation (SA-3). The SA-3 platform enables standards-based communications, automated configuration of substation devices, and an enhanced system protection design. The team set up a complete duplicate of the equipment installed in MacArthur Substation at SCE's Advanced Technology Labs in order to perform real-time simulations and component testing prior to field installation. Real-time simulation allowed testing of thousands of scenarios to verify proper operation under various grid conditions. The team has installed SA-3 components at MacArthur Substation and the system is now in service.

MacArthur Substation also represents the first field deployment of SCE's Common Cybersecurity Services (CCS) platform. ISGD is using CCS to provide high-assurance cybersecurity for substation devices and communications between the various field devices and ISGD back office systems. The team prepared detailed requirements and system design documents. The team assembled various communications and security components in the laboratory environment for end-to-end integration testing prior to field deployment. The team then installed the various components in the field and commissioned the system.

Next Generation Distribution System

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. This project domain includes technologies designed to help support grid resiliency and efficiency within this changing environment. Two 12 kV circuits fed from MacArthur Substation are demonstrating a set of advanced distribution automation technologies.

ISGD is using a distribution volt/VAR control (DVVC) application to optimize customer voltage profiles in pursuit of "conservation voltage reduction." DVVC can also provide VAR support to the transmission system. The DVVC application underwent multiple rounds of factory acceptance testing and site acceptance testing, and is now operating on seven distribution circuits out of MacArthur Substation.

ISGD's self-healing distribution circuit should improve reliability by identifying and isolating faults with greater speed and precision. This ISGD capability isolates faults within a smaller section of a distribution circuit while preserving service to the remaining customers. The self-healing distribution circuit uses a looped circuit topology with universal remote circuit interrupters (URCI). During a fault, the URCIs coordinate their operations using GOOSE (Generic Object Oriented Substation Event) messaging through high speed, low latency radios. The team performed simulations of the URCI system operating under a variety of grid conditions to evaluate its performance prior to field deployment. The team also performed pre-deployment testing of the URCI and radio components in preparation for field deployment.

ISGD is operating a 2 MW energy storage device to help relieve distribution circuit constraints and to mitigate overheating of the substation getaway. This battery is also being used along with phasor measurement technology installed within a transmission-level substation (upstream of MacArthur Substation) to try to detect changes in distribution circuit load from distributed energy resources (such as demand response resources or energy storage). The team performed lab testing of the battery system to prepare for field deployment.

Smart Energy Customer Solutions

Customers are modifying how they consume and generate electricity. This project domain includes a variety of technologies designed to help empower customers to make informed decisions about their energy use. The project extends into a residential neighborhood on the UCI campus used for faculty housing. ISGD has equipped three blocks of homes with an assortment of advanced energy components, including energy efficiency upgrades, electric vehicle supply equipment (EVSE), energy storage, rooftop solar photovoltaic (PV) panels, thermostats and smart appliances capable of demand response, and in-home displays. The project is using one block of homes to evaluate strategies and technologies for achieving zero net energy (ZNE). A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes on an annual basis. The project is also seeking to understand the impact of ZNE homes on the electric grid. The team performed energy simulations to determine the energy efficiency measures for each home. The project team performed laboratory testing on the smart appliances, EVSE, and other home area network (HAN) devices prior to field deployment. The team has performed demand response experiments on the EVSE, smart appliances, and the heating and cooling systems. To evaluate the ZNE technology and strategies, the team is collecting detailed energy usage information, by circuit.

ISGD is evaluating two types of energy storage devices in this neighborhood. The team has installed residential energy storage units (RESUs) in 14 homes, and is evaluating them using a variety of control modes. In addition, one block of homes shares community energy storage (CES) device. The team is also evaluating the CES using a variety of control modes. Both devices can provide a limited amount of backup power during electricity outages. Both types of energy storage devices underwent extensive laboratory testing prior to commissioning. The team then installed these devices and performed initial field experiments, including a demand response event and a series of load shifting tests.

To evaluate the impact of charging plug-in electric vehicles (PEVs) in the workplace, ISGD has installed a Solar Car Shade system within a parking garage on the UCI campus. The Solar Car Shade includes 48 kW of rooftop PV, 20

EVSE, and a 100 kW/100 kWh energy storage device. The objective of this system is to reduce or eliminate the grid impact of PEV charging during peak periods. The team performed component testing of the energy storage device and EVSEs prior to installation. The team then commissioned the system and performed an initial permanent load shifting (PLS) test over an eight-week period.

Workforce of the Future

Deploying smart grid technologies on a larger scale would affect the utility workforce, and it could have implications for the utility's organizational structure. The project team has developed workforce training for the relevant ISGD technologies. The team is also performing an organizational assessment to identify potential organizational impacts, and to develop recommendations for addressing those impacts.

Reporting Overview

Over the course of the project, SCE will file two Technology Performance Reports (TPRs) and a Final Technical Report. This document represents the first TPR, and addresses ISGD's design, deployment, the first eight months of field experimentation, and the associated lessons learned. The second TPR will address the second eight-month experimentation period, while the Final Technical Report will cover the entire two-year demonstration period. The final report will also provide benefit calculations and an appraisal of the commercial readiness and scalability of the various technologies demonstrated within ISGD.

Technology Performance Report Organization

Chapter 2 provides general information about the project, including overviews of the project team, location, schedule, and milestones. This chapter also provides additional details about the four project domains introduced above, and it summarizes the potential benefits that could result from the ISGD technologies.

Chapter 3 describes the objectives, technical approach, and research plan for each sub-project. The research plan describes the relevant technology evaluation activities including simulations, laboratory tests, commissioning tests, and field experiments for each of the technology components.

Chapter 4 summarizes the demonstration results for the design and installation phase, and for the first eight-months of field experimentation—from July 1, 2013 to February 28, 2014. Since this is the first TPR, this report emphasizes design and deployment. Field experiment results will make up a larger share of the second TPR and the Final Technical Report.

Chapter 5 summarizes the conclusions and key lessons learned from the design, deployment, and first eight months of field experiments.

Key Lessons Learned

Table 1 below summarizes the key lessons learned during the design, deployment, and first eight months of field experiments. The ISGD team is accumulating additional observations, and intends to present more lessons learned in both the second TPR and the Final Technical Report. The Final Technical Report will provide assessments of the commercial readiness and scalability of the various ISGD technologies. It will also provide specific recommendations or "calls to action" for relevant industry stakeholders, including utility executives, policymakers and regulators (federal and state), standards developing organizations, industry research organizations, and the vendor and service provider communities.

Table 1: ISGD Lessons Learned

ISGD Technology Domains/Lessons Learned	Lessons Learned Categories				
	Standards	Technical Maturity	Regulatory Landscape	Market Landscape	Deployment /Integration
Smart Energy Customer Solutions					
1. Smart inverter standards are too immature to support product development and market adoption	✓				
2. Proper integration of components from multiple vendors is critical to the successful operation of energy storage systems		✓			
3. Improved battery system diagnostic capabilities are required to help identify the causes of potential failures		✓			
4. Manufacturer implementations of the SAE J1772 EVSE standard limit the usefulness of electric vehicle demand response		✓			
5. Distributed energy resources should be designed and tested to ensure communications and operations compatibility with utility control systems		✓			✓
6. Remotely monitoring new technologies post-deployment is critical to timely identification and resolution of unknown issues					✓
7. Targeted “behind the meter” data collection will help future demonstration analytics					✓
Next Generation Distribution System					
1. Low latency radios require technical improvements or government allocation of radio spectrum		✓	✓		
2. Permitting is a significant challenge for siting smart grid field equipment outside of utility rights-of-way			✓		
Interoperability & Cybersecurity					
1. The flexibility allowed by the IEC 61850 standard limits interoperability	✓			✓	✓
2. Achieving interoperability requires concentrated market-based development and enforcement of industry standards	✓			✓	
3. An enterprise service bus can simplify the development and operation of visualization capabilities		✓			
4. Utilities need to perform a system integrator role in order to realize smart grid objectives					✓
5. Effective communications with software vendors is critical for smart grid deployments					✓
6. Acceptance testing should include integrated testing of software products and field devices in a lab environment					✓
Workforce of the Future					
1. Identify, assess and resolve impacts to departmental boundaries, and worker roles and responsibilities as a result of smart grid deployments					✓
2. Build time into any smart grid deployment planning for an iterative training development process					✓

2. Scope

SCE has been awarded up to $39.6 million in matching funds from the DOE to conduct a Regional Smart Grid Demonstration Project, an end-to-end demonstration of numerous smart grid technologies that SCE believes are necessary to meet federal and state policy goals. The ISGD project is testing the interoperability and efficacy of key elements of the grid, from the transmission level through the distribution system and into the home. SCE's experience with smart grid technologies, gained through the Avanti distribution circuit (co-funded by the DOE[1]), synchrophasor development, and the Edison SmartConnect® smart meter program, to name a few, provides an important foundation for this project. ISGD is a deep vertical dive that tests multiple components of an end-to-end smart grid. Thus, the project provides a living laboratory for simultaneously demonstrating and assessing the interoperability of, and interaction between, various smart grid technologies and systems. ISGD operates in the City of Irvine, a location that typifies some heavily populated areas of Southern California in climate, topography, environmental concerns, and other public policy issues.

2.1 Project Abstract

ISGD is a comprehensive demonstration that spans the electricity delivery system and extends into the customer premises. The project is using phasor measurement technology to enable substation-level situational awareness, and is demonstrating SCE's next-generation substation automation system. It extends beyond the substation to evaluate the latest generation of distribution automation technologies, including looped 12 kV distribution circuit topology using URCIs. The project team is using DVVC capabilities to demonstrate conservation voltage reduction (CVR). The project scope also includes customer homes, where it is evaluating HAN devices such as smart appliances, programmable communicating thermostats, and home energy management components. The homes also include energy storage, solar PV systems, and a number of energy efficiency measures (EEM). The team is using one block of homes to evaluate strategies and technologies for achieving ZNE. A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes annually. The project is also assessing the impact of device-specific demand response (DR), as well as load management capabilities involving energy storage devices and plug-in electric vehicle charging equipment. In addition, the ISGD project is seeking to better understand the impact of ZNE homes on the electric grid. ISGD's Secure Energy Network (SENet) enables end-to-end interoperability between multiple vendors' systems and devices, while also providing a level of cybersecurity that is essential to smart grid development and adoption across the nation.

The ISGD project includes a series of sub-projects grouped into four logical technology domains: Smart Energy Customer Solutions, Next Generation Distribution System, Interoperability and Cybersecurity, and Workforce of the Future. Chapter 2.3 provides a more detailed overview of these domains.

2.2 Project Overview

2.2.1 Objectives

The primary objective of ISGD is to verify and evaluate the ability of smart grid technologies to operate effectively and securely when deployed in an integrated framework. The project also provides a means to quantify the costs and benefits of these technologies in terms of overall energy consumption, operational efficiencies, and societal and environmental benefits. Finally, ISGD allows the project team to test and validate the applicability of the demonstrated smart grid elements for the Southern California region and the nation as a whole.

[1] This is a 12 kV distribution circuit that became operational in 2007 and serves more than 1,400 residential and business customers.

2.2.2 Project Team

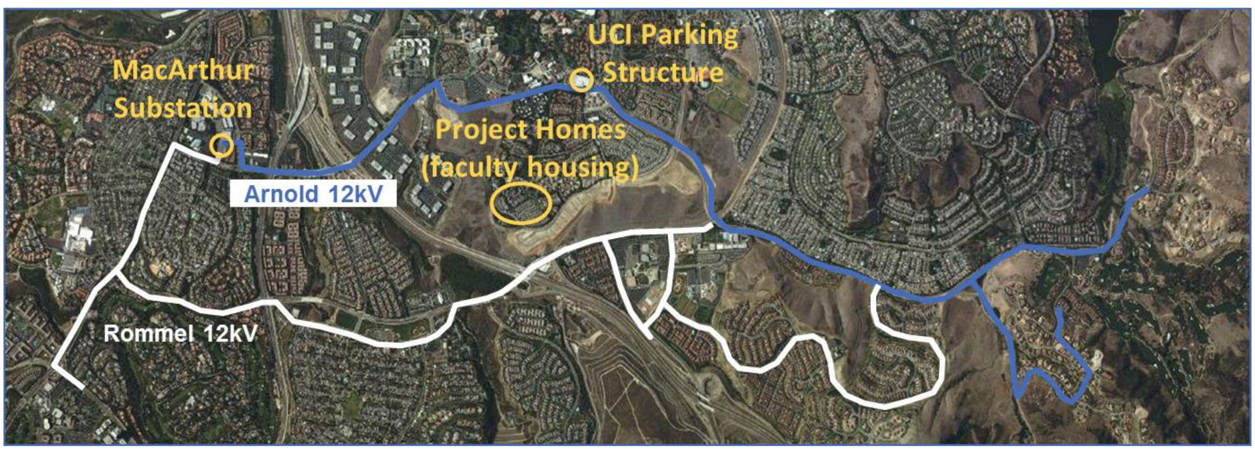
The ISGD project's participants, led by SCE, consist of a combination of industry leaders, with each one bringing essential expertise to the project. In addition to SCE, major participants currently include UCI's Advanced Power and Energy Program, General Electric (GE), SunPower Corporation, Space-Time Insight (STI), and the Electric Power Research Institute (EPRI). SCE is coordinating the efforts among project participants to capture and document "lessons learned" and to help share this knowledge with the broader industry.

2.2.3 Project Location

ISGD operates primarily in Irvine, in Orange County California, approximately 35 miles south of the City of Los Angeles. With a population of nearly 250,000 people, Irvine is widely recognized as one of the safest master-planned, business-friendly communities in the country. It is home to UCI and a number of corporations, including many in the technology sector.

ISGD is being carried out on two 12 kV distribution circuits (Arnold and Rommel circuits) that are fed by MacArthur Substation located in the City of Newport Beach, California. MacArthur Substation is supplied by Santiago Substation located 10 miles east in Irvine. In addition to the two circuits fed by MacArthur Substation, portions of the ISGD project are being conducted within 38 homes on the UCI campus (faculty housing), and at a UCI parking facility. **Figure 1** provides a graphical depiction of this smart grid system.

Figure 1: High Level Project Map



2.2.4 Project Schedule and Milestones

The following table represents a summary of ISGD's key milestones.

Table 2: Key ISGD Milestones

Key Milestones	Milestone Dates
Submit National Environmental Policy Act application and receive Categorical Exclusion from DOE	07/19/2010
Submit Interoperability & Cybersecurity Plan to DOE	10/24/2011
Submit Project Management Plan to DOE	07/31/2012
Complete engineering design and specifications	12/31/2012
Begin 24 months of measurement and verification activities	07/01/2013
Submit updated Metrics & Benefits Reporting Plan to DOE	12/12/2013
Submit first Technology Performance Report	06/03/2014
Submit second Technology Performance Report	01/31/2015
Complete data analysis and submit Final Technical Report	12/29/2015

2.3 Project Domains

The ISGD project includes the following four domains: Smart Energy Customer Solutions, Next Generation Distribution System, Interoperability & Cybersecurity, and Workforce of the Future. Each domain includes one or more sub-projects with distinct objectives, technical approaches, and research plans.

2.3.1 Smart Energy Customer Solutions

This project domain includes a variety of technologies that help empower customers to make informed decisions about how and when they consume (or produce) energy. ISGD is evaluating these customer technologies through the following two sub-projects:

- Sub-project 1: Zero Net Energy Homes through Smart Grid Technologies
- Sub-project 2: Solar Car Shade

2.3.2 Next Generation Distribution System

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. This project domain includes technologies designed to support grid efficiency and resiliency within this changing environment. ISGD is evaluating these electricity distribution technologies through the following four sub-projects:

- Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage
- Sub-project 4: Distribution Volt/VAR Control
- Sub-project 5: Self-healing Distribution Circuits
- Sub-project 6: Deep Grid Situational Awareness

2.3.3 Interoperability & Cybersecurity

The electric grid is evolving to include an increasing number of distributed and interconnected grid resources, both utility and customer-owned. The need for seamless interoperability within a secure environment is of critical importance. This project domain is a foundational element that underpins the development of smart grid capabilities. ISGD is evaluating interoperability and cybersecurity through sub-project 7, which is composed of two elements:

- Secure Energy Network
- Substation Automation 3

2.3.4 Workforce of the Future

This project domain consists of a single sub-project, Workforce of the Future (sub-project 8).This domain provides the workforce training tools and capabilities necessary to operate and maintain the various ISGD components. The sub-project is also evaluating the potential impacts of smart grid technologies on the utility's organizational structure. This assessment will relate principally to Southern California Edison, although it will also provide insights for the electric utility industry.

2.4 Smart Grid Functions and Energy Storage Applications

2.4.1 Smart Grid Functions

In providing guidance to demonstration grant recipients for preparing TPRs, the DOE presented a list of "Smart Grid Functions."[2] **Table 4** indicates which of these smart grid functions ISGD is demonstrating, by sub-project.

Table 3: Summary of Smart Grid Functions by Sub-project

DOE Smart Grid Function	Sub-project							
	1	2	3	4	5	6	7	8
Fault Current Limiting								
Wide Area Monitoring, Visualization, & Control							✓	
Dynamic Capability Rating								
Power Flow Control								
Adaptive Protection					✓			
Automated Feeder Switching					✓			
Automated Islanding and Reconnection	✓							
Automated Voltage & VAR Control				✓				
Diagnosis & Notification of Equipment Condition								
Enhanced Fault Protection					✓			
Real-time Load Measurement & Management								
Real-time Load Transfer					✓			
Customer Electricity Use Optimization	✓	✓						

2.4.2 Energy Storage Applications

The DOE's guidance for preparing TPRs included a list of potential "Energy Storage Applications."[3] **Table 5** indicates which of these energy storage applications ISGD is demonstrating, by sub-project[4].

[2] Guidance for Technology Performance Reports, Regional Demonstrations, V1 – Draft Submittal, June 17, 2011 (page 2).

Table 4: Summary of Energy Storage Applications by Sub-project

Energy Storage Applications	Sub-project 1 RESU	Sub-project 1 CES	Sub-project 2 BESS	Sub-project 3 DBESS
Electric Energy Time Shift	✓	✓	✓	✓
Electric Supply Capacity	✓	✓	✓	✓
Load Following	✓	✓	✓	✓
Area Regulation				
Electric Supply Reserve Capacity				
Voltage Support	✓	✓		
Transmission Support				
Transmission Congestion Relief				
T&D Upgrade Deferral		✓	✓	
Substation Onsite Power				
Time-of-Use Energy Cost Management	✓		✓	
Demand Charge Management	✓		✓	
Electric Service Reliability	✓	✓		
Electric Service Power Quality				
Renewables Energy Time Shift	✓	✓	✓	
Renewables Capacity Firming				
Wind Generation Grid Integration, Short Duration				
Wind Generation Grid Integration, Long Duration				

2.5 Potential Benefits

The ISGD project is demonstrating smart grid technologies meant to improve the performance and resilience of the electric system. These performance improvements provide four categories of benefits: economic, reliability, environmental, and security. **Table 5** below summarizes the types of benefits the ISGD team expects to observe within the project. Evaluating an individual smart grid technology requires establishing linkages between the technology and the associated impacts. Moreover, these impacts should be measurable and verifiable. When deploying multiple technologies, the associated impacts must be isolated and assigned to the individual technologies. Evaluating the impacts of complementary technologies (or foundational technologies which enable other technologies) also requires careful consideration and evaluation. Limiting the project to a discrete and well-defined area removes many confounding sources of variation that can complicate isolating and measuring individual impacts. Nevertheless, the smart grid technologies may demonstrate considerable variability in their impacts or benefits due to factors outside the control of testing protocols.

Chapter 3 describes the ISGD research plans for each technology, and it defines the linkages between these technologies, the physical impacts they have on the system, and the potential corresponding benefits. The ISGD team plans to run the DOE's Smart Grid Computational Tool to estimate the potential benefits resulting from ISGD. The ISGD project team may use other methods to estimate the benefits resulting from ISGD, and will document any such estimates in either the second TPR or the Final Technical Report.

[3] Guidance for Technology Performance Reports, Regional Demonstrations, V1 – Draft Submittal, June 17, 2011 (page 2).
[4] **Table 4** summarizes the operational uses of the residential energy storage unit (RESU), community energy storage (CES), battery energy storage system (BESS), and distribution-level battery energy storage system (DBESS)

Table 5 summarizes the benefits that may be attributable to the smart grid technologies and capabilities demonstrated on ISGD. This table includes each of the smart grid benefits identified in the DOE benefits framework, as well an additional benefit identified by SCE.[5]

Table 5: Summary of ISGD Benefits by Sub-project[6]

Benefit Category	Benefit	Measurable Impacts	Sub-project							
			1	2	3	4	5	6	7	8
Economic Benefits										
Market Revenue	Arbitrage revenue									
	Capacity revenue									
	Ancillary service revenue									
Improved Asset Utilization	Optimized generator operation									
	Deferred generation capacity investments	Demand (kW)	D	D	D				I	I
	Reduced ancillary service cost									
	Reduced congestion cost									
T&D Capital Savings	Deferred transmission capacity investments		D	D	D				I	I
	Deferred distribution capacity investments	Demand (kW)	D	D	D				I	I
	Reduced equipment failures	• Demand (kW) • Customer voltage • # of equipment operations/failures	D	D	D	D	D		I	I
T&D O&M Savings	Reduced distribution equipment maintenance cost	Equipment maintenance cost	D	D	D	D	D		I	
	Reduced distribution operations cost									
	Reduced meter reading cost	Identify sub-metering solution	D							
Theft Reduction	Reduced electricity theft									
Energy Efficiency	Reduced electricity losses	Feeder loading (kW)	D	D	D	D			I	I
Electricity Cost Savings	Reduced electricity cost	• Electricity use (kWh) • Demand (kW)	D	D		D		P	I	I

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[5] The DOE benefits framework was obtained from the DOE's "SGDP Smart Grid Demonstration Program, Guidance for Technology Performance Reports," June 17, 2011, page 3.

[6] The following is a legend for the sub-project benefits:

D Benefit is a direct result of this sub-project.

I Benefit is an indirect result of this sub-project (i.e., sub-project enables the relevant capability within a different sub-project).

P Benefit could potentially result from this sub-project. For example, sub-project 6 is demonstrating the potential for "deep grid situational awareness," a capability would have no immediate or direct benefit, but could provide benefits over the longer term.

Benefit Category	Benefit	Measurable Impacts	Sub-project							
			1	2	3	4	5	6	7	8
Reliability Benefits										
Reduced Service Interruption	Reduced sustained outages	• # of outages • Average outage duration	D				D		I	I
	Reduced major outages									
	Reduced restoration cost	Time required to identify fault					D		I	I
Improved Power Quality	Reduced momentary outages	• # of outages • Average outage duration	D				D		I	I
	Reduced sags and swells	Customer meter voltage				D				I
Environmental Benefits										
Reduced Air Pollution	Reduced carbon dioxide emissions	• PEV charging (kWh) • Solar PV generation (kWh) • Reduced electricity use (kWh) • Reduced electricity loss (kWh)	D	D	D	D			I	I
	Reduced SOx, NOx, and PM-2.5 emissions	• PEV charging (kWh) • Solar PV generation (kWh) • Reduced electricity use (kWh) • Reduced electricity loss (kWh)	D	D	D	D			I	I
Security Benefits										
Improved Energy Security	Reduced oil usage	PEV charging (kWh)	D	D					I	I
Improved Cybersecurity[7]		• Higher reliability • Increased resiliency • Improved situational awareness							D	I

Sections 2.5.1 to 2.5.4 describe how the benefits identified in **Table 5** could eventually result from the technologies demonstrated within the ISGD project.

2.5.1 Economic Benefits

Deferred Generation Capacity Investments: Utilities determine their generation capacity requirements based on the need to serve the maximum forecasted load. Efforts to reduce peak load through demand response and other load management capabilities could ultimately defer the need for incremental generation capacity investments, if utilities expand these capabilities.

[7] This benefit is not included in the DOE benefit framework.

Deferred Transmission Capacity Investments: Efforts to reduce peak load through demand response and other load management capabilities may reduce the load and stress on transmission infrastructure. This may result in deferring the need for incremental transmission capacity investments, if utilities expand these load management capabilities to large customer populations.

Deferred Distribution Capacity Investments: Distribution capacity requirements are generally determined based on non-coincident peak load. To the extent that new load management capabilities result in peak load reductions, it may be possible to defer distribution capacity investments.

Reduced Equipment Failures: Reducing the stress placed on distribution equipment has the potential to extend these assets' useful lives and reduce the number of equipment failures. Peak load reductions and enhanced fault protection can help to reduce distribution equipment stress.

Reduced Distribution Equipment Maintenance Cost: To the extent that enhancing circuit protection or reducing peak load reduce strain on distribution equipment, it may be possible to reduce the cost of maintaining this equipment.

Reduced Electricity Losses: As electricity travels from a generation source through the transmission and distribution system, a small portion of energy is lost due to system impedances. Conversely, locating generation resources closer to energy consumers can reduce energy losses. Lowering average customer voltage levels can also reduce electricity losses (i.e., conservation voltage reduction).

Reduced Electricity Cost: Energy efficiency measures installed within project participant homes, and conservation voltage reductions achieved through DVVC in sub-project 4 may contribute to overall reductions in electricity usage. Likewise, load management programs using direct load control of programmable communicating thermostats (PCTs), smart appliances, PEVs, and RESUs may support utility efforts to reduce peak load. Customers who enroll in time-of-use retail electricity rates or participate in load management programs would benefit financially from shifting their electricity use to off-peak periods.

2.5.2 Reliability Benefits

Reduced Sustained Outages: A sustained outage is an outage lasting more than 5 minutes. The self-healing distribution circuit in sub-project 5 may minimize the number of customers impacted by a fault condition. This should result in fewer sustained outages for customers served by this looped circuit. In addition, sub-project 1 includes two energy storage devices, the RESU and CES, which may help reduce the number of outages. The RESU is configured to support a circuit with secure loads (e.g., the garage door and refrigerator), such that these loads may continue to receive energy from the RESU during outages. Likewise, later in the project the team will configure the CES to provide an "islanding" capability to the homes on the CES Block during outages. In this case, the CES may provide electricity to this block of homes for a brief period.

Reduced Restoration Cost: The self-healing distribution circuit (i.e., the looped circuit in sub-project 5) has the potential to reduce the labor cost associated with restoring service following an outage. The looped circuit should automatically recognize when a fault occurs, identify and isolate the segment of the line that contains the fault, and reenergize the remaining segments of the looped circuit. This could result in less crew time in the field and lower vehicle fuel consumption since the field personnel would only have to search for the fault on the isolated circuit segment.

Reduced Momentary Outages: A momentary outage is an outage lasting less than 5 minutes. The looped circuit in sub-project 5 should identify the location of fault events and isolate the fault to a specific line segment, resulting in fewer momentary outages for customers on the looped circuit. The RESU and CES in sub-project 1 also have the ability to reduce momentary outages through their islanding and secure load backup capabilities.

Reduced Sags and Swells: Sags and swells refer to customer voltage levels that are above or below a defined range for a momentary duration. The DVVC capability in sub-project 4 dynamically controls customer voltage levels. However, since the DVVC algorithm operates every 5 minutes, it may not provide the voltage support necessary to mitigate all sags and swells on the associated distribution circuits.

2.5.3 Environmental Benefits

Reduced Carbon Dioxide Emissions: The ISGD project team expects to demonstrate three ways to reduce carbon dioxide emissions.

- Energy efficiency measures in the customer homes, and reducing the average customer voltage profile through DVVC both have the potential to reduce overall household energy usage. Reducing energy use would also reduce carbon dioxide emissions.
- Load management programs using PCTs, smart appliances, PEVs, and RESUs may help utilities avoid using "peaker" power plants by reducing energy use during critical peak periods, and by shifting some energy consumption from peak to off-peak periods. Shifting energy consumption to off-peak periods has the potential to reduce carbon dioxide emissions, depending on the relative generation resource mix between these two periods.
- Replacing internal combustion vehicles with PEVs also has the potential to reduce carbon dioxide emissions.

Reduced SOX, NOX, and PM-2.5 Emissions: Reducing energy consumption, reducing peak demand, and shifting from internal combustion engine-based vehicle to PEVs may reduce SOX, NOX, and PM-2.5 emissions.

2.5.4 Security Benefits

Reduced Oil Usage: Reducing energy consumption, reducing peak demand, and shifting from internal combustion engine-based vehicle to PEVs, thereby decreasing consumption of petroleum-based fuels, would likely improve our nation's energy security.

Improved Cybersecurity: Protecting the communication between smart grid devices, the utility, third-party service providers, and customers by incorporating an appropriate level of cybersecurity is a basic requirement and fundamental enabler of the smart grid.

2.6 Project Stakeholder Interactions

The ISGD project has a number of stakeholders, including the DOE's National Energy Technology Laboratory (NETL), vendors, internal SCE stakeholders, and the participating homeowners. **Table 6** summarizes the major project stakeholders and the nature of their interactions with the project team.

Table 6: Summary of Stakeholder Interactions

Stakeholder	Interaction	Frequency
NETL	Since the project's inception, the team has provided project updates to the Technical Project Officer during regularly scheduled meetings or more frequently as issues arise.	Bi-weekly and ad hoc
ISGD Project Team (*SCE internal*)	During the design and commissioning phases, each sub-project held regular meetings with the sub-project teams and any other relevant subject-matter experts. The project team also held regular meetings with the all sub-project leads to share project updates or issues across sub-projects.	Bi-weekly

Stakeholder	Interaction	Frequency
Advanced Technology Management (*SCE internal*)	The team provides project updates to the managers and directors in SCE's Advanced Technology organization on a regular basis.	Bi-monthly
ISGD Steering Committee (*SCE internal*)	The team provides project updates to directors of other SCE organizations that have touch points with ISGD (e.g., Field Engineering, Customer Programs and Services, etc.)	Quarterly
Vendors	The team meets with vendors either remotely or on-site to facilitate completing project deliverables.	Periodic project execution meetings
Industry Research Organizations	The team meets with UCI faculty and student researchers periodically to discuss research progress and test planning and execution. The team meets with EPRI periodically to discuss project progress, and SCE provides annual project updates at EPRI-hosted webinars.	Bi-weekly (UCI) Quarterly (EPRI) Annual (EPRI)
California Public Utilities Commission (CPUC)	The team meets with CPUC commissioners and staff on a periodic basis to provide general project updates.	Ad hoc
Homeowners	During project deployment, the team interacted with the project homeowners on a frequent basis (daily, during field installation). During the measurement and verification period, the team began preparing customized energy usage analysis reports for each homeowner on a monthly basis.	Monthly

3. Technical Approach

This chapter describes the approach for evaluating the various smart grid technologies included within ISGD's scope. As described in chapter 2, ISGD includes four domains: Smart Energy Customer Solutions, Next Generation Distribution System, Interoperability & Cybersecurity, and Workforce of the Future. Each domain includes one or more sub-projects with distinct objectives, technical approaches, and research plans. This section summarizes the objectives, technical approaches, and research plans for each ISGD sub-project. Chapter 4 documents the results of these planned research activities.

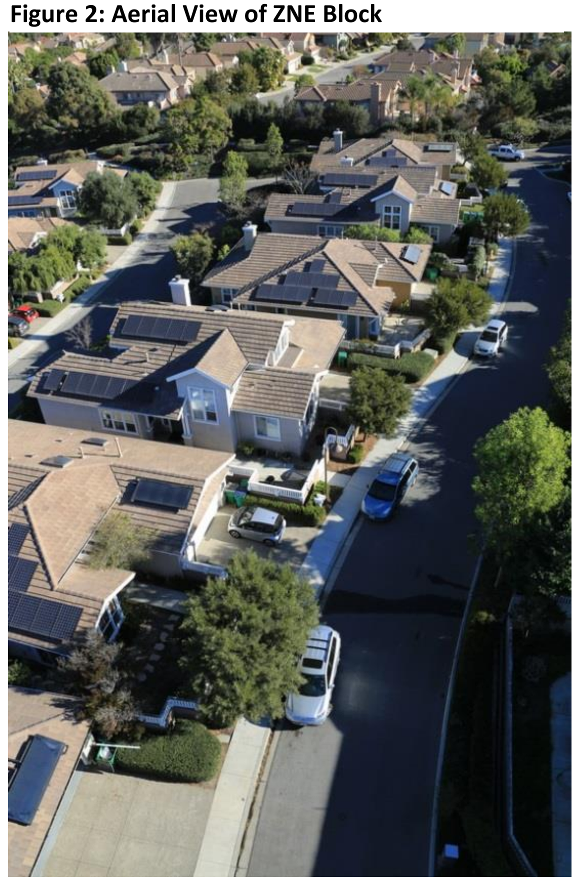
3.1 Smart Energy Customer Solutions

ISGD is evaluating a variety of technologies designed to help empower customers to make informed decisions about how and when they consume (or produce) energy. Such technologies have the potential to better enable customers to manage their energy costs, while also improving grid reliability and stability. ISGD is evaluating these customer technologies through two sub-projects: sub-project 1: Zero Net Energy Homes and sub-project 2: Solar Car Shade.

3.1.1 Sub-project 1: Zero Net Energy Homes

Various state and federal policies, technological innovations, and customer interest are likely to drive changes in residential energy consumption patterns by the year 2020. Sub-project 1 is evaluating various combinations of integrated demand side management (IDSM) technologies to better understand their impacts on the electric grid, and their contributions toward enabling homes to achieve ZNE[8]. ISGD includes four groups of project participant homes, including three test groups equipped with a variety of energy technologies, and a fourth group of homes used as a control group for experiment baselining purposes. All homes are located in the University Hills community on the UCI campus. The homes have two or three stories and range in size between 1,900 and 2,900 square feet. They have three to six bedrooms, three to three and a half bathrooms, and all have two-car garages. These homes were built between 2001 and 2002, and are located on a hillside with the lower floors built into the hill below street-level.

Figure 2: Aerial View of ZNE Block



3.1.1.1 Objectives

The objectives of this sub-project are to evaluate the impact of IDSM measures on customers' net energy consumption and usage patterns, and to assess the impact of these technologies on the grid.

3.1.1.2 Approach

This sub-project is demonstrating the integration of several IDSM measures intended to help customers achieve ZNE or near-ZNE homes. IDSM measures include the following:

[8] IDSM measures include both energy efficiency measures and demand response capabilities.

- Energy efficiency measures such as advanced lighting technologies, heating, ventilating and air conditioning (HVAC) technologies, smart appliances, and “building envelope” measures
- DR components such as PCTs, smart appliances, EVSEs, and RESUs
- A CES device
- Other customer technologies such as in-home displays (IHD), home energy management system (home EMS), and solar PV generation

The project team is assessing the impacts of these measures by tracking consumer use of the individual components, in terms of both total energy consumption and usage patterns. Appendix 3 summarizes the approach to collecting this energy usage information.

The following tables summarize the measures applied to each sub-project 1 test group.

Table 7: Sub-project 1 Test Group Designs

Test Group 1: ZNE Block
This represents the flagship test group for sub-project 1. The team outfitted these homes with a complete set of IDSM solutions, including energy efficiency upgrades, devices capable of demand response, a RESU, and a solar PV array. **Table 8** summarizes these upgrades. In addition to NETL, the CPUC will also likely find these outcomes informative for developing a strategy to establish ZNE as a goal for new residential buildings built beginning in 2020. A home achieves ZNE when it produces at least as much renewable energy as the amount of energy it consumes annually, including both natural gas and electricity. This would require homes to consume approximately 65% less energy than homes built with the 2005 California Building Energy Efficiency Standards. The team installed solar PV panels on the rooftops, sized to make these homes ZNE or near-ZNE, given the project’s budget and roof-space limitations. The array sizes are approximately 4 kW based on the results of eQUEST building energy simulations. After applying the cost-effective energy efficiency improvements and DR measures, the team sized the solar PV array to offset the remaining customer load. The RESUs are comprised of automotive-grade lithium ion cells, have nominal continuous power output ratings of 4 kW, and usable stored energy of 10 kWh. Additionally, the team installed plug load monitors and an electrical panel circuit monitoring system to measure energy consumption and demand. The team uses an Edison SmartConnect Itron sub-meter (sub-meter) to measure EVSE energy use, and an Edison SmartConnect Itron meter (smart meter) to monitor total household energy use. This meter is separate from SCE’s production billing meter. The smart appliances (refrigerator, dishwasher, and washing machine), communicating EVSE, PCT, and RESU all have demand response capabilities. These homes also have an IHD and a home EMS, which enable customer energy monitoring and control. IHDs are able to communicate DR program status and pricing signals to customers in real-time.
Test Group 2: RESU Block
All homes in this test group include identical components, including a RESU, rooftop solar PV array, IHD, home EMS, and a set of DR-capable HAN technologies, including PCTs, smart appliances, and communicating EVSEs. The team is using a sub-meter to monitor the EVSE branch circuit, and plug load monitors and an electrical panel load monitoring system to monitor other important loads. These homes have not received any of the energy efficiency upgrades included in Test Group 1.
Test Group 3: CES Block
All homes in this test group include identical components, including the same solar PV generation and HAN technologies as Test Group 2. However, instead of having a RESU in each home, the homes share a CES device (25 kVA, 50 kWh) installed near the distribution transformer. These homes are equipped with a communicating EVSE and sub-meter on the EVSE branch circuit. Additionally, plug load monitors and an electrical panel circuit monitor system capture end use device energy and demand. Similar to Test Group 2, these homes did not receive any of the energy efficiency upgrades included in Test Group 1.

Test Group 4: Control Block
These homes act as a control group to provide baseline data for analysis purposes. These homes received no advanced energy technologies, except for a smart meter and device power monitors used to record end-use demand and energy consumption information.

Table 8 summarizes the IDSM measures for each of the sub-project 1 test groups.

Table 8: IDSM Measures by Test Group

Test Group		Vendor	ZNE Block	RESU Block	CES Block	Control Block
Participating Homes/ Homes on Block			9/9	6/8	7/9	16/20
Demand Response	Energy Star Smart Refrigerator	GE	8	6	7	0
	Energy Star Smart Clothes Washer[9]	GE	8	6	7	0
	Energy Star Smart Dishwasher	GE	9	6	7	0
	Programmable Communicating Thermostat	GE	13	8	10	0
	Electric Vehicle Supply Equipment	BTC Power	9	6	7	0
	Home Energy Management System (home EMS)	GE	9	6	7	0
	In-Home Display	Aztech	9	6	7	0
Energy Efficiency Measures	Central Air Conditioning Replacement (Heat Pump)	Carrier	13	0	0	0
	Lighting Upgrades	Cree & George Kovacs	8	0	0	0
	Insulation	commodity insulation	8	0	0	0
	Efficient Hot Water Heater	A.O. Smith	2	0	0	0
	Domestic Solar Hot Water and Storage Tank	Bradford White	7	0	0	0
	Low Flow Shower Heads	High Sierra Shower-heads	29	0	0	0
	Plug Load Timers	Belkin	40	0	0	0
Solar PV & Energy Storage	Community Energy Storage Unit	S&C Electric	0	0	1	0
	Residential Energy Storage Unit with Smart Inverter	LG Chem	9	5	0	0
	3.3 – 3.6 kW Solar PV Panels	SunPower	0	5	5[10]	0
	3.9 kW Solar PV Panels	SunPower	9	0	0	0

[9] Although the three smart appliances are listed in the demand response section of this table, they are used for both demand response and energy efficiency.

[10] Some homes on the CES Block already had rooftop solar panels prior to ISGD. The team installed between 1.3 kW and 3.6 kW on each CES Block home, such that each of them now has 3.6 kW.

3.1.1.3 Research Plan

3.1.1.3.1 Energy Simulations

The team has conducted energy simulations on the ZNE Block homes using the eQUEST modeling tool. The team performed these simulations in conjunction with the design process for the ZNE Block homes. The purpose of these simulations was to estimate the impact and cost-effectiveness of the various EEM options. After incorporating energy efficiency measures into the retrofit plans for each home according to the results of the eQUEST model, solar PV of sufficient capacity was selected for the project homes to achieve ZNE (or near ZNE) on a forecasted basis.

3.1.1.3.2 Laboratory Tests

Individual technology components were laboratory tested before installation in the field to verify performance and functionality based on the manufacturer specifications.

3.1.1.3.3 Commissioning Tests

The team performed a series of tests in the field to verify that the devices and components would perform their required functions per the manufacturers' specifications. The team performed these tests on four classes of field devices: monitoring devices, HAN devices, the RESU, and the CES.

The monitoring devices consist of the plug load monitors, temperature sensors, branch circuit monitors, project smart meters, and transformer monitors. These devices collect the data required for the field experiments. The commissioning tests consisted of verifying the ability of these devices to monitor and collect data generated by the project participant homes.

The HAN devices include three smart appliances (refrigerator, dishwasher, and clothes washer), IHDs, PCTs, and EVSEs. These devices present energy usage information to the project homeowners and enable utility load management capabilities. The commissioning tests consisted of verifying the ability to send and receive demand response event signals using ZigBee Smart Energy Profile 1.x.

RESU commissioning included the following two tests:

- Utility Load Control: The intent of this test was to demonstrate SCE's ability to send remote signals to the RESUs to control the full spectrum of charge and discharge capabilities, as well as static VAR absorb/supply functionality.
- Secure Load Backup: The homes with RESUs are able to connect pre-determined circuits to the RESU Secure Load connection. The RESU should protect these circuits from outage for a short duration. The team will not perform any outages to test this RESU feature, but it will evaluate the RESU performance during any unplanned outages.

The CES commissioning included the following two tests:

- Utility Load Control: The intent of this test was to demonstrate SCE's ability to remotely control the CES's full spectrum of charge, discharge, and VAR inject/absorb functionalities. The team controlled the CES to charge and discharge real power, and to inject and absorb reactive power. Power quality monitors installed near the CES record data, confirm proper operation, and analyze the impact on the local grid. Part of the commissioning test was to verify that these data acquisition capabilities are operational.

- Islanding: The intent of this test was to confirm that the CES is able to provide an “islanding” capability following a grid outage. In the event of an outage, the CES may support the block’s distribution transformer load using stored energy, and allow the homes’ solar PV to continue generating energy. During any grid outage (or other event, such as short duration voltage sags or swells), locally installed power quality monitors and smart meters will record data. This data should confirm that the CES disconnects from the grid and begins supplying the required power to homes connected to the distribution transformer, provided the load is within the CES’s 25-kVA rating. Upon grid power restoration, the monitoring devices will confirm that the CES has reconnected to the grid without causing any power quality disturbances. Over the course of the demonstration period, if an opportunity arises due to a maintenance event, the team may initiate a forced islanding event to perform this test.

3.1.1.3.4 Field Experiments

The ISGD team is performing the following experiments to evaluate the impacts of the sub-project 1 capabilities.

Field Experiment 1A: Impact of Integrated Demand Side Management Measures on Home and Grid

The objective of this experiment is to quantify the impact of energy efficiency upgrades and other IDSM measures on the home and transformer load profiles. The specific measures implemented vary by home. The measures may include all the items or a subset, depending on homeowner preference. The list of potential upgrades includes the following: light emitting diode (LED) lighting, heat pump, high efficiency hot water heater, domestic solar hot water system, plug load timers, low flow showers, duct sealant, increased attic insulation, ENERGY STAR smart appliances, solar PV array, RESU, and other HAN devices. This experiment should help the team determine how the homes on the ZNE Block perform against the goal of achieving zero net energy, measured over a one-year period. The savings will be determined by comparing the collected data to past billing cycles, simulation results, and the Test Group 4 (Control Block) electricity usage. The experiment should also help the team assess the impact of the energy efficiency upgrades and the IDSM measures on the distribution transformer temperature and load profile. This experiment will also provide an understanding of the benefits associated with the IDSM measures installed on the RESU and CES Blocks.

Field Experiment 1B: Impact of Demand Response Events on Smart Devices, Homes, and Grid

The objective of this experiment is to quantify the impacts of DR[11] events on the load profiles of smart devices, the homes, and the secondary transformers. The following is a summary of ISGD’s various components and types of load control tests.

[11] Demand Response signals use the ZigBee Smart Energy Profile 1.x protocol via the project smart meters.

Table 9: Demand Response Components

Device	Demand Response Mode	Price Signal
Programmable Communicating Thermostat	• Degree offset • Degree set point • Duty cycle	None
Smart Appliances (clothes washer, dishwasher and refrigerator)	• Low power mode (all) • Delayed start (clothes washer and dishwasher)	None
In-home Display	None	Price displayed on screen
Residential Energy Storage Unit	• Calculated discharge	None

SCE plans to perform these experiments multiple times in order to evaluate performance under a variety of conditions, and to verify the consistency of results in terms of demand reduction. The team will likely perform these tests during summer months when the weather is warmer and the potential for load reduction is greater. The peak load reductions will be determined by comparing customer load profiles on experiment days with customer load profiles on non-experiment days, simulation results, and control home load profiles. The team will also observe the load pattern of the specific devices included within the test to determine their load reductions during the test event.

Field Experiment 1C: RESU Peak Load Shaving

The objective of this experiment is to quantify the ability of the RESU to shift coincident peak load to the off-peak period by discharging during the peak period. The team will place a group of RESUs (e.g., a block, the entire group of project homes, or another subset) into an operating mode (either a time or price-based mode) that schedules the RESUs to discharge during the peak period. Locally installed power meters and the customer's smart meter will record data throughout a test period of at least one week. The team will capture data to validate that the RESU appropriately charges and discharges to reduce the peak demand and energy consumption during peak hours. The team will evaluate the impact of the RESU using data from the control homes and the experiment homes for prior dates, over test periods of at least one week.

Field Experiment 1D: RESU Level Demand

The objective of this test is to quantify the ability of the RESU to automatically level demand over a 24-hour period. RESUs will operate in the Level Demand mode, which directs the RESU to discharge during periods of high demand and charge during periods with little load, thereby flattening the home's demand curve. The team will compare the customers' smart meter data with baseline data (loads without battery power) to ensure that the mode minimizes the customers' peak demand.

Field Experiment 1E: CES Peak Load Shaving

The objective of this experiment is to quantify the CES's ability to shave demand on the secondary transformer. The CES will automatically adjust its discharge power level based on real-time load provided from a locally installed power quality meter. This control will reduce the demand on the transformer. The team will analyze data collected from the power quality meter on the transformer to verify that the CES system reduces peak demand, and to investigate other impacts of this peak reduction (such as transformer temperature).

Field Experiment 1F: Impact of Solar PV on the Grid

The objective of this experiment is to quantify the impacts of rooftop solar PV generation on the load profile of the secondary transformer. This is a data collection activity only. Power quality meters installed on the local transformers will record transformer duty cycles (including load and temperature profiles). The team will compare this data to baseline duty cycles to analyze the impact the solar PV generation has on the transformer.

Field Experiment 1G: EVSE Demand Response Applications

The objective of this experiment is to demonstrate the utility's ability to modify PEV charging behavior by communicating demand response event signals to a PEV's EVSE. This experiment will test charging curtailment (i.e., reducing charging to 0 kW), as well as "throttling" whereby charging is reduced in 5% increments.

Field Experiment 1H: EVSE Sub-metering

The objective of this effort is to demonstrate the utility's ability to generate and transmit PEV-specific energy consumption data to the utility back office using both an EVSE integrated device and a utility owned device. As a stretch goal, the team will demonstrate how to reconcile "whole house" energy consumption with PEV charging consumption data in the back office, a potential PEV billing method referred to as "subtractive billing". This is a "proof of concept" demonstration of a PEV metering capability rather than an experiment.

3.1.2 Sub-project 2: Solar Car Shade

If plug-in electric vehicles achieve widespread adoption, it is likely that drivers will want to charge at work during the day to reduce "range anxiety," a driver's concern that a PEV would run out of energy before reaching their destination. However, daytime car charging will increase electricity demand during the day, and it may increase local or system peak demand. This sub-project is demonstrating a PEV charging system designed to minimize the net consumption of energy from the grid due to PEV charging. The team expects the system to reduce or eliminate the impact of PEV charging during on-peak periods.

Figure 3: Workplace Electric Vehicle Chargers and Solar PV Structure

3.1.2.1 Objective

The objective of this sub-project is to demonstrate how distributed solar PV generation, battery energy storage, and smart charging capabilities can help minimize the grid impact of PEV charging during peak periods.

3.1.2.2 Approach

The team installed solar panels above a parking garage on the UCI campus. The installation includes a 48 kW solar PV array that generates renewable energy during daylight hours and 20 parking spaces with EVSEs for PEV charging. SunPower supplied the solar PV array and BTC Power supplied the EVSEs. Anyone that has a UCI parking permit can charge a PEV in one of these spaces. Each EVSE is capable of receiving demand response messages and sending relevant energy consumption data to the manufacturer's back-office systems. Each EVSE has a maximum rating of 6.6 kW. The solar PV array receives support from a stationary BESS sized for 100 kW of power output and 100 kWh of energy storage. The energy storage system supports PEV charging during on-peak periods and cloudy days, and charges itself from the solar PV array and/or off-peak grid energy. Princeton Power Systems supplied the BESS.

3.1.2.3 Research Plan

3.1.2.3.1 Laboratory Tests

The team performed laboratory testing to simulate all BESS field tests in a controlled environment to ensure proper functionality and to prepare for the field tests. This testing helped the team determine whether the hardware and software operate according to the project's specifications. Testing helped to ensure that remote commands could control the system. The team also performed integrated system testing with a PV simulator to evaluate the PV functions.

3.1.2.3.2 Commissioning Tests

To commission the EVSEs and BESS, the team performed a series of tests in the field to verify that these components can perform their required functions.

- EVSE remote load control: The intent of this test was to verify that the EVSEs are capable of responding to remote load control signals to modify their charging behavior.
- Remote battery dispatch: The intent of this test was to verify that the BESS is capable of responding to a DR event signal. Power meters that record demand at the point of common coupling between the solar car charging system and the UCI grid were analyzed to ensure the BESS dispatched energy as requested and returned to its previous operation afterward.

3.1.2.3.3 Field Experiments

The ISGD team is performing the following experiments to evaluate the impacts of the sub-project 2 capabilities.

Field Experiment 2A: Minimize Peak Period Impact of PEV Charging

The objective of this test is to quantify the impact to the grid of charging electric vehicles using a charging system supported by solar PV and energy storage. The team performs this experiment by placing the BESS in a mode that minimizes the grid impact of electric vehicle charging. This mode attempts to reduce demand from the charging system to zero during peak periods. Local power meters record EVSE loads, solar PV generation, battery usage, and net demand. The team uses this data to analyze the behavior of the BESS and to verify its ability to minimize the impact of the PEV charging during peak periods.

Field Experiment 2B: Cap Demand of PEV Charging System

The objective of this test is to quantify the BESS' ability to limit demand of the PEV charging system at the interface with the electric grid. The team conducts this experiment by placing the BESS in a mode that limits demand to a specified threshold throughout the test period (24 hours a day) whereby it discharges whenever the load exceeds this setting. Power meters record EVSE loads, solar PV generation, battery usage, and net power. The team uses this data to analyze the behavior of the BESS and to verify that demand does not exceed the requested level.

Field Experiment 2C: BESS Load Shifting

The objective of this test is to quantify the impact of the PEV charging system while the BESS performs load shifting. The team performs this experiment by remotely configuring the BESS to shift load by charging during off peak periods and discharging during peak periods. Local power meters will record EVSE loads, solar PV generation, battery usage, and net power. The team uses this data to analyze the behavior of the BESS and to assess the PEV charging system's impact on the grid.

3.2 Next Generation Distribution System

The electric grid is evolving into an increasingly dynamic system with new types of distributed and variable generation resources and changing customer demands. ISGD is evaluating technologies designed to support grid efficiency and resiliency within this changing environment. The team is evaluating these technologies in four sub-projects: sub-project 3: Distribution Circuit Constraint Management Using Energy Storage, sub-project 4: Distribution Volt/VAR Control, sub-project 5: Self-healing Distribution Circuits, and sub-project 6: Deep Grid Situational Awareness.

3.2.1 Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage

3.2.1.1 Objectives

The objective of this sub-project is to demonstrate the use of battery energy storage to help prevent a distribution circuit load from exceeding a set limit and to mitigate overheating of the substation getaway.

3.2.1.2 Approach

This sub-project is demonstrating a mobile, containerized DBESS connected to the Arnold 12 kV distribution circuit. This circuit receives power from MacArthur Substation and is the same circuit where the project test homes in sub-project 1 are located. The DBESS has a rating of 2 MW of real power and 500 kWh of energy storage. The system includes supporting equipment such as a thermal management system and an interconnection skid to the 12 kV distribution system. SCE personnel monitor and control the DBESS locally.

3.2.1.3 Research Plan

3.2.1.3.1 Laboratory Tests

The team tested battery controls and all auxiliary system components prior to field installation to verify performance and proper functionality. The team also performed integrated system testing in the lab setting. To ensure that each component performs as expected, the team evaluated and repeatedly exercised the energy storage component, the power conversion system, and the control system. The team conducted real and reactive power import and export testing at various levels and durations to measure the response speed and to verify the precision and stability of the output. The team measured and analyzed cell voltage, state of charge (SOC), cell temperature, and inverter temperature to determine the relationships among these parameters.

3.2.1.3.2 Commissioning Tests

Prior to regular operation of the DBESS in the field, the team plans to perform a series of tests to verify that the components can perform their required functions. The intent of these tests is to verify that the device can synchronize with the grid, and that the protection elements are set properly. The team also plans to demonstrate SCE's ability to control the DBESS to inject or absorb power on the Arnold circuit.

3.2.1.3.3 Field Experiments

The ISGD team will perform the following experiment to evaluate the impacts of the sub-project 3 capabilities.

Field Experiment 3A: Peak Load Shaving/Feeder Relief

This experiment demonstrates the DBESS' ability to prevent the circuit load from exceeding a set limit and mitigate overheating of the substation getaways. This experiment is conducted by injecting or absorbing real power (up to +/- 2 MW) to keep the circuit load from exceeding a set limit. The storage device charges when conditions permit.

The team records and analyzes circuit load, circuit voltage, battery SOC, and system power input/output to determine if the system is capable of performing the peak load shaving/feeder relief function.

3.2.2 Sub-project 4: Distribution Volt/VAR Control

Delivering energy at lower voltage levels (within the required voltage limit) can result in CVR. This typically causes reductions in customer energy consumption. This sub-project is demonstrating the use of DVVC to optimize customer voltage profiles.

3.2.2.1 Objectives

The primary objective of DVVC is to achieve a “flat and low” voltage profile in pursuit of CVR. A 1% voltage reduction can potentially result in an approximate 1% reduction in customer energy consumption, in most cases. Superior voltage control may therefore be a cost-effective energy conservation measure. A secondary goal of DVVC is to rapidly raise the target voltage, by placing more capacitors on line, to support the transmission system’s VAR requirements.

3.2.2.2 Approach

SCE currently uses technology that was developed many years ago to maintain customer voltage within the lower half of the required customer voltage range, as designated in the American National Standards Institute (ANSI) C84 standard (114 to 120 volts at the customer service connection). SCE uses load tap changer (LTC) transformers and capacitors to regulate system voltage and VARs, depending on the grid voltage level. LTC transformers typically control sub-transmission system voltage. These devices reside between the bulk power system (500 kV – 220 kV) and the sub-transmission system (115 kV – 66 kV). SCE’s 12 kV and 16 kV distribution systems that are supplied by a 66 kV sub-transmission system primarily use switched capacitors located along the circuits and within each substation connected at the distribution bus. SCE's most common distribution capacitor controls operate based on the primary circuit voltage at its connection point, although some are strictly temperature controlled. Each capacitor controller usually has a control bandwidth that switches a capacitor off when the primary voltage exceeds the upper band and switches the capacitor back on when primary voltage drops below the lower band.

To compensate for additional voltage drop during peak conditions in the secondary system (120/240 volt), many of SCE’s capacitor controllers use time bias and/or temperature bias. The bias will raise (or lower) the entire bandwidth during specific times of the day or temperature conditions as a means to provide additional voltage support during peak conditions. The problem is that this bias attempts to estimate (and compensate for) secondary voltage drop based solely on time of day and/or temperature, irrespective of customer load and voltage conditions. While this system provides peak voltage/VAR support sufficient for SCE to comply with the ANSI C84 standard, it does not optimize the voltage profile for customers along each feeder, nor does it optimize for off-peak periods.

DVVC seeks to improve on this approach by building on experience gained from a previous SCE pilot in the 1990s called the Distribution Capacitor Automation Project (DCAP). The key to successful capacitor automation is to implement a smart centralized control algorithm that uses primary circuit voltage and substation Watt and VAR measurements to operate substation and field capacitors. The DVVC algorithm solves for the optimal system capacitor switching combination that will satisfy user-defined constraints for minimum and maximum voltage and reactive power flow. It calculates the optimal solution based on expected capacitor voltage changes derived from detailed circuit models. The team will verify system performance using actual customer voltages provided by Edison SmartConnect production meters. DVVC is an advanced application within the ISGD Distribution Management System (DMS) provided by GE.

In late 2014 or early 2015, the team intends to transition from DVVC to IVVC (Integrated Volt/VAR Control), an advanced DMS application that uses real-time load flow information to make decisions about capacitor switching.

After operating each application for between six and nine months, the team plans to assess their relative performance and feasibility for achieving CVR.

3.2.2.3 Research Plan

3.2.2.3.1 Simulations

The team will perform steady-state circuit modeling, via SCE's Real Time Digital Simulator (RTDS), to graphically display the system voltage profile and VAR flow resulting from DVVC. The team will use circuit modeling to verify that no adverse end-of-line voltage conditions exist.

3.2.2.3.2 Laboratory Tests

The team evaluated the field apparatus and systems comprising the DVVC at SCE's Advanced Technology Labs to determine if the DVVC system is capable of meeting voltage requirements and to assess system performance. Technology component testing occurred before field installation to verify performance and proper functionality. The team also performed integrated system testing in the lab setting. During the second year of the demonstration period, the project will transition to the integrated volt/VAR control (IVVC) method, which utilizes real-time load flow information to manage the capacitor bank operations.

3.2.2.3.3 Field Experiments

The ISGD team is performing the following experiments to evaluate the impacts of the sub-project 4 capabilities.

Field Experiment 4A: DVVC VAR Support

This experiment uses the DVVC application to supply additional VAR support to the transmission system. The team demonstrates this capability by verifying that the transmission system receives additional VAR support upon raising that customer target voltage to the highest allowable level (without exceeding upper regulatory limits). SCE Operations would make the emergency request in real life, but the ISGD team will simulate this request for the ISGD project. Test protocols and data collection from substation relays and customer meters are used measure the impacts.

Field Experiment 4B: DVVC Conservation Voltage Reduction

This experiment consists of operating the DVVC algorithm to determine if it satisfies DVVC's main objectives. These objectives include meeting volt/VAR requirements (when possible), minimizing average customer voltage, and minimizing capacitor controller switching.

3.2.3 Sub-project 5: Self-healing Distribution Circuits

This sub-project will demonstrate a self-healing, looped distribution circuit that uses low latency radio communications to locate and isolate a fault on a specific circuit segment, and then restore service once the fault clears. This protection scheme isolates the faulted circuit section before the substation breaker opens. This functionality should lead to improved distribution circuit reliability by reducing the number of customers exposed to momentary outages and easing the circuit restoration burden on system operators and equipment.

3.2.3.1 Objectives

The objective of this sub-project is to demonstrate an advanced circuit protection capability that reduces the number of customers impacted by outages, and reduces the service restoration time for customers impacted by outages.

3.2.3.2 Approach

When a fault occurs on a standard radial distribution circuit, a circuit breaker opens, which causes the entire circuit to lose power, affecting all customers served by that circuit. While automated switching can sometimes restore part of the circuit within a few minutes, all customers experience at least a short outage. This can negatively affect reliability statistics and extend outage restoration times for radial circuits.

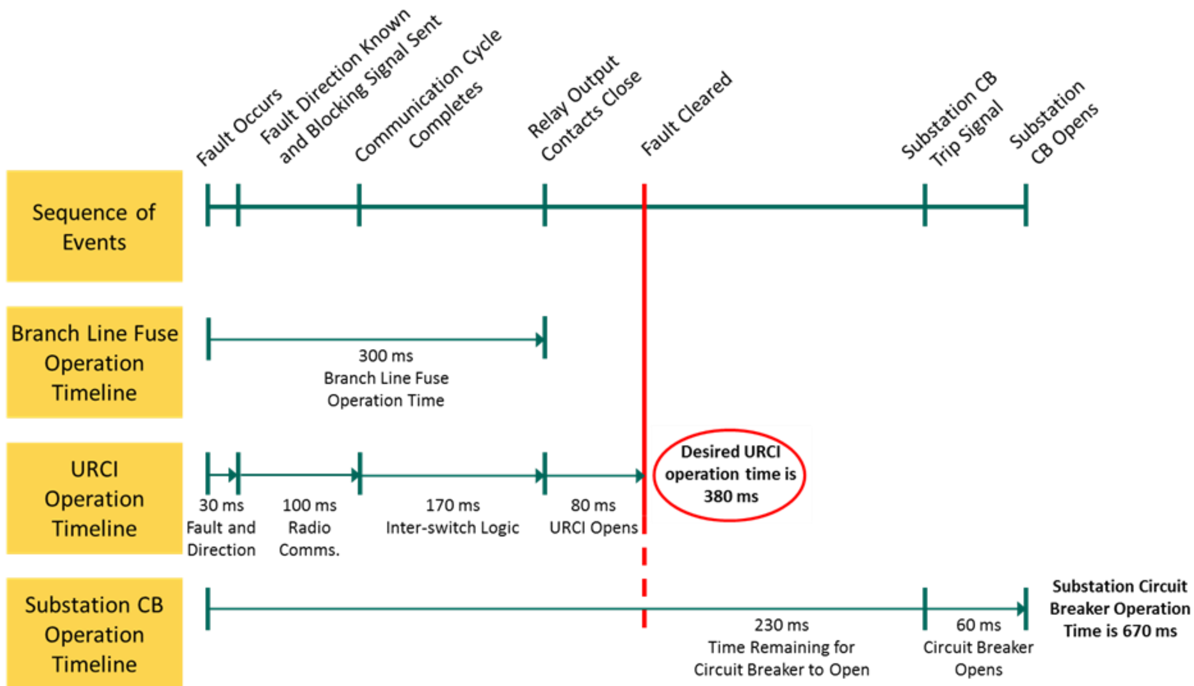
ISGD's self-healing distribution circuit includes a looped topography, four URCIs,[12] and low latency, high-speed radio communications between individual URCIs and the substation protection relays via a substation gateway. This communication system allows the URCIs and the substation protection relays to collaborate by isolating and managing faults that occur on two circuits fed by the substation. Quickly isolating a smaller circuit segment during fault events (before the substation breaker opens) can reduce the extent and duration of distribution outages, thereby improving electricity service reliability. A secondary benefit of this sub-project is demonstrating radio as a low cost alternative to fiber optic communications. This is a more cost-effective way to perform retrofits on existing substations and circuits.

This sub-project is using two 12 kV distribution circuits (Rommel and Arnold) out of Macarthur Substation to form a single looped circuit. Each of these circuits includes two URCIs. The URCIs communicate with each other and the substation feeder relays using standard IEC (International Electrotechnical Commission) 61850 Generic Object Oriented Substation Event (GOOSE) messaging for protection coordination. This protocol supports the high speed messaging required for this protection scheme. Since the purpose of this distribution protection system is to only interrupt the faulted section of a circuit, the protection communications and control operations need to operate faster than the substation circuit breaker. Substation circuit breakers currently operate within 500 to 600 milliseconds (ms) of a fault event. If the URCIs take longer to isolate a fault, the substation circuit breaker will open, causing the entire circuit to lose power.

Figure 4 depicts the timeline of a hypothetical fault on a distribution circuit, including the time required to clear the fault.

[12] Each URCI contains four key hardware components: G&W Viper-S Padmount Recloser, SEL 651R Recloser Controller, S&C Electric Intellicom Radio, and an Elastimold Control Power Transformer. These components provide power monitoring, device control, communications, and fault interruption.

Figure 4: Distribution System Protection Event Sequence and Timeline



Detecting the fault and determining its direction requires approximately 30 ms. The time required may be longer, depending upon the time/overcurrent curve in operation. An additional 100 ms is required for the radio communications to send the blocking signals between the URCI relays, and an additional 170 ms is needed for communications retries and execution of the logic within each URCI relay. This equates to 300 ms, the same amount of time allowed for circuit branch line fuses to operate. Branch line fuses limit outages to branches lines, which are smaller than segments that the URCIs are designed to isolate. Thus, the URCI logic intentionally waits 300 ms to allow the branch fuses to operate.

Once the URCI logic is complete, the URCI relays send signals to open the vacuum switches—this only applies to the two relevant URCIs involved in isolating the fault. The switch needs approximately 80 ms to physically open. If the protection scheme operates correctly, the system would clear the fault within about 380 ms. If the protection scheme does not operate properly, the substation circuit breakers would be signaled to open and interrupt the fault within another 230 ms. The circuit breaker needs an additional 60 ms to physically open. In this case, the system would clear the fault within 670 ms.

This protection scheme necessitates communications fast enough to send and receive GOOSE messages within 100 ms. Since GOOSE messages are small, the communications system does not need to be broadband. However, it must be low latency. The radio system also requires sufficient propagation to minimize the need for repeater radios, since these radios increase latency. ISGD is using a system that operates in the 2.4 GHz unlicensed spread-spectrum band, which requires several repeater radios to cover the area where the URCIs are located.

Since the URCIs are supposed to be universal, the logic is the same for all four URCIs. When a fault occurs, each URCI needs to determine whether the fault is either "upstream" or "downstream" from it. The team accomplishes this by properly setting the polarity of the connections to the current transformers at each location. Each URCI must also be able to communicate with the adjacent URCIs. The team accomplishes this by configuring each URCI to "subscribe" to messages from the neighboring URCIs.

During an actual fault event, once the URCIs determine the fault location and direction, the relevant URCIs send trip or block trip- messages to the neighboring URCIs using the IEC 61850 GOOSE messaging protocol. The URCIs use internal logic to identify a fault and its direction. The URCI senses both phase and neutral time-overcurrent, which determines whether the URCI sends the GOOSE blocking message “upstream” or “downstream.” When a URCI receives a blocking message, it stops the circuit breaker from opening. The URCI maintains this block as long as the blocking message is from an adjacent relay. When the time-overcurrent element of the relay times out, the URCI opens its circuit breaker. Because of different impedances for each of the two ways the current can flow around the circuit loop, the current feeding the fault will differ for each URCI. The direction with the higher current will trip its circuit breaker more quickly. To ensure that the URCI on the other side of the fault trips quickly and speeds fault isolation, the tripped URCI sends a signal to the URCI on the other side of the fault instructing it to open its circuit breaker.

3.2.3.3 Research Plan

3.2.3.3.1 Simulations

The team has conducted simulations to verify the fault isolation logic, timing, and successful tripping of URCI devices under a wide range of operating conditions, including failure of equipment (N-1) configurations. The team used RTDS to conduct these simulations. The actual protective relay inputs and outputs (three phase voltages and currents, trip contacts, close contacts, and breakers status input) interfaced with RTDS.

The team also plans to perform simulations using GE’s advanced DMS applications, Contingency Load Transfer (CLT), and Fault Detection, Isolation and Restoration (FDIR). The team will compare these simulation results to the simulation results using the URCI capability to determine the relative effectiveness of each for improving distribution system reliability.

3.2.3.3.2 Laboratory Tests

The team assembled and tested the technology components (e.g., relays and radios) before field installation to verify performance and proper functionality. The team imposed actual circuit fault conditions (derived from simulations) on the assembled components and recorded the protection system responses. The team also verified high-speed communication performance. This included assembling and testing the new substation automation system to verify the communications between the substation and the URCIs.

The team did not induce actual faults on the live circuit given the presence of customers on the circuit. Lab testing served as a proxy for this type of field testing. However, the team installed instrumentation to record any actual faults that occur on the circuit. Actual faults will provide additional verification of the design and operation of this advanced protection system.

3.2.3.3.3 Commissioning Tests

Prior to commissioning the self-healing circuit capability, the team will verify the functionality of the system by validating the operation of the low latency communication system and the URCIs in a bypassed condition. These tests will be performed a number of times by simulating faults on each of the looped circuit segments. Since the URCIs will operate in bypassed mode, there will be no service interruptions to SCE’s customers.

3.2.3.3.4 Field Experiments

The ISGD team will perform the following experiments to evaluate the impacts of the sub-project 5 capabilities.

Field Experiment 5A: Self-healing Circuit

Since the team will not impose any faults on Rommel or Arnold, it will only use actual fault events to evaluate the ability of these circuits to self-heal. In the event a fault does occur, the team will evaluate the enhanced fault protection and automated feeder switching functionality based on recorded substation and URCI fault event information.

Field Experiment 5B: De-looped Circuit

The team will also operate the circuits in a radial configuration to verify that the URCIs function properly using that configuration. The looped circuit may be de-looped to a radial configuration for test purposes, when high loads create circuit instability, or during other abnormal system conditions.

3.2.4 Sub-project 6: Deep Grid Situational Awareness

3.2.4.1 Objectives

The objective of this sub-project is to demonstrate how high-resolution power monitoring data captured at a transmission-level substation can detect changes in circuit load from a distributed energy resource (such as demand response resources, energy storage, or renewables). Such a capability could help enable aggregators of such resources to participate in energy markets by providing a means of verifying resource performance. This capability would obviate the need for additional and potentially costly metrology equipment for each individual participating resource.

3.2.4.2 Approach

Equipment located at the Santiago and MacArthur substations will capture high-speed power measurements. Santiago substation is a transmission-level substation located upstream of MacArthur Substation (a 66kV distribution substation). The installation of monitoring equipment at Santiago Substation is part of SCE's Phasor Monitoring and Grid Stability System previously approved by the California Public Utilities Commission. The MacArthur Substation relays are part of the SA-3 upgrade. These relays are equipped to provide high-speed data to a dedicated phasor data concentrator (PDC) at the MacArthur Substation. All high-speed data is stored within a PDC located in Alhambra for subsequent offline analysis.

The ISGD team is manually collecting data from the Santiago and MacArthur substations, and analyzing and comparing it to the actual load changes measured at the load source. To help analyze this data, UCI has developed an algorithm to aid in and potentially automate this verification process. The algorithm will help the team analyze high-speed data from the transmission-level substation (Santiago). Comparable data from the distribution-level substation (MacArthur Substation) will help the team to validate the Santiago Substation data analysis. The 2 MW, 500 kWh energy storage system connected to the Arnold 12 kV distribution circuit will provide the load changes that underpin this analysis. This is the same energy storage system used for sub-project 3.

3.2.4.3 Research Plan

3.2.4.3.1 Field Experiments

The ISGD team will perform the following experiment to evaluate the impacts of the sub-project 6 capabilities.

Field Experiment 6A: Verification of Distributed Energy Resources

SCE will operate a 2 MW battery to produce load changes of various magnitudes and durations, and at various ramp rates. The magnitude of these changes will be up to 4 MW, spanning from a maximum charge rate of 2 MW to a maximum discharge rate of 2 MW. UCI will then analyze high-speed data from Santiago Substation and attempt to identify the specific load change resulting from operation of the 2 MW battery. The high-speed data from MacArthur Substation will help the team validate whether or not the analysis of the Santiago Substation data was accurate.

3.3 Interoperability & Cybersecurity

The electric grid is evolving to include an increasing number of distributed and interconnected grid resources, both utility and customer-owned. The need for plug-and-play interoperability within a secure environment is therefore of critical importance. This project domain is a foundational element that underpins the development of smart grid capabilities. ISGD is evaluating interoperability and cybersecurity through sub-project 7, which is composed of two elements: Secure Energy Network and Substation Automation 3.

3.3.1 Sub-project 7: Secure Energy Net

3.3.1.1 Objective

The objective of SENet is to implement a secure communications and computing architecture to enable the interoperability of all ISGD sub-projects throughout the project lifecycle.

3.3.1.2 Approach

Secure communications between smart grid devices, the utility, and customers is a basic requirement and fundamental enabler of smart grid functionalities. The smart grid requires information sharing between many utilities and system operators, across electric reliability regions, to support the U.S. energy policies described in the 2007 Energy Independence and Security Act, Title XIII. A secure telecommunications infrastructure linking regional transmission and utility operations across the U.S. and North America will provide the essential information technology backbone for a smart grid.

Information demands will include not only those from the utility to support operations, but also from customers and third parties looking to support their own near real-time decision making needs such as DR.

Smart grid sensing and control devices require secure communications capabilities between utilities' central control centers and offices, across backbone networks out to the new in-substation networks, field area networks (FAN), and HANs. Finally, since the requirements for secure utility communications are emerging and evolving, a key challenge facing utilities is meeting these security requirements in a way that allows flexibility and avoids having to continually replace IT infrastructure.

The ISGD team designed a secure telecommunications infrastructure linking the following five network domains:

- Intra-utility Network: This network connects back-office data systems with grid control centers and to substation gateways. It also supports control, protection, and measurement functions using a high-speed fiber backbone leveraging MPLS (Multiprotocol Label Switching) routers.
- Substation Local Area Network: This provides communications between devices within a substation that support control, protection, and measurement functions for distribution automation.
- Field Area Network: This provides communications between a substation, circuit-connected devices, and HANs. This network supports wireless broadband, protection, and interfaces to the Intra-Utility network.
- Internet and Public Carrier: This network will provide non-critical monitoring data such as energy related information exchange over secure connections. This network may use wireless carriers and commercial Internet providers.
- Home Area Network: This network connects to customers' two-way devices to send, receive, and collect energy information. Gateways within the customer premises will provide connectivity to diverse networks.

To help satisfy the SENet objective of providing a secure communications and computing environment for ISGD, the team has implemented the following four capability groups:

- Modern Infrastructure and Communications: Implement and test the viability, compatibility, and resiliency of next generation networking protocols; and deploy grid control applications on modern, virtualized platforms, to enable faster detection and resolution of issues, while minimizing down time to business operations.
- High-Assurance Cybersecurity: Implement advanced security across the various smart grid domain networks. ISGD has implemented SCE's CCS platform, which the team expects to be scalable for a mature smart grid environment.
- Standards-driven Interoperability (communications and interfaces): Utilize standard system interfaces and communications protocols, where possible, to facilitate integration and interoperability between back-office systems and field components. ISGD has implemented a services oriented architecture using GE's Smart Grid Software Services Infrastructure (SSI) as a services integrator and broker, enabling interoperability across multiple vendors' software applications.
- Visualization: Enhance situational awareness by facilitating real-time decision making as well as after-the-fact investigation of catastrophic events by co-relating data elements from a disparate set of data sources, both historical and real-time, to serve a unified view to grid operations.

3.3.1.3 Research Plan

Following the architecture and design phase, vendors built the individual ISGD sub-systems. Once these successfully passed factory testing, they were installed at the SCE lab for further testing and full system integration. Following SCE lab installation, the team conducted comprehensive performance testing on the integrated production networks. The team will conduct performance testing during the measurement and verification period. This testing will address performance of the ISGD networks, security, interoperability, and visualization. This results of this testing will appear in either the second TPR or the Final Technical Report.

3.3.2 Sub-project 7: Substation Automation 3

3.3.2.1 Objectives

The goal of SA-3 is to transition substations to standards-based communications, automated control, and an enhanced protection design. Achieving these goals will support system interoperability and enable advanced functionalities such as automatic device configuration and backward compatibility with legacy systems.

3.3.2.2 Approach

The MacArthur Substation SA-3 pilot is demonstrating the following:

- An open standards-based human-machine interface (HMI), which helps avoid vendor lock-in
- Password management (user-specific, role-based passwords)
- Fully-automated substation device configuration
- Secure and remote access
- IP-based data and control communications
- Integration of CCS
- Process improvements
  - Project engineering (project file creation) efficiencies due to SEMT (Substation Engineering Modeling Tool) improvements
  - Factory acceptance testing and on-site testing process improvements due to standards-based device auto-configuration processes
  - Remote visibility and control of field devices

- Centralized distribution volt/VAR control
- Integration of DMS with substation control

The SA-3 design incorporates IP-based intelligent electronic devices (IED), a programmable logic controller (PLC), an industrial hardened HMI, and substation gateway integrated with CCS. One of the advantages of SA-3 is to enable device auto-configuration, compliant with the IEC 61850 standard, eliminating the need for manual configurations. The substation gateway securely bridges the FAN to the substation local area network (LAN), enabling the self-healing circuit capabilities of sub-project 5. Lastly, SA-3 allows SCE to compare the advantages or disadvantages of operating DNP3 (Distributed Network Protocol) over IP communications in lieu of the current DNP3 over serial communications.

SA-3 is a foundational element required for ISGD to implement sub-projects 3, 4, 5 and 6. SA-3 provides the secure communications, remote monitoring, and control schemes necessary for these sub-projects.

3.3.2.3 Research Plan

3.3.2.3.1 Simulations

The team performed steady-state circuit modeling to support the development and debugging of the SA-3 system.

3.3.2.3.2 Laboratory Tests

The ISGD team tested the system components before field installation to verify performance and functionality. Laboratory testing included component communication, password management, protection settings, logic configuration, and auto-configuration. By using a mobile Real-Time Digital Simulator, the team simulated thousands of system conditions and evaluated the SA-3 responses. Following these simulations, the team performed end-to-end interoperability and system integration testing at SCE's Advanced Technology facility. The final stage of testing included interface simulations with the Energy Management System (EMS), DMS, eDNA (archiving software), enterprise configuration management software (i.e., PowerSYSTEM Center), and the FAN.

3.3.2.3.3 Commissioning Tests

The deployment strategy for the SA-3 system followed SCE's existing construction and commissioning standards. These standards require qualified electrical workers to validate circuits, protection settings, and control logic. The introduction of new SA-3 functionalities requires additional work including device auto configuration and configuration management testing (e.g. remote secure access and password management).

3.4 Workforce of the Future

This project domain provides the workforce training tools and capabilities necessary to operate and maintain the various ISGD components. The sub-project is also evaluating the potential impacts of smart grid technologies on the organizational structure of the utility.

3.4.1 Workforce Training

The ISGD team developed training materials for the ISGD project in accordance with the ADDIE process. This process enables the authoring of training content through five major stages: (1) analysis, (2) design, (3) development, (4) implementation, and (5) evaluation.

3.4.1.1 Stage 1: Analysis

The team conducted a training needs analysis by identifying the Transmission and Distribution (T&D) personnel impacted by ISGD, and then assessing how ISGD would affect their roles. The job classifications included Linemen, Troublemen, System Operators, Substation Operators, Distribution Apparatus Test Technicians, Substation Test Technicians, and Field Engineers. Each of these personnel has specific roles with respect to operating and maintaining MacArthur Substation and the Arnold and Rommel 12 kV circuits. Therefore, at a minimum, these personnel need to understand ISGD's scope and its various field components.

Through discussions with ISGD subject matter experts (SME) and field personnel, the team determined that many tasks these personnel are responsible for would not change substantially due to the technologies introduced by ISGD. However, these personnel would need to understand how these technologies work. They would also need to understand how to work with these components if they experience a failure in the field. The ISGD technologies are not introducing fundamental changes in the required knowledge, skills, or abilities. However, in some instances there is a convergence of information technology with operations technology skills due to the communications capabilities of the field devices. In most cases, the ISGD technologies represent a logical iteration of current technologies.

3.4.1.2 Stage 2: Design

To ensure that field personnel are properly equipped with the knowledge necessary for working with the ISGD technologies when performing their daily duties, the team decided to produce introductory classes and role-specific reference content. Key reference documents are also available to personnel on an as-needed basis.

There are three deliverables associated with the project: (1) role-specific job aids, (2) introductory classroom training, and (3) an online training repository.

Role-Specific Job Aids: Job aids help to ensure that specific installation, operations, and maintenance activities are described in detail for specific job classifications.

Introductory Classroom Training: Impacted field personnel and their supervisors received classroom-training sessions led by the ISGD project managers and engineers, in partnership with the T&D Training organization. These classroom sessions covered overviews of the ISGD project, as well as details associated with the ISGD components affecting T&D.

Online Training Repository: A training repository tool provides personnel with fast, organized access to electronic versions of the ISGD training content, vendor documentation, and related internal SCE standards. This tool covers a self-guided basic overview of the project, as well as an intuitive user-interface, enabling the learner to find content quickly and efficiently.

3.4.1.3 Stage 3: Development

The team developed the three workforce training deliverables as follows:

Role-Specific Job Aids: SCE personnel developed job aids and captured all of the images during equipment mock-ups or actual installations.

Introductory Classroom Training: The team developed classroom-training sessions with heavy input from SMEs and project personnel.

Online Training Repository: The team developed the online training repository using an eLearning authoring software package. This software provided flexibility in designing the user interface, as well as the capability to effectively organize the content.

3.4.1.4 Stage 4: Implementation

The classroom training occurred between November 2013 and January 2014 for all personnel impacted by the CES device, DBESS, DVVC, URCI, and SA-3. During the classroom training, all personnel received hard copies of the training content for their reference and review.

3.4.1.5 Stage 5: Evaluation

The team performed informal evaluations throughout the training courses by collecting feedback from employees. Formal evaluations forms were provided during a few training sessions, and the feedback was generally positive. A feedback survey option will be included for any personnel accessing the online training tool.

3.4.2 Organizational Assessment

The organizational assessment will take place in 2014, and the team expects to complete it by early 2015. ISGD will report on this aspect of the project in either the second TPR or the Final Technical Report, depending on when the team finalizes the assessment results.

The objectives of the organizational assessment are to analyze the organizational impacts of implementing new technologies, and to develop recommendations and industry best practices for addressing these impacts. The assessment will address organizational impacts, organizational design, organizational readiness, and associated lessons learned from the ISGD project. The team will develop an organizational assessment report that includes the following:

- Identifies the most effective future organizational structure
- Compares the current and future organizational structures to identify the largest gaps and potential obstacles
- Specifies how future organization functions and responsibilities will differ from current ones, including changes in workforce size, organizational hierarchy, and the organizational functions
- Identifies policies and procedures necessary to facilitate the identified changes
- Identifies industry best practices for designing organizations that adequately support smart grid technologies

4. Results

This chapter summarizes the simulations, laboratory testing, commissioning tests, and field experiments used to assess the various ISGD technologies. The first TPR focuses on the engineering, design, and deployment activities. This TPR also summarizes the first eight months of field experiments. These field experiments are all from the Energy Smart Customer Solutions domain. Future TPRs will include the results of additional field experiments across all sub-projects.

4.1 Smart Energy Customer Solutions

4.1.1 Sub-project 1: Zero Net Energy Homes

ISGD has deployed a number of IDSM technologies to better understand their impacts on the customer homes and electric grid and to assess their contributions toward enabling homes to achieve ZNE. This section summarizes the energy simulations, laboratory tests, commissioning tests, and field experiments used to assess these technologies.

4.1.1.1 Energy Simulations

Energy simulations served a key role in helping the ISGD team identify the IDSM measures to for the customer homes, and to estimate the potential effect of the various EEM options. Simulations helped the team evaluate the effects of the IDSM measures chosen for each of the homes on the ZNE Block. The team used the eQUEST modeling tool to perform these simulations.

The initial step in this process was to obtain information about each of the 38 project homes within the four residential blocks to develop a baseline annual energy usage for each home. The homes include four distinct home styles that vary from a 1,900 square foot, two-story home to a 2,900 square foot three-story home. The home information was gathered through a series of online homeowner surveys and on-site energy audits. These included the following steps:

- Gathering monthly historical electricity and gas utility data for the past three to five years
- Gathering hourly historical weather data for the past three to five years
- Understanding the home envelopes, including floor and ceiling plans for the four home styles
- Analyzing the homeowner surveys and on-site energy audits

The team then updated computer-aided design drawings of each home, developed models for home energy simulations for each model type, and calibrated the energy models using energy usage information gathered from the utility bills, historical weather data, homeowner surveys, and home energy audits. The weather data was collected from a SCE weather station about five miles north of the homes.

The models aided the team in generating a list of potential EEMs for each home within the ZNE Block. The team reviewed these EEMs and created a final list of measures that balanced the project budget with the desire to maximize the homes' energy efficiency.

Based on the cost-benefit information for the final bundle of EEMs and the results of the solar PV analysis, the team developed flyers for each home on the ZNE Block of customer homes. These flyers provided a list of the EEMs and the associated savings for electricity and gas consumption. Appendix 5 includes an example flyer. Using the flyers, the project team met with the homeowners to discuss their options and preferences for installing the EEMs. The homeowners then made their final selection of the EEMs for installation. **Table 10** summarizes the final EEM selections. The homes on the ZNE Block were randomly assigned numbers one through nine in order to conceal the confidential customer information.

Table 10: Energy Efficiency Measures by ZNE Home

Energy Efficiency Measures	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Central Air Conditioning Replacement (Heat Pump)	✓	✓		✓	✓	✓	✓	✓	✓
Lighting Upgrades	✓	✓		✓	✓	✓	✓	✓	✓
Insulation	✓	✓		✓	✓	✓	✓	✓	✓
Efficient Hot Water Heater	✓	✓	✓	✓	✓	✓	✓	✓	✓
Domestic Solar Hot Water and Storage Tank	✓	✓		✓	✓	✓		✓	✓
Low Flow Shower Heads	✓	✓	✓		✓	✓	✓		✓
Plug Load Timers	✓	✓	✓	✓	✓	✓	✓	✓	✓
Duct Sealing	✓	✓		✓	✓	✓	✓	✓	✓

The team then performed simulations to estimate the energy savings that would result from the selected EEMs. The estimated combined gas and electricity energy savings ranged from 38% to 48%. **Table 11** summarizes the simulated energy savings by project home.

Table 11: Simulated Energy Savings by ZNE Home

Energy Savings	ZNE 1	ZNE 2	ZNE 3	ZNE 4	ZNE 5	ZNE 6	ZNE 7	ZNE 8	ZNE 9
Energy Savings (%)[13]	40	47	38	39	38	46	48	39	43
ZNE Goal (%)[14]	84	73	90	76	83	89	72	87	64

The EEM installations are complete, and the team has begun collecting energy consumption data. Once the team has accumulated a full year of data, it will perform the energy simulations again to evaluate the effectiveness of the EEMs in helping the project homes achieve ZNE. A full year of energy use is necessary to perform ZNE calculations.

4.1.1.2 Laboratory Tests

4.1.1.2.1 Smart Appliances

The ISGD project is demonstrating three smart appliances bearing the ENERGY STAR logo: a refrigerator, a clothes washer, and a dishwasher. Prior to installing these appliances in the customer homes, the ISGD team tested and evaluated them in a laboratory setting. The purpose of this testing was to quantify the demand reduction potential of these devices, and to characterize their responses to DR signals under various operational scenarios. SCE's Design & Engineering Services Technology Test Centers performed functional testing. SCE's HAN laboratory complemented this testing with communications testing.

The dishwasher's DR strategy consists of delaying the operating wash mode, or eliminating the heated dry mode. During testing, the team determined that the dishwasher has the potential to eliminate or delay up to 1 kW of demand. The team also determined that the DR delay scenario does not affect the dishwasher's energy consumption. However, the heated dry element increases the dishwasher's energy consumption of a normal wash mode by 40%. The dishwasher was able to consistently demonstrate compliance with its intended DR strategy.

[13] This reflects the percentage energy savings (combined both electricity and gas) by comparing historical energy usage to estimated energy usage (based upon simulations), after all recommended energy efficiency measures are accepted by the homeowners and installed in the project homes.
[14] A goal of 100% means that a home produces at least as much energy as it consumes within a year.

The refrigerator's DR strategy consists of raising the freezer setpoint temperature (causing the refrigeration components to turn off for a time), disabling the anti-sweat heaters, and delaying the defrost cycle. Overall, the refrigerator performed as anticipated for longer duration high and critical DR events. Under normal operating conditions, the refrigerator's demand reduction was approximately 90 W. This value depends on a number of factors, including the operational status of the various components, ambient conditions, and the type of DR signal received. The time duration of the response also depends on several variables. However, the load reduction appeared to last no longer than 60 minutes.

The clothes washer's DR strategy consists of delaying its start during high or critical DR events, or reducing its load during critical DR events. The load reduction varied depending on the DR event signal, the duration, and the timing of the DR event within the wash cycle. DR event signals to delay the start of the clothes washer must be received before the clothes washer begins operation, otherwise the event signal is ignored by the device. The clothes washer could reduce its load by nearly 50% during critical DR events (and during various stages of the clothes washer's operation).Overall, the laboratory testing demonstrated that the clothes washer was able to execute its intended DR strategies.

4.1.1.2.2 Electric Vehicle Supply Equipment

The vendor delivered its EVSEs to SCE in April 2013. SCE evaluated the EVSEs at its Electric Vehicle Technical Center (EVTC) during the same month, prior to field installation. This testing is critical to understanding charging system performance from the standpoint of the electric grid, the vehicle, and the safety and interface with the end-user. The EVTC laboratory evaluation consisted of functional tests (e.g., general operation, safety, grid events, and power quality), and ergonomics tests. This testing used a 2012 Toyota RAV4 EV.

The laboratory testing identified a few areas of concern, which the team is addressing with the manufacturer. For example, the Ground Integrity test revealed that the EVSE began charging while the service ground was not connected. The ISGD EVSEs are all grounded, so this issue is not a concern for this project. The current "total harmonic distortion" and the power factor of the EVSE operating in "no battery mode" (i.e., the EVSE is idle and not connected to a vehicle) were both above recommended limits. However, since the EVSE load is very small when operating in this mode, these are not serious concerns.

During initial physical inspection prior to the EVSE evaluation, the primary power cables were loose and not properly connected to the terminal block. EVTC personnel reattached these wires prior to lab testing. If left uncorrected, such loose connections could cause arcing or a circuit short, leading to potential shock or fire hazards. The ISGD team notified the manufacturer about the issue and its resolution.

Additionally, after periodic inspection of the sub-project 2 EVSEs, EVTC personnel observed signs of thermal degradation on the primary power cables. The ISGD team notified the manufacturer about the issue. The manufacturer determined that the issue resulted from improper termination. The team corrected the issue in the field.

4.1.1.2.3 Residential Energy Storage Unit

The vendor completed Underwriters Laboratories (UL) listing of the RESU in February 2013 after nearly three years of evaluating and refining various pre-production units. Upon receiving four "production" RESUs with UL certification in February 2013, SCE evaluated these units to ensure compliance with technical requirements. This lab testing consisted of three phases: functional testing, performance testing, and system protection testing.

During the testing, the ISGD team identified issues and reported them to the vendor. To address these issues, the vendor provided several updates to the RESU control system software and one hardware modification. Following each update, the team assessed the potential impacts of the update and repeated tests, when necessary. The RESUs passed all of the tests following the updates. This testing confirmed that the RESU satisfied the project's technical requirements, and the team approved the RESU for deployment.

4.1.1.2.4 *Community Energy Storage*

Prior to field deployment, SCE performed functional and performance testing of the CES device at EVTC. The purpose of this testing was to ensure that the unit operates safely and reliably. The lab testing consisted of two phases: performance and safety. Both phases consisted of examining device operation under various conditions by simulating real-world grid scenarios.

A range of tests allowed the team to characterize how the CES performs in a variety of modes and under a variety of grid conditions. The team used these tests to determine system efficiencies, including standby power consumption and inverter efficiency. The tests also helped the team to evaluate the CES's reaction to grid events and to identify its operating limits. These tests provided a baseline characterization of the CES.

Phase 1 testing confirmed the basic functionality of the unit. The unit responded accurately to real and reactive power commands. It successfully islanded upon grid outages and reconnected when stable grid voltage returned. The CES internal measurements—voltage, current and temperature—were compared to data collected from instruments connected to the CES output; the internal measurements were reasonably accurate.

Phase 2 consisted of evaluating the CES's ability to protect itself, the grid, and the load it serves. These tests included attempting to operate the system beyond its specified limits. Performing these tests in a controlled setting allowed the team to identify the CES's actual limits, and to verify that its protection mechanisms operate properly.

The CES exceeded the safety requirements in phase one and phase two testing. In addition to protecting itself from erroneous user input, the power control system shut down when the CES exceeded standard operating limits. The accuracy of the grid measurements ensured that the CES disconnected well before it exceeded utility voltage requirements.

4.1.1.3 Commissioning Tests

4.1.1.3.1 *Home Area Network Devices*

The ISGD team completed the HAN device field installations in August 2013. The devices came from two different vendors. One vendor produced the IHDs and another provided the smart appliances, PCTs, plug load monitors, and home EMS. The smart appliances consist of a refrigerator, dishwasher, and clothes washer. These appliances communicate with the home EMS via an Appliance Control Module (ACM). Each smart appliance requires a separate ACM.

The ISGD HAN devices support two key functions. They support load management capabilities, including demand response, and they provide customers with real-time energy usage information that they can use to make informed decisions about their energy use. **Table 12** summarizes the HAN device details.

Table 12: HAN Device Communications and Control

Function	Equipment	Refrigerator	Dishwasher	Clothes Washer	Thermostat	Plug Loads & IHD
		Communications/Control Paths				
Load Management	• Project meter • Home EMS	Generate load control signal in ISGD Advanced Load Control System, which sends message to the home EMS via the project meter; the home EMS then broadcasts the message to the relevant device class.				N/A
Customer Energy Usage Information	• Plug load monitors • Home EMS • IHD (total home demand and usage) • Solar PV[15] tool	• Smart appliances, plug load monitors and PCTs communicate data to the home EMS using a ZigBee connection; this data can then be provided to the customer's computer via Wi-Fi or Ethernet) • IHD receives total household energy use information from project meter • Solar PV tool collects data from solar PV installations, presents data to customers via the vendor portal			See smart appliance description at left	See smart appliance description at left for plug load comms. path. The IHD receives information from the project smart meter

The various HAN devices in the customer homes receive communication signals via smart meters. However, these meters can only pair with a limited number of devices. The team therefore used the home EMS to consolidate the PCT, refrigerator, dishwasher, and clothes washer. The meter paired with the home EMS, which then relays load management signals to these HAN devices.

The project team is using both the home EMS and a separate IHD to present energy usage information to the project homeowners. The home EMS is capable of presenting device specific load and energy usage information on both a real time and historical basis. However, it is not capable of measuring the discrete output of rooftop solar PV and displaying it on the home EMS screen. In addition, the home EMS reflects the net household load only if it is positive (i.e., if energy consumption is greater than the energy being generated by the solar PV). If the solar PV output exceeds the household load, although the total household load is actually negative, the home EMS displays zero household load. In order to provide customers with net demand and energy usage information that reflects their solar PV generation, the team is using the IHD.

The team installed 64 smart appliances in the 22 project homes within eight working days. These installations coincided with the deployment of the other HAN devices. One of the key tasks for deploying HAN devices is pairing them with the appropriate smart meters. Each ISGD project home has a project-specific meter, which is managed by a project-specific Network Management System (NMS). Having a project-specific NMS allowed the team to kit the HAN devices for each home and pair them to the correct meter prior to field deployment.

During deployment the team discovered that the refrigerators delivered by the vendor were different from the ones delivered several months earlier for the project team's lab testing. The most notable difference was the ACM. The refrigerator that the ISGD team laboratory tested had a built-in ACM. The refrigerators delivered for field deployment did not have a built-in ACM. Rather, they required a different version of the ACM that used different hardware and software, and attached externally to the refrigerator.

[15] The solar PV is not a HAN device, but it is included here to show the complete list of smart energy technologies that customers can monitor.

Following commissioning, the project team has had difficulty maintaining the communications between the refrigerators and the home EMS. The team worked closely with the vendor to determine the root cause of the device drops. The team determined that the refrigerator loses communications more frequently than the other two appliances due to a difference in the ACM software. If the refrigerator ACM loses communications with the home EMS, after a short time period the refrigerator “times out” and will not continue attempting to restore communications. Since the primary need for this communication link is to support the exchange of demand response signals between SCE and the refrigerator, the team’s strategy for addressing this issue is to ensure that the communications are stable prior to conducting load management tests.

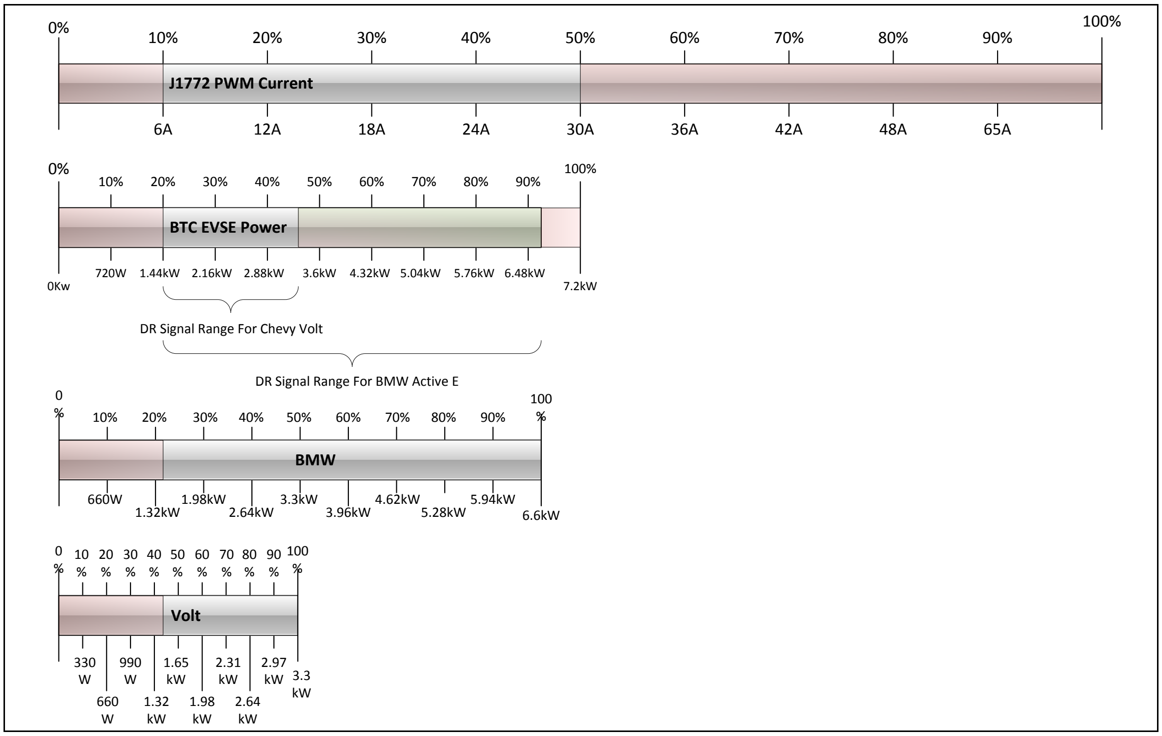
Prior to field deployment, the team understood that it would have no visibility of whether the HAN devices are connected to the meter or functioning properly unless a team member is physically at the project homes. This motivated the team to develop a mechanism for monitoring the communications status of the HAN devices. This mechanism consisted of a ZigBee communications traffic “sniffer” that passively monitors the communications between all the HAN devices and identifies when one of these devices has ceased communicating. The team has used this capability throughout commissioning and following deployment to assess the stability of HAN device communications. Prior to conducting load management experiments, the team uses this device to identify and resolve any communications issues that could affect the test. This device has also been helpful in managing the relationships with the project’s 38 homeowners. Being able to remotely diagnose and resolve communications problems is less disruptive than scheduling regular visits to the customer premises.

4.1.1.3.2 Electric Vehicle Supply Equipment

The ISGD team completed the EVSE field installation in all 22 project homes in May 2013. The team subsequently performed two series of commissioning tests to evaluate all aspects of the EVSE charging profile, and to examine the outcomes prior to field experimentation.

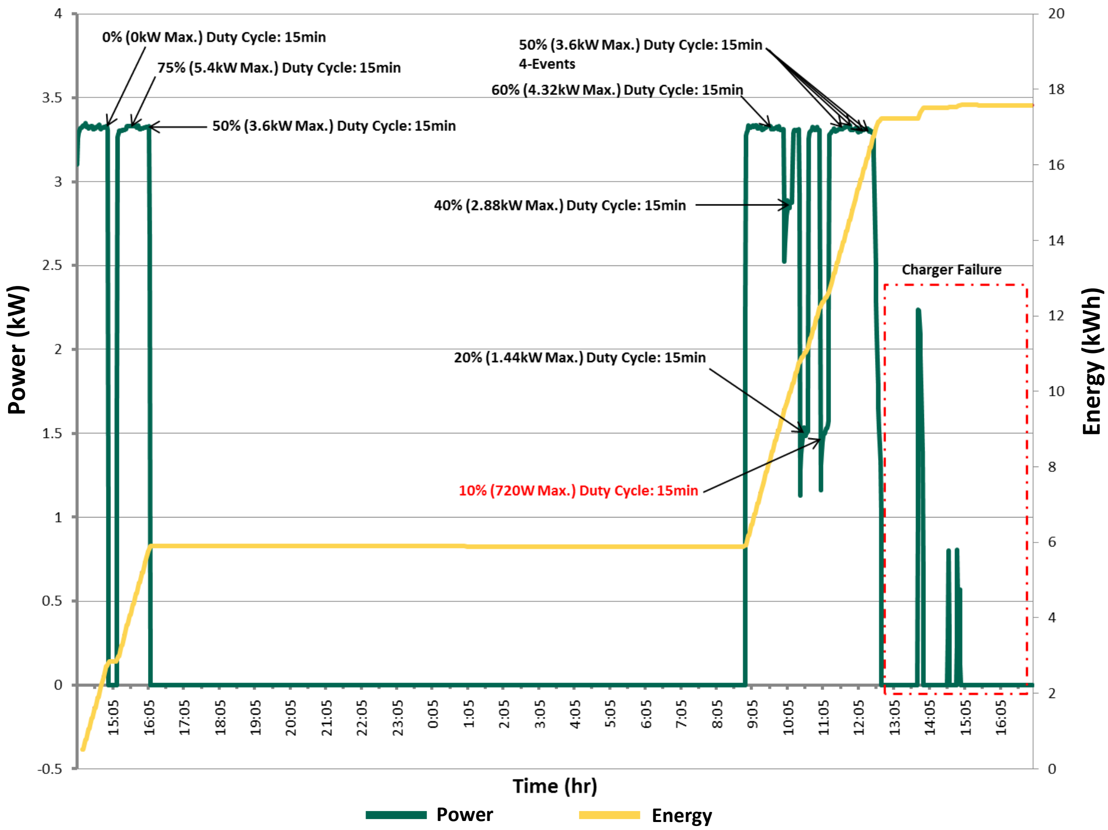
The first series of tests used a Chevrolet Volt (Volt) and a BTC EVSE. This evaluation consisted of sending multiple duty cycle DR events to the EVSE over a 24-hour period, with the goal of reducing the charging level to 75%, 60%, 50%, 40%, 20%, 10%, and 0% of the current charging levels. These tests revealed a limitation in how the Society of Automotive Engineers (SAE) J1772 standard for EVSEs has been implemented for DR by EVSE manufacturers. The SAE J1772 standard defines the acceptable PEV charging levels. The top of **Figure 5** depicts these PEV charging levels.

Figure 5 EVSE Duty Cycle Range Limits



Currently, when a DR event signal is sent to an EVSE to reduce the charging level by a certain percentage (e.g., 75% of current output), the EVSE reduces the charging level based on the maximum charging capacity of the EVSE, not by the actual PEV charging level. The BTC EVSE has a maximum capacity of 7.2 kW, so a 75% duty cycle DR event signal would cause the EVSE to reduce its charge level to 5.4 kW (75% of the 7.2 kW maximum charge level). However, a PEV's charging level is also constrained by the vehicle itself. For example, the Chevrolet Volt's maximum charging level is 3.3 kW. Thus, when the ISGD team sent a DR signal to reduce the PEV charging level to 75% (equivalent to 5.4 kW) the Volt did not reduce its charging level. Rather, it continued to charge at 3.3 kW, since the 5.4 kW was above the Volt's maximum charging level. **Figure 6** summarizes the EVSE power levels over the course of these various duty cycle events.

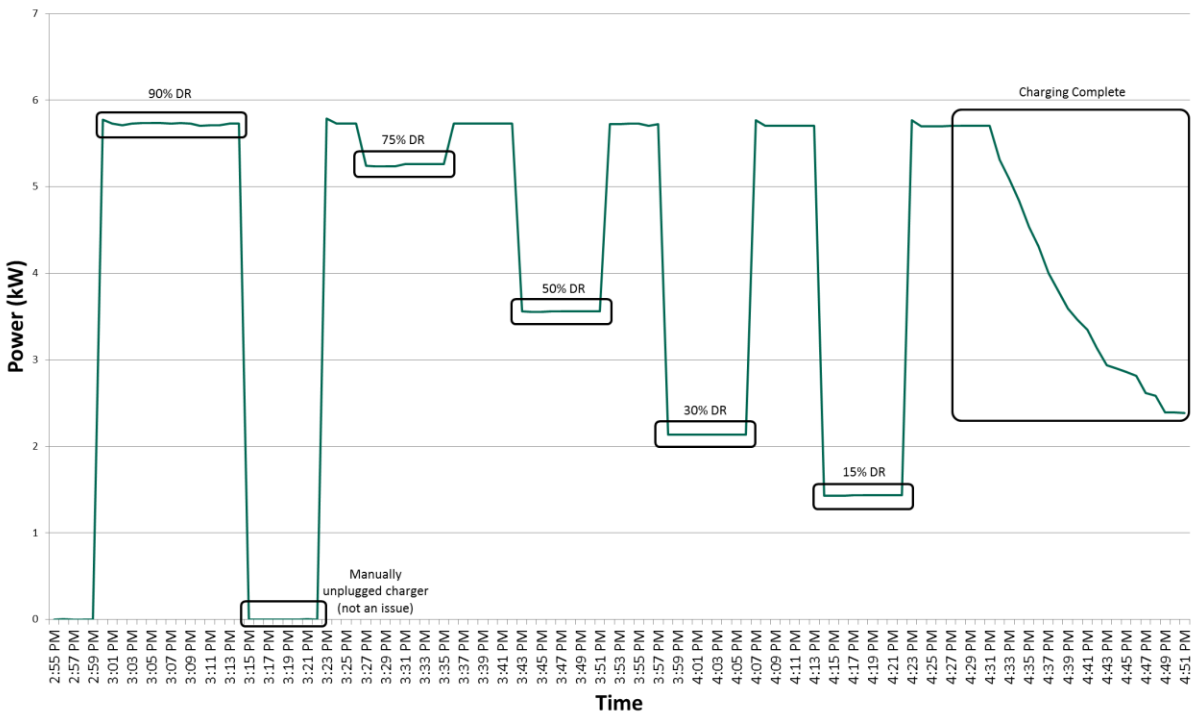
Figure 6: Chevrolet Volt Duty Cycle Power Profile



This testing improved the team's understanding of the vehicle limitations and the SAE J1772 standard constraints. This understanding allowed the team to identify the potential range of charging levels for each relevant vehicle EVSE combination. The Chevrolet Volt can charge at between 20% and 45% of the BTC EVSE's capacity. Anything over 45% is above the Volt's maximum charge level, while anything below 20% is below the SAE J1772 minimum charge level. **Figure 5** summarizes the range of possible PEV charging levels based on the J1772 standard constraints. This figure also includes the range of possible charging levels for the BTC EVSE, and for the Chevrolet Volt and BMW ActiveE when charged with a BTC EVSE.

A second series of tests used the BTC EVSE and a BMW 1 Series Electric (ActiveE). The ActiveE has a larger battery capacity and an internal charger rating (6.6 kW), which allowed the team to test a greater number of charging level scenarios. The team used this vehicle/EVSE combination to send duty cycle DR event signals to reduce the vehicle's charging to 15%, 30%, 50%, 75%, and 90% (again, the BTC EVSE provides a maximum charge level of 7.2 kW.) Duty cycle DR events reduce the charging level based on this 7.2 kW rating (e.g., a 75% duty cycle would reduce the maximum charge to 5.4 kW). However, duty cycle events using the BTC EVSE only affected the charging level of an ActiveE when they were below 6.6 kW (the ActiveE maximum charge rate). **Figure 7** summarizes the EVSE power levels during over the course of these various duty cycle events.

Figure 7: ActiveE Duty Cycle Power Profile



This second round of commissioning tests confirmed the results of the first round, that an EVSE's ability to perform duty cycle DR events is constrained by the charging capacity of the EVSE and the vehicle's onboard charger. Chapter 5 discusses this finding in more detail.

4.1.1.3.3 Residential Energy Storage Unit

Between July and October 2013, the team installed RESUs in 14 project homes, nine on the ZNE Block and five on the RESU Block. Following installation, each RESU underwent commissioning procedures and tests to ensure that all required electrical and communications connections were working properly and that the RESU could perform the required functions.

The team configured each RESU to communicate with the RESU Server, registered them, added them to a test group, and paired them with each home's project smart meter. The team also placed the RESUs in various operating modes to ensure they would charge and discharge as expected. These commissioning activities were successful for each RESU and the team identified no issues.

SCE identified three major operational issues with the RESUs within a few months of commissioning. These issues are described below. The team worked closely with the vendor to identify the root causes and develop solutions. These three issues have since been resolved, and the ISGD team continues to monitor the RESUs closely to identify and resolve any potential issue that arise in the future.

Battery Error: The first issue involved the RESUs erroneously reporting a battery error. RESUs typically report this error they reach an over-discharged state. However, the RESUs began reporting this error while operating in a normal state. After identifying the issue, SCE immediately provided all available data to the vendor. The vendor determined that the RESU falsely reported this error due to an advanced safety diagnostic process that was susceptible to noise interference. The vendor provided a firmware update that disabled this specific mechanism. Several redundant safety mechanisms remain in place. SCE verified these mechanisms through laboratory testing prior to updating the units in the field with the new firmware. This update allowed the RESUs to operate without sacrificing any performance or functionality.

Memory Error: The RESUs have a touchscreen computer that runs custom vendor programs on a Windows CE operating system. After running continuously for approximately one month, the RESU computers reported low memory errors. These errors caused the RESUs to cease operation and required manual intervention to reset. The vendor provided a software update that causes the RESUs to reboot on a weekly basis, which avoids the low memory error. SCE verified the performance of this software update prior to deploying it to the RESUs in the field.

Network Connectivity: The RESU Server provides remote monitoring and control of the RESUs. The RESU Server is located in the ISGD Pilot Production back office environment[16]. The RESUs communicate with the RESU Server using dynamic internet protocol (IP) addresses that they receive from ISGD's 4G radios. Following deployment, the RESUs had difficulty receiving these dynamic IP addresses, leading to loss of communication with the back office server. SCE determined that the cause was due to the RESU (internal) control computer not conforming to standard dynamic IP address protocol. The vendor confirmed this finding and provided a software update that improved the RESUs' acceptance of IP addresses.

One lesson from this experience is that although laboratory and commissioning tests are critical to assessing the functionality and performance of new technologies, it is important to monitor devices in the field throughout operation to identify other unknown issues. For example, ISGD's extensive laboratory testing did not identify the Battery Error. The team believes that this error notification resulted from specific location and environmental factors that a laboratory setting cannot replicate.

4.1.1.3.4 Community Energy Storage

The team installed the CES device on the CES Block in June 2013. The CES is helping to demonstrate utility-controlled, distributed energy storage. The Distributed Energy Manager (DEM) provides CES monitoring and control using a 4G connection to the ISGD Pilot Production back office environment. SCE grid operators also have real-time visibility of the CES. The CES is a four quadrant device (i.e., it can discharge and charge real power, and inject and absorb reactive power), has a power rating of 25 kVA, and may be controlled using real and reactive power commands.

The CES commissioning test helped to verify the basic communication, control and data acquisition features of the CES and DEM. The DEM allows for manual control and can command the CES to operate using a specified charge and discharge schedule. The testing demonstrated three basic features: discharging and absorbing real power, discharging and absorbing reactive power, and islanding. The power tests consisted of discharging and charging real power at 5 kW increments, up to 25 kW. The team performed the same testing for reactive power by injecting and absorbing at 5 kVAR increments, up to 25 kVAR. The islanding test demonstrated the CES's ability to disconnect from the grid upon command while continuing to power to itself. The current CES configuration does not provide islanding support for local customer loads.

The CES performed as expected, providing the full spectrum of real and reactive power when commanded. The accuracy and limitations of the CES output were consistent with the laboratory test findings, and the communications were reliable.

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[16] The Pilot Production environment consists of the back office computing environment used for ISGD. Section 4.3.1.2 provides a detailed description of this environment.

SCE identified a number of operational issues with the CES—hardware and software related—within a few months of commissioning. These issues are described below. The team worked closely with the manufacturer to identify the root causes and develop solutions. The ISGD team continues to monitor the CES closely to identify and resolve other issues that arise in the future.

CES Forced Disconnect Test: The team tested the CES's islanding functionality by using the DEM to command the CES to disconnect from the grid and island itself. However, during the test the CES and DEM communication was lost due to radio trouble. The radio was unable to resume communication and the CES remained in the islanded state—powering itself from the batteries—for an extended period.

Within about a week, the CES's contactors began closing and opening approximately every 30 seconds. This behavior was unexpected and laboratory testing could not replicate it. To identify the root cause of the behavior, SCE worked with the manufacturer, who provided a firmware upgrade to resolve the issue. Future testing will not involve forced islanding and the team will restore communication outages more promptly if they occur in the future.

DEM Software Failure: After restoring communication on September 4, 2013, the DEM database stopped logging CES data. This prevented data capture and control of the CES. The team installed an additional software component (IntelliLink Human Machine Interface) on the DEM to record more data. However, this resulted in further compatibility issues.

After several days of investigation and troubleshooting, the team re-imaged the DEM with the latest version of software, and the DEM then resumed data logging and normal operation. The team has implemented a daily image backup process to mitigate any future occurrences. This issue has not reoccurred.

DEM Boot Failure: Within a few months of commissioning, the DEM was not accessible through the ISGD Pilot Production network and was unresponsive to ping-attempts. SCE's Information Technology group visited the DEM and found that the hard disk was no longer accessible. The DEM was power cycled and then resumed proper operation. This happened again after about six months. The manufacturer provided SCE with a replacement DEM, and it has since worked properly.

CES Noise: Laboratory testing and initial field testing revealed that the CES emits a high frequency noise, which varies based on the charge or discharge level. Through discussions with the vendor, the team learned that the noise is due to the CES power electronics design. Reducing this noise would require a significant hardware re-design.

SCE performed several sound surveys to assess the noise. At maximum power, the CES exceeded the City of Irvine's nighttime noise requirements. However, none of the ISGD field experiments requires high power nighttime activity. SCE will complete all tests as designed, within the City of Irvine's noise ordinances, and will remain sensitive to any concerns raised by homeowners.

4.1.1.4 Field Experiments

4.1.1.4.1 Field Experiment 1A: Impact of Integrated Demand Side Management Measures on Home and Grid

The objective of this experiment is to quantify the impact of energy efficiency upgrades and DR strategies on the home and electric grid. This experiment includes four blocks of project homes. Three blocks received a series of IDSM measures through retrofits. The ZNE Block homes received the most extensive set of upgrades. Although the specific measures vary by home, most of the retrofits included LED lighting, heat pumps, high efficiency water heaters, domestic solar hot water heaters, plug load timers, low flow shower heads, duct sealant, increased attic insulation, ENERGY STAR smart appliances, solar PV arrays, RESUs, EVSEs, and other HAN devices. The homes on the RESU Block received RESUs, ENERGY STAR smart appliances, and EVSEs, but none of the other energy efficiency upgrades. The CES Block homes received the same equipment as the RESU homes, except rather than receiving a RESU, a CES was installed near the transformer to help manage load on the block's distribution transformer. The CES may also provide a limited amount of backup power in the event of an outage. The homes on the Control Block received no upgrades.

To evaluate the performance of these project homes, the team installed monitoring instrumentation in each home. These monitoring devices consist of branch circuit monitors, plug load monitors, temperature sensors, and project smart meters. Transformer monitors record the loading on each of the four distribution transformers. A more detailed discussion of the team's approach for collecting this data is included in Appendix 3. This instrumentation provides detailed visibility of the project homes' energy consumption patterns, allowing the team to compare energy usage for particular types of load—such as lighting or refrigeration—between individual homes or across blocks.

The electricity usage of each project home over the first eight months of ISGD is summarized in **Figure 8** through **Figure 11**. These figures are organized by project block. These figures illustrate the amount of detailed data the team is collecting to assess the impacts of the various energy efficiency components. For example, energy consumption for lighting is available for all the blocks, excluding the Control Block. Although the ZNE Block was the only block to receive high efficiency LED lighting upgrades, lighting is still a major source of energy usage within these homes. "Other Loads" consists of electricity use that the team does not monitor discretely. This likely includes devices plugged into wall outlets such as laptop computers, routers, cable boxes, floor lamps, microwaves, and ovens.

The second TPR will include a more comprehensive analysis of this data, once the project has accumulated a year of energy use data. The intent of this initial TPR is to characterize the project's data collection activities and to provide a high-level snapshot of the initial eight months of energy usage activity. The following are a few preliminary observations from this initial phase of the demonstration period.

- <u>Variability</u>: There are high degrees of variation in energy use among the homes and between the four blocks. Home office equipment and television usage is especially inconsistent and, in some cases, their use is quite high. Control home #5 had energy usage 20% higher than the next highest home, while some homes used far less energy than the average.
- <u>Heat Pumps</u>: The ZNE Block received electric heat pumps in exchange for their existing air conditioners and gas furnaces—or just the gas furnace for homes without air conditioning units. This resulted in higher HVAC electricity usage for these homes during the winter. However, this higher electricity use was offset by lower gas use.
- <u>Electric Vehicle Chargers</u>: PEV charging is a significant source of energy use. Depending on their charging levels, charging multiple vehicles on a single distribution circuit at the same time may place strain the distribution transformer.
- <u>Refrigerator Usage</u>: Refrigerator electricity use is significant since it cycles on and off all day, every day.

Figure 8: ZNE Block Energy Use Breakdown (July 1, 2013 to February 28, 2014)

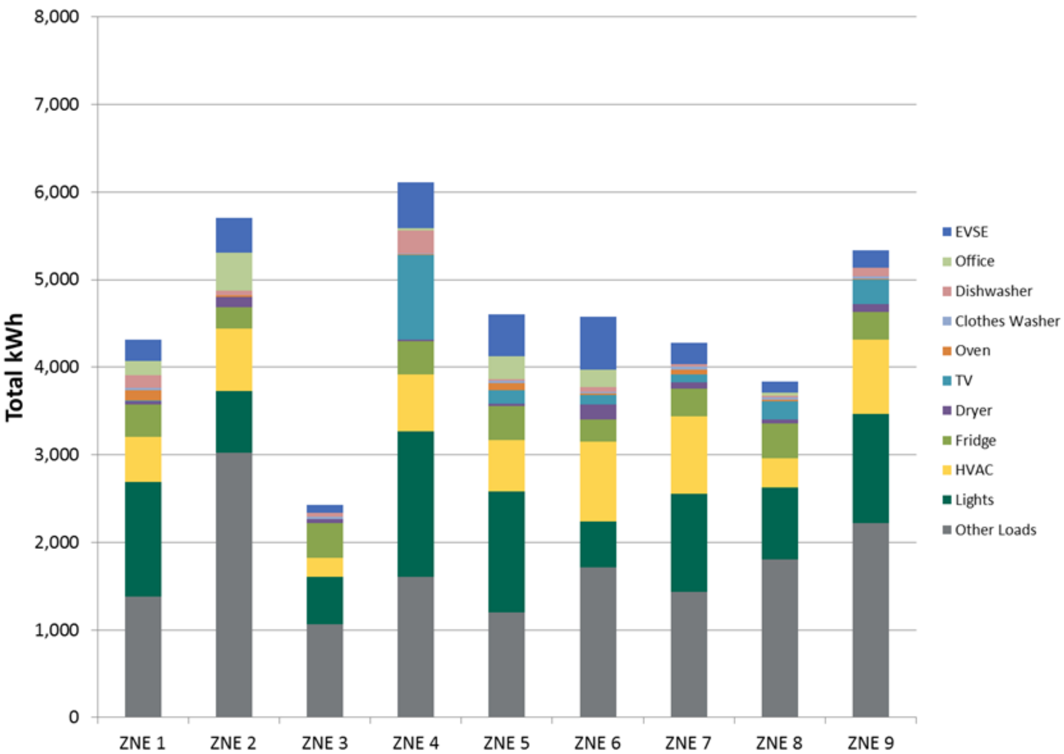


Figure 9: RESU Block Energy Use Breakdown (July 1, 2013 to February 28, 2014)

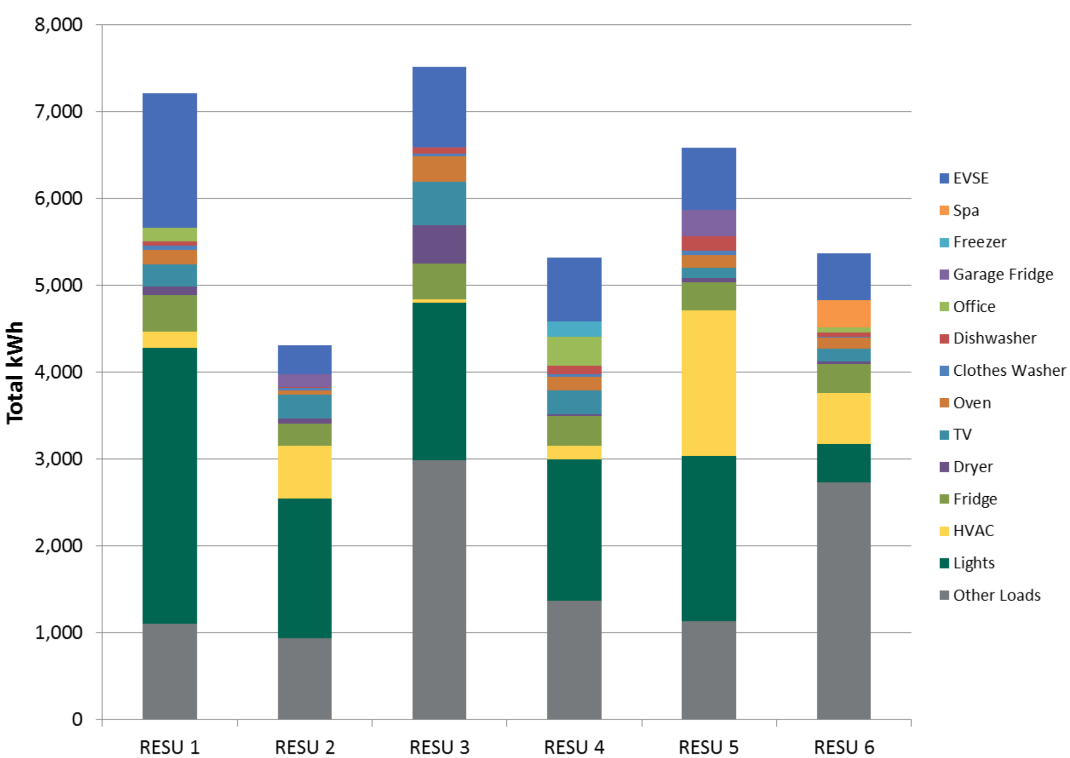


Figure 10: CES Block Energy Use Breakdown (July 1, 2013 to February 28, 2014)

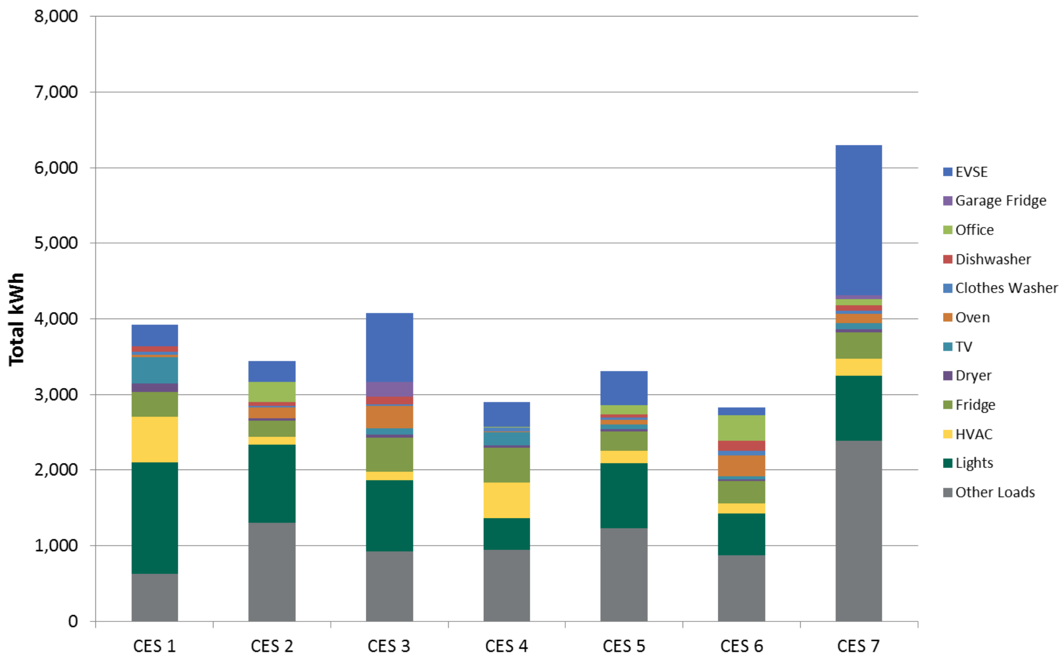
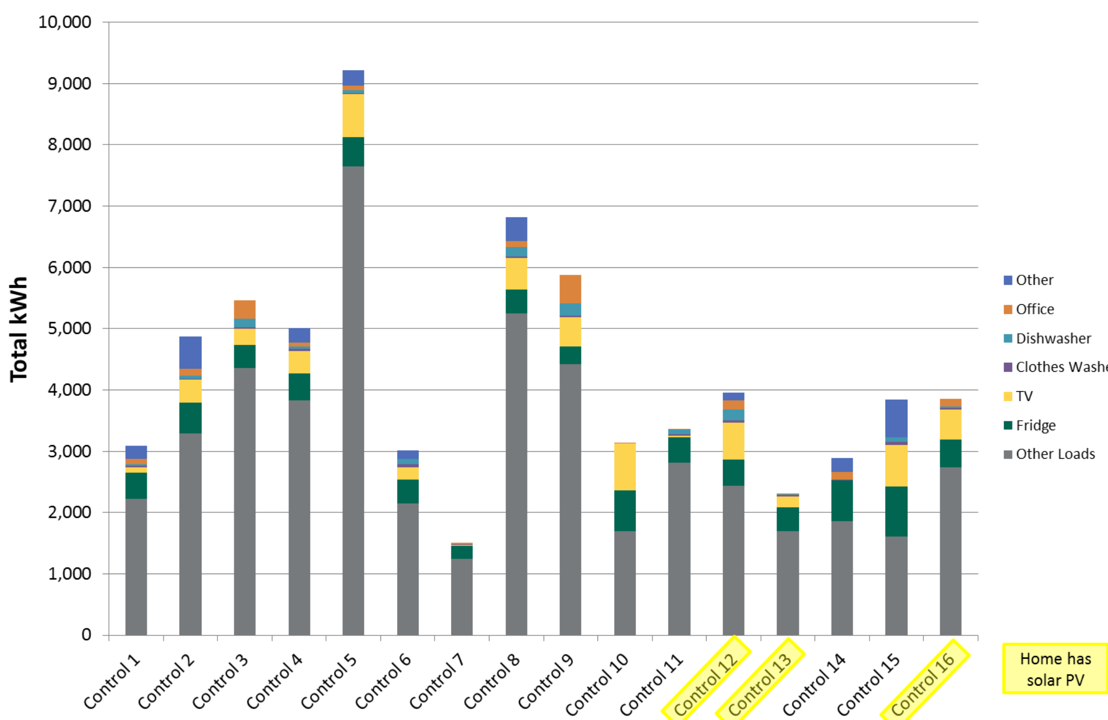


Figure 11: Control Block Energy Use Breakdown (July 1, 2013 to February 28, 2014)



Another aspect of this experiment is to evaluate the impact of the energy efficiency upgrades, DR strategies, solar PV, RESU, CES, and PEV charging on the grid. This consists of monitoring the load profiles of the four distribution transformers on the four blocks of project homes. **Figure 12** presents the load profile of all nine homes on the ZNE Block for December 2013. This represents the aggregate load for all nine homes, averaged for all 31 days in the month. The yellow line represents the homes' total load (kW) (i.e., how much power all the homes required at various times throughout the day). The thick gray line represents the net demand of these homes as measured by the project smart meters. The net demand is lower than total demand due to the solar PV generation, and the RESU charging and discharging activity (represented by the dotted line).

During the month of December 2013, the RESUs operated in the Cap Demand mode. When operating in this mode, a RESU will charge or discharge based on a set point for the net household demand. For example, in December 2013, this set point was set at 0 kW. The RESUs charged anytime the net household demand was below zero (e.g., the solar PV generation was greater than the home's electricity demand). The RESUs also discharged any time the net household demand was above zero. Naturally, the RESUs were constrained by their energy storage capacity (10 kWh), and could only discharge if there was energy in the RESU.

Figure 12 indicates that the solar PV generation was generally much higher than the household load during the peak solar generation periods. The surplus energy was used to charge the RESUs during the daytime. The RESUs discharged during the evening when household demand was greater.

Figure 12: ZNE Block Aggregate Home Load Profile (Daily Average for December 2013)

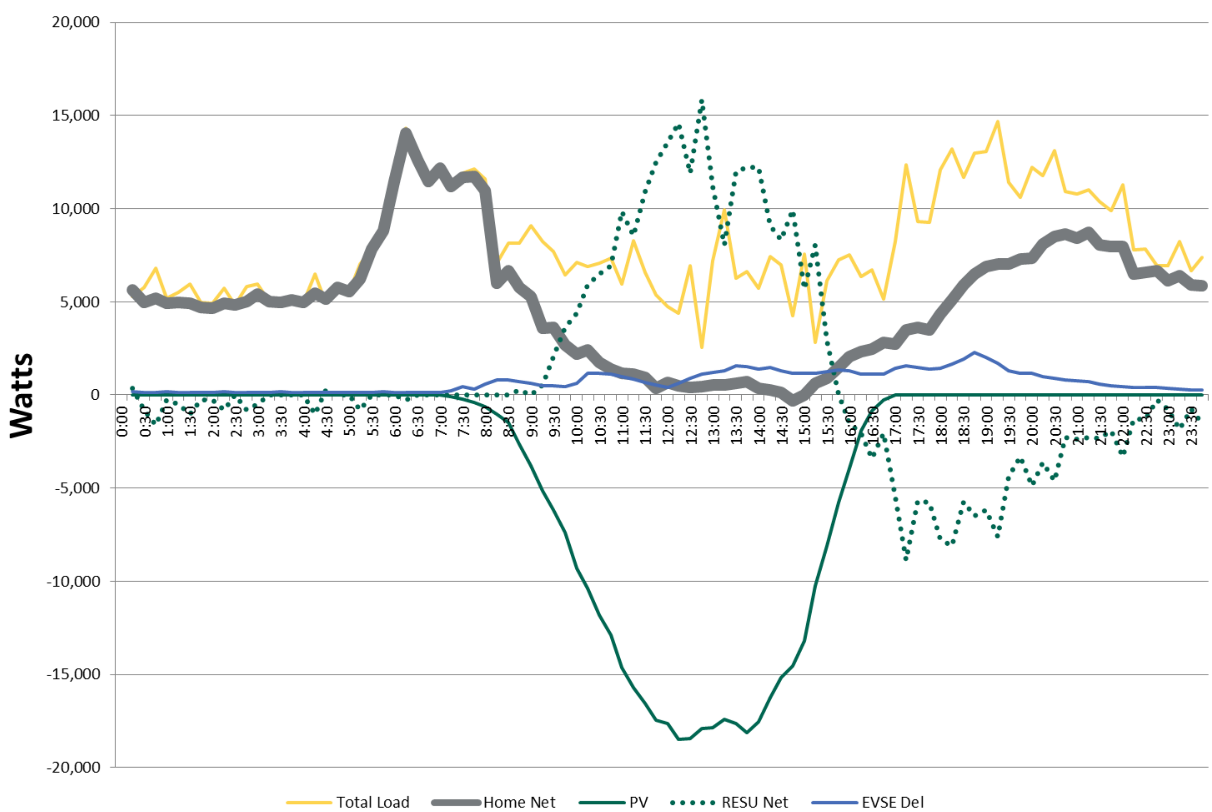
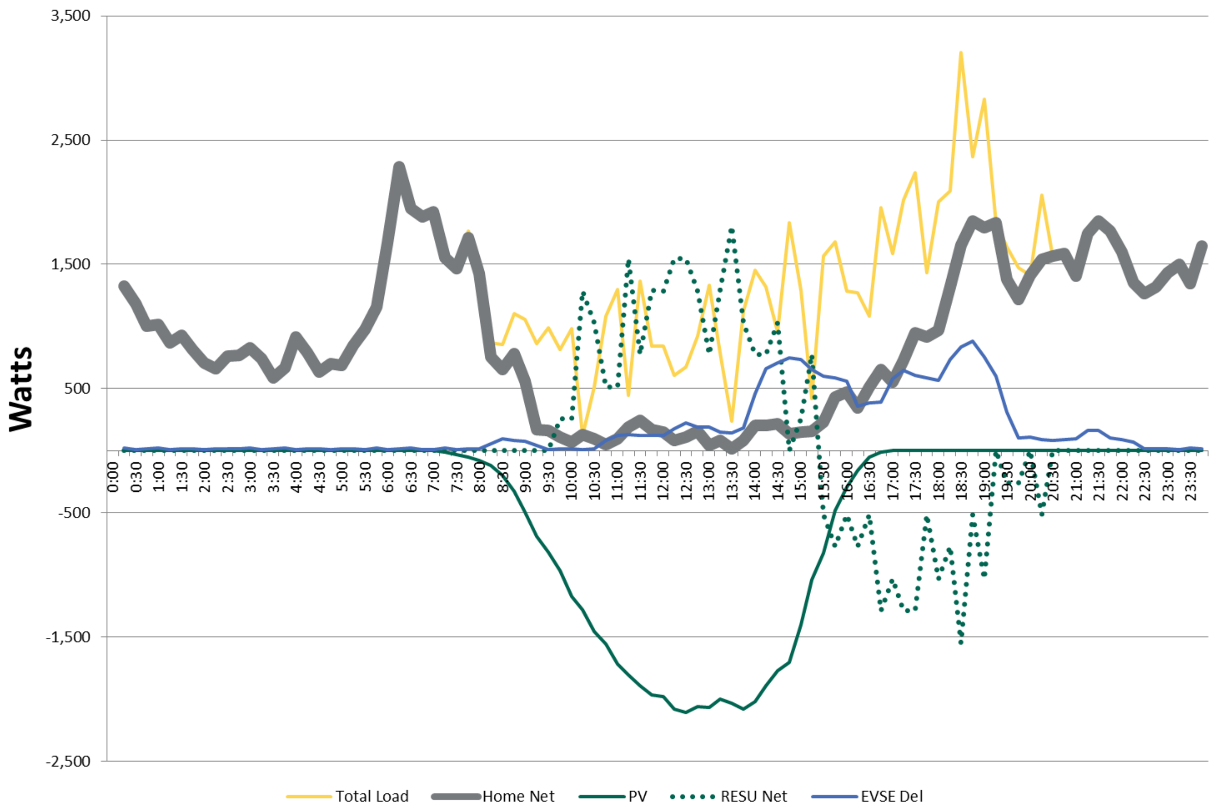


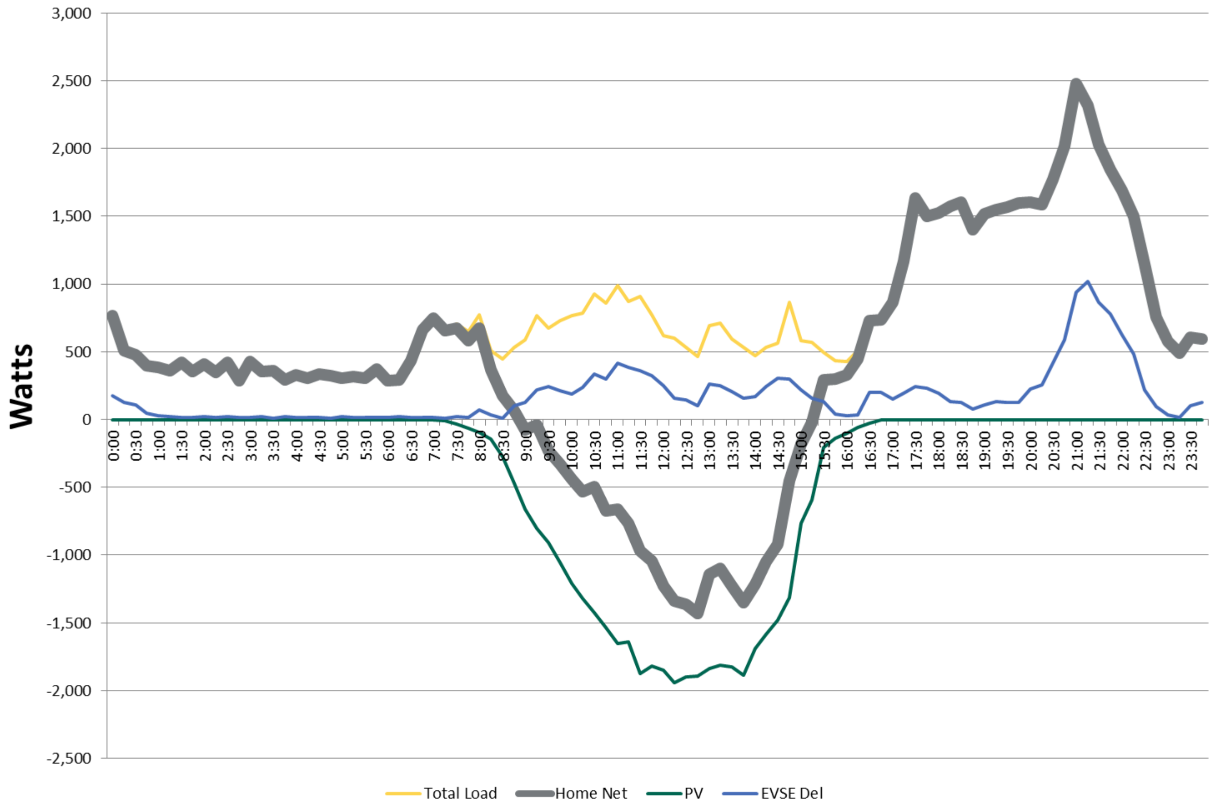
Figure 13 presents the load profile of home ZNE 4 for the same period (i.e., the daily average for December 2013). This home reveals a high degree of variation in its hourly demand. The RESU responded to this changing demand accordingly by charging and discharging itself, attempting to maintain the net household demand at zero.

Figure 13: ZNE 4 Load Profile (Daily Average for December 2014)



To illustrate the effect of the RESUs on the net load profiles of the ZNE Block homes, **Figure 14** presents the load profile of a single home on the CES Block for the same period. Since this home does not have a RESU to help regulate the homes' net demand, and since the solar PV generation was much greater than the home's energy demand, the net load was negative during much of the daytime hours.

Figure 14: CES 3 Load Profile (Daily Average for December 2013)



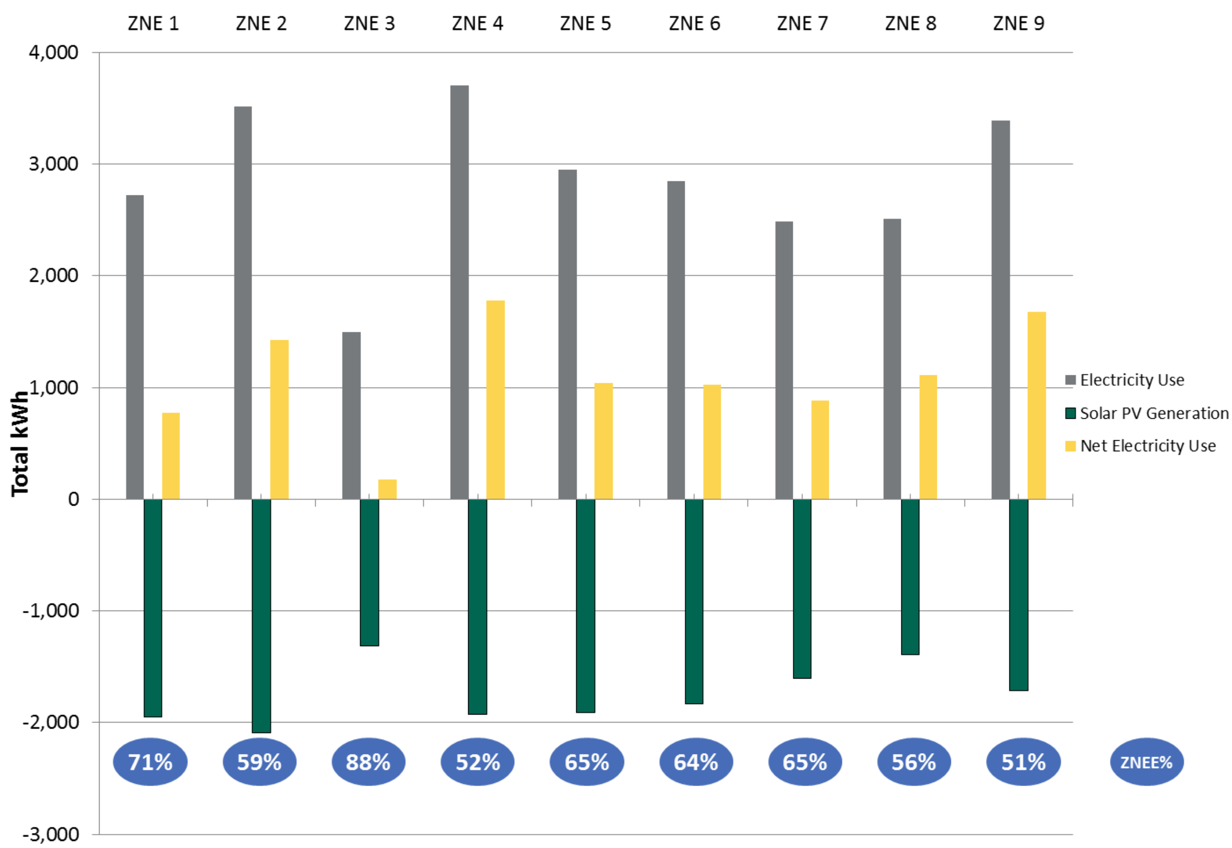
The second objective of this experiment is to assess the ability of the various energy efficiency measures to help homes achieve ZNE. Beginning in 2020, California's goal is for all new residential construction to achieve ZNE. **Figure 15** shows the current ZNE status for the electricity portion of the ZNE Block of homes' energy consumption—ZNEE, or Zero Net Electric Energy. This chart summarizes the amount of electricity each home consumed and generated through their rooftop solar PV panels over the demonstration period. This figure captures only five months of activity, starting in October 2013, since the solar installations were in September 2013. The energy use totals also exclude electric vehicle charging, since energy for transportation is not part of the ZNE definition used for this report.

None of the project homes has achieved ZNEE, although ZNE 3 achieved 88%[17]. Part of the shortfall is due to the seasonality of solar PV generation. Solar output is lower in the winter than in the summer. However, although summer PV output will likely increase, so will the customers' air conditioning usage.

All nine homes on the ZNE Block have identically sized solar PV arrays of 3.9 kW. However, there is significant variation in the energy produced by these nine homes, as indicated by **Figure 15**. The orientation of the homes' roofs (and therefore the solar arrays) is a likely source of this variation. Also, some of the RESUs were out of service during this period. Since the solar PV uses the RESU's inverter (i.e., one inverter is used for both the battery and PV), the RESU outages limited the generation output of the solar arrays.

[17] None of the homes was estimated to reach 100% ZNEE or ZNE. **Table 11** (page 41) summarizes the estimated ZNE targets.

Figure 15: Zero Net Electric Energy Status for ZNE Block (October 1, 2013 to February 28, 2014)



4.1.1.4.2 Field Experiment 1B: Impact of Demand Response Events on Smart Devices, Homes, and Grid

Test 1: In-home Display Price Signal (August 8, 2013)

The purpose of this experiment was to test the ability of the IHDs to receive a price signal from a smart meter, and to display the current price of electricity. This experiment consisted of sending a price signal from SCE's NMS to a group of 13 IHDs via the project smart meters. The IHDs would then display the current price of electricity for 24 hours. The ISGD customers are not enrolled in a dynamic pricing tariff, so the team used a simulated price of $0.50/kWh. The team also sent a text message to the IHDs requesting customers to confirm receipt of the message. This event occurred on August 8, 2013 between 4 pm and 7 pm. Upon sending the price signal and text messages to the 13 IHDs, six customers confirmed receipt of the message.

The team identified two abnormal device behaviors during this experiment. The first issue emerged during a visit to one of the project homes two days after the experiment. Upon visual inspection of the HAN devices, the team member noticed that the PCT and IHD still displayed the text message from the event, even though it should have stopped displaying after 24 hours. The team member attempted to confirm receipt of the message, but could not (i.e., the project meter did not report the event to the NMS).

The second abnormality was that one customer confirmed the same message four times on the PCT and two additional times on the IHD. The message should have stopped displaying on both devices after the customer first confirmed the message. The team replicated this experience by executing a second similar event. The team is continuing to investigate these issues in order to identify their root causes and resolve them. These types of errors could be confusing or annoying to customers, which could limit consumer adoption of these devices as well as customer participation in associated load management programs.

The team did not observe any load reduction at the customer premises because of this price signal. This was consistent with the team's expectations since the simulated price signal offered no incentive for customers to reduce their energy use.

Test 2: PCT Duty Cycle Demand Response Event During Cooling Operation (September 16, 2013)

The purpose of this experiment was to test the ability of the project's PCT to receive and respond appropriately to DR duty cycle signals. These signals should cause the air conditioning to turn off, thereby reducing electricity loads on hot days. This experiment consisted of sending a 50% duty cycle signal from the ISGD Advanced Load Control System (ALCS) via the project smart meters to all participating customer homes with air conditioning. Three homes operated their air conditioners at least once during the DR event (RESU 5, CES 4, and ZNE 7).

The DR events were scheduled for 3:30 pm, 4:00 pm, 4:30 pm, and 5:00 pm with durations of 15 minutes per event. The 50% duty cycle should have caused the PCTs to turn off for 7.5 minutes, and then turn back on for 7.5 minutes over the course of each 15-minute event. Unfortunately, the PCTs did not react as anticipated. The team learned that the PCTs ignore duty cycle commands. They simply curtail their operation for the duration of the event. Devices that responded to the events generally remained off for 15 minutes, rather than the expected 7.5 minutes.

The large number of short duration DR events made it difficult to assess their effectiveness. However, the homes with the air conditioning running during the event showed a load drop during some of the events. CES 4 turned on the air conditioner at 4:14 pm, and then turned off at the beginning of the second DR event at 4:30 pm. ZNE 7 turned on at 4:37 pm, and then turned off at 5:00 pm (the beginning of the fourth DR event). RESU 5 experienced load reductions that corresponded with the 3:30 pm and 4:30 pm events. The team could not determine why the response was limited to these two events. The other participating homes exhibited similar behavior in which load drops resulted from some of the events, but not others.

Based on these findings, the team plans to conduct several test events with a 100% duty cycle (off for the entire event duration) for an extended period of time (at least 2 hours) to capture more accurate results using parameters that are more similar to existing DR air conditioning cycling programs.

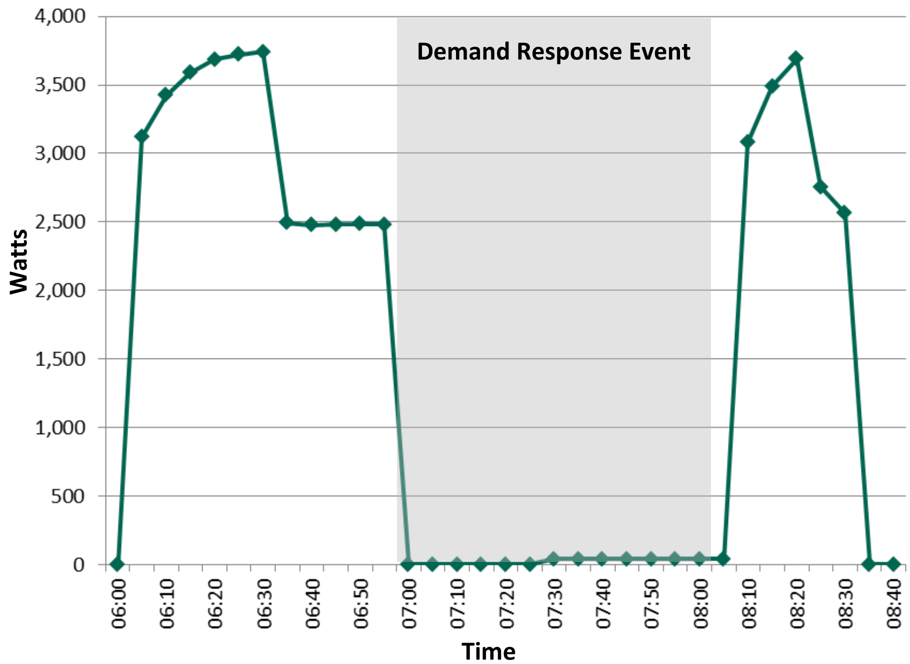
Test 3: PCT Duty Cycle Demand Response Event During Heating Operation (December 20, 2013)

The purpose of this experiment was to test the ability of PCTs to receive and respond appropriately to DR duty cycle signals. This particular test should cause the heat pump to turn off. This capability could reduce electric heating loads on cold mornings.

The experiment consisted of sending a 100% duty cycle signal from the ISGD ALCS via the project smart meters to all participating ZNE Block customer homes. Eight of the nine homes on the ZNE Block have heat pumps. One of the homes (ZNE 3) has a gas furnace, although this requires a forced air unit (FAU) which uses electricity. Each PCT was expected to cycle off 100% for the entire duration of the event, which was scheduled for 7am to 8am.

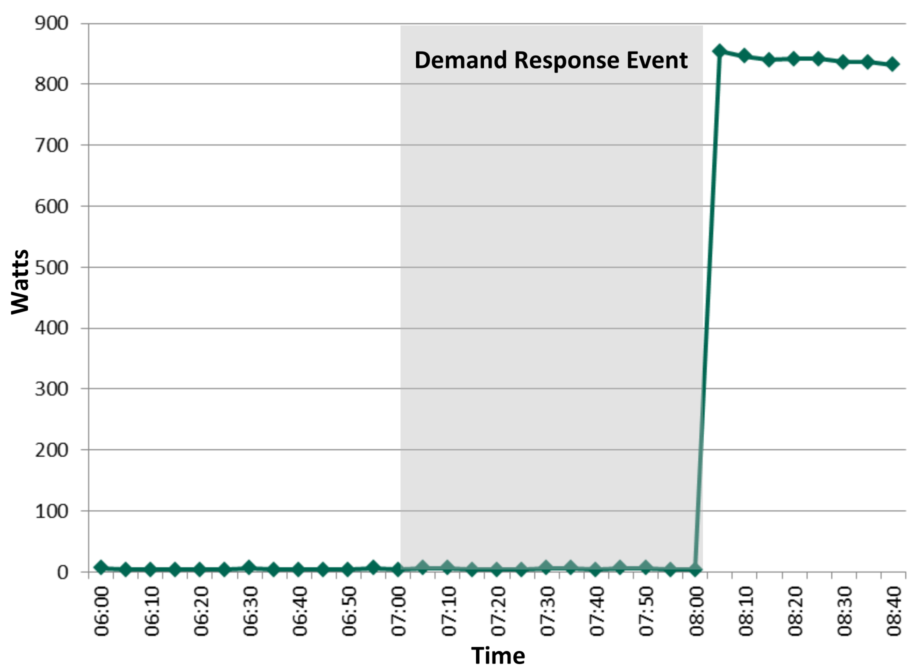
Four homes were operating their heat pumps during this event (ZNE homes 1, 4, 5, and 6). Three of the homes responded to the DR event signal by curtailing their heat pump use at 7:00 am. The fourth home (ZNE 6) continued to operate throughout the one-hour event. Either this home did not receive the DR event signal, or the homeowner overrode the event. The team's instrumentation does not have visibility of the reason for this home's response. Of the three homes that shut off their heat pumps, two resumed operation soon after the event ended at 8:00 am, while the third remained off. The third home likely remained off due to the customer's programmed set points (i.e., it was scheduled to turn off at or before 8:00 am). Each of these three homes experienced load reductions of approximately 2.5 kW throughout the experiment. **Figure 16** displays the air conditioning load of ZNE 1 during the DR event. This home shut off its heat pump at 7:00 am and resumed operation at 8:10 am.

Figure 16: ZNE 1 Air Conditioner Load



In addition to the four homes that operated their heat pumps during the experiment, it appears that ZNE 3 attempted to turn on its gas furnace during the experiment. It also appears that the DR event caused the gas heater to delay its operation until after the event ended, at 8:00 am. The gas furnace operates in conjunction with the FAU. **Figure 17** shows the FAU load of ZNE 3 during the DR event. The FAU did not operate until precisely 8:00 am. It is likely that the PCT was programmed to turn on the heater sometime between 7:00 am and 8:00 am, and that the DR event delayed its operation until 8:00 am.

Figure 17: ZNE 3 Forced Air Unit Load



Although SCE is a summer peaking utility, in the future it is likely that more flexible resources will be required on a year-round basis, during both on-peak and off-peak periods. Such resources could be useful in managing the grid impacts of increasing amounts of distributed energy resources (such as solar PV and energy storage), and new types of load (such as plug-in electric vehicles and energy storage). Heat pumps could therefore be a potentially valuable demand response resource.

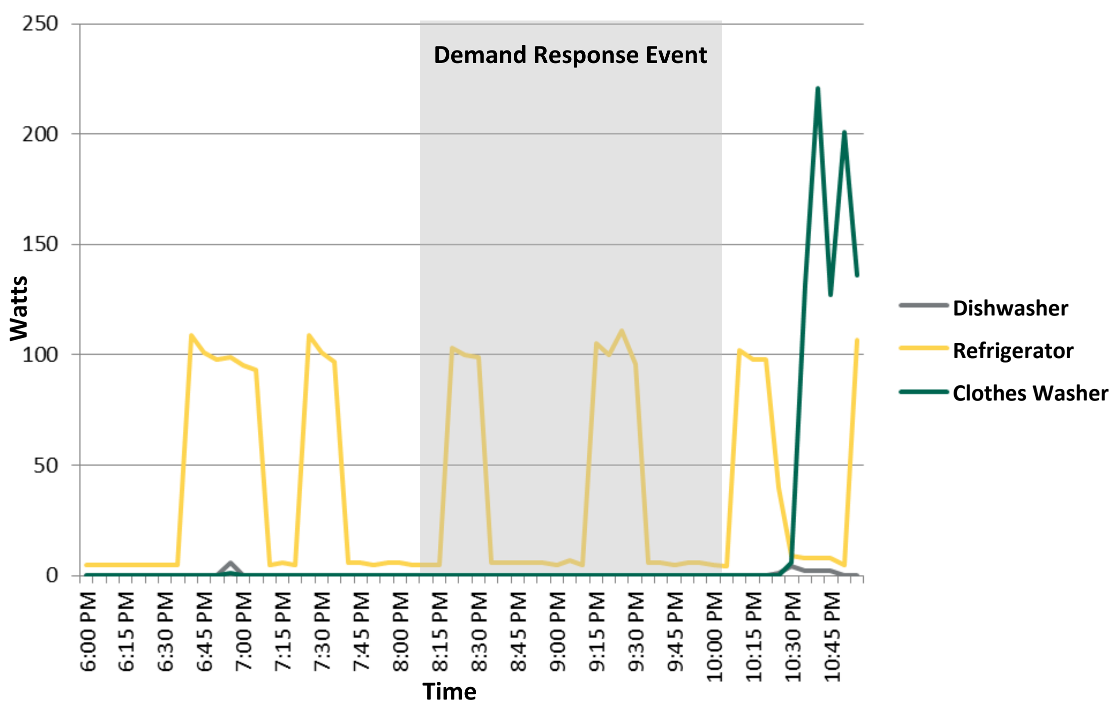
Test 4: Smart Appliance Demand Response Event (February 19, 2014)

The purpose of this experiment was to test the ability of smart appliances to receive and react appropriately to DR event signals in an attempt to reduce electricity loads. This experiment consisted of sending a DR event signal from the ISGD ALCS via the project smart meters to the 22 project homes with smart appliances. The DR event was scheduled from 8:00 pm to 10:00 pm.

If a smart appliance is operating during a DR event, the appliance is designed to switch to a "low power" mode of operation. This mode reduces the average wattage of the appliance operation by either eliminating an operation or reducing the energy use of a given operation. If the smart appliance is not operating and someone attempts to begin using it during the DR event, the smart appliance should delay its operation. The appliance should also display a message stating that a DR event is currently in process, and that the user can override the event.

Prior to initiating the test, the team notified the project homeowners of the event and asked them to run their appliances during the event. The team then compared the appliance loads to the loads on the day prior to the event in an attempt to identify noticeable load reductions. It was easy to identify energy use cycles in refrigerators and when clothes washers and dishwashers were in use. However, it was difficult to identify any load reductions or delayed loads that resulted from the DR event signal. **Figure 18** presents the smart appliance load shapes for CES 1. The clothes washer represents a typical load profile for a clothes washer operating during the evening.

Figure 18 CES 1 Smart Appliance Load



The refrigerator, identified by the yellow line, continues to cycle up to 100 watts approximately every 30 minutes throughout the event duration. The clothes washer, identified by the green line, begins operating at about 10:30 pm, but it is unclear whether this resulted from the DR event. In order to better understand the DR potential of appliances, the team plans to conduct additional DR events over much longer periods to better identify any load drop that results from these types of events.

4.1.1.4.3 Field Experiment 1C: RESU Peak Load Shaving

The RESU did not operate in the peak load-shaving mode during the timeframe covered by this report. The RESU will likely operate in this mode during both of the next two reporting periods. The second TPR and the Final Technical Report will summarize the results of this test.

4.1.1.4.4 Field Experiment 1D: RESU Level Demand

Test 1: RESU Demand Response Event (November 7, 2013)

The purpose of this experiment was to demonstrate the ability of the RESUs to receive DR event signals sent through the RESUs' ZigBee interface via a project smart meter. The test should also confirm that the RESUs automatically discharge at the appropriate time and for the appropriate duration, as defined in the DR event command. The test targeted the 14 RESUs deployed within the ZNE Block and RESU Block homes. The ISGD team conducted this experiment after the deployment as a one-time experiment.

This experiment consisted of configuring the RESUs to charge and discharge according to a predefined schedule. On November 6, 2013, the day before the demand response event, the RESUs were scheduled to charge during the peak PV generation period (12:00 pm to 4:00 pm), and to discharge during the evening peak load period (between 6:00 pm and 9:00 pm). The RESUs were configured to repeat this charge and discharge profile daily, and this schedule was expected to be interrupted by the DR event. The morning of November 7, 2013, the ISGD team published a 30-minute DR event for the RESUs to discharge at full power (4 kW) for 30 minutes. The RESU Block RESUs were scheduled to begin discharging at 1:40 pm, and the ZNE Block RESUs were schedule to begin discharging at 1:50 pm.

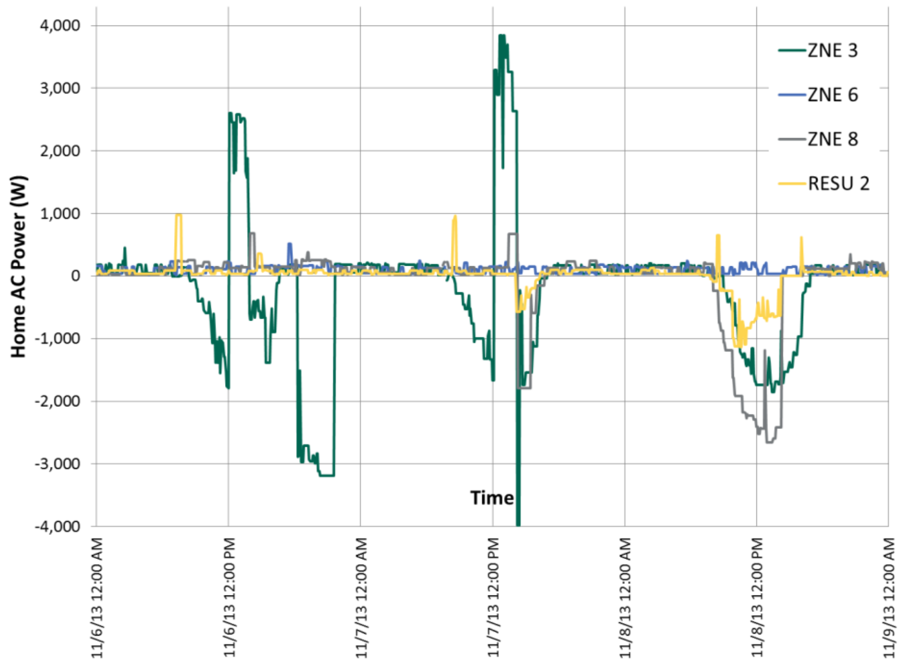
After completing the experiment, the team evaluated the RESUs' performance by analyzing data from multiple sources. **Figure 19** presents the RESU AC (alternating current) power recorded by the back office RESU server. This data indicates that the RESU behaved as expected during this test. Note that the negative power represents generation—power output from the RESU to the home/grid.

Figure 19: RESU Load (RESU Server)

The RESUs all began charging around noon, as defined by the daily schedule. The RESUs discharged during the schedule DR events, and then resumed charging after the events completed. Two notable exceptions are RESU 5 and RESU 6, which began charging closer to 12:30 pm (not 12:00 pm like the other RESUs). The team believes that these RESUs were setup with incorrect charging schedules (they were setup on the test date separately from the other RESUs). ZNE 3 is another notable exception. This RESU appears to have lost communication just before 1:30 pm. Due to a lack of communications with this RESU, the RESU server was unable to determine whether the RESU participated in the event. The behavior of ZNE 3 is discussed in more detail below.

Four out of the 13 RESUs included in this experiment were not operating during the test. These RESUs performed in three unique ways. The behaviors of these four RESUs (as measured by the RESU ION meter) are shown in **Figure 20**. Note that this meter also measures garage door opener and garage refrigerator energy use (referred to as secure loads).

Figure 20: RESU Load (TrendPoint ION Meter)



ZNE 6 stopped operating and communicating on November 6, 2013. As such, this RESU did not receive the DR event, and did not operate at all during the test. This was confirmed with the very low power recorded (between 0 and 500 W) which is attributable to this RESU's secure loads.

ZNE 3 lost communication just before the DR test occurred. The RESU database confirms that it was operating properly until approximately 1:30 pm on November 7. The TrendPoint data confirms that the RESU charged and discharged as expected until the DR Event. The loss of communication was due to local control problems. When these problems occur, a portion of the RESU becomes non-responsive, which explains why the RESU did not receive the DR event. Rather, the RESU continued charging through the event.

RESU 2 and ZNE 8 both failed due to a battery error in October 2013. This error prompted the RESU to turn off the RESU's internal battery charger and the inverter in order to protect the system. These RESUs did not charge or discharge for several weeks. However, both of these RESUs received the DR event signal on November 7, 2013. When the event began, the RESUs began outputting PV power to the grid. This was unexpected, since the team believed that the battery error would prevent the inverter from operating. **Figure 20** shows that RESU 2 and ZNE 8 provided PV power after the DR event began. Because this behavior was unexpected, the team manually shut down the RESUs. Based on discussions with the manufacturer, the team determined that the manufacturer had incorrectly programmed the RESUs to allow PV operation during the battery error. The manufacturer addressed this programming bug in a subsequent software release that was installed in all the RESUs. This experience highlights an important issue with respect to the potential future development of utility programs for managing distributed energy resources: device manufacturers must design and test their products to ensure that utility-provided signals do not lead to erroneous device behavior. The manufacturers cannot rely on certifications (including UL standards and communications protocol specifications), since these do not address device behaviors under specific internal fault conditions. Utilities cannot test every operational aspect of every device that connects to its system, and should therefore not assume this role. Device manufacturers must be responsible for the operational integrity and safety of the devices they sell to end-users. Chapter 5 discussed this lesson in more detail.

Test 2: RESU Level Demand (January 13, 2014 to February 25, 2014)

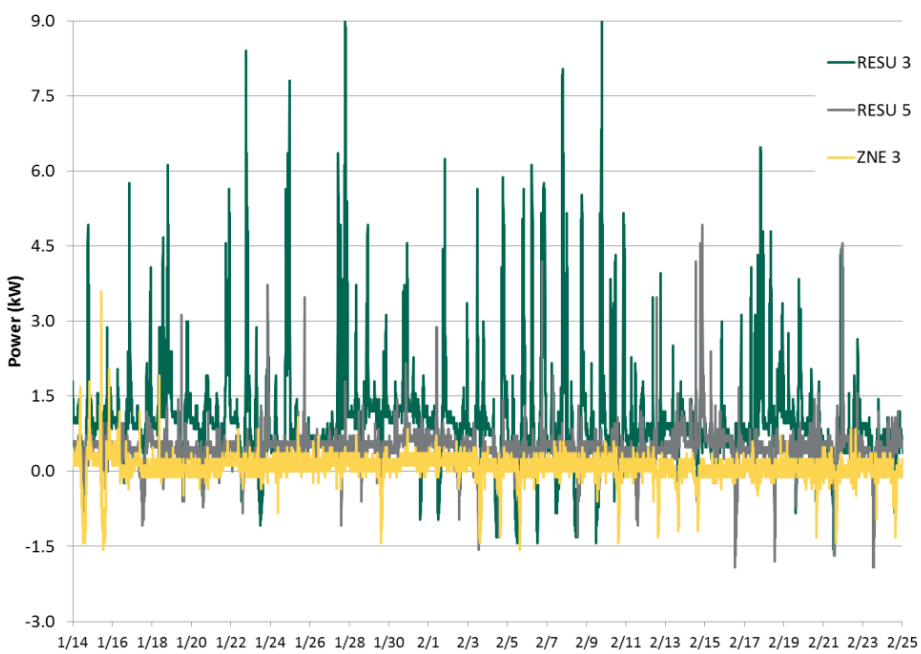
The purpose of the RESU Level Demand experiment was to demonstrate how RESUs could decrease a home's maximum demand and increase its minimum demand through charging and discharging. The goal is to "level" the home's demand throughout the day by removing peaks and valleys in the load profile. A secondary goal is to use as much of the solar PV generation as possible locally, without exporting it to the grid.

The RESU level demand algorithm uses 15-minute historical usage data to autonomously calculate maximum and minimum demand thresholds. When the household demand meets one of these thresholds, the RESU programming causes the RESU to either charge or discharge. The algorithm calculates the historical usage using a weighting parameter that determines the relative importance of prior day versus all other historical usage. For this particular experiment, the previous day's data received a 30% weighting and the historical average received a 70% weighting. The RESU updates its thresholds approximately every 15 minutes, and adjusts its charge or discharge levels approximately every 30 seconds based on the instantaneous demand received from the project smart meter. Ideally, a RESU could use this operating mode to maintain a home's demand at a constant power level throughout the test period.

This experiment included all 14 RESUs deployed on the ZNE Block and RESU Block. Each RESU operated in the level demand mode with the battery limited to operate between 20 and 100% SOC. During the 43-day test period, each PV array generated between 260 and 620 kWh DC (direct current) energy, while the homes consumed between 300 and 1,200 kWh AC. The RESUs were operational 97% of the time (on average) and autonomously charged and discharged throughout the test period.

During the test period, ZNE 3 had the lowest total load while RESU 5 had a moderate load and RESU 3 had the highest. **Figure 21** plots the demand of each home during the test period.

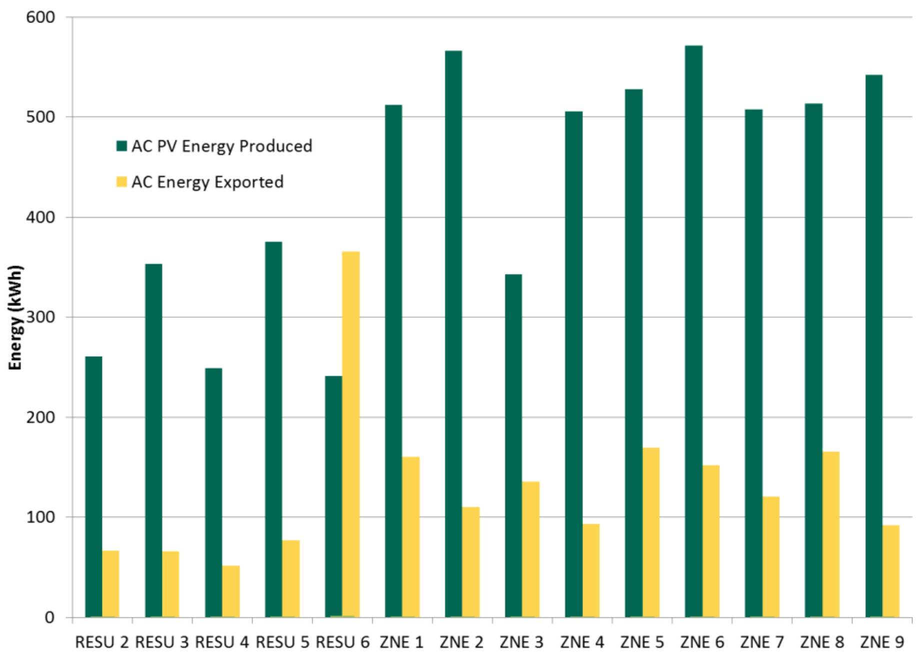
Figure 21: Household Demand During the RESU Level Demand Test Period



This plot shows that the RESU was able to maintain ZNE 3's load near 500 W throughout most of the test period. However, the RESU 3 exhibited numerous load spikes that the RESU was unable to respond to (i.e., by discharging to reduce the overall household demands from the grid). The RESU can discharge at up to 4 kW and can provide 8 kWh of energy (due to SOC restrictions) per cycle. However, due to the intermittent nature of the high-demand loads at RESU 3, it was difficult for the RESU to appropriately predict and respond to these demand spikes.

Overall, the homes used approximately 75% of the total solar PV energy generated either through instantaneous use, or through storage in the battery for later use. **Figure 22** summarizes the solar PV energy generated and the solar PV energy exported to the grid during the test period.

Figure 22: Solar PV Generation and RESU Export



This figure shows that the RESU Level Demand algorithm was able to use locally 70 to 80 % of the PV energy produced. RESU 6 was a significant exception. The energy this home exported to the grid exceeded the energy generated by its solar PV panels. This indicates that during the test period the RESU discharged energy that it received from the grid. The project data shows that this RESU's power varied frequently between full charge and full discharge. It is unknown exactly what conditions led to these large oscillations, but they may have resulted from the slow feedback loop and load averaging that the RESU uses to adjust its charge/discharge power levels. It appears that the RESU's 30-second control loop is insufficient for responding to dynamic load conditions.

The RESU Level Demand algorithm needs improvement in two areas: predicting future load, and response time. Due to the dynamic or unpredictable nature of certain loads (such as HVAC, forced air unit, and PEV charging), the RESU's historical data was unable to forecast and respond to such load variations. In addition, variations in solar PV output prevented the RESUs from fully 'leveling' demand, and the homes all experienced spikes in 5-minute demand. The RESU's load forecast calculations use historical average data that results in thresholds not flexible enough to account for daily load fluctuations. In addition, the RESU only adjusts its power every 30 to 60 seconds. These adjustments are based on moving averages of the site demand reported by project smart meters. The slow update and site demand averaging limit the accuracy of the RESU response.

The team will perform this experiment again during the demonstration period. Prior to the next test, the team will adjust the level demand algorithm's weighting parameter. The current weighting of 30% and 70% (between prior day and historical average) produced consistent thresholds. However, due to the highly dynamic nature of the home loads and generation, the prior day usage will receive a 70% weighting and the historical average usage will receive a 30% weighting. This will make the calculations more dependent on the previous day's profile and reduce the impact of the previously recorded historical data.

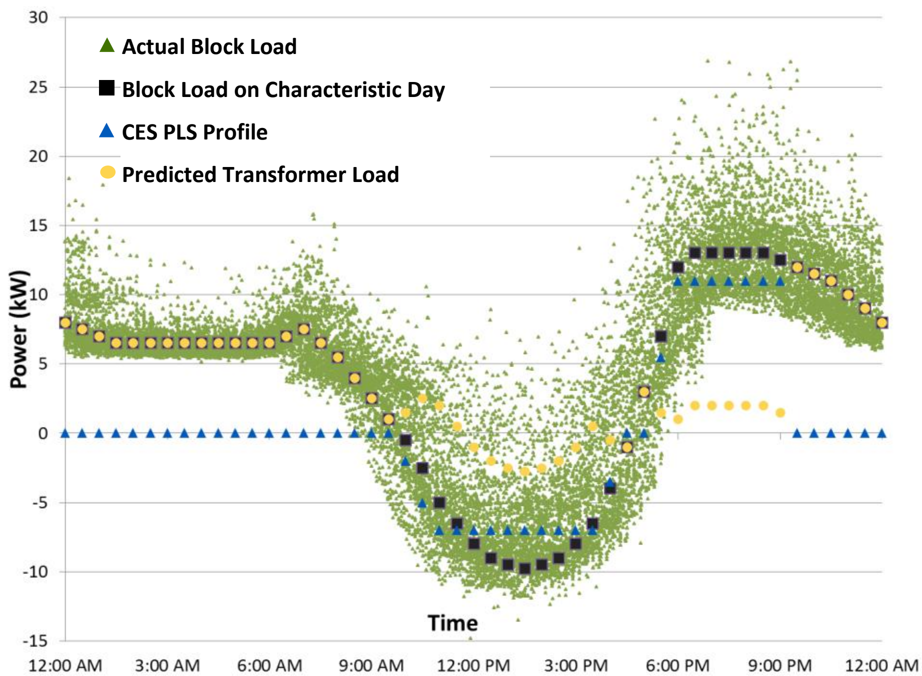
4.1.1.4.5 Field Experiment 1E: CES Peak Load Shaving

Test 1: CES Permanent Load Shifting (November 18, 2013 to January 13, 2014)

The purpose of this test was to evaluate the ability of the CES to shave demand on the distribution transformer by charging during periods of excess local PV generation and discharging during periods of maximum home electricity use.

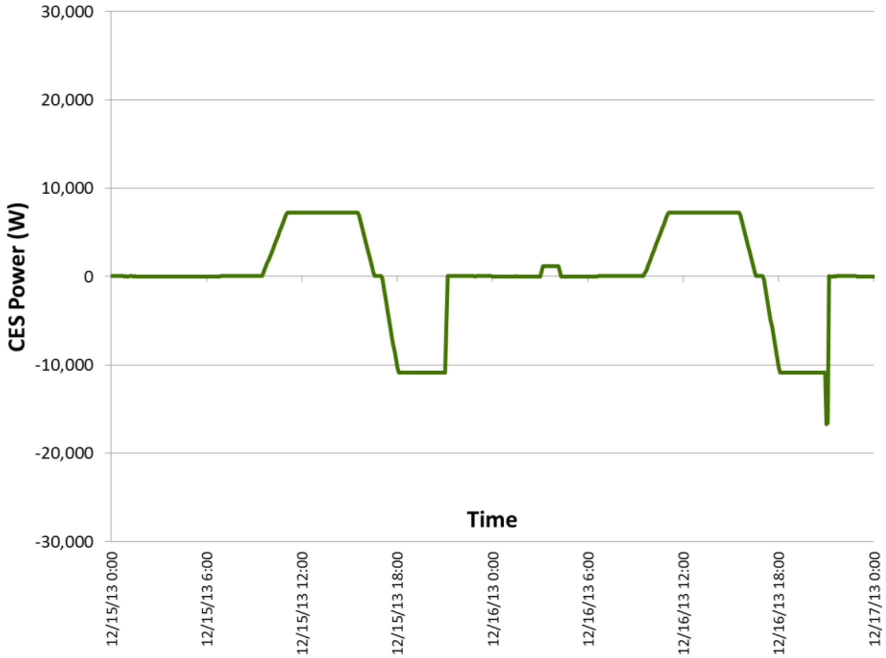
To construct the CES charge/discharge schedule, the team analyzed the load on the CES Block between September 1, 2013 and November 15, 2013. The hourly load for each day within this period is plotted in **Figure 23** below (identified by the green triangles). The team used this hourly load data to create a characteristic load curve for this block (identified by the black squares). The team then designed a CES charge/discharge profile (CES PLS profile) with the goal of reducing the variation in load on the transformer by minimizing both PV export and peak evening demand. The blue triangles identify the CES PLS profile, and the yellow circles identify the resulting predicted transformer load profile. By charging the CES during periods of excess solar PV generation and discharging when energy use peaks in the early evening, the CES should reduce the peak transformer load during the early evening.

Figure 23: PV CES PLS Profile



The CES charged and discharged daily throughout the test period, following the CES PLS profile as expected. **Figure 24** shows the actual CES charge/discharge behavior for December 15th and 16th, 2013. While the CES behaved ideally on December 15, 2013, the team observed two abnormalities on December 16, 2013: a small charge period at approximately 3:00 am and a spike in discharge at the end of the discharge period. These abnormalities occurred many times throughout the test period. The project team is still evaluating the cause of this behavior. The team is also assessing the impact on the residential transformer. The second TPR will include more details on the CES behavior and the associated impacts on the distribution system.

Figure 24: CES PLS Power Profile



4.1.1.4.6 Field Experiment 1F: Impact of Solar PV on the Grid

Test 1: RESU PV Grid Impact (October 11, 2013 to November 6, 2013)

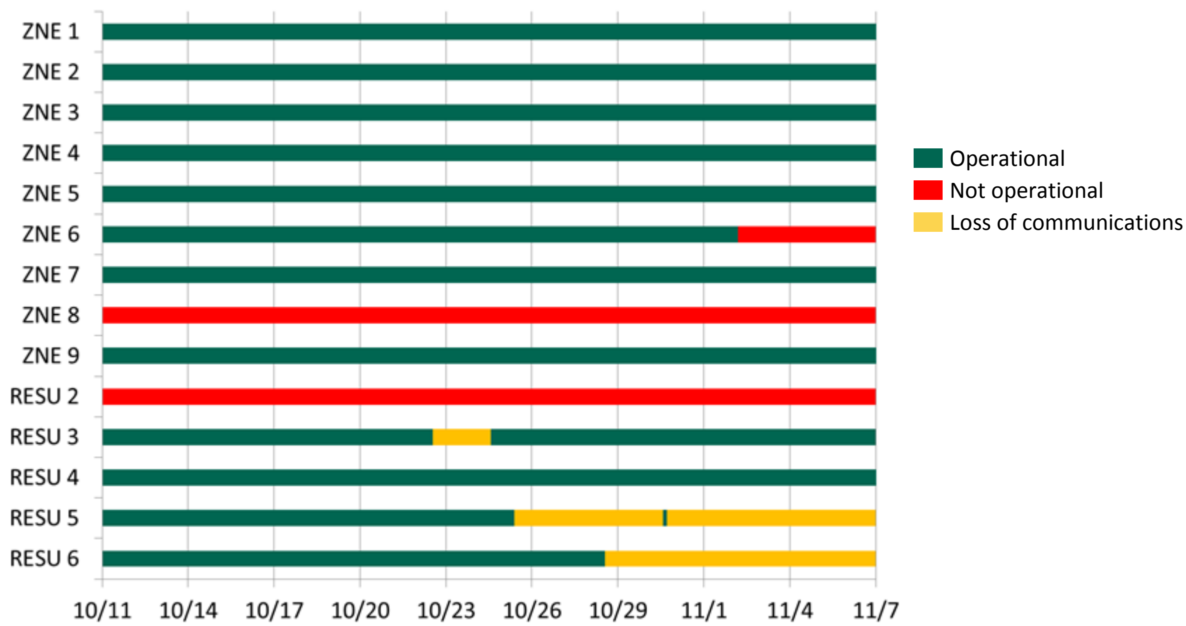
This experiment used all 14 RESUs deployed on the ZNE Block and the RESU Block. Two RESUs were not functioning throughout the test, and another RESU encountered a functional problem that limited its PV output. Each RESU was programmed to act as a standard PV inverter throughout the test period, with the batteries disabled. Over the 26-day test period, each of the homes with operational RESUs generated between 150 and 400 kWh AC.

This test confirmed that the PV arrays on each of the RESU homes could significantly affect the home's load profile. Each of the arrays exported power to the grid during most sunny periods since the electricity produced was typically greater than the electricity consumed by the homes during the daytime. The significant PV penetration in these test locations (particularly the ZNE Block), led to higher average current on the transformers. Because the PV generation is not coincident with most customer load, the power exported through the transformer increased the current through the transformer during the formerly low-load periods.

In addition to investigating the grid impact of these arrays, the team validated the performance and characteristics of the PV arrays when coupled with the RESUs. Test results indicate that several PV arrays are shaded in the afternoon, while two other arrays may not be performing as expected. The team validated the RESU data collection and gathered approximate "calibrated" efficiencies in order to translate RESU-recorded DC PV power and energy to approximate AC power and energy. The team estimates that converting the recorded DC PV energy to AC PV energy has 92% efficiency, while converting DC PV power to AC PV power is 95%. These calibrated efficiencies differ significantly since energy is an accumulative value while the recorded power is an instantaneous value.

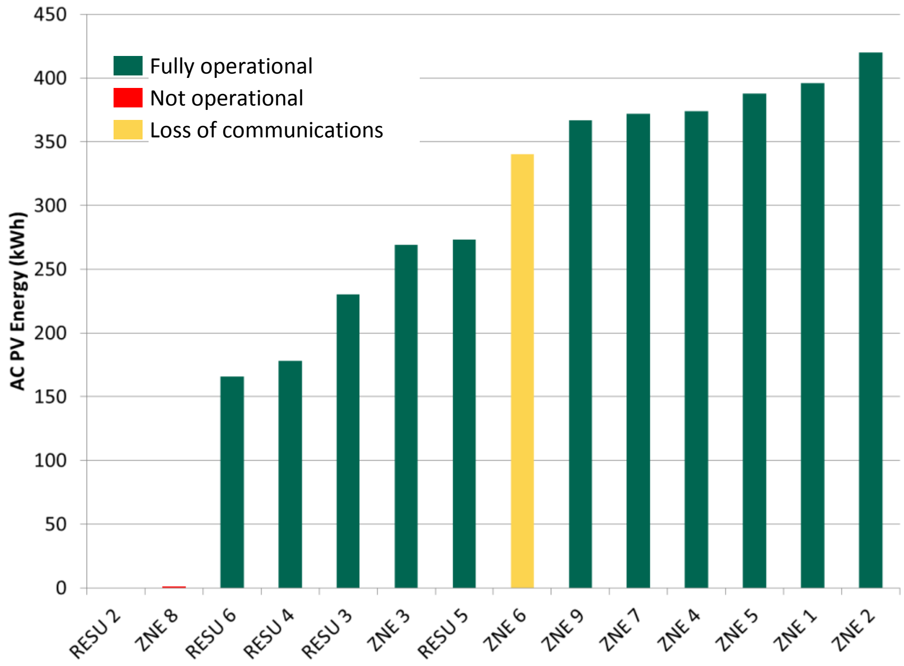
Several RESUs reported errors during the test period. These errors prevented operation of the systems, including the PV generation. Throughout this test period, the team calculated the RESU "uptime" by determining the average percentage of time that all RESUs were operational. The RESU uptime was only 78% over the 26-day test period. Two RESUs did not function at all, while four additional RESUs experienced performance issues in the second half of the test period. **Figure 25** presents a timeline with failure time (in red) for each of the RESUs. This figure also indicates periods where the RESUs lost communication (in yellow). The TrendPoint meters functioned as expected throughout the experiment. The TrendPoint data indicates that the RESUs provided PV power despite the communication errors. The RESU uptime, including periods when the RESUs lost communication but the PV was still operational, is approximately 85%. The errors are described in 4.1.1.3.3.

Figure 25: RESU Operational State Summary



During the 26-day experiment, the RESUs output between 150 and 450 kWh AC to the home. **Figure 26** shows the total energy produced by the PV arrays.

Figure 26: RESU AC PV Energy Delivered

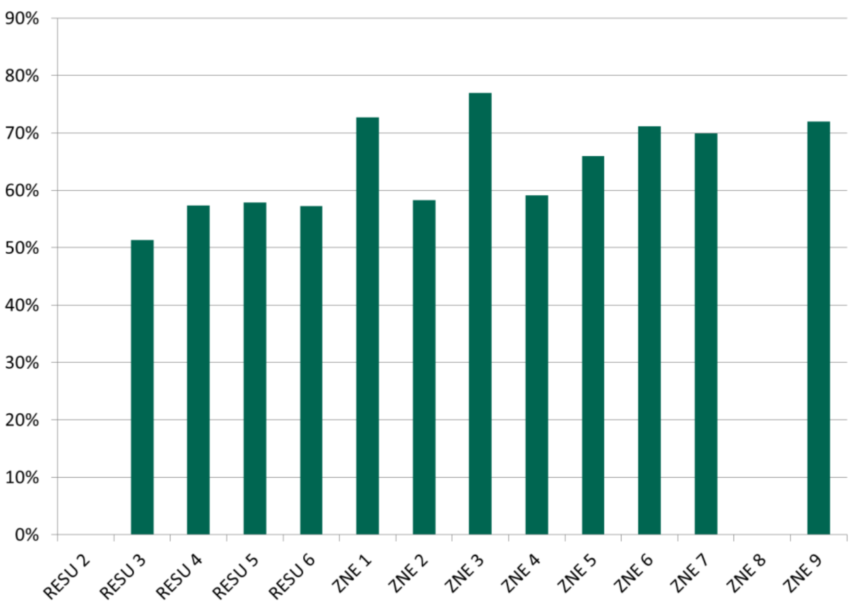


The ZNE Block has nine homes with solar PV arrays, each identically sized at 3.9 kW. Six of these produced over 350 kWh during the test period. The array at ZNE 6 produced less than 350 kWh, probably because it stopped operating late in the test. The RESU at ZNE 8 was never operational during the test period, and the array therefore produced no energy due to software issues. The array at ZNE 3 produced just 270 kWh. This is approximately 75% of the generation by the other arrays.

The RESU Block has five homes with solar PV arrays, each identically sized at 3 kW. Two of these (RESU 2 and RESU 3) produced approximately 250 kWh over the test period. The other two operational arrays (RESU 1 and RESU 5) produced approximately 175 kWh during the test period, about 70% of the production of the other PV arrays. This large variation in PV generation may be due to the physical orientation, shading, environmental factors, or hardware issues.

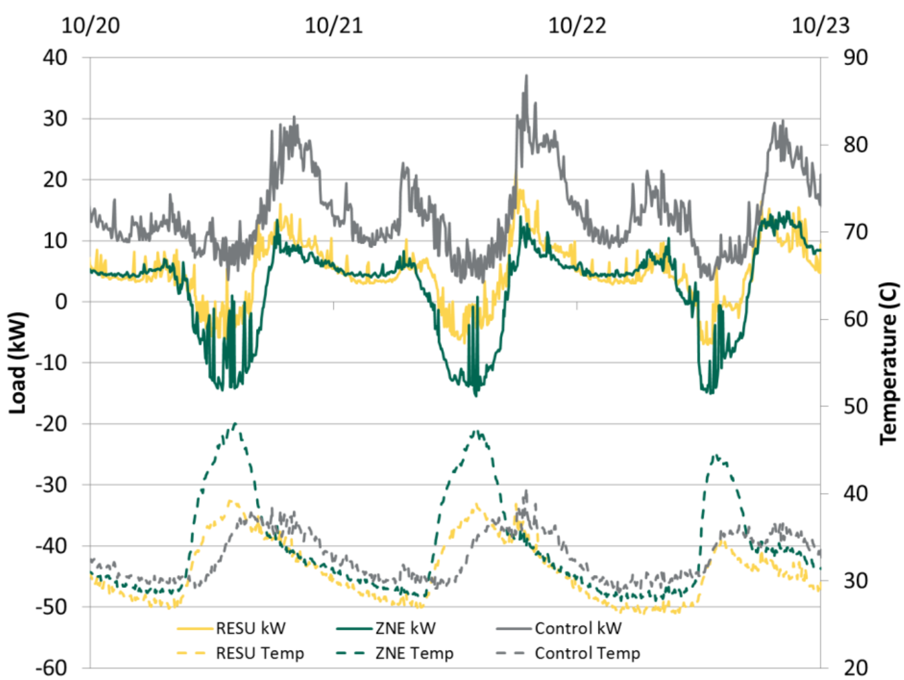
While operating as a standard inverter, the homes exported much of the PV generation to the grid. Residential electricity consumption is typically highest during the evening. To maximize the financial benefit of PV arrays, customers enroll in the net energy metering (NEM) tariff. However, due to the energy storage capabilities of the RESUs (not used during this experiment), these homes are not eligible for NEM. These customers therefore received no credit for any exported energy. The amount of energy exported to the grid for each home varied based on both the PV production of the specific array and the electricity consumed by each respective home. **Figure 27** summarizes the share of solar PV energy exported to the grid.

Figure 27: Share of Solar PV Generation Exported to Grid



During this experiment, the homes exported more than 50% of the energy produced by the solar PV arrays to the grid, which affected the load profiles of the ZNE and RESU Block transformers. Although the customers' energy consumption peaked during the evenings, solar PV generation was exported to the grid during the day. This means that the distribution transformers had high currents during both the evenings and daytime. All nine homes on the ZNE Block have 3.9 kW PV arrays, while the RESU Block has five homes (out of eight homes on the block) with 3 kW PV arrays, and one additional home with a 4 kW array (but no RESU). The Control Block has two homes (out of 20 homes on the block) with PV arrays, totaling less than 8 kW of PV capacity. **Figure 28** shows the loading and hot spot temperature of the ISGD transformers for a three-day period with high PV output.

Figure 28: Transformer Loading and Temperature



Both the ZNE and RESU Block transformers fed power back into the grid during peak solar periods. The Control Block transformer (10% PV penetration) showed reduced load during the day while the RESU Block (75% PV penetration) exported to the circuit during peak periods. The additional generation on the ZNE Block—which has 100% PV penetration—was readily apparent on the transformer, as the power output by the entire block during the test period was over 15 kW.

The changes in the transformer load profiles also seem to have noticeable impacts on the transformer temperatures. The RESU Block and ZNE Block transformers reached peak temperature at approximately 2:00 pm, while the Control Block peaked between 6:00 pm and 8:00 pm. In addition, the large amount of generation on the ZNE Block significantly increased the average current through the transformer.

4.1.1.4.7 Field Experiment 1G: EVSE Demand Response Applications

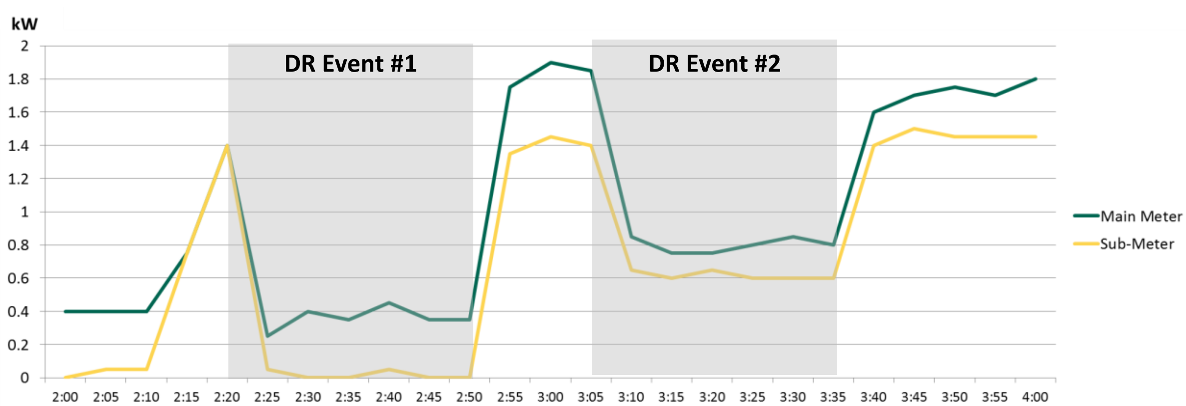
Test 1: EVSE Demand Response Event (November 20, 2013)

The purpose of this experiment was to demonstrate the ability of the EVSEs to receive DR event signals sent through the homes' project smart meters. The intent of this test was also to confirm that the EVSEs respond to the DR event signals properly. This includes automatically reducing the EVSE charging level by the proper amount, at the correct time, and for the correct duration, and returning to the normal charge level once the DR event is complete.

This test consisted of two DR duty cycle events. Both events targeted one home on the CES Block of customer homes (CES 7). The first was a 50% duty cycle event, scheduled for 30 minutes (from 2:20 pm to 2:50 pm). The second event was a 20% duty cycle event, scheduled for an additional 30 minutes (from 3:05 pm to 3:35 pm). The events were initiated in the ISGD ALCS, which then delivered the event signals to the EVSE through the home's project smart meter.

The EVSE response to both DR event signals was consistent with the ISGD team's expectations. The EVSE reduced charging from 1.4 kW to zero at 2:20 pm, and continued in this state until 2:50 pm, when the EVSE resumed charging at 1.4 kW. At 3:05 pm, the EVSE reduced its charging level from 1.4 kW to 0.6 kW, consistent with the team's expectations for a 20% duty cycle event. At 3:35 pm, the EVSE resumed charging at 1.4 kW. **Figure 29** presents the total household demand and sub-metered EVSE demand for the period covered by these DR events.

Figure 29 CES 7 Demand During EVSE Demand Response Event



Field Experiment 1H: EVSE Sub-metering

The project team monitored and collected PEV charging activity through separately metered EVSE usage. **Table 13** summarizes the aggregate PEV charging activity for the 8 months covered by this report.

Table 13: Sub-metered PEV Charging Activity

Usage Metric	EVSE Charging Activity by Month (kWh)								
	Jul. '13	Aug. '13	Sep. '13	Oct. '13	Nov. '13	Dec. '13	Jan. '14	Feb. '14	Total
Average Home	39.1	38.8	52.2	77.5	83.8	86.7	85.7	83.6	547.2
High Home	150.5	167.0	166.0	326.6	291.7	269.9	306.7	335.3	1,987.9
Low Home	10.7	11.0	4.2	12.0	11.5	10.8	10.8	9.8	87.9
All Homes	859.6	852.9	1,148.6	1,705.3	1,842.5	1,906.3	1,885.0	1,839.0	12,039.1

4.1.1.5 Impact Metrics and Benefits Analysis

The Final Technical Report will address the impact metrics and benefits, to allow sufficient time for the project team has accumulate sufficient data and perform the necessary analyses.

4.1.2 Sub-project 2: Solar Car Shade

The solar car shade consists of an array of solar panels on the roof of a parking structure on the UCI campus, a battery energy storage system, and 20 electric vehicle chargers. The various system components were deployed between July and November 2013, and field experimentation began in December 2013. This section summarizes the lab testing, commissioning tests and field experiments used to assess this system.

4.1.2.1 Laboratory Tests

4.1.2.1.1 Battery Energy Storage System

Prior to installing the BESS in the field, SCE performed lab testing to validate the behavior of the system under simulated duty cycles and operating modes. The results helped the team determine the system's reaction to grid events, limits, and efficiencies (including standby power consumption, inverter efficiency, and PV maximum power point tracking). Since the inverter is UL listed, the team only performed functional and performance testing to verify the overall integration of the system components. The laboratory testing allowed the team to verify the BESS' technical capabilities and its readiness for field deployment.

4.1.2.1.2 Electric Vehicle Supply Equipment

Refer to sub-project 1 (4.1.1.2.2) for a summary of the laboratory testing performed on the EVSEs prior to field deployment.

4.1.2.2 Commissioning Tests

4.1.2.2.1 Battery Energy Storage System

Following the field deployment of the BESS in August 2013, the ISGD team demonstrated the BESS' PLS capability over approximately eight weeks, between September 10, 2013 and November 7, 2013. The first day of this experiment constituted the BESS commissioning wherein the team verified its ability to remotely control the BESS and confirmed the device's ability to cycle at constant charge/discharge rates. The Field Experiment 2C discussion below describes this experiment in more detail.

4.1.2.3 Field Experiments

The field experiments defined within ISGD's Metrics and Benefits Reporting Plan (MBRP) are discussed below. In addition to those experiments, the team is also monitoring the overall performance of the entire Solar Car Shade system in terms of the energy used for electric vehicle charging and the electricity production of the solar PV arrays. The following table summarizes the performance of these components over the initial several months following deployment. The battery system was installed and operational in September 2013, the PV was installed in early November 2013, and the EVSEs were available for public PEV charging in December 2013.

Table 14: Solar Car Shade System Performance

• Values are in AC kWh • Negative values indicate net generation, positive values are load		Electric Vehicle Charging	Net BESS (Solar generation less BESS load[18])	Net Load from Solar Car Shade System
2013	September	0	1,398	1,398
	October	0	1,669	1,669
	November	289	(424)	(135)
	December	1,539	(1,023)	516
2014	January	2,977	(1,356)	1,621
	February	2,893	(2,973)	(80)

4.1.2.3.1 Field Experiment 2A: Minimize Peak Period Impact of PEV Charging

The solar car shade did not operate in this mode during the timeframe covered by this report. It will likely operate in this mode during the final reporting period. The Final Technical Report will summarize the results of this field experiment.

4.1.2.3.2 Field Experiment 2B: Cap Demand of PEV Charging System

The solar car shade did not operate in this mode during the timeframe covered by this report. It will likely operate in this mode during the final reporting period. The Final Technical Report will summarize the results of this field experiment.

4.1.2.3.3 Field Experiment 2C: BESS Load Shifting

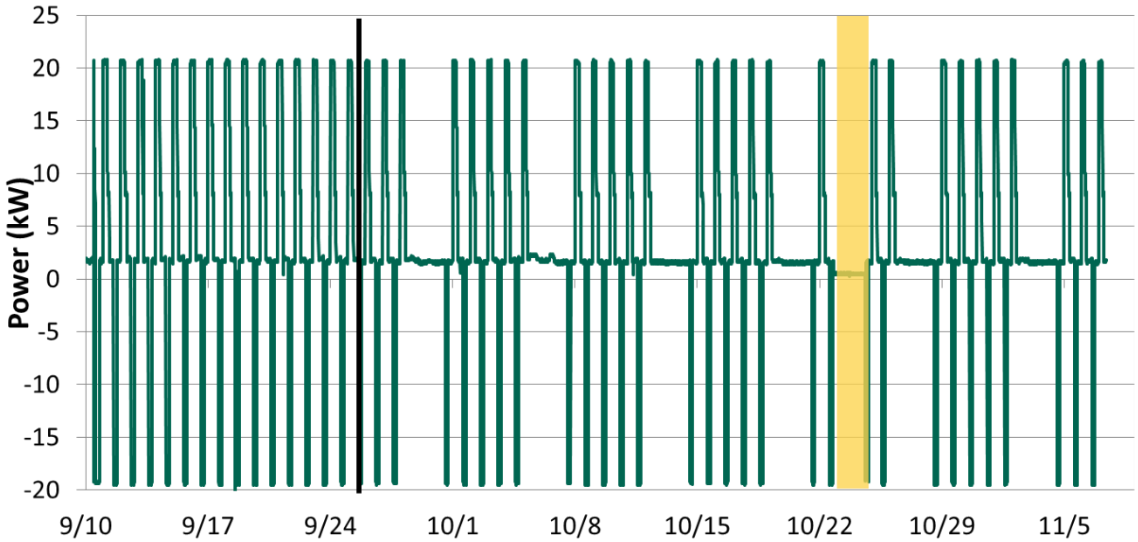
Test 1: September 10, 2013 to November 7, 2013

This experiment was a demonstration of the BESS' internal control mechanisms and long-term (approximately 8 weeks) performance using a scheduled constant power control algorithm. The test occurred between September 10 and November 7, 2013. During the test period, neither the solar PV nor the EVSEs were operational, so no other devices affected the BESS' performance. The team scheduled the BESS to charge at 12:00 am at a rate of 20 kW, and discharge at 2:00 pm (also at 20 kW) on a daily basis. The team altered the BESS' charge and discharge schedule once during the test period, and at one point, a system trip interrupted testing for about two days. The BESS operated with a time-based schedule that the team configured in the BESS site controller.

Testing confirmed that the BESS controls operated as expected throughout the test period. The BESS charged and discharged per the defined schedule. Below is a plot of the power of the BESS throughout the test period. As noted above, the initial schedule included a daily charge and discharge. However, on September 25 (identified by the black line), the schedule was modified to operate only on weekdays.

[18] The BESS load includes efficiency losses from the AC to DC conversion and DC to AC conversion, and auxiliary load from internal electronic components.

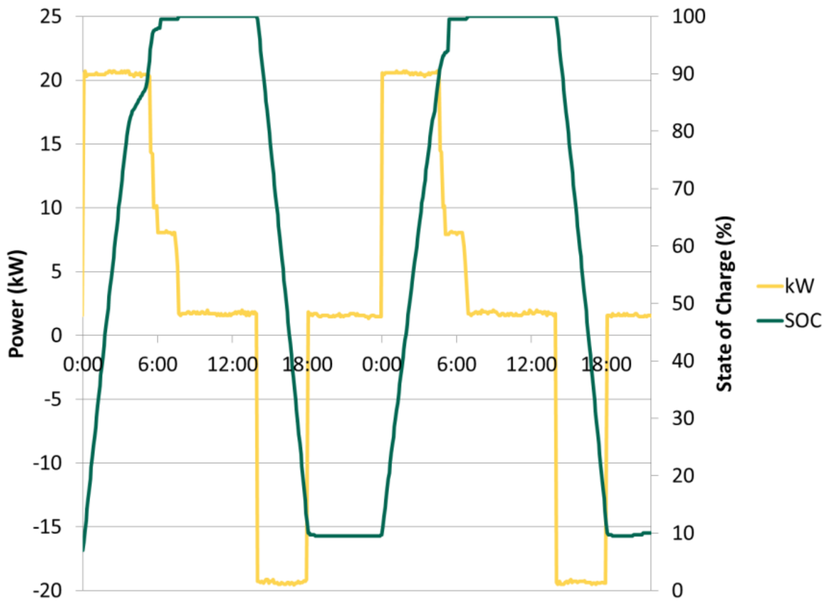
Figure 30: BESS Rate of Charge and Discharge



During the eight-week test period, the BESS tripped once on October 22, 2013 (identified by the yellow shaded region in **Figure 30**). The trip caused the system to safely shut itself down utilizing protections built into the system. The team immediately downloaded diagnostic data collected by the BESS and investigated the issue with the manufacturer. The manufacturer was unable to find the cause of the trip. This produced a lesson learned that is described further in chapter 5. The team successfully restarted the BESS manually during a visit on October 24, 2013. After the restart, the BESS resumed normal operation.

The BESS charged and discharged at 20 kW, until limited by the battery. The BESS began discharging at 2:00 pm and began charging at midnight. The system provided constant power during the discharge but saw a reduction in charging power as the battery neared a full SOC. **Figure 31** shows a typical daily 90 percent discharge. The charge tapers to just 8 kW when the battery's SOC exceeds approximately 90 percent. This plot also shows that the base load of the BESS is approximately 2 kW and that over 7.5 hours is required to fully charge the BESS when limited to 20 kW initially (the charge tapering increases the charge time).

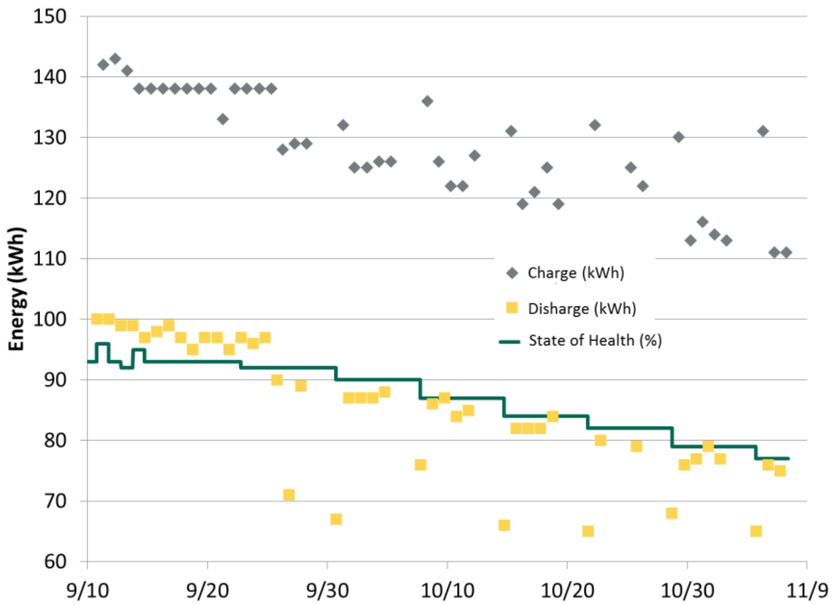
Figure 31: Daily Power Cycle Schedule for PLS



The second issue identified during testing was an artificially accelerated degradation in available battery capacity. Initial cycles discharged approximately 100 kWh AC as expected. However, after the eight-week test period, the available discharged energy was just 75 kWh AC. This performance degradation was realized by significant reduction in the "state of health" (SOH) measured by the battery management system (BMS)[19]. After discovering this issue, the team downloaded the diagnostic data and provided it to the BESS integrator and the battery manufacturer.

[19] The SOH is a manufacturer-specific algorithm that measures the battery's capacity degradation over time. The BMS uses the SOH to determine the BESS' amount of dischargeable energy. As the SOH decreases, the BMS limits the system's dischargeable energy. The BMS calculates the SOH by measuring the energy discharged by the battery once it discharges from a 100% SOC to an 8% SOC. Once the battery reaches an 8% SOC, the BMS compares the discharged energy measurement with the amount measured during previous cycle, and then adjusts the SOH (by up to 3% per cycle). If the amount of energy discharged is less than the amount discharged during the previous cycle, the algorithm adjusts the SOH downward.

Figure 32: BESS State of Health Degradation



SCE addressed this issue with the manufacturers. This behavior was due to a combination of unusual software calculation methods and the inverter using energy from the battery to operate. Several calculations act as inputs to determine the health and current state of the battery (including the SOC). These calculations erroneously indicated the battery was rapidly degrading and, thus, the BMS was artificially limiting the battery's discharge capacity. The manufacturer provided a firmware upgrade to fix this issue, and the BESS has now resumed operation at its expected capacity. Chapter 5 describes the lessons learned from this field experiment in more detail.

4.1.2.4 Impact Metrics and Benefits Analysis

The Final Technical Report will address the impact metrics and benefits, to allow sufficient time for the project team has accumulate sufficient data and perform the necessary analyses.

4.2 Next Generation Distribution System

4.2.1 Sub-project 3: Distribution Circuit Constraint Management Using Energy Storage

This sub-project is demonstrating a mobile, containerized DBESS that will help prevent load on the distribution circuits from exceeding a set limit. The DBESS will also help mitigate overheating of the substation getaway. This section summarizes the laboratory testing performed on the DBESS prior to field deployment. The team relocated the DBESS to the field in March 2014, and first connected it to the grid on April 15, 2014. The second TPR and Final Technical Report will summarize the results of the commissioning test and field experiment activities.

4.2.1.1 Laboratory Testing

In December 2009, SCE acquired two 2-MW/0.5 MWh grid battery systems (GBS) to gain firsthand experience with the operation and performance of large transportable energy storage devices. The intent was to use the GBS for various applications on SCE's distribution system, including distribution feeder relief.

SCE performed an extensive evaluation under a tightly controlled environment at its facilities in Westminster, California. Based on these evaluations, the system was effective in reducing circuit overloads by automatically and continuously injecting or absorbing energy. The monitoring equipment and control algorithm used to implement the feeder relief function performed as expected.

4.2.1.2 Commissioning Tests

The DBESS was relocated to the field in March 2014, and was first connected to the grid on April 15, 2014. The second TPR will summarize the commissioning test activities.

4.2.1.3 Field Experiments

4.2.1.3.1 Field Experiment 3A: Peak Load Shaving/Feeder Relief

The DBESS did not operate during the timeframe covered by this report. It will likely operate in this mode during the final reporting periods. The Final Technical Report will summarize the testing results.

4.2.1.4 Impact Metrics and Benefits Analysis

The Final Technical Report will address the impact metrics and benefits, to allow sufficient time for the project team has accumulate sufficient data and perform the necessary analyses.

4.2.2 Sub-project 4: Distribution Volt/VAR Control

This sub-project is demonstrating a method for achieving CVR by delivering energy at lower voltages (that are within the required voltage limits). Reducing customer voltages typically leads to lower energy consumption by customers. ISGD's approach to CVR consists of automating the capacitor banks (both in the field and at MacArthur Substation), by using a centralized control algorithm to determine the optimal capacitor operations. This algorithm relies on primary circuit voltage, Watt, and VAR measurements at the substation. The DVVC algorithm determines the optimal capacitor switching operations (every 5 minutes) that satisfy user-defined constraints for minimum and maximum voltage and reactive power flow.

4.2.2.1 Simulations

In January 2012, the vendor's technical team that supported sub-project visited SCE to begin discussions regarding the software and hardware requirements for DVVC. The ISGD team presented the methodology that the DVVC algorithm should follow by demonstrating it with an in-house Microsoft Excel-based software solution. The vendor team then documented the DVVC algorithm definition, which it would use to implement the software solution for ISGD.

In April 2012, SCE obtained a very early version of the vendor software. SCE tested the DVVC algorithm under various scenarios to check the algorithm logic, and provided feedback to the vendor to further refine the software. A few months later, SCE tested the algorithm logic of the DMS DVVC software on a server utilizing GE's XA21 platform. SCE performed side-by-side test scenarios using SCE's Microsoft Excel model as a baseline for evaluating the DMS DVVC test results. These scenarios were designed to demonstrate the ability of the DVVC application to reduce or raise average system voltage using field capacitors, substation capacitors, or combinations of both. Likewise, these tests were designed to demonstrate "pushing" or "pulling" VARs between distribution and sub-transmission systems. Both of these sets of simulations also demonstrated the ability of the DVVC algorithm to limit the number of capacitor switching operations. These tests relied solely on the vendor software, and did not use any field devices.

4.2.2.2 Laboratory Testing

Between August 2012 and December 2012, SCE developed tests for evaluating DVVC during FAT (field acceptance testing) and SAT (site acceptance testing). The purpose of these tests was to evaluate the DVVC algorithm by using actual field devices (i.e., programmable capacitor controllers or PCCs). This consisted of evaluating the DVVC algorithm by performing end-to-end testing from the software to the field devices. The purpose of this testing was to demonstrate the ability of the DVVC algorithm to receive telemetered inputs from the PCCs, derive an optimal PCC switching solution, and either raise or reduce voltage, or provide reactive power to the sub-transmission system. Acceptance test procedures (ATP) were aligned with the DVVC business requirements to ensure that the FAT and SAT testing would demonstrate that DVVC met SCE's requirements.

To facilitate end-to-end testing in a laboratory, the DVVC vendor set up a test environment in their product testing facility, to emulate SCE's Advanced Technology Labs in Westminster, California. This laboratory included four S&C Electric IntelliCAP Plus PCCs and four Netcomm radios. Variable transformers provided distribution circuit primary voltage inputs and provided a power sources to the PCCs. The vendor server housing the DVVC algorithm was configured to the PCCs via the radio network. This system was used throughout the various FAT cycles in 2013, including a round of Pre-FAT testing, and two rounds of FAT testing. SCE personnel witnessed and approved all vendor ATPs, ensuring that the application satisfied ISGD's DVVC application requirements.

SCE conducted the first round of SAT testing in September 2013. This testing used the same test scenarios and ATPs as FAT. During the second round in October 2013, SCE verified that the DVVC application satisfied all of SCE's business requirements.

4.2.2.3 Commissioning Tests

The ISGD team performed field testing of the DVVC algorithm in December 2013 for approximately two weeks. This testing verified that DVVC could communicate with the field PCCs and the PCC at MacArthur Substation. The algorithm made the correct selections for switching PCCs. During field testing, the team encountered a connectivity problem with SCE's Netcomm radio network. A firmware upgrade to this network disabled some of the radios, which limited the DVVC algorithm's ability to deliver switching commands to all the PCCs.

The DVVC application became operational at MacArthur Substation in January 2014 for the team to experiment with the volt/VAR control set points. The team monitored the distribution system's behavior closely, and adjusted the set points when appropriate. To assess the reliability of radio communications for the DVVC algorithm's control signals, the team also monitored the Netcomm Radio system. The DVVC application's logic was determined to be successful during these field tests. The overall impact on average system voltage was also consistent with the team's expectations.

4.2.2.4 Field Experiments

4.2.2.4.1 Field Experiment 4A: DVVC VAR Support

The ISGD team began operating the DVVC algorithm in January 2014, and preliminary results indicate that it is performing as expected. The second TPR will present the DVVC performance results, after the team has compiled and analyzed the results more thoroughly.

4.2.2.4.2 Field Experiment 4B: DVVC Conservation Voltage Reduction

The ISGD team began operating the DVVC algorithm in January 2014, and preliminary results indicate that it is performing as expected. The second TPR will present the DVVC performance results, after the team has compiled and analyzed the results more thoroughly.

4.2.2.5 Impact Metrics and Benefits Analysis

The Final Technical Report will address the impact metrics and benefits, to allow sufficient time for the project team has accumulate sufficient data and perform the necessary analyses.

4.2.3 Sub-project 5: Self-healing Distribution Circuits

This project is demonstrating a self-healing, looped distribution circuit that uses low latency radio communications to locate and isolate a fault on a specific circuit segment, and then restore service once the fault is removed. This protection scheme is designed to isolate the faulted circuit section before the substation breaker opens (typically 670 milliseconds after a fault). This functionality should lead to improved distribution circuit reliability by reducing the number of customers exposed to momentary outages and easing the circuit restoration burden on system operators.

4.2.3.1 Simulations

The team performed simulations to determine the maximum load levels for which looped operation is appropriate. Additional simulations helped to verify the fault isolation logic and timing for a wide range of operating conditions. The simulations included various fault scenarios at different locations on the Arnold and Rommel distribution circuits. They also included different types of faults at each location (all combinations of phase to ground, phase to phase, double phase to ground, and a three-phase fault). Faults were simulated at each section of load between the protection relays to verify that they operate correctly. The team performed these simulations using SCE's RTDS with the actual protective relay inputs and outputs attached to the simulator for closed loop testing. Outputs from the RTDS were physically connected to four Schweitzer Engineering Laboratories (SEL) 651Rs and two GE F60 relays.

The team reviewed all event files and oscillography files the simulation produced an undesired outcome. These files helped the team to troubleshoot the protection logic. When changes were required for the protection settings, all testing performed again.

The simulation testing was successful in validating the system protection scheme, and helped the team identify the need for a few modifications to the protection settings. The biggest issues were false tripping under heavy loaded conditions, box loops around URCIs, and clearing end-of-line faults. To address the heavy loaded condition issue, the team decided that if the circuit loading exceeds 600 amps, the Arnold and Rommel circuits would be de-looped to prevent both circuits from tripping. In the event that a box loop forms around a URCI, the two circuits would be de-looped to minimize the number of customers affected by the fault. The last issue related to end-of-line faults. The protection scheme required six seconds to clear a three-phase fault at the end of the line. To resolve this issue the team reduced the trip settings on two of the URCIs.

4.2.3.2 Laboratory Testing

The relays and radios were assembled and tested as a system prior to field installation to verify performance and proper functionality. Actual circuit fault conditions (derived from simulation tests) were imposed on the assembled laboratory test setup, and the responses of the protection scheme were recorded. High-speed communications system performance was also verified in the laboratory. The team also evaluated the SA-3 system's ability to coordinate with the URCI protection scheme.

The team did not test the URCI protection scheme by inducing actual faults on the live circuit since this would require a service interruption for SCE customers. The team conducted laboratory testing in lieu of field testing. The team also installed instrumentation in the field to record actual faults that might occur during the demonstration period. Any actual faults would provide additional verification of the design and operation of this advanced protection system.

The team also performed laboratory testing to verify that the ISGD DMS could monitor and control the URCIs. The URCI relays communicate using IEC 61850 GOOSE messages, while the ISGD DMS communicates using DNP 3.0. ISGD DMS receives URCI GOOSE messages via the substation gateway, which translates the messages from IEC 61850 to DNP 3.0. Laboratory testing validated that this translation works effectively and that the ISGD DMS is capable of receiving and responding to the URCI communications appropriately.

4.2.3.3 Commissioning Tests

Commissioning tests have consisted of verifying the radio network communications. A number of repeater radios were necessary to allow the URCI network to communicate with each other and with MacArthur Substation. Reliability and latency were the two critical factors evaluated.

Once field deployment of the URCIs is complete, the team will perform tests similar to the ones completed in the lab. The team will verify that the ISGD DMS is able to monitor and control the URCIs. The team will also perform an "end point test" to test all the functionalities of the URCI protection scheme. Once these two tests are complete, the team will verify that the URCIs perform the correct operations when a fault occurs. The team will use Doble Simulators to inject voltage and current into the relays. This testing will rely on COMTRADE files created from the RTDS simulations, which the team will replay through the Doble Test sets to simulate fault conditions. The team will simulate faults on each section of load between each protection device and verify that the correct devices operate.

4.2.3.4 Field Experiments

4.2.3.4.1 Field Experiment 5A: Self-healing Circuit

This consists of a passive experiment whereby the team will verify self-healing circuit capability on an energized circuit only if a fault occurs on the circuit. Although the team will not induce a fault to test this capability, it will be tested using lab simulations. It will also be tested by isolating the URCI from the circuit using the bypass switches, and then injecting fault currents into the field devices. However, this testing will not interrupt any customers' service. The team currently expects the URCIs to be in service during the fourth quarter of 2014. Once they are in service, the team will be able to assess their effectiveness if a fault occurs on the circuit during the demonstration period.

4.2.3.4.2 Field Experiment 5B: De-looped Circuit

The team currently expects the URCIs to be in service during the fourth quarter of 2014. Once they are in service, the team will be able to assess their effectiveness if a fault occurs on the circuit during the demonstration period.

4.2.3.5 Impact metrics and Benefits Analysis

The Final Technical Report will address the impact metrics and benefits, to allow sufficient time for the project team has accumulate sufficient data and perform the necessary analyses.

4.2.4 Sub-project 6: Deep Grid Situational Awareness

The objective of this sub-project is to demonstrate how high-resolution power monitoring data captured at a transmission-level substation can detect changes in circuit load from a distributed energy resource (such as demand response resources, energy storage, or renewables). Such a capability could help enable aggregators of such resources to participate in energy markets by providing a means of verifying resource performance. 2 MW DBESS from sub-project 3 will support this testing. The team will operate the DBESS to produce load changes of various magnitudes and durations, and at various ramp rates, to simulate the behaviors of distributed energy resources. The DBESS was relocated to the field in March 2014, and was first connected to the grid on April 15, 2014. The team expects to begin field testing in September 2014.

4.2.4.1 Pre-deployment testing

The second TPR will summarize this testing activity.

4.2.4.2 Field Experiments

4.2.4.2.1 Field Experiment 6A: Verification of Distributed Energy Resources

The DBESS did not operate during the timeframe covered by this report. The team plans to begin this field experiment in late September 2014, and to continue testing during 2015. The second TPR and the Final Technical Report will summarize the results of this testing.

4.3 Interoperability & Cybersecurity

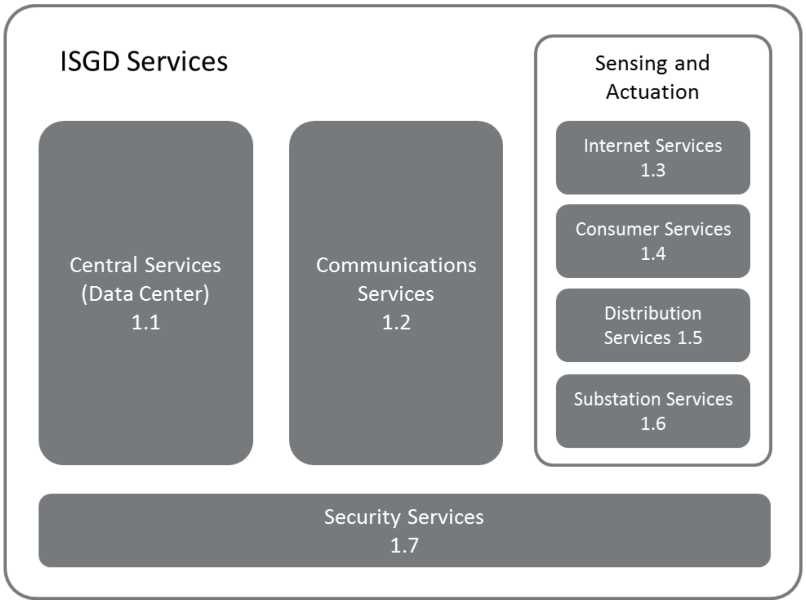
4.3.1 Sub-project 7: Secure Energy Net

Smart grid capabilities typically require electronic communications between field devices and utility back office systems. Creating SENet was one of ISGD's most technically demanding and resource intensive sub-projects. Its development had to address diverse communications and security requirements for back office services, including data collection and control functions for a variety of applications involving field equipment. Although the SENet design was mindful of interoperability and cybersecurity needs, it also had to accommodate legacy SCE systems. Using a rigorous systems engineering approach, SCE designed, developed, integrated, and tested several communication networks and back office software systems. SENet operated as planned since deployment. It represents a solid baseline for future SCE distribution system back office automation.

4.3.1.1 Design

ISGD used a structured systems engineering process that began with developing a logical architecture of system services. The team then decomposed service domains into lower level service components to develop system specifications and interfaces. Each new level of decomposition inherited the requirements of the higher-level service (within the logical structure), resulting in clear traceability and interoperability across components with shared services. **Figure 33** shows the grouping of functional services into seven domains, each representing different logical processing environments.

Figure 33: ISGD Services Domains



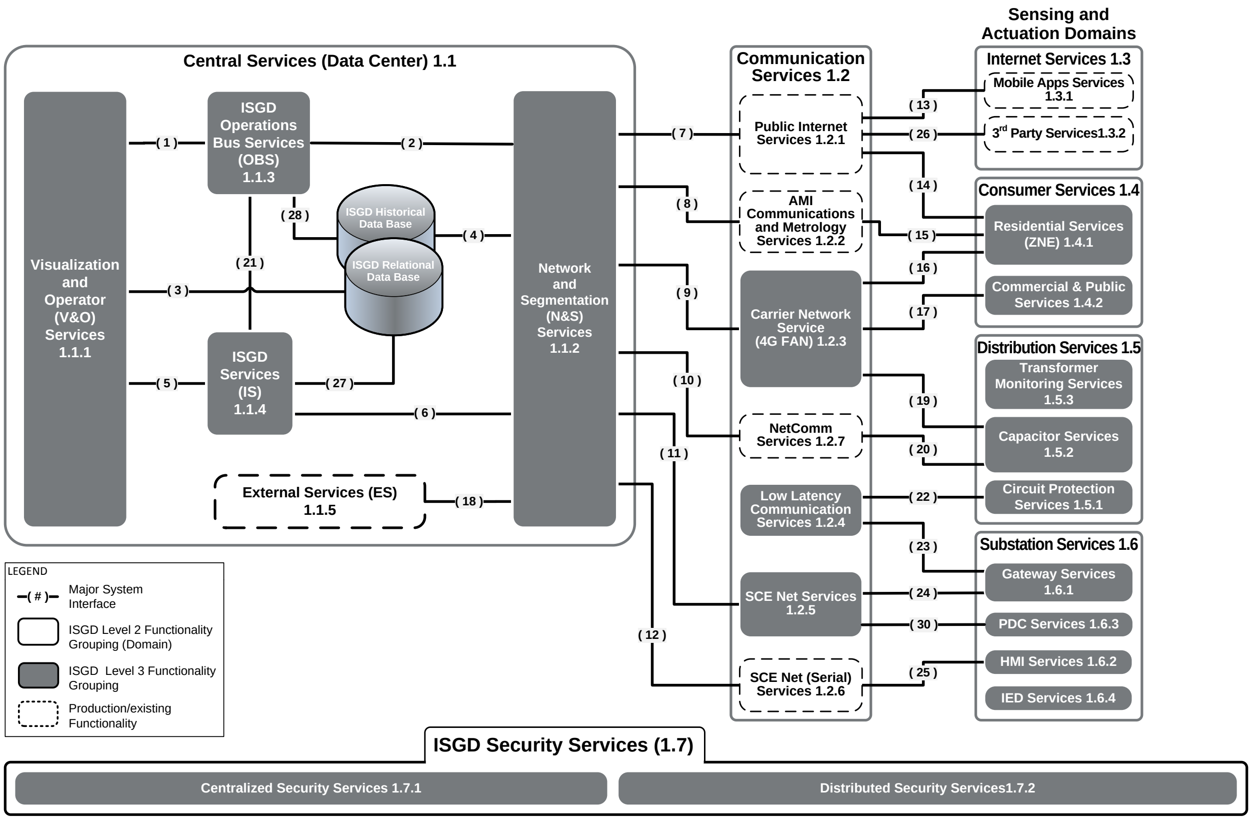
Security is a foundational service, which supports the other service domains. A general design principle was to share resources and services wherever possible, including the areas listed in **Table 15**.

Table 15: SENet Resources and Services Sharing

Functional Area	Technology Sharing or Reuse
Computing	Server operating system virtualization (VMware)
Networking	• Packet switched networks (Internet protocols) • MPLS
Storage	• SAN (storage area network) • Relational Database Management System • Time-series data historian (point/time/value)
Integration	• Web service application containers/platform • Queuing

Figure 34 shows the second level decomposition of the ISGD logical system architecture.

Figure 34: ISGD Logical System Architecture



Decomposing the ISGD services domains into more discrete services, defining their requirements, and preparing detailed designs for each component provided the basis for selecting systems, equipment, and applications. Designs were prepared for each component, including processing, storage, and communications.

The resulting ISGD physical architecture is complex, and includes over 100 applications and 50 integrations (i.e., information exchanges between components).

4.3.1.1.1 Interoperability

ISGD attempted to implement smart grid protocols and interfaces wherever possible to support interoperability and to help facilitate integration. The level of standards adoption was an important consideration when selecting products. **Table 16** lists the primary smart grid and other general-purpose standards specified and used by SENet.

Table 16: ISGD Use of Interoperability Standards

Standard	ISGD Use of Standard
IEC 61850	IEC 61850 is used for substation device configuration and communications. Also, GOOSE messages (Generic Object-Oriented Substation Events) are used for high-speed transfer of events between URCIs and the substation gateway.
IEC CIM (61968/61970)	ISGD uses the CIM (Common Information Model) for integrating data from measurement devices. Primarily, some of the schemas in the central database are CIM-based. In addition, a set of CIM-based views allows for reading retrieval from various systems in a consistent form.
ZigBee Smart Energy	The programmable communicating thermostats, plug-in electric vehicle

Standard	ISGD Use of Standard
	chargers, and smart appliances receive demand response event signals to automatically reduce consumption during peak periods.
ICCP	The Inter-Control Center Communications Protocol (ICCP or IEC 60870-6/TASE.2) is used to exchange capacitor, transformer, and URCI data between the ISGD DMS and production systems.
DNP3	This protocol is used by the ISGD DMS for measurement and control data to and from capacitor bank controllers and the CES device.
IEEE 802	This is used for wired (802.3) and wireless (802.11) networking in all ISGD communications links.
IETF Standards	Many internet protocols are specified by IETF RFCs (Internet Engineering Task Force Request for Comments). Such standards include IPv4, IPsec (Internet Protocol Security), HTTP, etc. These standards are used throughout ISGD for all IP-routable communications.
W3C-WS-* (or REST)	Use of HTTP, SOAP (Simple Object Access Protocol), and XML (Extensible Markup Language) for web services interface definitions, used in several exchanges between back-office servers, and with "cloud" services including On-Ramp, TrendPoint, ALCS, and SSI.
Smart Grid Software Services Infrastructure	Visualization, reporting, and analysis integration retrieves data using Structured Query Language (SQL).

Enterprise Service Bus Overview

An enterprise service bus (ESB) is a software architecture model used in corporate environments to integrate multiple disparate software applications and systems. The cost of this integration can be prohibitive when each application or system requires a separate and unique interface. An ESB addresses this problem by using a Common Information Model (CIM) to support standard interfaces such that each application can communicate with each other through the ESB, which acts as an interpreter. An ESB should enable easy integration and secure, standards-based interoperability of third-party products and legacy systems, providing an ecosystem for smart grid operations. The key benefits of an ESB include:

- Increases flexibility (easier to adapt to changing requirements)
- Moves from point-to-point solutions to enterprise deployments
- Emphasizes configuration while reducing integration coding
- Leverages legacy systems to participate in future architectures

As utilities consider incorporating an ESB into their smart grid roadmaps, they should evaluate the following priorities to determine whether an ESB architecture is appropriate.

- Distributing information across the utility enterprise (including the grid control center), quickly and easily
- Creating a unified architecture among multiple underlying platforms, software architectures and network protocols
- Providing flexibility to accommodate future smart grid applications (both planned and unforeseen)

The level of effort required to integrate the ESB with legacy systems can be significant. Once a utility invests in an ESB, it should ensure that it has both the in-house skills and third-party vendors mature enough to realize the full potential of an ESB. This recommendation is discussed in detail in 5.1.3.3.

Enterprise Service Bus Role within ISGD

SCE implemented GE's SSI as an ESB for ISGD. SSI supports high-speed command and control of a fully integrated smart grid with interoperability and cybersecurity. SSI is based on a service provider framework that enables modular applications to "plug in" to the infrastructure using well-defined, IEC CIM-driven services (such as IEC

61850, IEC 61968, IEC 61970, etc.). Adapters were developed and implemented to interface with legacy systems that do not conform to standard service definitions. These adapters were available as standard adapters from SSI, or were developed by GE or SCE. SCE is demonstrating the following services using SSI:

- Advanced metering infrastructure
- Transformer monitoring
- Home area network access via Internet
- Advanced load control
- Power outage/restoration messaging
- Distribution automation

ISGD's SENet architecture is comprised of both new and legacy devices and information systems. The legacy systems may use a variety of standards and protocols as well as proprietary technologies. The SSI adapters enable interoperability among these devices and systems. The adapters translate communications protocols as well as data formats between systems, regardless of which hardware platforms and operating systems they run on. In addition, the SSI adapters, in conjunction with SCE's Common Cybersecurity Services, enforce the correct level of security to the connected systems at the point these systems interface with SENet.

ISGD's SSI implementation centered on creating a data store called the ISGD central database. This store serves as the basis for applications to exchange data. The team uses SSI as an execution platform in which applications retrieve and store data in the database. Storing data in the database was an integration approach, but it also supports ISGD's advanced visualization capabilities. SSI is used to access various services, retrieve data, and serve the data to a situational intelligence visualization service. This service provides a single operational view from multiple systems, allowing the team to visualize grid conditions using multiple data sources. This constitutes a lesson learned, which is discussed in detail in 5.1.

The SSI integration toolset integrates devices, applications, services and processes, which supports interoperability and secure communications across ISGD. SSI incorporates the emerging National Institute of Standards and Technology (NIST) smart grid standards across ISGD, while providing the flexibility to upgrade, extend, and scale the solution in the future so that the system can evolve as standards and technology evolves. The translation of communication protocols and data formats from legacy systems to SSI interfaces demonstrates an incremental migration path that will allow the systems to mature and evolve, while also accommodating new system components to interact. It is likely that adapters will be developed for the most common standards, and that these will be reusable across the industry.

4.3.1.1.2 Cybersecurity

SCE recognizes that redundant services (such as databases and web services) have the potential to create incompatibilities and duplicative expense. The ISGD team has defined security services as common services, and has implemented them using a common platform for all ISGD components.

SCE's CCS platform provides ISGD's security services. CCS has implemented NIST-recommended cybersecurity suites and protocols. Specifically, Internet Key Exchange (IKEv2) is used for key exchange, and encapsulating secure payload (ESP) is used to establish IPsec VPN tunnels with rotating keys, which encrypts all communication traffic. Several vendor applications have already implemented these services. For the vendor applications that have not already implemented these services, the ISGD team relies on CCS to provide them. For example, CCS can create a secured Internet Protocol Security (IPSec) tunnel for sending protected communications.

CCS uses the Microsoft Windows Active Directory as the repository of identity information, governing access to ISGD resources by both human and non-human clients, using roles to specify privileges. Each user session requires authentication (proof of identity), and no shared accounts or passwords are allowed. Passwords must change periodically and meet minimum complexity requirements.

The guiding principles of the CCS security solution include the following:

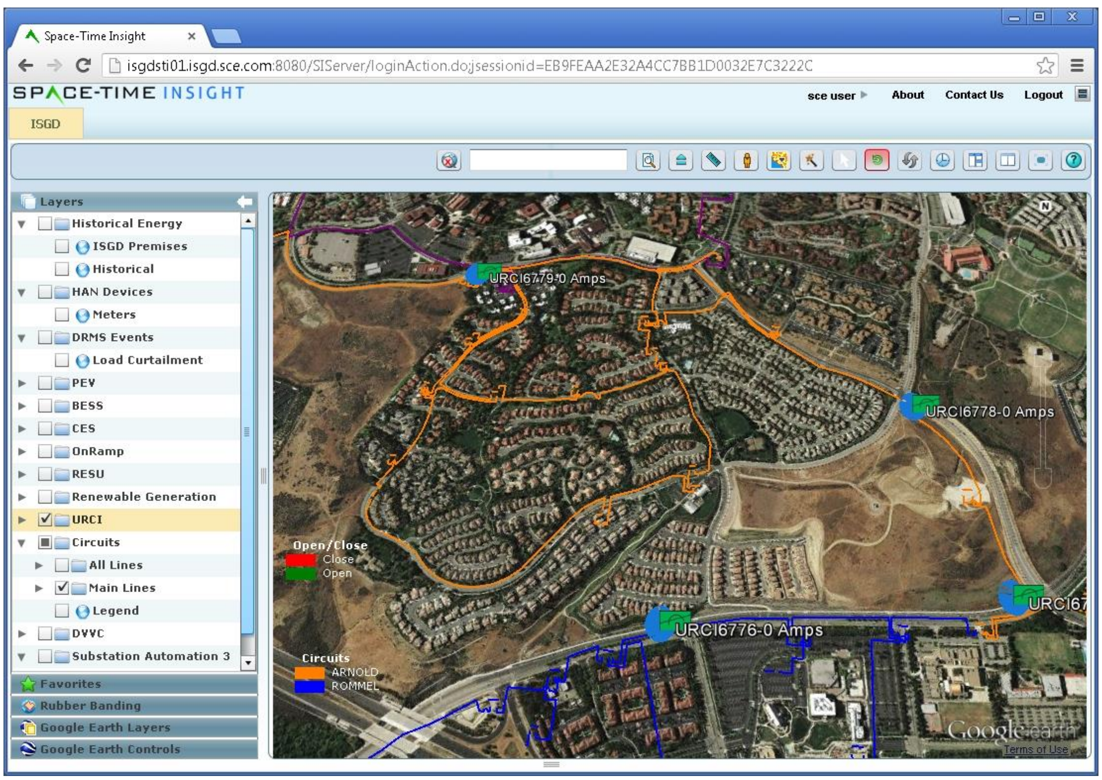
- All unnecessary services are turned off, such as communications ports for unused remote access methods
- All communications take place over secured channels; all other channels are blocked
- Communications traffic only allowed if it is specifically enabled (it is denied by default)
- Default accounts are removed or changed so that no simple or shared passwords exist
- Access to devices via external interfaces is explicitly controlled; using CCS-provided, device-specific certificate(s), unique ID, connection configuration file(s), and firewall rules
- Industry standards are used to harden client and server operating systems to prevent "back door" access and changes to installed software

The second TPR will include an expanded discussion of SCE's CCS platform.

4.3.1.1.3 Visualization

Most ISGD applications (e.g. ALCS, AMI, CES, RESU, BESS, and TrendPoint) have graphical user interfaces containing views of system measurement trends, system data, and configuration. The ISGD team also implemented a visualization application that provides integrated views of the various ISGD components in operation. ISGD is using this application for demonstration purposes only. Although it would be possible to build controls into this environment, ISGD is only using it as a situational awareness tool. **Figure 35** provides a sample screen view from the visualization application.

Figure 35: ISGD Visualization System Sample View



4.3.1.2 Deployment

ISGD is using two environments for SENet.

- Lab Test Environment: This environment resides within SCE's Advanced Technology Labs. Test equipment was assembled and configured to resemble the production environment, to the extent possible.
- Pilot Production Environment: This environment resides within an existing grid control center, within a new network domain.

The team used both environments to conduct three phases of testing per system. The team performed each series of tests in the Lab Test Environment before performing them in the Pilot Production Environment. The systems were accepted and commissioned only after all tests were either successful or withdrawn.

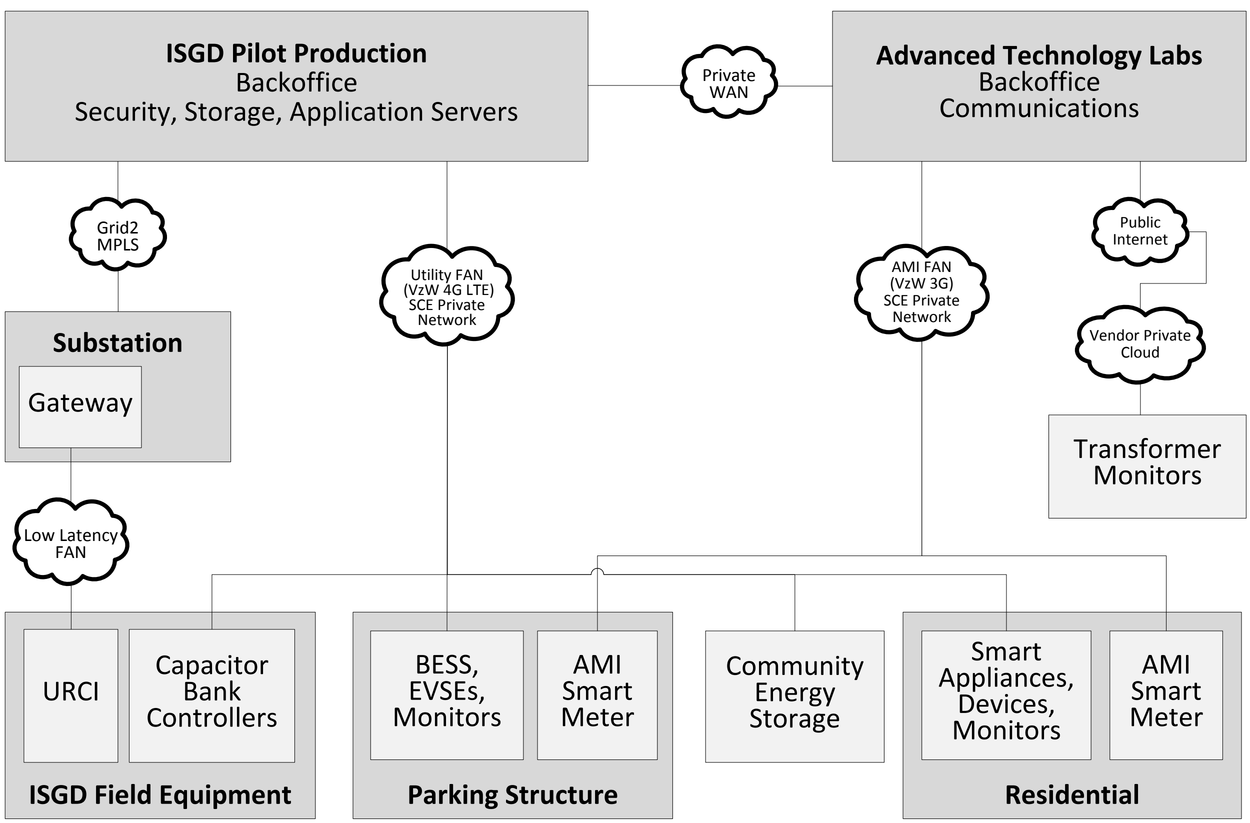
- Component Testing was performed by the component developer. All tests were documented and issues were identified prior to attempting any testing with other components.
- String Testing involved testing data flows between components, starting with simple exchanges, and then progressing to more complex or longer scenarios.
- End-to-end Testing helped the team to verify that business requirements were satisfied with all equipment, communications, and required functionality.

In addition to the above testing, in certain cases the team performed simulations in order to run scenarios that would be difficult or impossible to run with the actual equipment in the field.

4.3.1.2.1 Network Infrastructure

Figure 36 provides an overview of the equipment, locations, and network links involved in the system.

Figure 36: ISGD Back Office Systems Overview



Customer Home Area Network

HAN devices in the customer premises and plug-in electric vehicle chargers at the Solar Car Shade parking structure both support the Smart Energy Profile 1.x (SEP 1.x) protocol. These devices are capable of receiving demand response signals through project smart meters, or through a home EMS gateway, which receives the signals through a project smart meter. The home EMS is used in the sub-project 1 customer homes (not the solar car shade). The home EMS is a gateway that may be joined with a customer Wi-Fi network to allow controlled access to HAN devices via a customer device using a smartphone app. This gateway may also use a public carrier secure connection to store data from the HAN devices on a "cloud" home EMS server (if the customer elects to register with the home EMS vendor for this service).

Field Area Network

The FAN consists of both the smart meter (Advanced Metering Infrastructure) FAN, and the Low-latency FAN. The AMI FAN is a secure RF (radio frequency) mesh network with an SCE private network over a 3G wireless public carrier backhaul, using a DMZ (demilitarized zone). The DMZ is a network set up specifically to provide only the functionality needed for communications to external systems (in this case, the AMI system), prevent unauthorized access, and pass authenticated electronic communications along to back office systems in higher security level networks. This network provides communication of usage measurements from project smart meters and EVSE sub-meters, and demand response event signals.

The RESUs are securely connected to the back office via the Utility FAN (an SCE private network over 4G public carrier backhaul), and the ISGD CCS DMZ. This Utility FAN provides a secure, high bandwidth connection for transmitting data with higher sample rates, and for sending frequent commands. The CES, BESS, and TrendPoint circuit monitoring systems connect securely to the back office via the same path.

The Low-Latency FAN connects field devices outside of the substation (such as the universal remote circuit interrupters), to the substation gateway. The Low-Latency FAN uses a secure RF network with an access point on the URCI LAN at the substation. Devices on the Low-Latency FAN communicate through the substation gateway to the ISGD Pilot Production network via the ISGD CCS DMZ. These FAN devices and networks support enhanced situational awareness of the distribution system.

Internet

On-Ramp Wireless devices monitor each of the four distribution transformers on the four blocks of customer homes. These devices connect to the vendor's cloud server via a secure wireless network. The ISGD Vendor DMZ retrieves data from the cloud server using a site-to-site VPN over the public Internet. The ISGD Vendor DMZ provides a secure connection to the ISGD back office systems.

Substation LAN

The substation LAN supports control, protection, and measurement applications for devices located within MacArthur Substation. The substation gateway provides support for legacy and proprietary systems, potentially handing all communications to and from the substation, and eliminating all other channels, such as serial ("dial up") connections. Devices on the substation LAN can connect with legacy communications links via the substation HMI (human-machine interface) to support both channels during testing.

Intra-utility WAN

Devices connected to the Intra-Utility wide area network (WAN) high-speed backbone have fiber connectivity to other such devices, substations, and head-end systems in data centers and grid control centers. The high-speed backbone supports control, protection, and measurement applications with MPLS, DMZs, and VPNs to assure the integrity and confidentiality of ISGD data/control from other SCE users on this backbone.

4.3.1.2.2 Computing and Storage

Hardware

The ISGD project uses 16 blade servers with storage area network (SAN) storage as the main computing environment in the back-office. The Lab Test and Pilot Production back office environments have similar hardware. ISGD is also using online and tape backup equipment, network switches, routers, management and monitoring equipment, a virtual desktop user interface server, and two additional rack-mounted application servers.

In addition to the back-office locations (Lab Test and Pilot Production), the product has installed equipment in MacArthur Substation, on two 12 kV circuits fed by MacArthur Substation, in the project neighborhood and participant homes, and within the Solar Car Shade parking structure.

Software

Table 17 summarizes the major software applications used for ISGD.

Table 17: ISGD Software Applications

Application	Functionality
Circuit Monitoring	Monitors energy usage on multiple circuits within a home. Supports analyzing the effect of smart appliances and other energy efficiency measures.
Demand Response	Manages, dispatches, and tracks DR events and programs.
Advanced Metering Infrastructure	Captures 5-minute directional usage and voltage from smart meters, and supports ZigBee Smart Energy 1.x for sending DR signals to smart appliances.
Residential Energy Storage Unit	Contain energy storage and inverters for the rooftop solar panels.
Battery Energy Storage System	Paired with 20 electric vehicle charging stations and a rooftop solar PV system to support PEV charging.
Community Energy Storage	CES is a distribution scale battery for peak shifting, islanding, and other functions.
Transformer Monitoring	The On-Ramp Wireless system provides transformer measurements securely over the Internet.
Substation Gateway	The substation gateway provides communications and substation configuration management services.
Distribution Management System and Energy Management System	Model the distribution and bulk power systems to provide a variety of operational functions. The URCI and DVVC functions were added for ISGD.
Universal Remote Circuit Interrupter	URCIs provide self-healing functionality to preserve power to segments of a looped circuit not containing a fault.
Distribution Volt/VAR Control	Operates in the DMS system to optimize voltage by controlling capacitor banks based on monitored grid inputs.
Enterprise Service Bus	Integrates AMI, meter data services, TrendPoint, On-Ramp Wireless, BESS to Oracle.
Visualization	Contains custom views of project data integrated within Google Earth.
Cybersecurity	See section 4.3.1.1.2 for a description of the cybersecurity functions.
Operating System	Manages physical resources (memory, disk, and network) for the software resources running on the hardware.
Relational Storage	Stores general purpose tabular data.
Data Historian	Stores numeric values as time-series data.

4.3.1.3 Design Considerations and Findings

The ISGD design went through a number of revisions during design and engineering phase. This section describes aspects of the design and implementation that required the team to consider alternatives and the associated tradeoffs.

4.3.1.3.1 Field Area Network Backhaul (4G)

Secure and reliable communications with field devices is a critical foundational element of a smart grid. Communications networks typically require a combination of technologies, depending upon the number of communicating nodes and the required bandwidth. Mesh networks are often cost-effective if the nodes are close enough together. Mesh networks allow multiple devices to share a longer-range backhaul communications links, potentially avoiding duplicate expenses.

- <u>Short range, broadcast</u>: Wi-Fi, Wi-Max, and other home area wireless networking technologies, as well as home wired standards such as Ethernet, are appropriate over short distances, or longer distances if linking them together with a mesh network. However, long-range, point-to-point links are necessary for transferring large amounts of communications traffic from central servers to these network devices.
- <u>Long-range, point-to-point</u>: Fiber-optic, copper, point-to-point wireless (using parabolic dishes), satellite, line-of-sight optical, and cellular (3G or 4G) communications can all support long distance communication. However, these technologies may be expensive to install, and/or could require a service provider with monthly fees. Certain applications may be able to justify exclusive using this type of communications (applications used for grid control, for example). But for general-purpose coverage, sharing these links may be necessary.

A number of factors contribute to the preferred FAN design, including bandwidth and latency requirements, existing spectrum and other communications infrastructure, technology maturity, and capital investment constraints. The design needs to balance cost, performance, and schedule requirements.

The ISGD team elected to use a dedicated 4G LTE cellular data backhaul due to its versatility, technological maturity, coverage, cost, and availability. Since deploying this 4G network, the team has found that 4G provides more bandwidth than most smart grid applications require; 3G may be viable in some scenarios. Future projects may explore the use of mesh networks (e.g. Wi-Fi or Wi-Max) in addition to 4G communications.

4.3.1.3.2 Hardware and Environment

Wireless communications are sensitive to a number of environmental factors. Achieving consistent and reliable connections requires attention to a number of factors, including the following:

- Optimization of radio and antenna placement
- Use of external antennas or repeaters in areas with low signal strength
- Antenna extension cables of the correct length
- Power supply and correct circuit protection sizing
- Regulation of temperature to rated limits
- Control of dust and humidity
- Interference or signal degradation from enclosures
- Disruption of transmission due to reflections from walls and other objects

Radio form factor is another design consideration. In general, smaller enclosures are more expensive, while large enclosures may be difficult to fit within existing equipment. Weatherproofing and physical security is required if equipment is outside.

Multiple components span the communications paths between field devices and back office systems. Such components include incoming links to communication rooms, internal networks and security components (e.g., switches, routers, firewalls, VPNs, and the connections between them). These components each represent potential points of failure that could disrupt communications. Common causes of disruptions to network equipment include power interruptions; wear due to improper operating conditions such as heat or dust; use of equipment beyond its recommended life; and incompatibilities following upgrades and configuration changes.

4.3.1.3.3 Software and Firmware

ISGD has a large number of communications nodes. Manually executing configuration commands (e.g. upgrading firmware) for each node is time consuming, and therefore requires management software. Since communication links are sometimes unreliable, this software must monitor command successes and (if necessary) retry to ensure completion. Since configuration files can be complex, the software must also be capable of managing each version of each configuration.

The team discovered a number of issues among the components that connect to the field devices, including incompatible versions or implementations of protocols such as Transport Layer Security (TLS), IPsec, Simple Certificate Enrollment Protocol (SCEP), and Dynamic Host Configuration Protocol (DHCP). When using new devices with custom features, time and effort is required to work through these issues.

Integrating individually developed modules or components into a single unit can also present challenges. For example, interactions between the internal components or modules can cause conditions that are difficult to diagnose and might not be possible to fix in the current component versions. For example, the 4G functionality in the 4G radios was implemented in a circuit board module that was integrated with other radio components such as Wi-Fi and CCS. Since the code for the 4G module was not under the radio vendor's control, brute force (such as rebooting a module) was sometimes necessary to resolve problems. Temporary workarounds may necessary to resolve these types of issues, but this can cause stability problems until the underlying issues are resolved.

4.3.1.3.4 Network Congestion

Field devices connect directly to the 4G network, where they are provisioned and tracked using vendor SIM cards. To connect the 4G network to the back office, the project uses a private network connection from the wireless network provider to the internal SCE network. However, the 4G network itself is still shared across all devices connecting to the 4G towers and is therefore subject to service degradation during times of peak usage.

4.3.1.3.5 Troubleshooting

Maintaining the signal strength of the 4G network was a challenge during deployment. To address this challenge, the team prepared daily reports on RSSI (received signal strength indication), and events such as cell disconnections. This helped the team to optimize the antennas for optimal reception. When planning field installations, projects should try using alternate equipment, placements, antennas, and configurations—while also monitoring signal strength. Projects should also test communications with enclosures both open and closed. This helps to ensure that communications is stable before leaving the site.

Network equipment in the field should operate continuously and autonomously. However, this type of equipment is typically not immune to rare, complex memory management or timing bugs, electromagnetic disturbances, or other long-term abnormalities. When problems occur, traditional methods of troubleshooting (such as power cycling) are not available for this equipment, since it is not physically accessible (i.e., the devices are located in the field, inside electrical equipment enclosures). If the equipment has stopped communicating, options are limited. If possible, a secure method for remotely rebooting equipment that has stopped communicating would decrease downtime. If a remote reboot is not possible, a method for securely rebooting from a nearby location, but without having to open enclosures or enter customer residences or facilities, would be useful.

In an effort to monitor and maintain network stability, the team evaluated several network monitoring tools. While there are many viable network monitoring tools available, configuring them to provide an appropriate level of reporting and notification is challenging. In order to receive alerts if the production network is down, it is necessary to establish a monitoring mechanism outside the production network. ISGD is using HP System Insight Manager and Solar Winds Network Performance Monitor to monitor the systems and send e-mail alerts when they detect problems.

4.3.1.3.6 Guaranteed Delivery of Communications

A common misconception about communications networks is that they guarantee message delivery. Communications networks will attempt to resend messages if a delivery failure occurs. However, the message will "timeout" if communications are lost for too long. To avoid this problem, applications require strategies for queuing and retrying, which requires storing unsent messages in case the network is down for an extended period. These strategies should consider the business requirements around loss of data. The following is a list of issues to consider when designing communications capabilities:

1. Applications require a retry strategy for when network communications fail
2. Applications must not simply log an error when a communication link is not responding
3. Devices must contain some storage of historical readings or data in order to support retry
4. Exponential back off (waiting successively longer intervals between retries) is useful for recovering quickly while not wasting resources during longer outages
5. Applications must not store or report false (or estimated) values without indicating they are false (or estimated)

4.3.1.3.7 Interoperability Design Approach

The electric utility industry has focused on interoperability standards as a way to reduce smart grid implementation costs. Such standards should enable applications to communicate and react to information exchanged with other applications. The ISGD project team has found that interoperability continues to be a challenging aspect of smart grid deployments.

Two approaches to achieving interoperability include using standard interfaces and performing custom integrations. Both approaches require careful consideration of the associated design decisions and tradeoffs.

Standard Interfaces

While it may be possible to procure a number of smart grid capabilities from a single vendor, SCE prefers to procure open and standards-based interoperable system components from multiple vendors. This approach promotes market competition and innovation. A vision embraced by many in the utility industry is that vendor software implements standard interfaces, enabling devices and applications from multiple vendors to interoperate without requiring costly integration services.

Intellectual property law is one reason why vendors are cautious towards this approach. The threat of patent infringement lawsuits makes vendors cautious about implementing standards. Vendors often rely upon proprietary communications to mitigate this risk, restricting their use of standard communications to where it is necessary.

Standards are typically most effective when vendors form an industry alliance or consortium that requires legal agreements between parties, and defines and enforces governance processes. Alliances can certify products as interoperable, usually for specific exchange scenarios defined by profiles. Examples of multi-vendor alliances include Wi-Fi, Bluetooth, and ZigBee.

Custom Integration

Integrating applications that were not designed to interoperate with each other requires substantial effort. Various technical approaches may be useful, such as using messaging middleware or service oriented architecture, extracting, transforming and loading files, or using database gateway tables. Regardless of the tools and platforms used, translating between data formats and orchestrating the exchanges requires custom code. Vendor-supported APIs are preferred for integrating applications, over use of native database or file formats. Likewise, standards-based interfaces (such as web services) help to reduce the complexity of adapters.

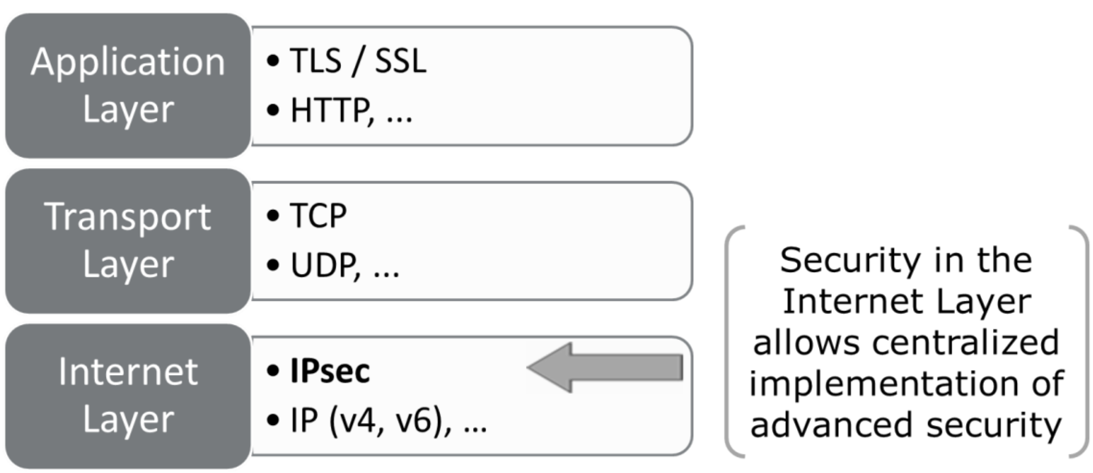
Integration work is generally divided among vendors, system integrators, and in-house developers. Dividing the integration responsibilities inevitably leads to disagreements and misunderstandings. Assigning overall responsibility to a single entity can mitigate this challenge. Custom integrations require highly effective communication and collaboration among diverse groups.

4.3.1.3.8 NERC CIP v5

The North American Electric Reliability Corporation (NERC) is responsible for ensuring the reliability of the bulk power system in North America. NERC's Critical Infrastructure Protection (CIP) standards provide guidance and requirements for securing the bulk electric system. The latest version of this standard clarifies the applicability of cybersecurity protections to serial connections. One of the goals of ISGD is to demonstrate implementation of the recommended cybersecurity measures to and from a substation through a secure communications gateway. This approach uses routable protocols over a WAN fiber link to the grid control center. Although this substation is not classified as part of the bulk electric system, SCE's goal is to eventually implement high-capacity, secure, IP-routable electronic communications capabilities for all substations.

SCE developed the CCS specification to meet the requirements of NISTIR 7628, the National Institute of Standards and Technology Interagency Report on Guidelines for Smart Grid Cybersecurity. The CCS specification was used as a set of requirements for the vendors that implemented the central security services in the back office, as well as the software clients in the substation gateway and the 4G radios used for certain field devices. The solution uses IPSec instead of TLS or Secure Sockets Layer (SSL), allowing security to be built into a lower layer of the Internet protocol suite. This allows application traffic protection without requiring those applications to be specifically designed to use IPsec.

Figure 37: IPSec in the Internet Protocol Suite



4.3.1.3.9 Scalability

In order for smart grid capabilities to be widely deployed, they must be scalable. Certain ISGD components are scalable, including of-the-shelf software applications and database hardware. Other ISGD components require further evaluation to assess their scalability, including the networking infrastructure. The ISGD team plans to perform simulations to evaluate how the ISGD communications network performs under various conditions and with various levels of data throughput. The team will also assess how the Common Cybersecurity Services capability affects network performance. The results of these evaluations will be included in either the second TPR or the Final Technical Report.

4.3.1.3.10 IT Capability Maturity

The smart grid requires mature communications and computing capabilities to support the advanced use of operational technologies (e.g., physical grid equipment such as transformers, capacitor banks, relays, and switches). Utilities have long thought of operational technology as separate from IT, which initially focused on financial records, billing, and other "non-operational" functions. However, most operational equipment now includes some amount of electronic monitoring, communication, and even automated remote control functions. This automation requires an increased role for IT.

Each of these automated functions requires hardware and software that must be maintained and integrated with other applications or hardware. They also require databases for reporting. Maintaining this IT infrastructure is especially complex given the need to periodically add functionalities, perform upgrades, and change hardware, networks, or security. The following is a list of key questions that IT departments should be able to answer:

1. **Vision** – What are the long-term goals of the company, and how will customers, shareholders, regulators, company business units, and projects support it?
2. **Business Case** – How are projects evaluated and selected?
3. **Governance** – Who makes decisions about resources used by multiple business units?
4. **Requirements management** – What should each component do, specifically? What if a requirement changes?
5. **Configuration management** – Which versions of the software and hardware are in use?
6. **Test equipment and environments** – How are changes evaluated to ensure they will not cause problems?
7. **Manage process changes** – How is confusion from and resistance to change minimized?
8. **Customer communications** – How are customers included in managing these changes?

Advancing the maturity of the IT organization can improve the efficiency and effectiveness of smart grid technology rollouts.

4.3.2 Sub-project 7: Substation Automation 3

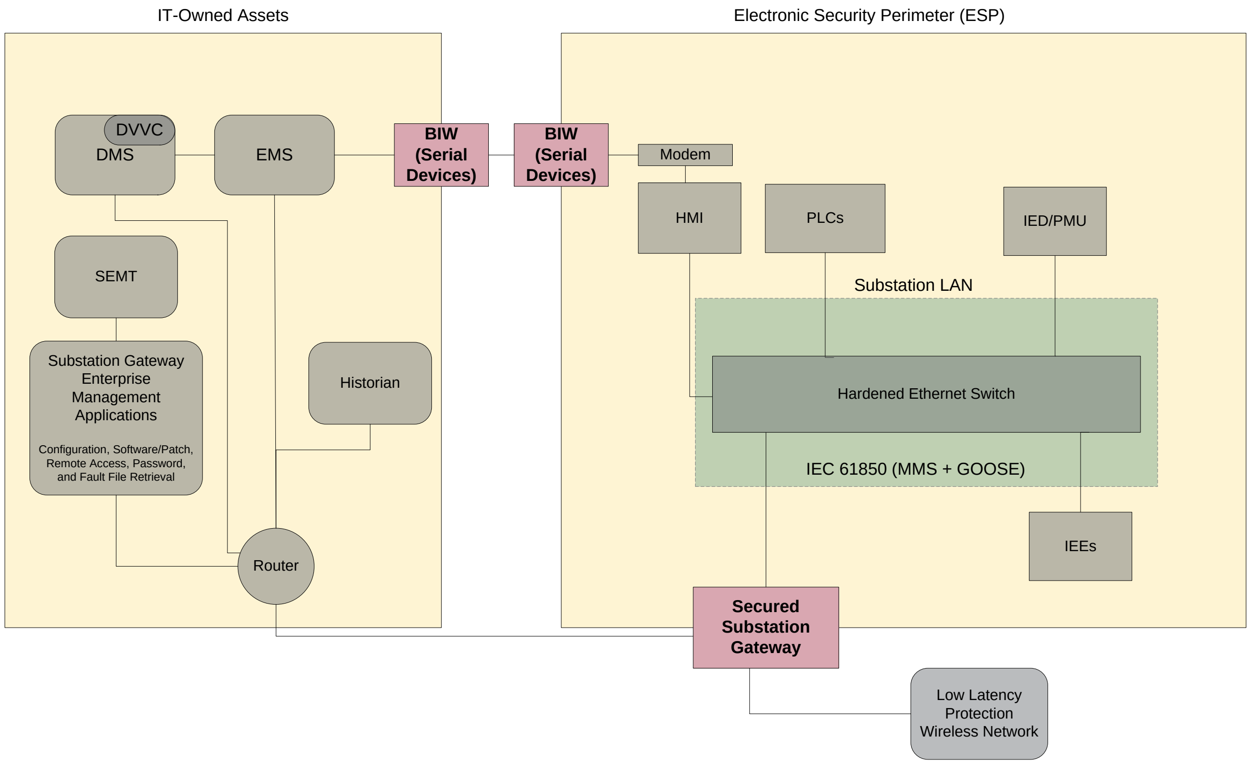
The goal of SA-3 is to transition substations to standards-based, automated configuration of communications, interfaces, control, and an enhanced protection design. Achieving these goals will provide enhanced system interoperability and enable advanced functionalities such as automatic device configuration while introducing integration compatibility with legacy systems.

This section provides an overview of the primary SA-3 components, and describes the new features and capabilities of the system. This section also summarizes the challenges the team faced during deployment.

4.3.2.1 Design

ISGD's SA-3 design includes several key components, listed and described in further detail below.

Figure 38: SA-3 Network Architecture



PowerSYSTEM Center

The PowerSYSTEM Center application suite provides centralized configuration management and automated configuration support for the substation gateway. This software suite includes the following:

- Repository for substation metadata and equipment inventory
- Version controlled repository for device configuration files
- User access and change control for specific configuration elements
- Automatic capture of field configuration changes (in conjunction with SubSTATION Server)
- Remote, secure engineering and maintenance access to substation IEDs using proprietary vendor tools (myIEDs)
- Password management of access to individual substation devices such as the substation gateway, managed switches, HMI and IEDs (myPasswords)
- Automatic capture of device fault records (myFaults)

Substation Gateway

The substation gateway consists of software running on an environmentally hardened, scalable processor and data concentrator. This provides a single, secure, enterprise-wide point of access to substation data. This provides the following capabilities:

- Automatically retrieves all substation event and disturbance records for secure, centralized processing and storage
- Hosts integrated Common Cybersecurity Services to enforce corporate security policies
- Acts as the substation communications hub by enabling local or remote access to field devices

Engineers and technicians have secure, local access to the substation gateway via Remote Desktop Protocol using a dedicated Ethernet access port. The substation gateway enables secure two-way pass through to the substation

IEC 61850 LAN. Authorized users are therefore able to access individual device configurations and settings. This is the primary process for configuring SA-3 system relays. The substation gateway with CCS (Common Cybersecurity Services) provides secure access of Critical Cyber Assets (CCA), something that the current IEDs cannot provide.

Human Machine Interface

Authorized operations and maintenance personnel use the HMI for local supervisory control of substation apparatus (circuit breakers, switches, reclosers, relays, etc.). The HMI acquires, transports, and presents real-time operational data locally and to the SCADA EMS (Energy Management System). The HMI can now be modified automatically via the substation gateway using Substation Engineering Modeling Tool (SEMT) configuration files.

Managed Gigabit Ethernet Switches

The substation managed switch network consists of an array of RuggedCom® RSG2100 Modular Managed Gigabit Ethernet Switches connected in a ring configuration. This allows for rapid network reconfiguration in the event of a network link failure.

IEC 61850 Protective Relays

Primary and backup substation protection, metering and control functions, and data communications are using state-of-the-art IEC 61850-compliant microprocessor-based GE UR (Universal Relay) and SEL relays (also known as IEDs.)

The IEC 61850 protective relays introduce new communications protocols to the SA-3 system design: MMS (Manufacturing Message Specification) for reporting, polling, and controls; and GOOSE messages for publishing and subscribing to relay data.

Phasor Data Concentrator

MacArthur Substation is using a SEL-3373 PDC to archive phasor data locally at the substation. This PDC stores data from the 66 kV lines between MacArthur Substation and Santiago Substation (GEUR D60 and GEUR T60 relays), and from the Arnold and Rommel 12 kV distribution circuits (GEUR F60 relays). This data supports the deep grid situational awareness capability in sub-project 6.

Substation Engineering Modeling Tool

The SEMT is a software application used by SCE to create artifacts required to configure substation automation devices including IEDs, managed switches, the substation gateway, and the HMI. Primary SA-3 improvements involve the creation of artifacts which are now IEC 61850 standards-based, and Substation Configuration Description (SCD) files, which drive the SA-3 substation gateway configuration process. The SEMT will remain backwards compatible with earlier versions of substation automation, and can support point list generation for substations based on these earlier versions. The SEMT also now generates reports such as point list, the Applied Systems Engineering Inc. test set, and HMI test scripts.

4.3.2.2 Key Features of SA-3

The SA-3 System introduces the following new features and functionality to SCE's existing Substation Automation system design.

Configuration Management

Introduces an array of tools to configure, compare, and secure settings on system devices (e.g. relays, phasor data concentrators). Specifically such tools include:

- Automatic generation of SCD files which are then parsed and stored in the PowerSYSTEM Center CMS repository

- Automatic device configuration when updating a substation
- Substation gateway interoperability with the PowerSYSTEM Center CMS is responsible for local and remote monitoring of system devices for operating status, configuration changes and access authorization
- Identification and notification of file changes, also known as “incremental differencing” (i.e., system identification of any change to any device configuration or setting)
- Device firmware version and patch management of operating systems, software and firmware
- Device password management for IEDs, HMI, managed switches and the substation gateway

Automatic Event and Fault File Recovery and Management

This function centralizes access to event files (such as system faults) by enabling automatic device poling and data archiving. Protection engineers currently access these files locally at the substation.

Remote Secure Engineering Access

Substation engineers are able to remotely access substation device data. This can be valuable to protection engineers in validating specific in-service protection settings following a fault. The ISGD team uses this capability to access and upload PMU data from the PDC.

New Human Machine Interface

The SA-3 HMI automatically generates substation one-line diagrams based on the SEMT output, resulting in completely data-driven configuration. These diagrams are linked to SCADA systems for operations and maintenance. This eliminates the time and expense of having a proprietary HMI vendor generate project HMI configurations based on SCE-generated point lists. This timely and error prone process required additional Protection Automation Development subject matter expert support to debug vendor-provided project HMI configurations.

Enhanced Protection Schemes

Recent advances in energy and information technologies allow for improved circuit protection schemes that were not possible with legacy devices. For example, protection schemes for the 66 kV and 12 kV circuits into and out of MacArthur Substation have been migrated to IEC 61850-compliant relays. These relays use peer-to-peer GOOSE messaging for Permissive Trip Bus (PTB) protection. The project is also testing high impedance protection on the Arnold and Rommel 12 kV distribution circuits. The team is evaluating these pilot schemes to assess their potential value for future applications.

Common Cybersecurity Services

The substation gateway has implemented CCS, providing secure communications paths between MacArthur Substation and the back office, and between MacArthur Substation and the field area network.

System Optimized for IEC 61850

The system supports simple integration of IEC 61850-compliant devices from multiple vendors.

4.3.2.3 Deployment Challenges

4.3.2.3.1 Back Office Integration

Depending on a utility’s current back office functionality, introducing a substation automation system may pose integration challenges. Specifically, the additional data provided by SA-3 may impact operational systems such as the Energy Management System and Outage Management System. Other systems such as data historians, circuit protection repositories, and fault file databases will also need to establish interfaces with the new substation automation application. Utilities considering an advanced SA-3 system should establish key system requirements and identify the impacts to any existing systems. Some systems may be unable to interface with SA-3, and these could require replacement.

4.3.2.3.2 Interpretation of IEC 61850

When deploying complex systems, utilities typically procure hardware and software from a single vendor. This helps utilities avoid having to manage device interoperability, thereby mitigating deployment challenges. However, avoiding vendor lock-in requires that multiple potential vendors exist for these products.

SCE's SA-3 design incorporated IEC 61850[20]-compliant software and hardware from multiple vendors. The primary objective of this standard is to achieve interoperability among devices from multiple vendors. The effort required to integrate these components into one system highlights the current lack of interoperability within the industry. Many manufacturers claim to offer products that are IEC 61850-compliant. However, their interpretations of the standard are inconsistent. This made their devices unable to communicate with one another.

The IEC 61850 suite of standards is intended to be flexible. This flexibility was instrumental in allowing SCE to create the necessary "private data," which enables interoperability between most vendor devices. However, this flexibility increases the standard's complexity, while also introducing the potential for different interpretations among various vendors. The ISGD team experienced this issue when it received relays from two vendors. Although these relays were both IEC 61850-compliant, they would not interoperate. This lack of interoperability led to longer than expected laboratory testing and coordination with product manufacturers.

The ISGD team coordinated the development and evaluation of solutions for these integration challenges among the ISGD vendors. The team also invested a substantial amount of time testing the functionality and interoperability of the SA-3 system in SCE's Substation Automation Lab. This lack of interoperability caused schedule delays and budget overruns, while the team also had to make some compromises on functionality due the limited amount of time available to address these technical challenges. While two devices may conform to a standard, this does not automatically ensure interoperability. Interoperability certification by an independent testing laboratory would ease this problem.

4.3.2.3.3 Old Versus New Processes

Instituting a substation automation system not only affects systems, it also influences the operational processes associated with these systems. As SA-3 integrates with or replaces operational systems, it will lead to procedural changes. For example, to configure the protection settings of substation protection devices, protection engineers currently load protection setting files to a database. Field personnel then manually download these files, take them to the substation, and manually input them into the substation devices. SA-3 enables authorized field personnel to download these files directly to the substation gateway and to auto-configure the substation devices directly from within the substation. Although such procedural changes may seem trivial, the ramifications across system operations can be significant. SA-3 impacts back office processes as well as processes within the substation. Substation test technicians and other field workers are now required to operate a new HMI with active directory password management. Device configuration occurs via a substation gateway rather than directly through the device. The primary reason for this process change is that the substation gateway (with CCS) now enables secure user access to IEDs. The impacts to operational processes can be challenging to identify, and even more difficult to implement. Utilities planning to adopt a substation automation system should obtain stakeholder buy-in early in the process. They should also obtain support from corporate training.

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[20] The IEC 61850 standard provides an internationally recognized method of communications for substation circuit protection, monitoring, control, and substation metering. The standard was specifically designed to provide a utility standard for object-oriented development, resulting in simplified system configuration and integration, and increased processing speeds.

4.3.2.3.4 Engineering the Substation

Traditional substation engineering practices include developing electrical engineering plans and manually inputting them into modeling tools. One of the options SCE may pursue as part of a future SA-3 deployment (after the ISGD project is complete) is to incorporate computer aided drafting (CAD) to help automate design and modeling processes. This could eliminate the need to manually input substation configuration files into a modeling tool. Rather, after completing the electrical plans, the CAD software would automatically generate a set of substation files. A modeling tool would then read these files and automatically generate a point list. The modeling tool would then use this point list to generate the standard configuration files, consisting of communication, automation logic, protection settings, and HMI screens.

4.4 Workforce of the Future

This project area does not include any field experimentation or performance testing. The results of the organizational assessment will be included in the Final Technical Report.

5. Conclusions

This chapter draws upon the results documented in chapter 4 to summarize the key conclusions and learnings of the ISGD project team. These conclusions include lessons learned, organized around the four ISGD domains, an evaluation of the commercial readiness of the various ISGD capabilities, and specific "calls to action" for the various industry stakeholders.

5.1 Lessons Learned

Over the course of the design, deployment, and demonstration periods, the team has accumulated a series of insights that may be useful to the project stakeholders and to the utility industry more broadly. This section provides a summary of these lessons. This first TPR includes lessons from through the first eight months of field experimentation. The second TPR and Final Technical Report will provide additional lessons learned.

5.1.1 Smart Energy Customer Solutions

5.1.1.1 Smart Inverter Standards Remain Immature

The ISGD project originally intended to use smart inverters to support distribution volt/VAR control and the integration of rooftop photovoltaic solar panels and energy storage devices. The project has been unable to use smart inverters due to the absence of standards and UL certification of these devices. SCE anticipates that the IEEE 1547 standard (standard for interconnecting distributed resources with electric power systems) will be modified to include provisions for smart inverters, perhaps by year-end. UL would then need to update the relevant testing standard (UL 1741) to meet the revised interconnection standard and certify devices for home and business installations. SCE and other utilities would also have to modify interconnection procedures to understand, verify, and possible control these advanced inverter functions.

5.1.1.2 Proper Integration of Components from Multiple Vendors is Critical to the Successful Operation of Energy Storage Systems

Many energy storage systems use components from multiple manufacturers. The two most significant components, the battery and inverter, are not commonly produced by the same manufacturer. For example, the CES unit used in sub-project 1 uses a lithium ion battery and BMS from one vendor, and a power conversion system (PCS) from another vendor. When integrating these devices, careful evaluations must be performed to verify that the systems' control mechanisms are compatible. In the case of the Solar Car Shade BESS, the inverter draws energy from the battery at a level that the BMS cannot detect. Since the BMS does not detect the low level of current drawn by the inverter, it cannot consider this lost energy when determining the BESS' state of health. More detailed testing by the vendors could have identified and resolved this issue before deployment.

Customers or device end-users typically do not choose a battery or BMS vendor and a PCS vendor, and then perform the integration themselves. Instead, the battery/BMS vendor, PCS vendor, or an independent integrator chooses the components and performs the final integration. Whichever entity performs the integration should conduct a final system evaluation prior to selling the device to customers. The integrator should be responsible for ensuring the various subsystems in their final product are compatible. In the case of the emergent technologies and integration techniques used in energy storage systems, it may also be wise for the customer (if technically capable) to work with the integrator to perform their own customized system acceptance testing on the completed product prior to final acceptance and payment.

5.1.1.3 Improved Battery System Diagnostic Capabilities Are Required to Help Identify the Causes of Potential Failures

In October 2013, the sub-project 2 BESS tripped, causing the battery to shut itself down using protections built into the system. The ISGD team immediately downloaded the diagnostic data collected by the BESS and investigated the issue with the manufacturer. However, the manufacturer was unable to identify the cause of the trip. The system had followed a self-protection scheme designed and implemented by the manufacturer, but it did not record enough diagnostic information for the manufacturer to understand exactly what happened. Although the system returned to normal operation, the manufacturer made no changes that would prevent a similar trip in the future since they could not determine the cause of the trip. In the event of failures or unexpected events, battery systems need to capture detailed information to properly identify the cause of the event. This type of issue is not limited to this device or manufacturer, and is characteristic of emerging technologies and applications where manufacturers' design and integration techniques are still maturing.

5.1.1.4 Manufacturer Implementations of the SAE J1772 EVSE Standard Limit the Usefulness of Electric Vehicle Demand Response

PEVs have the potential to increase customer electricity demand substantially during peak periods. Peak periods include times of high electricity demand on the entire electric system or on particular distribution circuits. To help mitigate the potential impacts of PEV charging activity, ISGD is evaluating DR functions that specifically target PEV load. The eventual development of utility load management programs for PEVs may be helpful in empowering customers to better manage their PEV charging costs while also helping to preserve grid stability.

One of the prerequisites for conducting effective PEV load management is being able to send DR signals that reduce PEV load on a consistent and reliable basis. For example, if a vehicle is currently charging at 7.2 kW, a 50% duty cycle DR event should reduce the charging rate to 3.6 kW. During ISGD's commissioning tests, SCE determined that EVSE manufacturers have implemented the DR function in a way that may limit the effectiveness of PEV load management. Currently, when a DR event signal[21] is sent to an EVSE to reduce the charging level by a certain percentage (e.g., 75% of current output), the EVSE reduces the charging level based on the maximum charging capacity of the EVSE, not by the actual PEV charging level. The project EVSE has a maximum capacity of 7.2 kW, so a 75% duty cycle DR event signal would cause the EVSE to reduce its charge level to 5.4 kW (75% of the 7.2 kW maximum charge level).

Meanwhile, PEV charging levels are also constrained by the vehicles themselves. For example, the Chevrolet Volt's maximum charging level is 3.3 kW, while the BMW ActiveE's is 6.6 kW. To illustrate why this matters, suppose both vehicles are charged using an EVSE with a maximum charging capacity of 7.2 kW. A 75% duty cycling DR event signal would reduce the current charging level to 5.4 kW for both vehicles. This would reduce the BMW Active E charge level from 6.6 kW to 5.4 kW, but the Volt would continue to charge at 3.3 kW (since the Volt's maximum charge level is below the 75% duty cycle level of 5.4 kW). The inconsistency and unpredictability of the impact of this type of DR event limits its usefulness as a tool for managing PEV load.

DR signals that reduce PEV charging levels based on the current charging rate would make PEV load management more effective for managing grid conditions in real-time. Using the example above, a 75% duty cycle DR signal would reduce the charging levels of both vehicles to 75% of their current charging levels. To accomplish this objective, the EVSE or PEV should actively monitor the charging load and use the SAE J1772 and the relevant Smart Energy Profile (SEP) communications standards to determine the desired charging rate.

EVSE manufacturers can enable DR on a "percentage of load" basis by incorporating a meter to provide the real-time charging level and a microcontroller to convert DR event signals into a demand setpoint that corresponding to

[21] SCE uses SEP duty cycle messaging to perform PEV demand response.

the setpoint defined by the SAE J1772 standard. The EVSE can then use its “pilot wire” to reduce the charging level to the desired rate.[22]

PEV manufacturers could also leverage their existing vehicle metrology to implement this capability in the same manner. In this case, the meter and microcontroller would be located within the vehicle. Upon receiving a utility DR signal (via a smart meter or an internet connection to the vehicle), the vehicle would read the current vehicle load, use a microcontroller to convert the DR signal into the desired power level, and then modify the vehicle charging to the desired level. The Smart Grid Interoperability Panel (SGIP) and the ANSI Electric Vehicle Standards Panel are two standards organizations that could facilitate PEV and EVSE manufacturer efforts to develop these solutions. The industry would also benefit from a service bulletin from SAE that clarifies the terminology used in the J1772 standard (e.g., the duty cycle of the pulse width modulation versus the PEV charging rate), and explains the limits of the standard for constructing demand response capabilities within EVSEs and PEVs.

5.1.1.5 Distributed Energy Resources Should Be Designed and Tested to Ensure That They Respond Properly to Utility Control Signals

During a demand response event using a group of RESUs, two RESUs that should not have responded to the DR event signal did so by exporting PV power to the grid. Following a battery error in October 2013, the two RESUs turned off their internal battery chargers and inverters. These RESUs did not charge or discharge for several weeks. However, both of these RESUs received the DR event signal on November 7, 2013. When the event began, the RESUs began outputting PV power to the grid. This was unexpected, since the team believed that the battery error would prevent the inverter from operating. Based on discussions with the manufacturer, the team determined that the manufacturer had incorrectly programmed the RESUs to allow PV operation during the battery error. The manufacturer addressed this programming bug in a subsequent software release that was installed in all the RESUs. This experience highlights an important issue with respect to the potential future development of utility programs for managing distributed energy resources. Device manufacturers must design and test their products to ensure that any utility-provided signals do not lead to erroneous device behavior. This is the manufacturer’s responsibility, since certifications (including UL standards, communication protocol specifications, etc.), cannot address the wide range of functionality of the various devices. This is true for energy storage, distributed energy resources, smart inverters, smart appliances, electric vehicles, and other equipment that may interact with the electric grid in the future.

5.1.1.6 Remotely Monitoring New Technologies after Feld Deployment Is Critical to Timely Identification and Resolution of Unknown Issues

Technology components that have undergone laboratory, commissioning, and other forms of testing may still encounter operational issues following field deployment. This may be due to environmental or other factors. For example, ISGD is demonstrating multiple HAN devices in an integrated environment using multiple communications networks. It is thus important to continue monitoring these devices following deployment to assess their interoperability and potential for interference with each other. Refer to the RESU Battery Error discussion in 4.1.1.3.3.

5.1.1.7 Targeted “Behind the Meter” Data Collection Will Help Future Demonstration Analytics

The team implemented an approach for monitoring energy usage in the project homes to measure the potential impacts of the energy efficiency measures and demand response events. This data acquisition system allows the team to monitor up to 21 individual circuits in each home (watts, watt-hours, amps, and voltage), the total household energy usage, and the RESU loads. The system also measures loads plugged into the wall, and

[22] SCE has leveraged this ISGD finding by working with an EVSE manufacturer to implement this capability with EVSEs used for the “Smart Charging Pilot,” a CPUC-funded DR pilot project. This is outside of the ISGD project.

temperatures on each floor and within the air conditioning duct system. Over the course of the design, installation, commissioning, and operation of this system, the ISGD team identified a number of lessons for how to improve such a system in future demonstrations. These findings are summarized in Appendix 3.

5.1.2 Next Generation Distribution System

5.1.2.1 Low Latency Radios Are in an Early Stage of Commercial Development

During the design and engineering phase of the project, only one radio vendor partially satisfied the project's requirements for sub-project 5 (the self-healing distribution circuit). This limited the team's procurement flexibility. The team would like to see the vendor community develop radios with latency low enough to satisfy SCE's protection requirements, operate at a radio frequency with sufficient propagation characteristics to obtain adequate coverage (e.g., 900 MHz), and which communicate using the IEC 61850 standard. For the ISGD project, SCE is using 2.4 MHz radios that satisfy SCE's latency requirements, but do not have sufficient coverage. As a result, the project team is using multiple radio repeaters to obtain the coverage needed to satisfy the project requirements. This was particularly challenging due to the terrain, distance, and permitting requirements. The radios are located in an area with a high concentration of hills, buildings, and trees. The team had to install more radio repeaters than originally planned.

5.1.2.2 Permitting Is a Significant Challenge for Siting Smart Grid Field Equipment Outside of Utility Rights-of-Way

The most substantial challenge faced by the sub-project 5 team involved obtaining the necessary permits for siting and installing field equipment (e.g., the pad-mounted cabinets for the URCIs and bypass switches, and the radio repeaters). The URCI field installation was delayed by several months as the team navigated the permitting process with the City of Irvine. The team originally planned to affix all the repeater radios installed on SCE light poles. After finalizing the repeater radio network design, the team met with the City of Irvine, which denied the installation of all the radios on the SCE light poles. The final design consisted of installing radios only on Irvine Campus Housing Authority and UCI property, since the project team was able to obtain permission to perform these installations. This required a larger number of radio repeaters than the original design, since the optimal locations on City of Irvine property were not available.

Permitting represents a potential challenge to the broad scale deployment of smart grid technologies. As municipalities increase their permitting requirements for siting field components, utilities will have less flexibility and fewer options for deploying smart grid capabilities that require field equipment.

5.1.3 Interoperability & Cybersecurity

5.1.3.1 The Flexibility Allowed by the IEC 61850 Standard Limits Interoperability

SCE has implemented an IEC 61850 standard based substation automation system at MacArthur Substation. During this implementation, SCE had to develop temporary workarounds to overcome vendors' design decisions. For example, configuring a substation IED requires both a CID file to configure IEC 61850-related settings and a proprietary file to configure all other settings. Each file typically requires a separate configuration tool provided by the manufacturer. This makes the configuration process cumbersome, especially when a substation uses IEDs from multiple manufacturers. The IEC 61850 standard allows manufacturer-specific data to be included in the CID file. However, manufacturers are using these vendor-specific fields on a limited basis, instead including this information within a proprietary configuration file.

To overcome the challenge of using multiple configuration files, SCE embedded the proprietary configuration files into the manufacturer's CID file. This allows the IED configuration to be managed using a single CID file. A long-term solution is to require that manufacturers adopt the CID file as their configuration format for all settings, and for the standard to further define the structure of the CID file to eliminate incompatibilities between device CIDs. Incompatibilities can result from different interpretations of the IEC 61850 standard.

Another challenge SCE encountered with the IEC 61850 implementation involved configuring the IEDs for sending GOOSE messages. Since GOOSE messages are sent between IEDs, each IED pair/GOOSE message combination must be configured. This configuration process requires that the IEDs' CID files be imported into the manufacturers' IEC 61850 configuration tools. This process must be performed for each GOOSE message, resulting in several iterations of importing and exporting CID files between manufacturers' configuration tools. This process becomes nearly impossible to perform when there are incompatibilities between the manufacturers' CID files.

The IEC 61850 standard also includes many optional features covering many types of IEDs. In practice, these optional fields limit the interoperability between devices from different manufacturers. Since each manufacturer chooses which optional fields to implement, manufacturers may implement different optional fields, restricting interoperability to a very basic level. Greater consistency in the implementation of optional features between manufacturers would improve interoperability.

SCE intends to share its learnings with the UCA (Utility Communications Architecture) International Users Group to help influence the future standard updates.

5.1.3.2 Achieving Interoperability Requires Concentrated Market-Based Development and Enforcement of Industry Standards

Interoperability among devices and systems from different manufacturers requires industry standards. The development of standards requires the guidance and enforcement of either a centralized governance body or the market. It appears that the market is currently driving the industry's slow move toward interoperability.

Although various interoperability standards are emerging, the overwhelming majority of vendor offerings use proprietary network infrastructure that must be integrated one at a time. And although vendor implementations may claim CIM conformance or compliance, their API deployments vary enough that simple integration is not currently possible. Profiles against the CIM (such as the ESPI/Green Button standard) are required to ensure multi-vendor interoperability. The emergence of these standards will depend on the market coalescing around certain products and solutions.

One of the lessons from the ISGD team's experience with SA-3 is that utilities could provide more leadership in bringing third parties (other utilities and the vendor community) together to develop and enforce interoperability standards. The following recommendations to other electric utilities, if acted upon, would help promote the development of interoperable products:

- Demand that vendors design interoperability within their devices by adhering to the IEC 61850 standard
- Use relevant electric utility industry forums to promote the idea that standards be implemented in a manner consistent with their intent, which is that products should be vendor agnostic
- Encourage or require vendors to provide a single configuration tool which produces a single IEC 61850-compliant configuration file
- Encourage IED vendors to support the IEC 61850 standard by developing logical nodes that are compliant, thereby reducing the level of propriety configuration workarounds
- Obtain electric utility representation on recognized organizations such as IEEE and the IEC Technical Committee Working Group (IEC TC WG 10 and WG 14)

In the interim, utilities should establish procedures for verifying and validating equipment interoperability prior to deployments. The ISGS team used SCE's substation automation lab to build the entire SA-3 system remotely and commission the functionality of the system prior to deployment. Although this process may not be efficient for every deployment, it allowed the team to thoroughly evaluate and debug the SA-3 system prior to deployment to MacArthur Substation.

5.1.3.3 An Enterprise Service Bus Can Simplify the Development and Operation of Visualization Capabilities

ISGD coupled SSI with the STI visualization capability to design a situational awareness capability that presents major ISGD elements on a geospatial map in near-real time and on a historical basis. This capability provides grid operators with a greater understanding of the state of the distribution network, distribution circuits, and "behind-the-meter" devices and applications. This enhanced situational awareness has the potential to diagnose and correct grid events with greater accuracy and speed than what is available today. Key functions of the visualization system include the ability to replay historical events to perform root-cause analysis, drill down to obtain device-level information, and aggregate data into summary information at the circuit or substation levels. This system also eases integration by allowing data to reside within the "system of record," and then being able to retrieve it for presentation when requested by a user.

It is important to use an iterative approach to solicit feedback from end-users when developing and integrating visualization tools. SCE used SSI and STI to develop its visualization capabilities in six to eight week sprints. Initial attempts to gather requirements and deliver the visualization screens provided the end-user with unsatisfactory results. The subsequent adoption of an iterative approach provided a path for end-user buy in.

5.1.3.4 Utilities Need to Perform a System Integrator Role to Realize Smart Grid Objectives

One of ISGD's key interoperability goals is to implement service definitions (i.e., Application Programming Interface or API) in an ESB to ensure that CIM compliant interfaces are explicit, testable, and broadly available to the industry. Standardization of the service definitions, together with standardization of the data (i.e., Common Information Model), would create an interoperable grid control environment for smart grid applications.

SCE had some significant success incorporating GE's SSI, an ESB, into ISGD's SENet architecture. Specifically, SSI helped SCE break down system and operational barriers so that a grid control operator can see information from substations, distribution circuits, energy storage devices, and even beyond the meter applications such as smart appliances, solar panels, and plug in electric vehicles. This yields a level of situational awareness not available historically. This could become valuable to grid operators as larger amounts of distributed energy resources interconnect with the distribution system.

The ESB is a concept that requires careful consideration when choosing smart grid implementation partners. For utilities to realize their smart grid objectives while maintaining an open architecture using standards, utilities must become the systems integrator (or be able to take on at least some of the systems integrator role). The utility as the systems integrator requires certain key elements:

- Developing a core competency of programming APIs, where necessary (this is crucial since relying on third-party vendors can become cost prohibitive as requirements change or are updated as the architecture matures)
- Understanding the standards at a detailed level with the ability to identify conflicts and gaps early can avoid development pitfalls
- Dedication to working within a CIM framework across the utility can be a long adoption process among internal utility stakeholders
- Demand that vendors use standard service definitions when they have flexibility in their design (although this is difficult to enforce when managing multiple vendors)
- Understanding the utility architecture at a low enough level to anticipate and budget for the level of integration is necessary to manage costs and expectations

5.1.3.5 Effective Communication with Software Vendors Is Critical for Smart Grid Deployments

Software vendors often lack a detailed understanding of the electric utility business. Likewise, utilities often do not understand the software development business. Problems often arise when utilities attempt to communicate their requirements to software vendors. Utilities and software vendors (or other industries) can understand or interpret identical words differently. This results in a false sense of mutual understanding, creating flawed expectations, and incomplete or misunderstood assumptions.

Utilities can accelerate or improve their smart grid deployment efforts by becoming more effective communicating with software vendors. Specifically, utilities should capture and articulate all assumptions made during the design and architecture phases of the software development lifecycle. Since different industries often assign different meanings to identical words, it is important to reach a common and complete understanding of how software should function. This understanding should also include the required capabilities, and interoperability and cyber security features.

Since the electric utility industry is challenging to understand and design software for, larger utilities should prepare themselves to become the systems integrator. This requires a commitment to develop the necessary project management and software development lifecycle skills. These skills would need to be paired with a detailed understanding of the electric grid in order to deploy sophisticated, integrated smart grid capabilities.

5.1.3.6 Acceptance Testing Should Include Integrated Testing of Software Products and Field Devices in a Lab Environment

One of the standard practices used by utility software developers is to validate system functionality with hardware simulators. This practice is extremely common for many reasons, including the fact that hardware is expensive, bulky and varies significantly across utilities. Unfortunately, simulators do not realistically represent actual hardware, which often leads to erroneous factory acceptance testing. Simulation testing places the burden on the utility to validate software performance using real hardware during site acceptance testing.

Vendors that develop distribution substation software that controls field equipment should conduct simulations using these field devices. These simulations should be part of the development and factory acceptance testing procedures.

Equipment vendors should also conduct lab testing with actual fixed devices (e.g., relays, programmable logic controllers, and gateways). This testing should include voltage and current injection testing equipment. Real-time digital simulator controlled injection testing, although expensive, would also improve the simulation quality.

Utilities should use a real-time digital simulator to build a model of the distribution grid to conduct “closed loop” testing as part of a more thorough acceptance testing process. This simulator should connect to the actual devices in order to perform test scripts prior to field deployment. SCE uses the RTDS product for this purpose and it is a powerful tool for system acceptance testing.

5.1.4 Workforce of the Future

5.1.4.1 Assess and Resolve Smart Grid Impacts to Department Boundaries, and Worker Roles and Responsibilities

Deploying smart grid capabilities has the potential to create new roles and responsibilities for utility workers, especially related to high speed, secure communications, and advanced field applications and devices. For example, field devices that are monitored and controlled using high speed communications would require that field personnel have additional IT and communications skills (that they do not currently possess) Sometimes these new requirements impact multiple departments, so it is important to resolve inter-departmental boundary issues early. Some of these new requirements may be difficult to identify, and may not be apparent until installation. These changes may be met with resistance, and they may result in skill gaps. Utilities should address these changing requirements and any potential skill gaps during the design phase, prior to commissioning.

5.1.4.2 Build Training Development Time into Smart Grid Deployment Planning

The most significant challenge the team encountered while developing training materials for the smart grid technologies deployed on ISGD is that the materials were developed in parallel with the design and deployment of the technologies themselves. This was particularly difficult for software components with graphical user interfaces. Training best practices helped the team overcome this challenge. Such best practices include engaging the workers and their supervisors early on in the process; building awareness among the stakeholders; involving the stakeholders in the technology development/deployments; conducting training sessions that allow participants to touch and feel the technologies; and providing easy access to training materials for workers. It is highly recommended that time buffers for training development activities be built into project plans between technology stabilization and deployment to ensure that content development is based on as complete a product as possible.

5.2 Commercial Readiness of ISGD Technologies

This section will be completed in either the second TPR or the Final Technical Report.

5.3 Calls to Action

The Final Technical Report will include a list of specific recommendations to various electric utility stakeholders. These recommendations will address the gaps and opportunities identified in 5.1 (Lessons Learned), and will be directed toward the following industry stakeholders:

- Policy makers (federal and state)
- Regulators (e.g., DOE and CPUC)
- Standards Developing Organizations (SDO)
- Industry research organizations (e.g., EPRI and universities)
- Equipment/product vendors
- Service providers
- Utility executives

Appendices

Appendix 1: Abbreviations

AC	Alternating Current
ACM	Appliance Control Module
ALCS	Advanced Load Control System
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
API	Application Programming Interface
ATP	Acceptance Test Procedures
BESS	Battery Energy Storage System
BMS	Battery Management System
BTC	Broadband TelCom Power, Inc.
CAD	Computer Aided Drafting
CCS	Common Cybersecurity Services
CES	Community Energy Storage
CIM	Common Information Model
CLT	Contingency Load Transfer
CPUC	California Public Utilities Commission
CT	Current Transformer
CVR	Conservation Voltage Reduction
DBESS	Distribution-level Battery Energy Storage System
DC	Direct Current
DCAP	Distribution Capacitor Automation Project
DEM	Distributed Energy Manager
DHCP	Dynamic Host Configuration Protocol
DMS	Distribution Management System
DMZ	Demilitarized Zone
DNP3	Distributed Network Protocol
DOE	Department of Energy
DR	Demand Response
DVVC	Distribution Volt/VAR Control
eDNA	Enterprise Distributed Network Architecture
EEM	Energy Efficiency Measure
EMS	Energy Management System
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ESP	Encapsulating Secure Payload
EVSE	Electric Vehicle Supply Equipment
EVTC	Electric Vehicle Technical Center
FAN	Field Area Network
FAU	Forced Air Unit
FDIR	Fault Detection, Isolation and Restoration
FLISR	Fault Location, Isolation, and Service Restoration
GBS	Grid Battery System
GE	General Electric
HAN	Home Area Network
HMI	Human-Machine Interface

HVAC	Heating, Ventilation and Air Conditioning
IDSM	Integrated Demand Side Management
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IETF RFC	Internet Engineering Task Force Request for Comment
IHD	In-home Display
IKE	Internet Key Exchange
IPSec	Internet Protocol Security
ISGD	Irvine Smart Grid Demonstration
IVVC	Integrated Volt/VAR Control
kVA	Kilovolt-amps
kVAR	Kilovolt-ampere Reactive
kW	Kilowatt
kWh	Kilowatt Hour
LAN	Local Area Network
LED	Light Emitting Diode
LL	Low Latency
LTC	Load Tap Changer
LTE	Long Term Evolution
MBRP	Metric and Benefits Reporting Plan
MPLS	Multiprotocol Label Switching
ms	Millisecond
MVAR	Megavolt-ampere Reactive
MW	Megawatt
NEM	Net Energy Metering
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology
NMS	Network Management System
PCC	Programmable Capacitor Controller
PCT	Programmable Communicating Thermostat
PDC	Phasor Data Concentrator
PEV	Plug-in Electric Vehicle
PLC	Programmable Logic Controller
PLM	Plug Load Monitor
PLS	Permanent Load Shifting
PV	Photovoltaic
QA/UAT	Quality Assurance/User Acceptance Test
RDP	Remote Desktop Protocol
RESU	Residential Energy Storage Unit
RF	Radio Frequency
RTDS	Real Time Digital Simulator
SAE	Society of Automotive Engineers
SAN	Storage Area Network
SA-3	Substation Automation 3
SCE	Southern California Edison
SCEP	Simple Certificate Enrollment Protocol
SDO	Standards Developing Organization
SEL	Schweitzer Engineering Laboratories

SEMT	Substation Engineering Modeling Tool
SENet	Secure Energy Network
SEP	Smart Energy Profile
SME	Subject Matter Expert
SNMP	Simple Network Management Protocol
SOAP	Simple Object Access Protocol
SOC	State of Charge
SOH	State of Health
SQL	Structured Query Language
SSI	Smart Grid Software Services Infrastructure
STI	Space-Time Insight
TLS	Transport Layer Security
TPR	Technology Performance Report
T&D	Transmission and Distribution
UCA	Utility Communications Architecture
UCI	University of California, Irvine
UL	Underwriters Laboratories
URCI	Universal Remote Circuit Interrupter
VAR	Volt-ampere Reactive
WAN	Wide Area Network
XML	Extensible Markup Language
ZNE	Zero Net Energy
ZNEE	Zero Net Electric Energy

Appendix 2: Build Metrics

Over the course of the project, the ISGD team files "build metrics" with NETL on a quarterly basis. The tables in this appendix summarize the ISGD build metrics as of December 31, 2013. Interested parties can obtain future updates to these metrics on the smartgrid.gov website:
https://www.smartgrid.gov/project/southern_california_edison_company_irvine_smart_grid_demonstration/latest_data

AMI smart meters installed and operational	Quantity	Cost
Total	38	$59,559
Residential	38	
Commercial	0	
Industrial	0	
AMI smart meter features operational	**Feature enabled**	**# of meters with feature**
Interval reads	Yes	38
Remote connection/disconnection	Yes	38
Outage detection/reporting	Yes	38
Tamper detection	Yes	38
AMI communication networks and data systems	**Description**	**Cost**
Backhaul communications	The backhaul from the collector meters (cell relays) to SCE back office uses 4G cellular services employing the CDMA protocol	$0
Meter communications network	Meter to meter and meter to collector (cell relays) use 900 MHz communications in the ISM band and uses Itron's RF Mesh protocol	
Head end server	The head end system consists of Itron's OpenWay system. The primary component is the Network Management System (NMS). The function of the NMS is to pass through meter data (e.g., consumption), events, and two-way communications between the meters and MDMS. Other tasks performed by the NMS include managing meter configurations, managing groups of meters, and supporting reads of individual meters for diagnostics.	$1,075,244
Meter data analysis system	All meter data are collected through the Network Management System and stored in an Oracle relational database	
Other IT systems and applications	Not applicable	
Web portal deployed and operational	**Quantity**	**Description**
Customers with access to web portal	0	
Customers enrolled in web portal	0	The gateway that each home has received is capable of displaying a web portal

Customer systems installed and operational	Quantity	Description	Cost
Communication networks and home area networks	N/A	A HAN is a network established in the home to enable access, control, and operation of devices such as appliances and air conditioners. ISGD uses the Zigbee Smart Energy Profile 1.X protocol for the HAN network.	N/A
In home displays	22	Most IHDs provide consumers with comprehensive information about their energy consumption, including: current household energy use in both kilowatts and dollars per hour, daily energy cost, including a comparison to the prior day's cost, the real time cost of electricity, monthly bill tracking with up-to-date billing information and an estimated end – of-month bill, and demand response event messages.	$7,020
Energy management devices	22	Energy management systems control loads in the home and centralize operation and control of other HAN devices. They typically function as a gateway or hub and can be accessed locally in the HAN or remotely through the meter of the internet.	N/A
Direct load control devices	0	Not applicable	$0
Programmable communicating thermostats	31	PCTs are capable of communicating wirelessly with the HAN and enable customers to take advantage of AC DR pricing programs.	$9,610
Smart appliances	64	Smart appliances are capable of receiving signals from the AMI HAN and can react to DR commands from an AMI load control system. The smart appliances being evaluated on ISGD include refrigerators, dishwashers and clothes washers.	$137,428
Customer system communication networks			**Description**
Network characteristics within the customer premises			A HAN is a network established in the home to enable access, control and operation devices such as appliances and air conditioners. ISGD uses the Zigbee Smart Energy Profile 1.X protocol for the HAN network.

Distributed energy resources	Quantity	Capacity	Description	Cost
Distributed generation	23	108 kW		$390,288
Energy storage	16	181 kW		$1,850,130
Plug-in electric vehicle charging points	44	158 kW		$0
Distributed energy resource interface	Not applicable	Not applicable	RESUs connect via internet connection to a server accessible on the network. A utility interface is hosted on this server showing detailed information regarding both current status and history of each of RESUs activity. This interface is a web page accessible in a standard browser. Some of the information viewable includes: the power being dispatched or drawn from or to the grid, the PV power passing through each unit, the energy available in each RESU, the reactive power of each unit and a log of errors and events on each system. This interface allows the utility to group the RESUs and control them in bulk. From this interface, the utility can send Demand Response events specifically to a group of RESUs, set up a specific charging or discharging schedule, enter any of the Smart Modes built in to the devices, and enable or disable Reactive Power Support. The Community Energy Storage (CES) is controllable and accessible through a SCADA interface utilizing DNP3 communication. A Distributed Energy Management (DEM) server communicates with the CES via this SCADA connection to log data and allow remote control of the system. The DEM displays voltages, power (real and reactive), battery energy, and monitors CES system alarms. ISGD CES operators use the DEM to send operating commands, including setting up a daily charge and discharge schedule. The DEM also allows control over the islanding behavior of the CES; this can be inhibited or manually triggered as desired.	$0

Electric distribution system	%	Description
Portion of distribution system with SCADA due to SGIG/SGD program	0%	Not applicable to project
Portion of distribution system with SCADA due to SGIG/SGD program	0%	Not applicable to project

DA devices installed and operational	Quantity	Description	Cost
Automated feeder switches	0	Not applicable to project	$0
Automated capacitors	0		$0

Automated regulators	0		$0
Feeder monitors	0		$0
Remote fault indicators	0		$0
Transformer monitors (line)	0		$782,755
Smart relays	0		$0
Fault current limiter	0		$0
Other devices	0		$0
SCADA and DA communications network			**Cost**
Communications equipment and SCADA			$0
Distribution management systems integration		**Integrated**	**Description**
AMI		No	DMS is used by system operators to monitor and control the distribution system. DMS will also be used to monitor and display to the system operator the status of the URCIs and provide manual override capabilities. DMS is also being used to control distribution capacitors and provide capacitor readings to DVVC.
Outage management system		No	Not applicable to project
Distributed energy resource interface		No	
Other		No	Not applicable to project
Distribution automation features/functionality		**Function enabled**	**Description**
Fault location, isolation and service restoration (FLISR)		No	Not applicable to project
Voltage optimization		No	Anticipated for ISGD: DMS will be used to control distribution capacitors and to provide voltage readings to DVVC.
Feeder peak load management		No	Not applicable to project
Microgrids		No	Not applicable to project
Other functions		No	Not applicable to project

Appendix 3: Instrumentation for Home Data Collection

A3.1 Requirements

During the ISGD design phase, the team needed to identify a method for monitoring the electricity usage in the project homes. This includes 38 homes (16 control homes and 22 homes with modifications). These homes are located on four blocks in the University Hills housing area of the University of California, Irvine. This monitoring system has to help the team measure the electricity savings stemming from energy efficiency upgrades. It also has to measure the impacts of the ISGD field experiments. The data acquisition system needs to monitor up to 21 individual circuits in each home (watts, amps, voltage, and watt-hours) as well as loads plugged into the wall (watts, watt-hours), ambient temperatures on each floor, and temperature in the air conditioning duct system. Data should also be recorded at down to one-minute intervals. The monitoring system also needs a method to communicate data back to Southern California Edison's back office where it is stored, validated, and made available to users. After researching several systems, the team selected a package assembled by TrendPoint for implementation in the homes. In addition to this system, the team installed two additional Smart Connect® meters in each home to avoid disturbing the existing billing meter.

A3.2 Design Overview

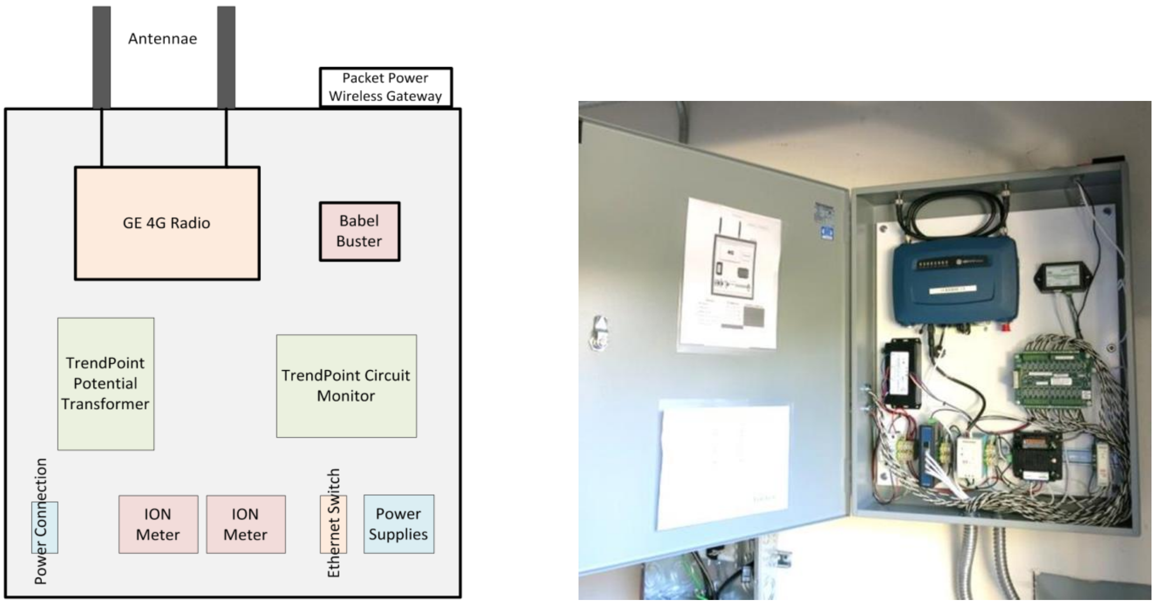
The TrendPoint monitoring system is composed of a data collection and communications cabinet installed in the garage as well as sensors located throughout each home. In addition to the monitoring equipment, a HAN supports communications between the project's Smart Connect meter and the smart appliances, thermostat, in-home display, EVSE, and RESU.

A3.3 Data Collection Cabinet

The TrendPoint data collection cabinet houses a number of monitoring and communications components, which are depicted in **Figure 39**. These components include:

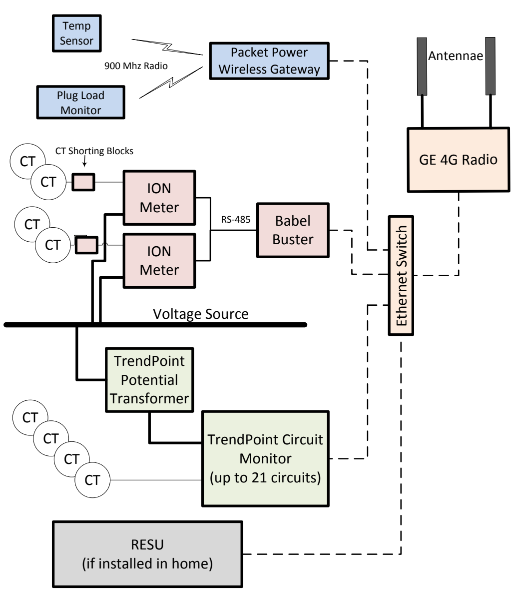
- TrendPoint Enersure circuit monitoring board (with its potential transformer)
- Schneider ION meter(s) and Babel Buster (converts metered readings to Simple Network Management Protocol (SNMP)/Ethernet)
- Packet Power wireless gateway (receive signals from wireless plug load monitors and temperature sensors)
- GE 4G radio with externally mounted antennae
- Current transformer shorting blocks, Ethernet switch and power supplies

Figure 39: Home Data Collection Cabinet Arrangement



Due to the limited modifications in the control homes, these homes only received a data collection cabinet with a wireless gateway, 4G radio, and required power supplies. **Figure 40** depicts how these components are connected. All data collected in the cabinet is converted to Ethernet, which is pooled in an Ethernet switch and connected to the 4G radio for transmission to the TrendPoint server located in the SCE back office in Alhambra. This path uses the public cell system to the public carrier back office where the data is placed on a leased circuit going directly to SCE's Alhambra facility. All data is converted to SNMP for transmission to the back office. The project also uses this 4G link to communicate directly with the RESU.

Figure 40: Home Data Collection Cabinet Block Diagram



A3.4 TrendPoint Enersure System

The TrendPoint Enersure system is composed of a stack of circuit boards located in the home data collection cabinet that is connected to current transformers (CT) installed in the home electrical panel and subpanel. This system is capable of monitoring up to 21 separate 120 VAC circuits (ranging from 20 to 200 amps). There is also a potential transformer installed in the data collection cabinet that converts the 120 VAC signals to low voltage for use by the TrendPoint measurement boards. The CTs used for each circuit have internal resistors in them so low voltage signals are delivered to the TrendPoint boards and they do not require shorting blocks for safety. The Enersure system is capable of measuring amps, watts, watt-hours, volts, and power factor for each home circuit. Proper installation of the CTs and voltage selector jumpers is necessary to correctly measure power – this system is not capable of measuring reverse power. Data is sent to the 4G radio through Ethernet using the SNMP protocol.

A3.5 Schneider ION Metering System

The team installed up to two Schneider ION meters at each home. These meters allow measurement of two-way power flow and provide more detail than is possible with the TrendPoint Enersure system. The CES Block homes have one ION meter that measures the total home load. The ZNE Block and RESU Block homes have two ION meters to measure the total home load and RESU operations. The Control Block homes did not receive ION meters. The ION metering system is composed of the ION meter, CTs with shorting blocks, and the Babel Buster module that converted the ION meter's RS-485/Modbus connection to Ethernet/SNMP. The Babel Buster polls the ION meters and stores the results in a buffer. When the Babel Buster is polled by the TrendPoint back office server, it returns the latest value in its buffer. This system is capable of measuring a full range of two-way electrical values including amps, volts, Watts, VARs, power factor, Watt-hours, VAR-hours, harmonics, and frequency.

A3.6 Packet Power Wireless Sensor System

A Packet Power wireless sensor system is installed in each project home. This system is composed of a wireless gateway located on the exterior of the data collection cabinet, plug load monitors (PLMs) and temperature sensors. The wireless gateway is connected by Ethernet cable to the 4G radio through an Ethernet switch. The wireless sensors communicate with the wireless gateway through a 900 MHz radio network and are located throughout the home. The wireless sensors report to the wireless gateway to store the latest reading on a regular basis. The wireless gateway is then polled by the TrendPoint back office server and the latest value in the gateway buffer is retrieved. The PLMs report watt-hours, watts, frequency, amps, volt-amps, power factor, and volts. The temperature sensors only report temperature.

A3.7 General Electric 4G Radio Gateway

Each home data collection cabinet contains a 4G radio that communicates data from the local Ethernet network and makes a connection to the public carrier back office through the public 3/4G cell network. This radio gateway contains a 4G radio and has inputs for Ethernet, RS-232, and Wi-Fi. The radio also contains software that provides a connection to SCE's centralized cybersecurity system. Once the communications makes its way to the public carrier back office, it passes through a lease-line link to SCE's project back office servers in Alhambra.

A3.8 Back Office Systems

SCE houses a number of servers at its back office facility in Alhambra, California. These servers include:

- RESU SQL database (directly accessed for data)
- TrendPoint Smart Grid Management Console (data transferred to Oracle server)
- DEM for the CES (data transferred to Oracle server)
- BESS local server (data transferred to Oracle server)
- NMS for project smart meters (data transferred to Oracle server)
- Oracle (stores validated data from TrendPoint, DEM, BESS, and NMS servers)

All data is consolidated in SCE's back office, checked for errors, and transferred to an Oracle database for use by the ISGD team. Data from the RESU server is accessed directly. These servers are routinely backed-up and maintained by SCE's Information Technology department.

A3.9 Lessons Learned

Over the course of design, installation, commissioning, and operation of the data acquisition system, the team learned a number of lessons. The following is a listing of the major lessons and a description of what the project team learned.

A3.9.1 Local Data Storage Would Improve Data Retention

Wireless communications for retrieving data from the project homes has been unreliable, leading to lost data. This challenge has manifested itself in two ways: retrieving data from the wireless plug load monitors and temperature sensors within the project homes, and retrieving the data from the homes through the 4G radio system.

Since the plug load monitors and temperature sensors needed to be installed in existing homes on a retrofit basis, the team chose to retrieve the sensor data on a wireless basis. Unfortunately, some of the locations in the homes have poor connections to the wireless gateway in the garage. This has led to lost data from these sensors. Although some temperature data was lost, enough was recovered to determine the temperature trends in the homes for analysis. Temporary loss of communications with the plug load monitors led to some minor losses of kW data. However, the plug load monitors contain a running counter for kWh, which allows the team to calculate usage data after restoring communications. A better design would have used local data storage at each sensor so data lost due to communications problems could be recovered later when the communications channel was working better. The instrumentation manufacturer has been to the sites and made suggestions on how SCE might improve data recovery through relocating the wireless gateway.

The team has encountered a similar problem retrieving data from the customer homes. All home data is retrieved through the 4G radio system. The cell coverage at some of the homes is weak, causing loss of communications at times. Because of how the home data collection package was designed, there is no local storage of data. This leads to the loss of data when the 4G cell communications fails. A better system design would have been to require some local storage so data lost during communications dropouts could be recovered later when the communications channel was working better. Changes have been made to the configuration of these radios to reduce the duration of the dropouts. With these changes, sufficient data is recovered to allow the required analyses to be performed.

A3.9.2 Retrofitting Current Transformers into the Customers' Electrical Panels Was Difficult Due to Space Constraints

The team is monitoring the circuits in each home using small clamp-on CTs. These CTs are placed in the customer's electrical panel and the leads routed back to the TrendPoint Enersure circuit monitor boards. Because of space constraints, these CTs are hard to fit in the panel and routing of sensor wires is difficult. This leads to a very crowded panel and misidentification of some of the leads as well as installation of the CTs in a reversed direction. Since the TrendPoint measurement board only measures power flow in one direction, any CT installed backwards or misidentified as to which leg of the panel it was connected to causes zero values for power and energy. Because of this, each panel needs to be verified and CTs or potential jumpers corrected to ensure proper recording of the data. This is very time consuming. A measuring system with either smaller CTs or the ability to switch potential settings or CT orientation remotely would have made installation easier. A system that would have measured power in either direction would also have made installation easier and obviated the need for the installation of the Schneider ION meters to observe two-way power flow.

A3.9.3 Installing Instrumentation in Existing Homes Is Difficult

Retrofitting instrumentation into homes is difficult and takes significant amounts of time. Once instrumentation is installed, it may take several more visits to the home to work out all of the bugs. This is difficult since it requires appointments with the homeowners to gain access. This slows the progress of correcting installation problems and makes it difficult to fix problems as they occur during the monitoring period.

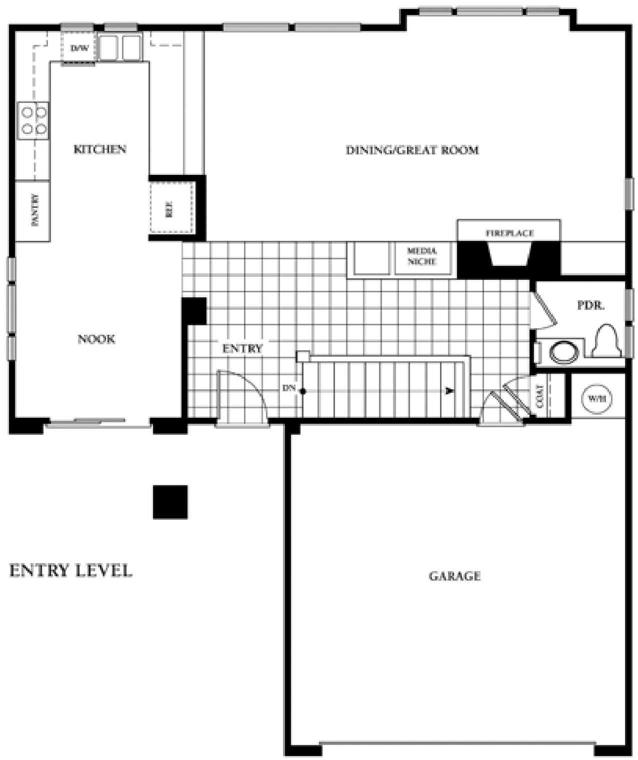
A3.9.4 Understand How Instruments Can Fail and Use This to Help Validate Data

Understanding how the various communications paths can fail (and how this affects the data), can provide insights for identifying bad data or failed sensors. For example, a reading of zero might be caused by zero current flow, or it could be caused by a wireless sensor not reporting as expected. With an understanding of the failure mechanisms for each measurement system, data can be validated more easily.

Appendix 4: Project Home Floor Plans

Plan 751

- Two Story Hillside Home
- Approximately 1,900 Square Feet
- Three Bedrooms
- Two and a Half Bathrooms
- Great Room/Dining Room with Wood-Burning Fireplace
- Kitchen with Breakfast Nook
- Attached Two-Car Garage



ENTRY LEVEL

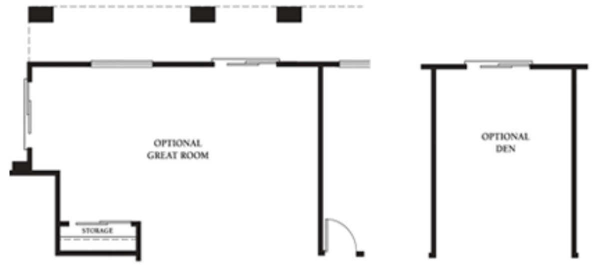
LOWER LEVEL

Plan 752

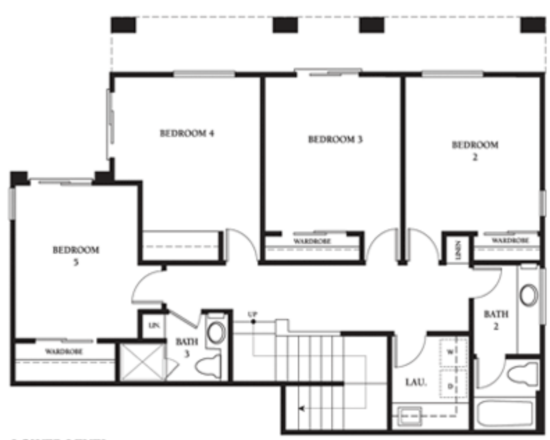
- Two Story Hillside Home
- Approximately 2,200 Square Feet
- Three Bedrooms plus Den
- Three Bathrooms
- Great Room/Dining Room with Wood-Burning Fireplace
- Kitchen with Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage

Plan 753

- Two Story Hillside Home
- Approximately 2,500 Square Feet
- Five Bedrooms
- Three and a Half Bathrooms
- Family Room with Wood-Burning Fireplace
- Dining Area and Kitchen with Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage



ENTRY LEVEL

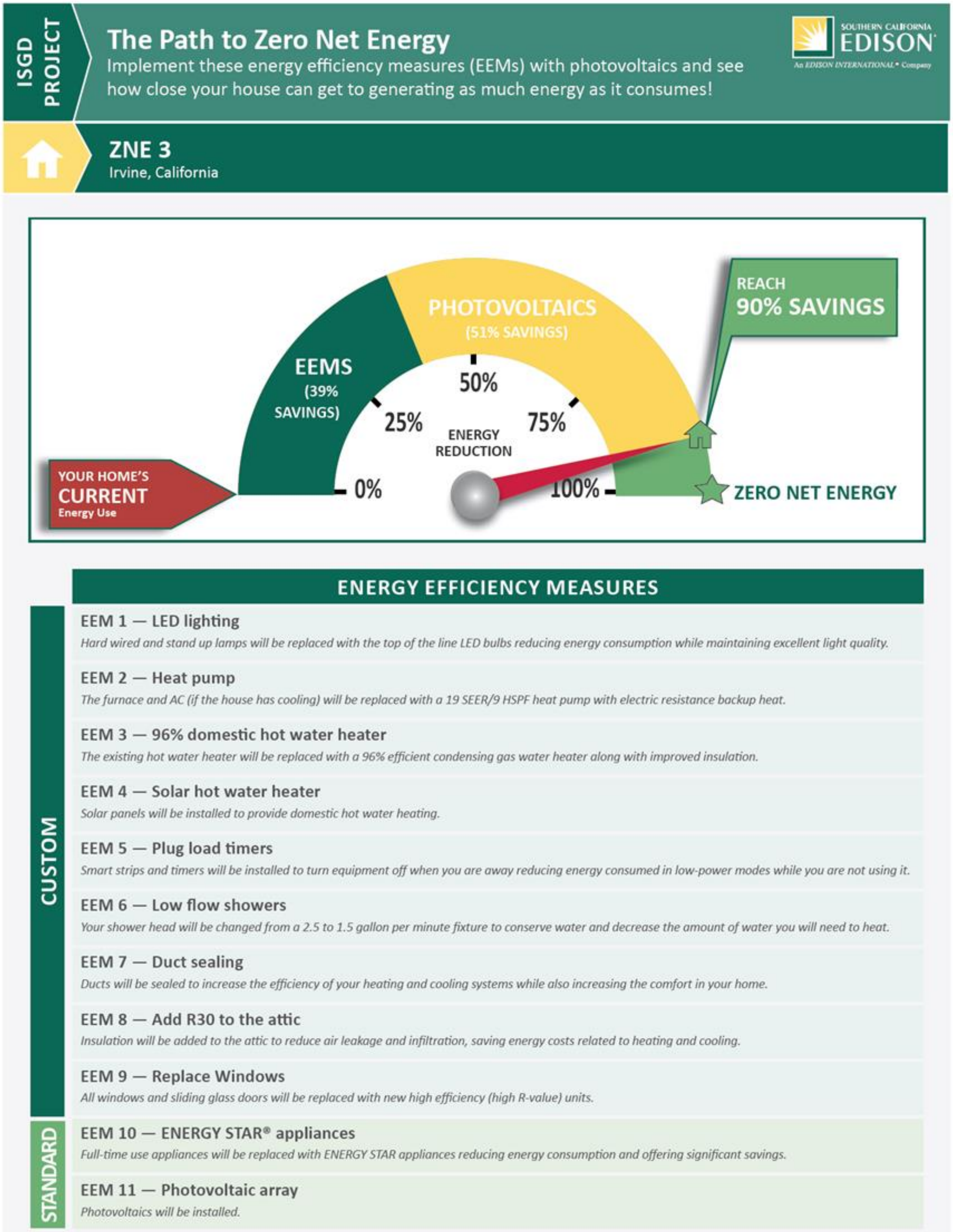


LOWER LEVEL

Plan 754

- Three Story Hillside Home
- Approximately 2,900 Square Feet
- Four Bedrooms plus Loft
- Three and a Half Bathrooms
- Wood-Burning Fireplace
- Dining Area and Kitchen with Island and Breakfast Nook
- Inside Laundry Room with Sink
- Attached Two-Car Garage

Appendix 5: ZNE Flyer Sample

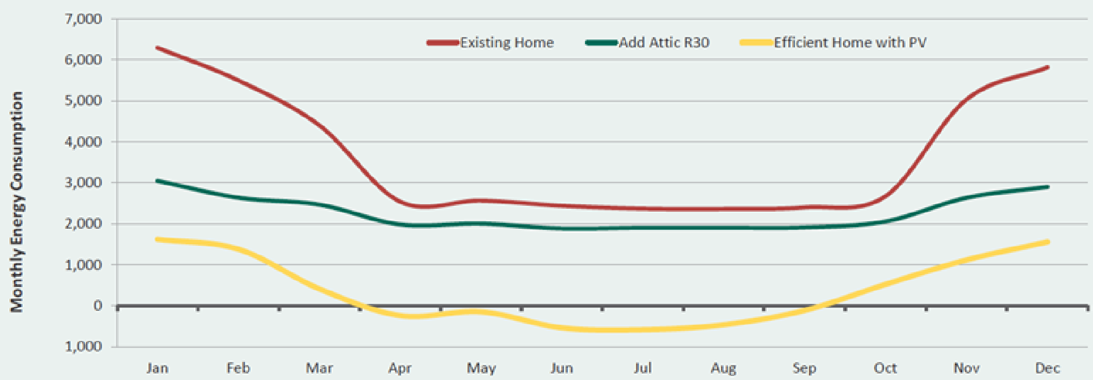


ZNE 3
Irvine, California

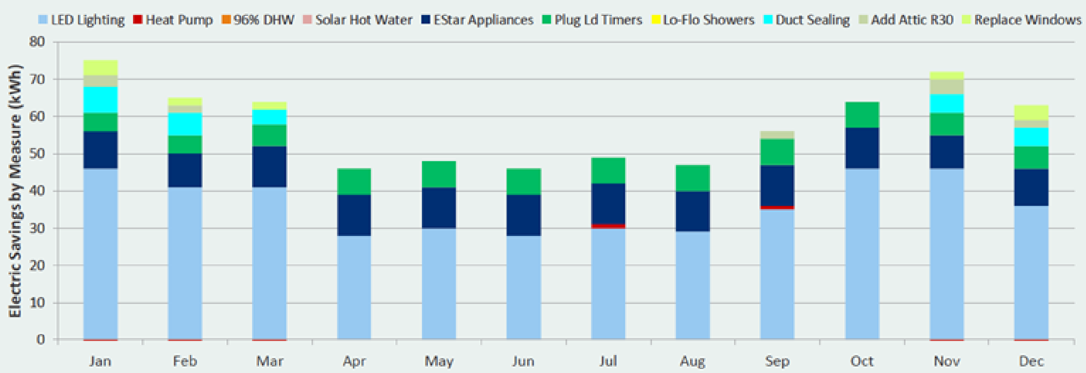
YOUR HOME'S PERCENT SAVINGS
(compared to your current energy consumption)

90%
PER YEAR

Annual Energy Consumption/Generation Comparison



ELECTRIC — Monthly Energy Savings by Measure



GAS — Monthly Energy Savings by Measure