



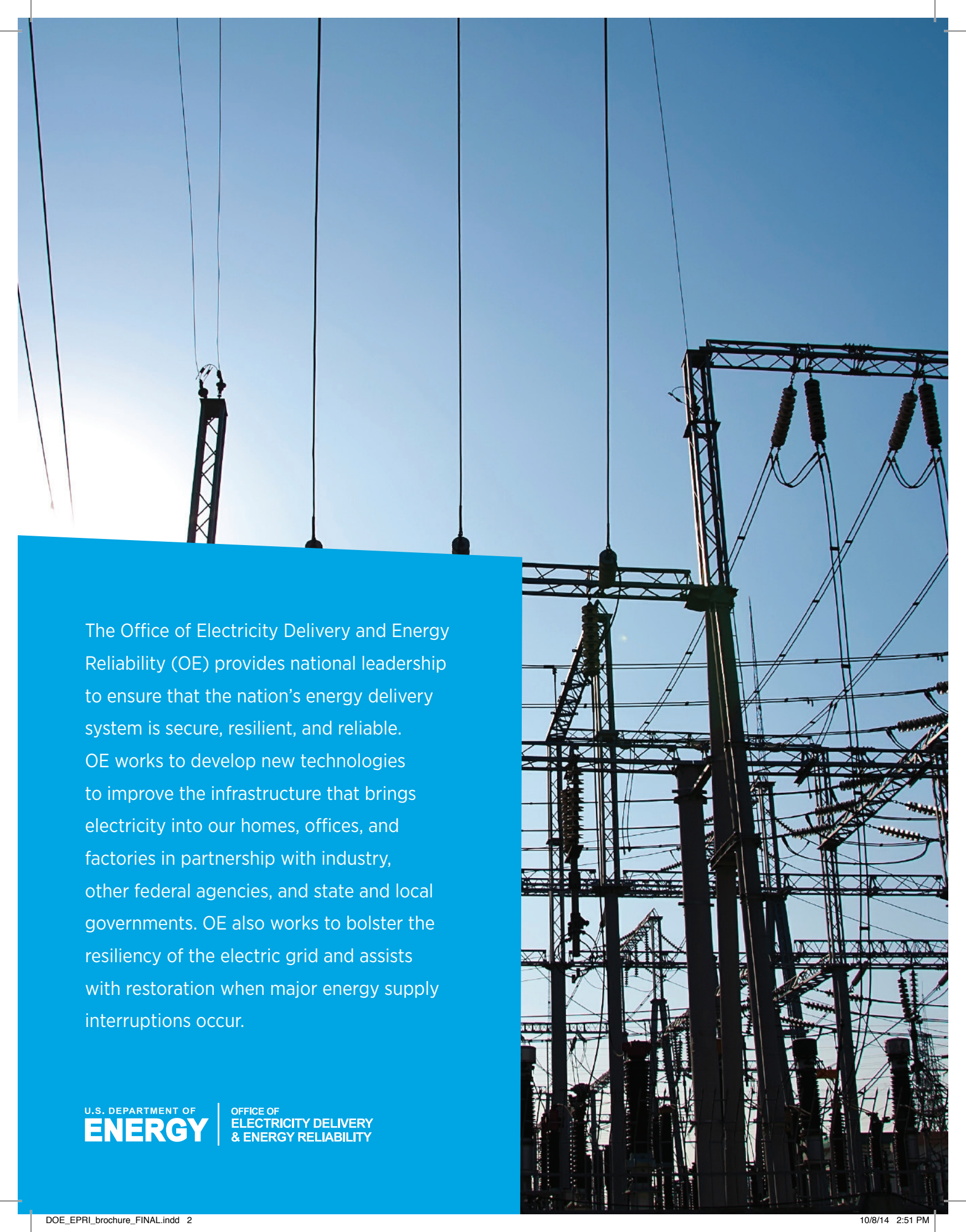
The American Recovery and Reinvestment Act Smart Grid Highlights

Jumpstarting a Modern Grid

October, 2014

U.S. DEPARTMENT OF
ENERGY

OFFICE OF
ELECTRICITY DELIVERY
& ENERGY RELIABILITY



The Office of Electricity Delivery and Energy Reliability (OE) provides national leadership to ensure that the nation's energy delivery system is secure, resilient, and reliable. OE works to develop new technologies to improve the infrastructure that brings electricity into our homes, offices, and factories in partnership with industry, other federal agencies, and state and local governments. OE also works to bolster the resiliency of the electric grid and assists with restoration when major energy supply interruptions occur.

To Our Stakeholders

Under the American Recovery and Reinvestment Act of 2009, my department was charged with investing \$4.5 billion to modernize the U.S. electric grid through the deployment of smart grid technologies. We leveraged these funds with private sector funding to more than double the investment. Implementation of these projects has been instrumental in catalyzing the transition to a modern grid.

With the recovery act projects, more than 8,500 automated feeder switches, over 15 million smart meters, and more than 1,000 new phasor measurement units have been deployed on transmission and distribution systems throughout the country. The investment in and large-scale deployment of these technologies has given utilities—and the industry—the opportunity to gain critical operational experience thus allowing us to move from the cycle of pilot projects to full-scale deployment in utility operations. I am excited about the results we have achieved and the knowledge we have gained. Projects continue to deliver important data on real-world benefits, costs, and best practices that can inform future investment decisions.

It is essential that the industry share lessons learned and best practices as we navigate the transition to a modern grid. Therefore, I am pleased to partner with Electric Power Research Institute (EPRI) on *The Smart Grid Experience: Applying Results, Reaching Beyond*, which will present the collective learnings from both the EPRI Smart Grid Demonstration Initiative and the U.S. Department of Energy (DOE) American Recovery and Reinvestment Act (ARRA) Smart Grid Programs. It is my hope that the successes and insights will help us as we reach beyond current projects to achieve a 21st century grid that meets society's needs and provides the foundation for a secure and vibrant economy.

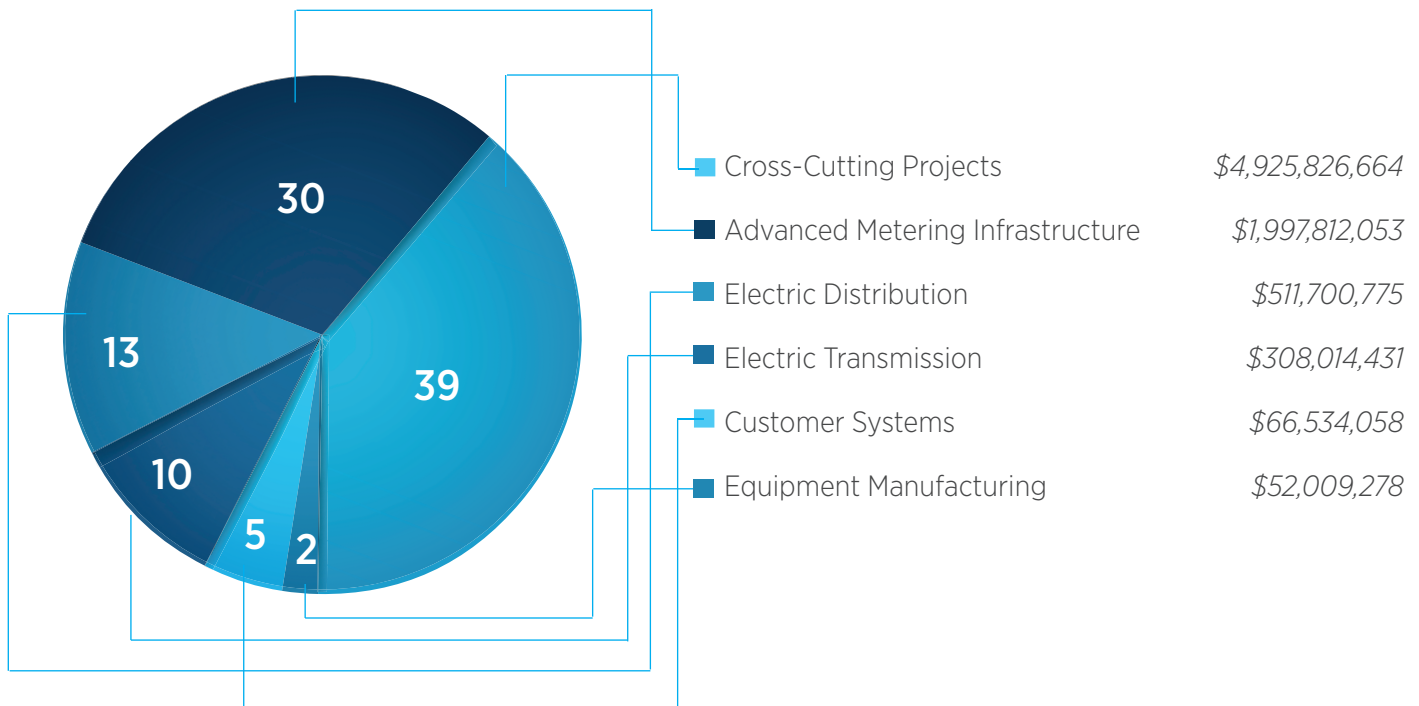
Sincerely,

Patricia A. Hoffman
Assistant Secretary
Office of Electricity Delivery and Energy Reliability

The Recovery Act Smart Grid Investments

The American Recovery and Reinvestment Act of 2009 (Recovery Act) provided the U.S. Department of Energy (DOE) with \$4.5 billion to modernize the electric power grid. Under the largest program, the Smart Grid Investment Grant (SGIG), DOE, and the electricity industry have jointly invested \$8 billion in 99 cost-shared projects involving more than 200 participating electric utilities and other organizations to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid operations and benefits.

Smart Grid Investment Grant Projects Total Value of \$8 Billion.

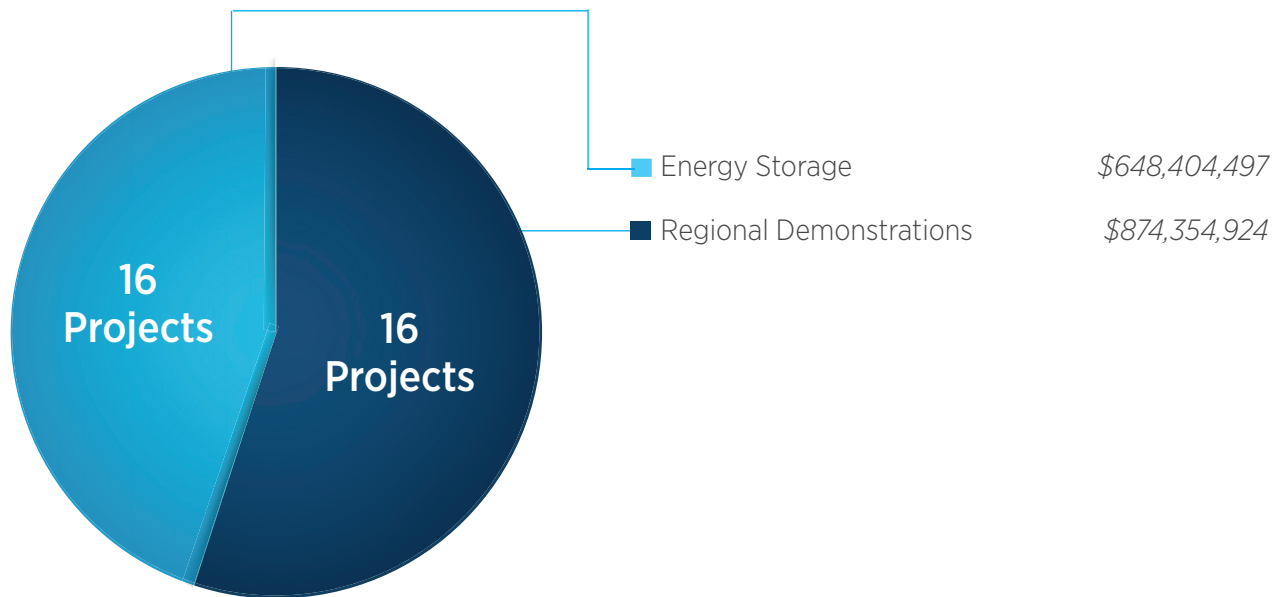


The Recovery Act also enabled DOE to invest \$600 million along with \$900 million industry cost share in 32 Regional Smart Grid Demonstrations and Energy Storage Demonstration projects under the Smart Grid Demonstration Program (SGDP). The goal of the Smart Grid Demonstration Program is to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today.



Smart Grid Demonstration Projects

Total Value of \$1.5 Billion.



Another area of great importance for grid modernization is the development of the workforce. Through the Recovery Act \$100 million was invested in Smart Grid Workforce Training and Development. The workforce program consists of 52 programs that will facilitate the development of a trained and skilled workforce capable of implementing a national clean-energy smart grid and providing for the next generation of skilled technicians, engineers, and managers for the electric power industry.

What Did \$9.5 Billion Buy?

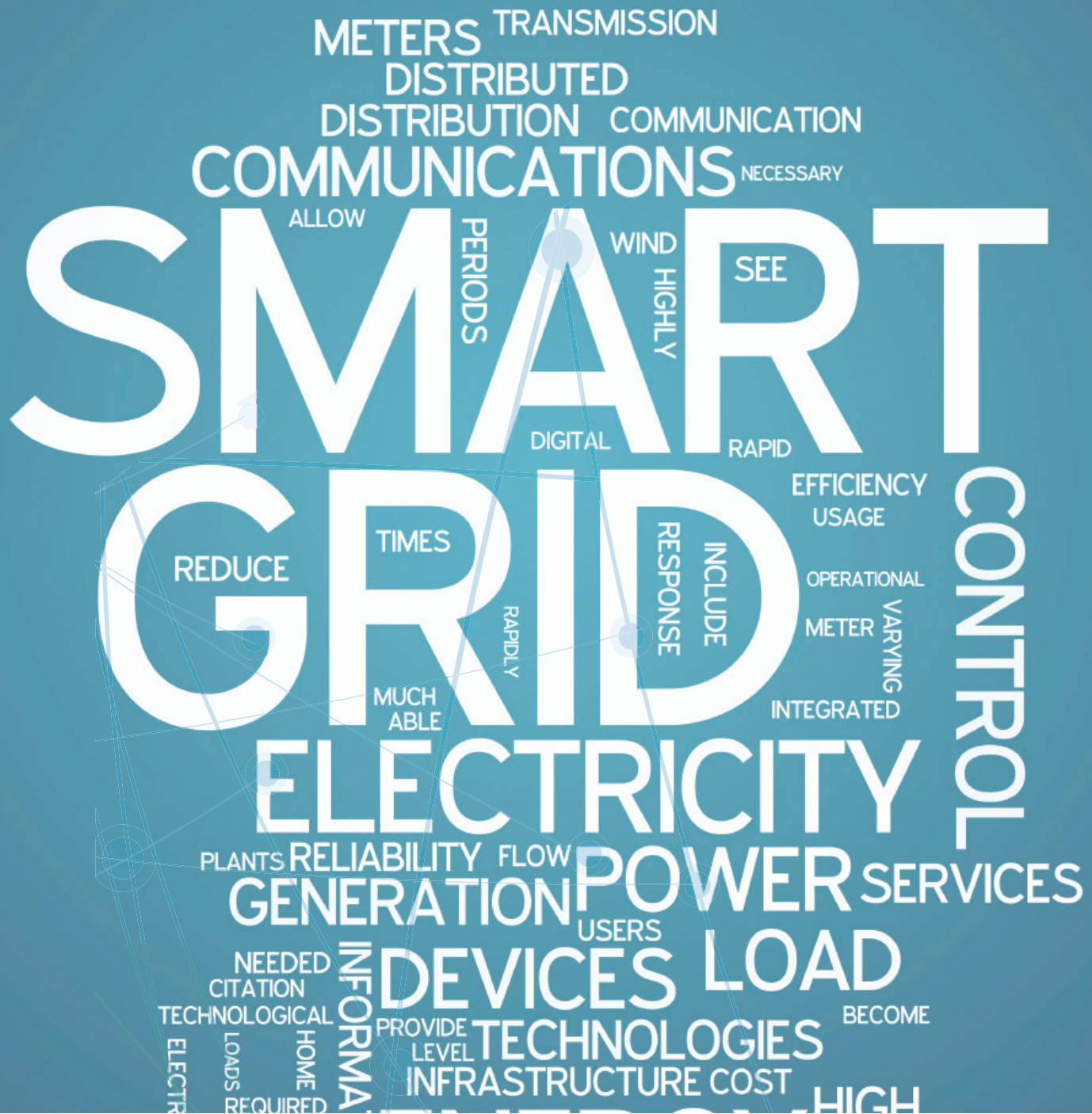
While the \$9.5 billion invested in these programs is small compared to the hundreds of billions of dollars the electric power industry will need to fully modernize the electric grid over the next several decades, these funds are helping to build a smarter and more modern electric grid that will be needed to accomplish our nation's most important economic, energy, and environmental priorities.

The Recovery Act Smart Grid investments helped utilities acquire and deploy the technologies that enable a more intelligent electricity delivery system, such as more than 15 million smart meters, 20,000 substation monitors, 1000, new synchophasors, and even 492 electric vehicle charging stations. And while we can count the equipment installed and the number of truck rolls avoided, what is more difficult to measure is the impact the Recovery Act Smart Grid programs are having on the future operations of electric power industry. The Recovery Act investments—the largest ever one-time investment in upgrading the U.S. electric infrastructure—helped utilities take the first steps. It mitigated some of the risk of being first, and is helping utilities share what they learned with others so that the industry can be better prepared to meet the needs of a growing digital economy, enable greater levels of clean energy deployment, and strengthen the electric grid to be more resilient to natural disasters and cyberattacks.

More information on the results and impacts of the Recovery Act Smart Grid Investments is available on SmartGrid.gov, including project reports, topical reports, and case studies.

Recovery Act Smart Grid Projects by Category

The American Recovery and Reinvestment Act of 2009 provided funding for smart grid projects across the United States. Projects that received funding through the Smart Grid Investment Grant program and Smart Grid Demonstration program are listed here. The location, project description, and data for each project are available on SmartGrid.gov.



Project Types

SGIG Project Recipients

	ETS	EDS	AMI	CS
American Transmission Company LLC (I)	●			
American Transmission Company LLC (II)	●			
Atlantic City Electric Company		●		●
Avista Utilities		●		
Baltimore Gas and Electric Company			●	●
Black Hills Corporation/Colorado Electric			●	●
Black Hills Power			●	
Burbank Water and Power		●	●	●
CenterPoint Energy Houston Electric, LLC		●	●	●
Central Lincoln People's Utility District		●	●	●
Central Maine Power Company			●	●
Cheyenne Light, Fuel and Power Company			●	
City of Anaheim Public Utilities Department		●	●	
City of Auburn, Indiana		●	●	●
City of Fort Collins Utilities		●	●	●
City of Fulton, Missouri			●	●
City of Glendale Water & Power		●	●	●
City of Leesburg, Florida		●	●	●
City of Naperville, Illinois		●	●	●
City of Quincy, Florida			●	●
City of Ruston, Louisiana		●	●	●
City of Tallahassee, Florida		●		●

ETS – Electric Transmission Systems
EDS – Electric Distribution Systems
AMI – Advanced Metering Infrastructure
CS – Customer Systems

Project Types

SGIG Project Recipients

	ETS	EDS	AMI	CS
City of Wadsworth, Ohio		●	●	●
Cleco Power LLC			●	
Cobb Electric Membership Corporation			●	●
Connecticut Municipal Electric Energy Cooperative		●	●	●
Consolidated Edison Company of New York, Inc.	●			
Cuming County Public Power District		●		●
Denton County Electric Cooperative		●	●	●
Detroit Edison Company		●	●	●
Duke Energy Business Services LLC		●	●	●
Duke Energy Carolinas, LLC	●			
El Paso Electric		●		
Entergy New Orleans, Inc.			●	●
Entergy Services, Inc.	●			
EPB		●	●	●
FirstEnergy Services Corporation		●	●	●
Florida Power & Light Company	●	●	●	●
Georgia System Operations Corporation Inc.	●			
Golden Spread Electric Cooperative, Inc.		●	●	●
Guam Power Authority		●	●	●
Hawaiian Electric Company Inc.		●		
Honeywell International, Inc.				●
Idaho Power Company	●	●	●	●

Project Types

SGIG Project Recipients

	ETS	EDS	AMI	CS
Indianapolis Power and Light Company		●	●	●
Iowa Association of Municipal Utilities			●	●
ISO New England, Inc.	●			
JEA			●	●
Knoxville Utilities Board		●	●	●
Lafayette Consolidated Government	●	●	●	●
Lakeland Electric			●	●
M2M Communications				●
Madison Gas and Electric Company		●	●	
Marblehead Municipal Light Department			●	●
Memphis Light, Gas and Water Division		●		
Midwest Energy	●			
Midwest Independent Transmission System Operator	●			
Minnesota Power		●	●	●
Modesto Irrigation District		●	●	●
Municipal Electric Authority of Georgia	●	●		
Navajo Tribal Utility Authority			●	
New Hampshire Electric Cooperative			●	●
New York Independent System Operator, Inc.	●			
Northern Virginia Electric Cooperative		●		
NSTAR Electric Company		●		

ETS – Electric Transmission Systems
EDS – Electric Distribution Systems
AMI – Advanced Metering Infrastructure
CS – Customer Systems

Project Types

SGIG Project Recipients

ETS EDS AMI CS

SGIG Project Recipients	ETS	EDS	AMI	CS
NV Energy			●	●
Oklahoma Gas and Electric Company		●	●	●
Pacific Northwest Generating Cooperative			●	●
PECO Energy Company		●	●	●
PJM Interconnection, LLC	●			
Potomac Electric Power Company (DC)		●	●	●
Potomac Electric Power Company (MD)		●	●	●
Powder River Energy Corporation		●		
PPL Electric Utilities		●		
Progress Energy Service Company	●	●	●	●
Qualcomm Atheros, Inc.				●
Rappahannock Electric Cooperative		●	●	●
Reliant Energy Retail Services, LLC				●
Sacramento Municipal Utility District		●	●	●
Salt River Project			●	●
San Diego Gas & Electric Company	●	●		
Sioux Valley Energy			●	●
Snohomish County PUD		●		
South Kentucky Rural Electric Cooperative Corp.			●	●
South Mississippi Electric Power Association		●	●	●
Southern Company Services, Inc.	●	●		
Southwest Transmission Cooperative, Inc.	●	●	●	●

Project Types

SGIG Project Recipients

	ETS	EDS	AMI	CS
Stanton County Public Power District			●	
Talquin Electric Cooperative, Inc.		●	●	●
Town of Danvers, Massachusetts		●	●	●
Tri-State Electric Membership Corporation			●	●
Vermont Transco, LLC		●	●	●
Vineyard Energy Project				●
Wellsboro Electric Company			●	●
Westar Energy, Inc.		●	●	●
Western Electricity Coordinating Council	●			
Whirlpool Corporation				●
Wisconsin Power and Light Company		●		
Woodruff Electric			●	

ETS – Electric Transmission Systems

EDS – Electric Distribution Systems

AMI – Advanced Metering Infrastructure

CS – Customer Systems



Smart Grid Demonstration Projects

Project Types

SGDP Project Recipients

ETS EDS AMI CS

SGDP Project Recipients	ETS	EDS	AMI	CS
AEP Ohio		●	●	●
Battelle Memorial Institute		●	●	●
The Boeing Company	●			
Center for the Commercialization of Electric Technologies	●			●
Consolidated Edison Company of New York, Inc.	●	●	●	●
Kansas City Power & Light		●	●	●
Long Island Power Authority	●	●	●	●
Los Angeles Department of Water and Power		●	●	●
National Rural Electric Cooperative Association		●	●	●
NSTAR Electric and Gas Corporation (AMR)			●	●
NSTAR Electric and Gas Corporation (UGM)	●	●	●	
Oncor Electric Delivery Company	●	●		
Pecan Street Project, Inc.			●	●
Power Authority of New York	●			
Southern California Edison Company	●	●	●	●
SuperPower, Inc.	●	●		

The Recovery and Reinvestment Act also provided funding for 16 energy storage demonstration projects. *Project locations, descriptions, and data are available for each project on SmartGrid.gov.*

- ETS** - Electric Transmission Systems
- EDS** - Electric Distribution Systems
- AMI** - Advanced Metering Infrastructure
- CS** - Customer Systems

The Smart Grid Experience: Applying Results, Reaching Beyond

The project descriptions included on the following pages are for those participating in the joint U.S. Department of Energy/EPRI Conference “The Smart Grid Experience: Applying Results, Reaching Beyond.” Project descriptions, information, and data for all smart grid projects funded through the American Recovery and Reinvestment Act Smart Grid Programs can be found at https://smartgrid.gov/recovery_act/project_information.

Participating Projects:

AEP Ohio

Baltimore Gas and Electric Company

Battelle Memorial Institute

CenterPoint Energy

Central Lincoln People’s Utility District

Central Maine Power

City of Fort Collins

Consolidated Edison Company of New York, Inc.

Duke Energy Business Services, LLC

Electric Power Board of Chattanooga (EPB)

FirstEnergy Services Corporation

Florida Power & Light Company

Iowa Association of Municipal Utilities

Kansas City Power & Light

National Rural Electric Cooperative Association

Pecan Street Inc.

PECO

Pepco – District of Columbia

Public Service Company of New Mexico

Salt River Project

San Diego Gas & Electric Company

Sacramento Municipal Utility District

Snohomish County PUD

Southern California Edison Company

Southern Company Services, Inc.

AEP Ohio

gridSMARTSM Demonstration Project

Scope of Work

AEP Ohio and its partners are building a secure, interoperable, and integrated smart grid infrastructure in Ohio that demonstrates the ability to maximize distribution system efficiency and reliability, and consumer use of demand response programs to reduce energy consumption, peak demand costs, and fossil fuel emissions. The demonstration area includes 150 square miles, including parts of Columbus, Bexley, Gahanna, New Albany, Whitehall, Reynoldsburg, Westerville, Blacklick, Johnstown, Alexandria, Minerva Park, and Pataskala. This area includes approximately 110,000 meters and 70 distribution circuits. AEP Ohio will implement smart grid technology over 58 13kV circuits from 10 distribution stations and 12 34.5kV circuits from six distribution stations. Included in this project is a new distribution management system (GE ENMAC), integrated volt-VAR control, distribution automation, advanced meter infrastructure, home area networks, community energy storage, sodium sulfur battery storage, and renewable generation sources. These technologies will be combined with two-way consumer communication and information sharing, demand response, dynamic pricing, and consumer products, such as plug-in hybrid vehicles.

Objectives

- Reduce energy demand by 15 MW; energy consumption by 18,000 megawatt-hours; CO2 emissions by 16,650 tons; and save consumers an estimated \$5.75 million over the length of the project.
- Improve distribution system efficiency and reliability by 30%-40%.
- Integrate more than 100 kW of storage resources into the existing grid.

At-A-Glance

Recipient: AEP Ohio
State: Ohio
Total Project Value: \$148,821,823
DOE/Non-DOE Share:
\$73,660,317/\$75,161,506

Equipment Installed

- Reclosers
- Automated Switches
- Capacitors Regulators
- Mesh Radios
- DA Logic Software

Partners

- Lockheed Martin
- UT-Battelle LLC
- General Electric
- S&C Electric Company
- Schweitzer Engineering Laboratories, Inc.
- Silver Spring Networks, Inc.

Key Milestones

- 42 of 70 circuits have distribution automation installed (February 2011)
- Completed conversion and deployment of 10 Prius vehicles as plug-in hybrid electric vehicle (PHEV) (March 2011)
- 70 circuits have distribution automation installed (January 2012)
- Installed 4 Community Energy Storage units (July 2013)
- Completed data collection (Jan 2014)
- Finalized technical project report (April 2014).

Benefits

- Decreased energy costs, improved Smart Grid reliability, reduced energy consumption, lowered peak demand, and significantly reduced carbon emissions
- Lower risk of implementing new technologies into existing electrical networks
- Greater U.S. energy security from reduced oil consumption.



Baltimore Gas and Electric Company

Smart Grid Initiative

Scope of Work

Baltimore Gas and Electric Company's (BGE's) Smart Grid Initiative consisted of a territory-wide deployment of advanced metering infrastructure (AMI), which included the replacement of more than 575,000 electric meters. The utility also implemented a customer Web portal and home energy management reports, which provide customers with behavioral science-based presentations of usage information to encourage home energy efficiency and conservation. A newly deployed customer care and billing system and meter data management system (MDMS) enable optimal utilization of the new technologies and allow BGE to leverage the AMI data to offer residential customers a peak-time rebate (PTR) program. Finally, the BGE project built upon an existing direct load control program, PeakRewardsSM, that offers customers financial incentives to allow BGE to cycle central air conditioning equipment and electric hot water heaters.

Objectives

The AMI deployment reduced BGE operations and maintenance costs and allowed the utility to retrain and redeploy legacy meter readers. Combined with new capabilities such as remote connect/disconnect and meter pinging, AMI also supports improved customer service and outage management. Direct load control and the new PTR program reduce peak demand and help customers lower their monthly bills.

Deployed Smart Grid Tools and Technologies

- **Communications infrastructure:** BGE implemented a two-way radio frequency mesh technology consisting of a network backbone of approximately 1,250 access points and relays. A public carrier network was selected for the backhaul.
- **Advanced metering infrastructure:** The project entailed deployment of AMI meters to more than 575,000 electric customers. The new MDMS receives meter data from the AMI head-end system and processes it to support billing and PTR events.

At-A-Glance

Recipient: Baltimore Gas and Electric Company
 State: Maryland
 NERC Region: Reliability First Corporation
 Total Project Cost: \$451,814,234
 Total Federal Share: \$200,000,000

Project Type

Advanced Metering Infrastructure
 Customer Systems

Equipment Installed

- 575,081 Million Smart Meters
- AMI Communications Systems
 - Meter Communications Network (RF Mesh, 1,250 network devices)
 - Backhaul Communications (Cellular)
- Customer Care and Billing System (partially funded by the SGIG program)
- Meter Data Management System
- Customer Web Portal and Home Energy Reports
- 202,906 Direct Load Control Devices
- 144,482 Smart Thermostats

Time-Based Rate Program

- Peak-Time Rebate (Default Residential Tariff)

Key Benefits

- Operational Savings
- Avoided Capital Expenditures
- Avoided Transmission and Distribution Infrastructure
- Wholesale Capacity Market Benefits

- **Advanced electricity service options:** The project implemented a web portal that displays interactive energy usage information and tools to help customers better manage their consumption and bills. The web portal provides interval and trending data, peak event notifications, energy saving tips, and budget alerts. BGE also deployed an advanced customer care and billing system to replace their legacy customer information system and fully leverage the data produced by the AMI system. This system is used to manage customer accounts, billing, start/stop service requests, on-demand meter reads, payment processing, and collections.
- **Direct load control:** BGE has installed more than 202,000 direct load control devices and 144,000 programmable thermostats in customer homes. In exchange for monthly bill credits, customers give the utility the option to cycle air conditioning units and electric hot water heaters during periods of high demand. By curtailing peak loads, investments in generation, transmission, and distribution can be deferred. In addition, demand response capacity puts downward pressure on energy prices, and customers have additional tools to reduce their electric bills.
- **Time-based rate programs:** The AMI system enabled BGE to introduce a PTR tariff to all customers with smart meters. The utility notifies participants about forecasted peak events via phone, email, or text the day before an Energy Savings Day. Customers can choose to use less electricity during the event and earn bill credits of \$1.25 for every kilowatt-hour saved compared to typical usage. This calculation is done for all residential customers with AMI meters using the new MDMS, and timely feedback is provided to customers earning bill credits to reinforce energy efficient behaviors.

Benefits Realized

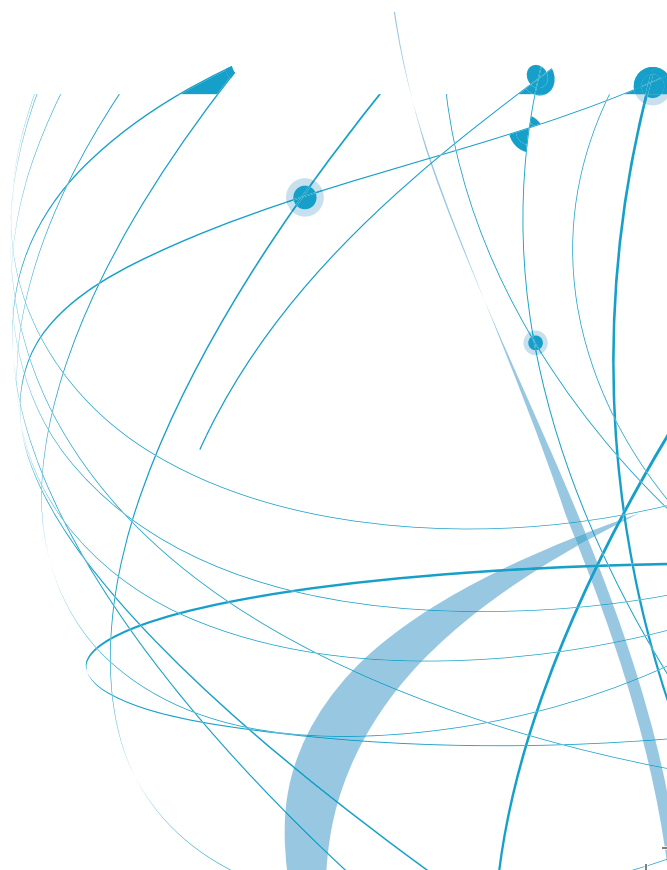
- **Operational savings: \$9.2M**
 - Reduction in manual meter reading costs
 - Meter operations costs from remote turn-on and turn-off
- **Avoided capital expenditures: \$7.2M**
 - Avoided capital expenditures relating to legacy metering systems
- **Avoided transmission and distribution infrastructure: \$7.0M**
 - Dollar value of avoided transmission and distribution infrastructure due to load reductions achieved through the Peak Time Rebate program
- **Wholesale capacity market benefits: \$326.3M**
 - Wholesale capacity revenue from sale of load reductions achieved through the Peak Time Rebate program
 - Related reduction in capacity prices associated with lower regional peak demand

Lessons Learned

BGE encountered significant challenges with gaining access to its indoor meter population, which represented approximately 50% of the planned meter exchanges. As a result, meter deployment fell behind schedule in May 2012. BGE decided to engage a second meter installation vendor and work proactively with regulators on a program to address customers who opt out of the AMI technology. To accelerate the pace of installations, BGE negotiated with the original vendor to increase the number of planned installers in the field, the second installation vendor was brought on board, and BGE cross-trained more of its own technicians to perform installations.

Future Plans

SGIG funds covered the first 575,081 electric meters under BGE's Smart Grid Initiative. The utility plans to continue AMI deployment—gas and electric—until 100% of their 1.25 million customers are reached. Once the territory is saturated with AMI meters, BGE engineers will work with the technology vendor to fine-tune the network for optimal performance. BGE also plans to implement an enterprise-wide data analytics platform to fully leverage the volumes of meter data being produced by the new system.



Battelle Memorial Institute

Pacific Northwest Smart Grid Demonstration

Scope of Work

Battelle Memorial Institute is collaborating with utilities, universities, and technology partners in a Smart Grid demonstration project across five states and three climatic regions, spanning the electrical system from generation to end-use, and containing all key functionalities of the future Smart Grid. This demonstration will validate new technologies; provide two-way communication between distributed generation, storage and demand assets, and the existing grid infrastructure; quantify Smart Grid costs and benefits; advance interoperability standards and cyber security approaches; and validate new business models. More than 20 types of responsive Smart Grid assets will be tested across six regional and utility operational objectives at 15 unique distribution sites operated by 11 utilities. A base of Smart Grid technology serving more than 60,000 customers will be installed, validated, and operated. All use classes are represented in the demonstration including residential, commercial, industrial, and irrigation customers. The demonstration will develop a single integrated Smart Grid incentive-signaling approach and will test and validate its ability to continuously coordinate the responses of Smart Grid assets to meet a wide range of operational objectives. It will also be among the first to engage distributed control so that wind integration problems are mitigated. Micro-grid islanding will also be evaluated for its potential to enhance reliability for customers and relieve energy demand. Team members are committed to commercializing proven technologies.

Goals/Objectives

- Measure and validate Smart Grid costs and benefits for customers, utilities, regulators and the nation, laying the foundation for future investment
- Develop standards and communications and control methodologies for a secure, scalable, interoperable Smart Grid for regulated and non-regulated utilities
- 75 percent of the assets installed by the project will remain responsive and functioning after the demonstration term.

At-A-Glance

Recipient: Battelle Memorial Institute
(Pacific Northwest Division Smart Grid Demonstration Project)

State: Washington

Total Budget: \$177,642,503

Federal Share: \$88,821,251

Project Type

- Advanced Metering Infrastructure
- Customer Systems
- Distributed Energy Resource
- Distribution System

Equipment

- Advanced Metering Infrastructure (AMI) / Smart Meters
- Controllable and Regulating Inverter
- Direct Load Control Device
- Distributed Energy Resource
- Distribution Automation
- Electricity Storage Technologies
- Programmable Communicating Thermostat
- Smart Meter - Industrial

Targeted Benefits

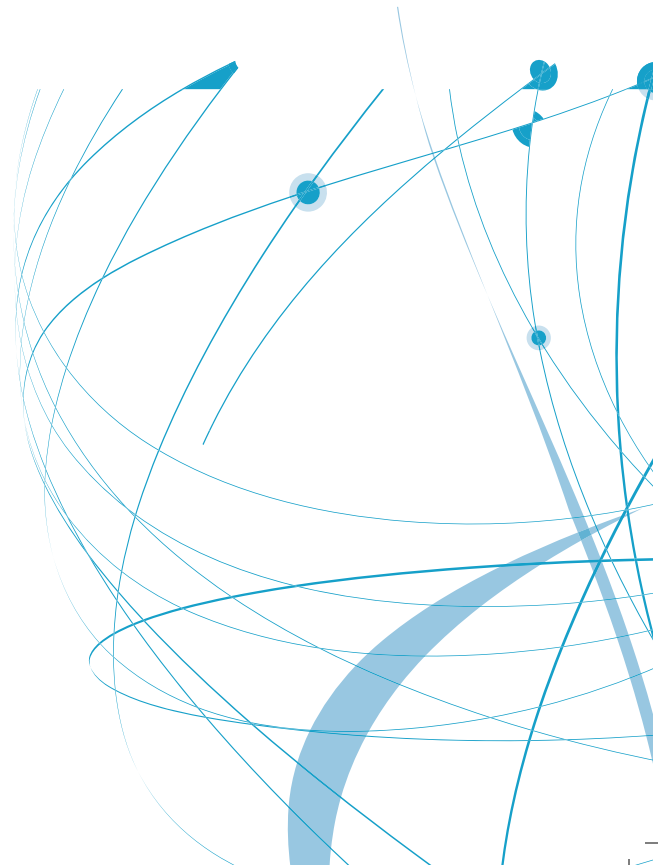
- Creation of approximately 1,500 jobs in manufacturing, installing, and operating Smart Grid equipment, telecommunications networks, software, and controls
- More cost effective, clean, reliable electricity supply
- Increased grid efficiency, reliability, and intelligence
- Customers empowered to conserve energy and avert increased energy cost

Key Milestones

- Transactive Control Design Complete (July 2011)
- Transactive Control Initial Node Implemented and Tested (August 2012)
- Smart grid assets installed, tested and operational as of January 2013)
- Transactive control Initial Node Connected to Smart Grid (January 2013)
- Final Report to DOE, with data collection and analysis (January 2015)

Benefits

- Creation of approximately 1,500 jobs in manufacturing, installing, and operating Smart Grid equipment, telecommunications networks, software, and controls
- More cost effective, clean, reliable electricity supply
- Increased grid efficiency, reliability, and intelligence
- Customers empowered to conserve energy and avert increased energy costs



CenterPoint Energy

Smart Grid Project

Scope of Work

CenterPoint Energy Houston Electric's (CEHE) Smart Grid Project (Project) consists of (1) advanced metering infrastructure (AMI) including the deployment of more than 2.2 million advanced meters across CEHE's entire service territory; (2) communications infrastructure which links the meters and facilitates the transfer of usage data from the meter back to CEHE's data collection engine and ultimately to customers through the Smart Meter Texas (SMT) Web portal; and (3) distribution automation system upgrades covering a portion of the service territory. This area encompasses a portion of the Texas Medical Center (the world's largest medical center), Houston's key business districts, the Port of Houston, petrochemical infrastructure facilities that are vital to the nation's fuel supply, and high reliability impact areas along the northern portion of the service territory. Project objectives include (1) automating meter reading, (2) eliminating truck rolls, (3) enabling residential and commercial customers to effectively manage and control their electricity usage, and (4) improving distribution system efficiency and reliability.

Smart Grid Features

- **Advanced metering infrastructure:** Includes deployment of approximately 2.2 million smart meters. This infrastructure provides automated service connection and disconnection and meter reading, improved meter accuracy, enhanced outage notification and response, and improved tamper and theft detection. The availability of more detailed and timely data on peak electricity usage and distribution system conditions improves load forecasting and capital investment planning.
- **Communications infrastructure:** Includes a combination of radio, microwave, and fiber optic technology to support AMI and distribution automation functionalities. This infrastructure provides CEHE with expanded capabilities for communicating customer information to retail electric providers and provides remote switching capabilities for improved control of the distribution system.

At-A-Glance

Recipient: CenterPoint Energy Houston Electric, LLC.

State: Texas

NERC Region: Texas Reliability Entity

Total Budget: \$639,187,435

Federal Share: \$200,000,000

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- 2,200,000 Smart Meters
- Web Portal Access for 2,200,000 Customers
- Distribution System Automation/Upgrade for 187 of 1,516 Circuits
 - Distribution Management Systems
 - Supervisory Control and Data Acquisition (SCADA) Communications Network
 - Equipment Condition Monitors
 - 187 Smart Relays

Key Targeted Benefits

- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Equipment Failures, Distribution Line Losses, and Theft
- Reduced Greenhouse Gas and Pollutant Emissions
- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs
- Reduced Truck Fleet Fuel Usage
- Reduced Frequency and Duration of Outages

- **Advanced electricity service options:** Include Web portal access available for all 2.2 million customers receiving new smart meters, provided that they have Internet access and complete the registration process. This Smart Meter Texas Web Portal and Common Data Repository is intended to provide customers with information that, combined with the retail electric provider service offerings and behavioral changes, may allow them to better manage their energy usage and costs.
- **Distribution automation system upgrades:** Include the installation of new remote controlled devices on up to 187 distribution circuits that encompass a large area of the service territory where much of the critical chemical, petrochemical, and oil refining infrastructure is located. These devices are expected to enable the ability to improve the reliability of the distribution system as well as its overall operational efficiency. At a minimum, CEHE expects these system upgrades to reduce the extent and duration of service interruptions and minimize field operational requirements. These devices will measure and digitally communicate information regarding distribution line loading, voltage levels and fault data that will enable operators to remotely locate and isolate faulted distribution line sections so that they can be more quickly repaired.

Timeline

Key Milestones	Target Dates
AMI installation begins	Q1 2009
Communications infrastructure installation begins	Q1 2009
Distribution automation systems installation begins	Q4 2010
Installation of AMI completed	Q2 2012
Installation of communications infrastructure completed	Q4 2013
Installation of distribution automation systems upgrades completed	Q4 2014
Smart Grid Program complete	Q1 2015

Central Lincoln People's Utility District

Smart Grid Team 2020 Program

Scope of Work

As part of their Smart Grid Team 2020 Project, Central Lincoln People's Utility District (Central Lincoln PUD) deployed advanced metering infrastructure (AMI), a meter data management system (MDMS), an AMI-enabled web portal, an outage management system (OMS), and distribution automation (DA) assets. The AMI component of the project included system-wide installation of smart meters and deployment of communications infrastructure to support the AMI data transfer. DA upgrades included deployment of an enhanced supervisory control and data acquisition (SCADA) system; automated distribution feeder controls, regulators, monitors, and fault indicators; and an upgraded fiber optic cable network.

Objectives

Central Lincoln PUD's primary goal was to establish a two-way communications network between the utility monitoring and control systems and intelligent grid devices to enable a variety of smart grid and energy conservation programs and applications. The enhancements also improve power quality, system reliability, and system efficiency.

Deployed Smart Grid Tools and Technologies

- **Communications infrastructure:** A combination radio frequency (RF) mesh and fiber optic cable network connects the systemwide deployment of smart meters. The network provides the necessary communications infrastructure to enable smart grid features such as AMI portal-based customer energy management tools and time-based pricing programs. Additional fiber was deployed to connect all substations to the control center. DA devices communicate with the substations via a high-speed wireless connection.
- **Advanced metering infrastructure:** Central Lincoln PUD deployed 38,620 smart meters to residential, commercial, and industrial customers systemwide. Residential meters are equipped with remote service disconnect and wireless home area network capability.

At-A-Glance

Recipient: Central Lincoln People's Utility District

State: Oregon

NERC Region: Western Electricity Coordinating Council

Total Project Cost: \$19,159,194

Total Federal Share: \$9,579,597

Project Type

Advanced Metering
Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- 38,620 Smart Meters
- AMI Communications Systems
 - Meter Communications Network (RF Mesh)
 - Backhaul Communications (Fiber Optic)
- Meter Data Management System
- 46 In-Home Displays
- Customer Web Portal Access
- Outage Management System
- Distribution Automation
- SCADA System
 - Communications Network (Fiber Optic Cable and High-Speed Wireless)
 - Automated Feeder Switches
 - Automated Reclosers
 - Regulator Automation Equipment

Key Benefits

- Reduced Operating and Maintenance Costs
- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Distribution Line Losses
- Reduced Truck Fleet Fuel Usage

- **Advanced electricity service options:** All customers receiving smart meters now have access to a customer Web portal that displays interval usage data, trending information, and energy conservation tips. All residential meters now have operational remote connect/disconnect functionality and can support time-based pricing if needed in the future.
- **Distribution automation systems:** Central Lincoln PUD deployed automated line sectionalizing switches. Feeders can now be reconfigured remotely to reduce the affected area in the event of a fault or to handle unexpected changes in electricity demand. These assets work together to improve distribution system reliability, stability, and operational efficiency.
- **Distribution system energy efficiency improvements:** Automated regulators were deployed at select substations to pilot the use of AMI voltage readings at the meter level to enable a conservation voltage regulation capability.

Benefits Realized

- **Reduced operating and maintenance costs:** The AMI system enables efficiency in dispatching field crews which, in turn, reduces meter operations miles and costs and associated greenhouse gases. AMI also allows for remote monitoring and troubleshooting of the 38,620 meters on its system.
- **Reduced costs from distribution line losses and improved electric service reliability:** Central Lincoln PUD has implemented a unique approach to voltage optimization, utilizing near-real-time premise-level voltage measurements collected through the AMI system and integrated with SCADA control to deliver voltages more closely aligned with optimal operating requirements.

Lessons Learned

- AMI transforms every aspect of utility operations. It is especially important to dedicate time and resources to engage all departments in requirements collection and business process redesign.
- Leveraging the AMI system to implement a conservation voltage regulation capability benefits all customers without requiring their active participation.
- The integration effort between legacy and new information technology (IT) systems is significant and should be adequately planned for during the design phase.
- A robust communications network is critical for both AMI and DA. In Central Lincoln PUD's case, utilizing a variety of communications technologies was necessary to ensure adequate coverage, redundancy, and performance. Collecting GPS location data for each meter and DA device was essential for network optimization.

Future Plans

- Central Lincoln PUD plans to leverage experience gained on this project to implement conservation voltage regulation territorywide and install additional DA devices on the system. Additionally, a prepay program and timebased pricing options for customers, made feasible by AMI, are in early planning stages.

Central Maine Power

CMP Advanced Metering Infrastructure Project

Scope of Work

Central Maine Power Company's (CMP) Advanced Metering Infrastructure (AMI) project consists of territorywide deployments of more than 600,000 smart meters to all of its residential, commercial, and industrial customers. This project is designed to create a technology platform for providing customers with electricity usage information and alternative electricity rates from third-party energy providers. Customers view their energy consumption through a Web portal and can use that information to help manage electricity bills. This project aims to reduce operations and maintenance costs and service restoration times for customers through quicker and more accurate location of faults and power outages. CMP plans to assess the load-shape and consumption impacts of providing customers with different types of information using Web portals and proactive bill alert messages.

Smart Grid Features

- **Communications infrastructure:** Includes a wireless mesh system that provides two-way communications between smart meters and CMP's central information processing systems. The high-bandwidth wireless network will support distribution automation devices as well as metering data. This infrastructure provides CMP with expanded capabilities for adding future programs and functionality to optimize energy delivery, system reliability, and customer participation.
- **Advanced metering infrastructure:** Includes a systemwide roll out to more than 600,000 residential, commercial, and industrial customers. These advanced meters provide the capability for a variety of future customer electricity price and service options, and reduce CMP's costs of electricity delivery through lower meter reading and customer services costs. New AMI features such as outage and restoration notification help CMP identify customer service outages and respond more quickly. Remote service connection and disconnection can

At-A-Glance

Recipient: Central Maine Power Company

State: Maine

NERC Region: Northeast Power Coordinating Council

Total Budget: \$195,900,000

Federal Share: \$95,900,000

Project Type

Advanced Metering Infrastructure

Equipment Installed

- 630,000 Smart Meters
- AMI Communication Systems
 - Meter Communications Networks
 - Backhaul Communications
- Meter Data Management System
- Customer Systems for 630,000 Customers
 - Home Area Networks
 - Customer Web Portal

Key Benefits

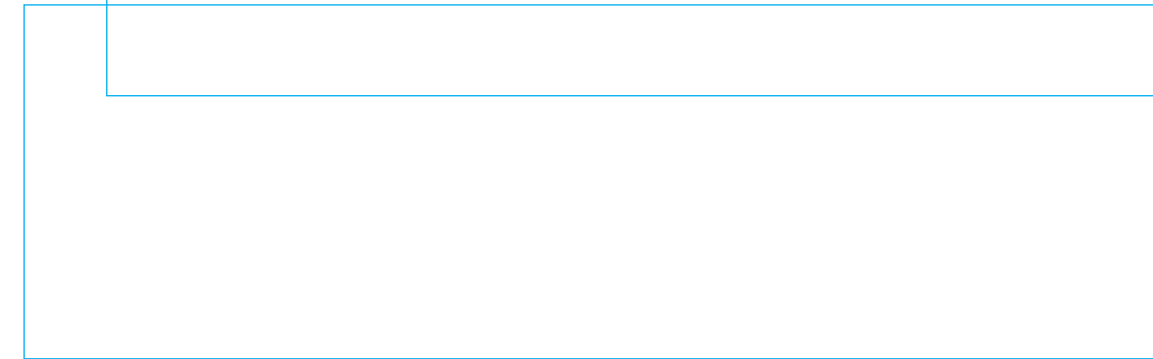
- Reduced Meter Reading Costs
- Reduced Electricity Costs for Customers
- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Distribution Line Losses and Theft
- Deferred Investment in Generation Capacity Expansion
- Reduced Greenhouse Gas and Criteria Pollutant Emissions
- Reduced Truck Fleet Fuel Usage

reduce operations costs and the time it takes CMP to reconnect existing utility service to customers. Increased monitoring capability of voltage sags and swells help CMP improve power quality for its customers.

- **Advanced electricity service options:** Include access to Web portals for all of CMP's customers that enable customers to view their historical electricity use patterns. Furthermore, these services support the information pilot for CMP to demonstrate how its customers respond to different forms of consumption presentation.

Timeline

Key Milestones	Target Dates
AMI deployment begins	Q3 2010
AMI deployment ends	Q2 2012



City of Fort Collins Utilities

Front Range Smart Grid Cities

Scope of Work

The City of Fort Collins' Front Range Smart Grid Development project involves the municipal utilities for the cities of Fort Collins and Fountain, Colorado. The project includes citywide deployment of advanced metering infrastructure (AMI); expansion of distribution automation capabilities including supervisory control and data acquisition (SCADA) system-connected fault indicators; SCADA-connected remote operated feeder switches; incorporation of meter "last-gasp" signals into the outage management system; demand response products; evaluation and potential implementation of time-based rate programs including time-of-use and critical peak pricing; customer education; and Web portal access. Information from this project facilitates: (1) customer-participants' ability to view their energy consumption through in-home displays, a Web portal, or both; and (2) the ability of City of Fort Collins and the City of Fountain to manage, measure, and verify targeted demand reductions during peak periods. The new AMI and distribution automation technologies help improve service quality and reliability by enabling more efficient outage management, distribution circuit monitoring, and remote circuit switching.

Smart Grid Features

- **Communications infrastructure:** Includes a new digital point-to-multi-point radio network from each substation and other points throughout the cities to meters and distribution automation devices, and enhancements to an existing fiber-optic backhaul network from the substations to the utility operations center. This infrastructure provides the cities of Fort Collins and Fountain with expanded communication capabilities to better understand and integrate customer information, energy delivery system operations, and distribution system reliability information.
- **Advanced metering infrastructure:** Includes the deployment of about 84,290 advanced meters throughout the entirety of the cities of Fort Collins and Fountain as well as supporting information technologies and data management infrastructure. This system provides automated meter reading, improved long-term meter accuracy, enhanced outage

At-A-Glance

Recipient: City of Fort Collins Utilities
 State: Colorado
 NERC Region: Western Electricity Coordinating Council
 Total Budget: \$36,202,526
 Federal Share: \$18,101,263
 Partners: City of Fountain, Colorado

Project Type

Advanced Metering Infrastructure
 Customer Systems
 Electric Distribution Systems

Equipment Installed

- 84,290 Smart Meters
- Advanced Metering Infrastructure Communication System
 - Meter Communications Network
 - Backhaul Communications
- Meter Data Management System
- Customer Web Portal Access for 84,290 Customers
- In-Home Displays/Energy Management Systems^a
- Programmable Communicating Thermostats^a
- Direct Load Control Devices^a
- Distribution System Automation/Upgrade for at least 4 out of 221 Distribution Circuits
 - Automated Distribution Circuit Switches

a. Offered as customer option

Time-based Rate Programs^b

- Time of Use
- Critical Peak Pricing

b. Currently under City Council review.

Key Targeted Benefits

- Reduced Operating and Maintenance Costs
- Increased Electricity Service Reliability and Power Quality
- Deferred Investment in Distribution Capacity Expansion
- Reduced Costs from Equipment Failures and Distribution Line Losses
- Reduced Greenhouse Gas Emissions

detection, power quality monitoring, improved meter tampering detection, and remote connect/disconnect capabilities. A new meter data management system provides expanded capabilities to analyze, interpret, and query meter readings and interval power consumption information, which improves billing and electricity management efforts and load forecasting abilities.

- **Advanced electricity service options:** Offered through the project, they encompass the development of a portfolio of solutions to help reduce demand and energy consumption. The portfolio is anticipated to include equipment such as programmable communicating thermostats, in-home displays, Web portal access, and direct load-control devices that control water heaters and air conditioning equipment in homes and businesses. Customers in the cities of Fort Collins and Fountain who choose to enroll in the demand response programs may receive programmable communicating thermostats, load-control switches, and have access to a Web portal that provides information on their electricity use.
- **Time-based rate programs:** Under consideration, they include an inclining block rate, seasonal tiers, time-of-use pricing, and a time-of-use rate with critical peak pricing. These pricing options are designed to encourage customers to reduce and/or shift their consumption from on-peak to off-peak periods, with the expectation that it also reduces overall peak demand, greenhouse gas emissions, and costs of using power plant peaking generation units during times of peak system demand.
- **Distribution automation systems:** Include an outage management system, automated switches, feeder power quality and fault monitoring equipment, and remote fault indicators integrated with the outage management system on select distribution circuits. These investments reduce the duration of service interruptions and field operations requirements. Thus, system reliability and power quality are targeted benefits of this upgrade. Having the capability to monitor for rapid, small fluctuations in grid voltage and current supports future implementation of distribution automation that can allow for increased penetration of distributed generation installed on or near residential and commercial buildings.

Timeline

Key Milestones	Target Dates
AMI deployment begins	Q1 2012
Customer systems deployment begins	Q1 2012
Distribution automation deployment begins	Q1 2012
AMI deployment completed	Q2 2013
Customer systems deployment completed	Q2 2014
Distribution automation completed	Q4 2014

Consolidated Edison Company of New York, Inc.

Smart Grid Deployment Project

Scope of Work

The Consolidated Edison Company of New York, Inc. (Con Edison) Smart Grid Deployment project involves the deployment of smart grid systems and components to enhance electric distribution planning and operations. It is aimed at reducing operations and maintenance costs and deferring distribution capacity investments while increasing distribution system efficiency, reliability, and power quality. The project is deploying various types of distribution automation equipment such as substation and feeder monitors, automated switches, and capacitor automation devices on 1,388 feeder lines to improve operational efficiency and control. When combined with the integration of distribution management systems and supervisory control and data acquisition (SCADA) systems, the automated devices allow Con Edison to better control its distribution system and improve the reliability of its electricity service.

Smart Grid Features

- **Communications infrastructure:** Includes an upgrade of existing radio sites for the SCADA system. The upgrade enables increased capacity and enhanced security through encryption and allows for automated communication and control of the auto loop reclosers. The project upgrades existing radio sites and complies with the North American Electric Reliability Council Critical Infrastructure Protection Requirements for data authentication and encryption.
- **Advanced metering infrastructure:** Central Lincoln PUD deployed 38,620 smart meters to residential, commercial, and industrial customers systemwide. Residential meters are equipped with remote service disconnect and wireless home area network capability.
- **Distribution automation systems:** Include the deployment of automated sectionalizing switches with SCADA control. The switches allow for rapid restoration of electricity loss to sections of the grid affected by an outage as well as reduced restoration time as faults are easier to locate. Additionally, Con Edison is deploying approximately

At-A-Glance

Recipient: Consolidated Edison Company of New York, Inc.
 States: New York and New Jersey
 NERC Region: Northeast Power Coordinating Council
 Total Federal Share: \$136,170,899
 Total Budget: \$272,341,798
 Key Partner: Orange and Rockland Electric Utilities, Inc.

Project Type

Electric Distribution Systems

Equipment Installed

- Distribution Automation Equipment for 938 out of 2,297 Circuits
 - New Distribution Management System
 - SCADA Communications Network
 - 758 Automated Distribution Circuit Switches
 - 450 Automated Capacitors
 - 17,000 Equipment Condition Monitors
- Distributed Energy Resources Interface Capability

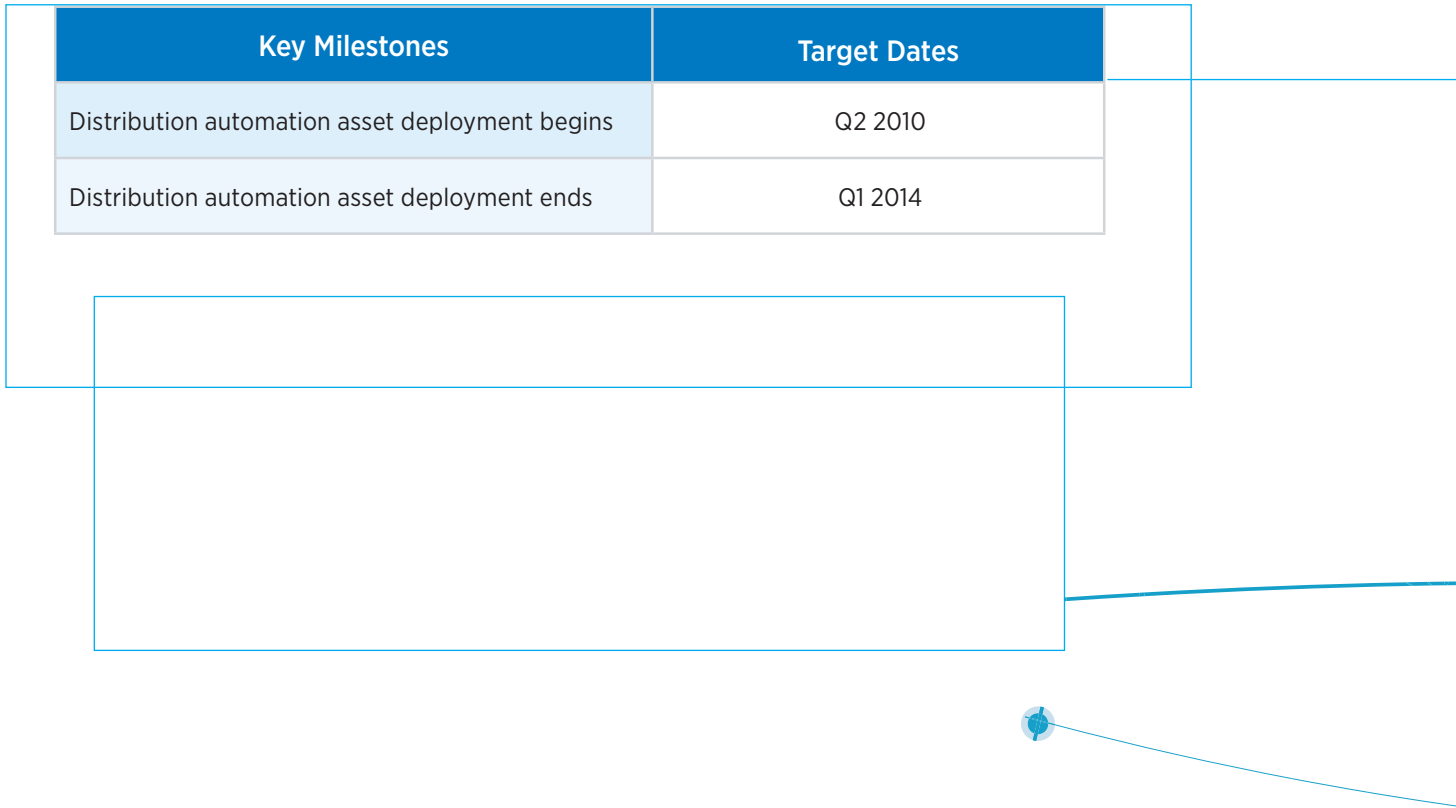
Key Benefits

- Deferred Investment in Distribution Capacity Expansion
- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Equipment Failures and Distribution Line Losses
- Reduced Operating and Maintenance Costs
- Reduced Truck Fleet Fuel Usage
- Reduced Greenhouse Gas and Criteria Pollutant Emissions

17,000 transformer condition-monitoring devices that use the power line communications infrastructure to alert Con Edison of any problems with the distribution equipment. The sensors enable maintenance crews to perform targeted preventative maintenance, thus reducing the number of equipment failures and outages. The automated sectionalizing switches and the equipment condition monitors help to increase reliability while reducing operations and maintenance costs.

- **Distribution system energy efficiency improvements:** Involve the integration of capacitor automation and a power quality monitoring system. The enhancements are being made to the 4kV portion of the grid (the 4kV portion of the grid consists of the primary feeders that deliver power to homes, such as the overhead wires seen in residential neighborhoods) and are aimed at improving the power quality of the grid and reducing operations and maintenance costs. The capacitors improve voltage control, power quality, and increase distribution capacity through grid efficiency.
- **Distributed energy resources interface capability:** Involves the deployment of secure two-way wireless communication to approximately 180 network type underground distribution transformers. The cybersecure communication system will allow for distributed generation to be fed into the grid without causing safety issues, reliability issues, or damage to the grid. When the project is completed, the communication infrastructure will be used to implement flexible monitoring and control of the distribution system to enhance efficiency, reliability, power quality, and enable integration of distributed generation such as solar and combined heat and power (CHP) in the future.

Timeline



Duke Energy Business Services, LLC

Smart Grid Deployment Project

Scope of Work

Duke Energy Business Services, LLC's (Duke) Smart Grid Program began in 2008 and includes the development and implementation of comprehensive end-to-end solutions that will transform its five-state electric system, and lead to products and services that increase the consumer's role in reducing energy use and carbon emissions. Duke's Smart Grid Deployment projects include advanced metering infrastructure (AMI) and distribution automation systems in five states. The projects involve large-scale deployments of AMI and distribution automation in Ohio and North Carolina, and smaller limited deployments of distribution automation in Indiana, Kentucky, and South Carolina. The effort also includes pilot programs for electricity pricing including time-of-use rates, peak-time rebates, and critical-peak pricing. Customers in these pilot programs will test home area networks, Web portals, and direct load-control devices to reduce their electricity consumption and peak demand. In December 2008, Duke received a state regulatory order to proceed with Smart Grid deployment in Ohio.

Smart Grid Features

- **Communications infrastructure:** Includes an open, interoperable two-way network that provides the backbone for AMI and distribution automation systems deployed as part of this project and allows for future integration with distribution automation, substation automation, and home area networks.
- **Advanced metering infrastructure:** Includes plans to install 1,119,050 smart meters in Ohio, North Carolina, and South Carolina during the DOE grant period. The infrastructure provides automated meter reading, enhanced outage notification and response, remote meter connect and disconnect capability, and improved detection of theft. More detailed and timely data on peak electricity usage improves load forecasting and capital investment planning.
- **Time-based rate programs:** Include a variety of options implemented in a series of pilot programs. The pilots measure customer load impacts,

At-A-Glance

Recipient: Duke Energy Business Services, LLC

States: Indiana, Kentucky, North Carolina, Ohio, and South Carolina

NERC Region: ReliabilityFirst Corporation and SERC Reliability Corporation

Total Federal Share: \$200,000,000

Total Budget: \$555,706,307

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- 398,800 Smart Meters in North/South Carolina
- 720,250 Smart Meters in Ohio
- AMI Communication Systems
 - Meter Communications Network
 - Backhaul Communications
- Meter Data Management System
- Home Area Networks
- In-Home Displays
- Remote Fault Indicators
- Customer Web Portals
- Distribution Automation Equipment
 - Distribution Automation Communications Network
 - SCADA Communications Network
 - Automated Distribution Circuit Switches

Key Benefits

- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs
- Deferred Investment in Distribution Capacity Expansion
- Improved Electric Service Reliability, Power Quality
- Reduced Costs from Distribution Line Losses, Theft
- Reduced Greenhouse Gas and Criteria Pollutants
- Reduced Truck Fleet Fuel Usage

bill impacts, customer acceptance, and test the capabilities of billing software and smart meters. In Ohio, Duke will conduct a 1-year pilot for time-of-use rates to selected residential customers who have a certified single-phase smart electric meter. Rates are divided into winter and summer months and vary based on the time of day energy is used. The pilot measures customer bill impacts, the customer's experience, the daily/hourly kW and kWh impacts, and leverages enhancements to billing systems capabilities. In addition, Duke is considering a variety of pilot pricing programs including: flat with peak-time rebates, critical peak price, and critical peak price "lite."

- **Distribution system automation:** Includes automated switches, capacitors, and reclosers as well as sensors on the distribution system. This distribution system upgrade also includes integrating the supervisory control and data acquisition system (SCADA), geographical interface system, outage management system, and work management system. The integration of these systems provides more efficient system management through a single operator interface and enables the benefits of the distribution automation devices. These devices enable power quality monitoring, voltage regulation, and power flow reconfiguration to limit the spread of power interruptions. This enhanced functionality improves power quality and electric system reliability and lowers operating and maintenance costs.
- **Distribution system energy-efficiency improvements:** Include automated switches and upgraded communications network capabilities for capacitor banks and distribution/transmission substation equipment. The automation of the capacitor banks improves power factor and voltage regulation, reducing distribution energy losses while improving service quality for customers. In addition, Duke is supporting plug-in electric vehicles with the distribution system improvements.

Timeline

Key Milestones	Target Dates
Distribution automation asset deployment begins	Q3 2009
AMI asset deployment begins	Q3 2009
Distribution automation asset deployment ends	Q1 2013
AMI asset deployment ends	Q1 2013

Electric Power Board of Chattanooga (EPB)

Smart Grid Project

Scope of Work

EPB's smart grid project involved deployment of a fiber optic network as the primary means of communication for all smart grid equipment, an advanced metering infrastructure (AMI) system, an energy management Web portal, and distribution automation (DA) equipment on more than half of EPB's circuits. The project also delivered time-based rate programs to customers to create incentives for peak load and overall bill reductions.

Objectives

The EPB smart grid project has enabled a new kind of partnership with customers aimed at reducing peak loads, overall electricity use, and operations and maintenance costs. The distribution system upgrades increase operational efficiency, reduce line losses, and improve service reliability for customers.

Smart Grid Tools and Technologies

- **Communications infrastructure:** The project deployed a fiber optic network that enables two-way communication and data transfer between the meters, switches, substations, and control center. This infrastructure also provides EPB with expanded capabilities and functionality to optimize energy delivery, system reliability, and customer service options.
- **Advanced metering infrastructure:** The project deployed approximately 170,000 smart meters, providing AMI coverage for all EPB customers. New AMI features such as outage and restoration notification and remote service connect/disconnect switches enable EPB to respond to outages and customer requests faster and more efficiently.
- **Customer system devices:** EPB deployed an AMI-enabled web portal for all 170,000 customers to provide them with account balances and interval usage data from their smart meters.

At-A-Glance

Recipient: EPB
States: Georgia and Tennessee
NERC Region: SERC Reliability Corporation (SERC)
Total Project Cost: \$226,707,562
Total Federal Share: \$111,567,606

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- 170,000 Smart Meters
- AMI Communications Systems
 - Meter Communications Network
 - Backhaul Communications
- Customer Web Portal
- Replacement of SCADA System
- Distribution System Automation/Upgrade for 232 out of 370 Circuits
 - SCADA Communications Network
 - 1,405 Automated Distribution Circuit Switches*

* Including automation of existing motor-operated switches at the sub-transmission level

Time-Based Rate Program

- Targeting up to 5,000 Customers

Key Benefits

- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs
- Improved Electric Service Reliability
- Reduced Costs from Equipment Failures and Theft
- Reduced Truck Fleet Fuel Usage
- Reduced Greenhouse Gas and Criteria Pollutant Emissions

- **Time-based rate programs:** EPB developed and offered a time-of-use residential rate program to give customers more choices and greater control over their electricity costs.
- **Distribution system reliability improvements:** EPB deployed automated feeder switches and sensor equipment on 171 distribution circuits in the service territory. The project also included the automation of existing motor-operated switches on 61 sub-transmission circuits for improved system reliability. Supervisory control and data acquisition (SCADA) system upgrades leveraged an Internet protocol-based fiber optic communications infrastructure to support expanded automation equipment installations and provide improved situational awareness for dispatch operators.

Benefits Realized

- **Reduced operating and maintenance costs:** EPB has realized \$1.6 million in annual operational cost savings through automation of meter reading. Furthermore, avoided manual switching costs have saved the utility approximately \$40,000 annually. The automated switching has significantly reduced the need to send staff into the field during and after storms to identify damage locations, isolate the damage, and restore the unaffected sections. In one severe storm that occurred July 5, 2012, EPB realized savings of more than \$1 million in overtime costs associated with the restoration effort.
- **Improved reliability:** The DA devices provide data for the fault isolation and service restoration (FISR) function of the DMS. Whether working in an advisory capacity or automatically, FISR can identify faulted line sections and either automatically restore power to unfaulted sections or direct operators and line personnel to the appropriate area for line isolation and repair. This improved response reduces the frequency and duration of outages as well as reducing crew and vehicle travel time.
- **Increased distribution system reliability:** Voltage control allows EPB to reduce peak demand by up to 30 MW per month, resulting in \$2 million in wholesale demand savings annually. Over the last two years, EPB has experienced a 42% improvement in the System Average Interruption Duration Index (SAIDI) and a 51% improvement in the System Average Interruption Frequency Index (SAIFI).

Lessons Learned

EPB's system, which is more than 60 years old, was designed with 115 small substations and limited centralized communications architecture. With a 600-square-mile territory and extreme annual storms, this lack of connected communications and distribution management capabilities has traditionally meant slow response times and labor-intensive outage recovery. With the addition of AMI and DA, EPB has turned an antiquated system design into an automated, integrated grid with built-in redundancies.

Future Plans

The strategic deployment of DA equipment is part of EPB's plan to more fully automate its distribution system. Data from the smart switches will also provide the intelligence needed to calculate real-time loading on each of EPB's transformers so that demand can be better calculated and forecasted, thus utilizing existing capital assets more effectively. EPB is also considering exploring opportunities around distributed storage.

FirstEnergy Services Corporation

Smart Grid Modernization Initiatives

Scope of Work

FirstEnergy Services Corporation's (FirstEnergy) Smart Grid Modernization Initiative (SGMI) involved deployment of advanced metering infrastructure (AMI), distribution automation (DA), volt/VAR optimization (VVO), time-based rate programs, direct load-control (DLC) devices, and customer systems in parts of New Jersey, Ohio, and Pennsylvania. SGMI's Ohio footprint covered a 400-square-mile area southeast of Cleveland. Smart meters were piloted in Ohio, and a statistically rigorous study assessed load impacts and customer acceptance of time-based rate programs. DA equipment deployed in New Jersey, Ohio, and Pennsylvania included reclosers, capacitor banks and grid sensing devices. VVO equipment, deployed in Ohio and Pennsylvania, included capacitor banks and load tap changer regulator controls. Advanced load control devices were deployed in New Jersey and Pennsylvania.

Objectives

FirstEnergy aimed to enable customers' informed participation in electricity consumption management, improve power quality and operational monitoring capabilities, optimize asset utilization and operating efficiencies, evaluate wireless network technologies, and better predict and respond to abnormal system conditions.

Deployed Smart Grid Technologies

- **Communications infrastructure:** FirstEnergy deployed various network infrastructures to create a communications system within each deployment location. Each system consists of public code division multiple accesses (CDMA) technology, fiber optics, public and private spectrum networks, and radio frequency (RF) mesh network technology with pole-mounted concentrators. The various systems facilitate communications between centralized software systems and a wide range of AMI, DA, and DLC field devices.
- **Advanced metering infrastructure:** FirstEnergy deployed 34,309 smart meters for residential and commercial customers, enabling two-way communication between the utility, meters, and in-home technologies

At-A-Glance

Recipient: FirstEnergy Services Corporation

State: New Jersey, Ohio, and Pennsylvania

NERC Region: Reliability First Council

Total Project Cost: \$114,940,274

Total Federal Share: \$57,470,137

Key Partners: Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, and Metropolitan Edison Company

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- 34,309 Smart Meters
- AMI Communication Systems (RF Mesh)
- Backhaul Network (Fiber and Cellular)
- Home Area Networks
- 720 In-Home Displays
- 535 Programmable Communicating Thermostats
- 37,721 Direct Load-Control Devices
- Upgrades to 64 Distribution Automation Circuits
 - 172 Automated Distribution Circuit Reclosers
- Upgrades to 46 VVO Circuits
 - 187 Automated Capacitors
 - 4 Automated Voltage Regulators
 - 236 Equipment Condition Monitors
- Distribution Automation Communications Network
- SCADA Communications Network

Time-Based Rate Programs

- Peak-Time Rebate
- Critical Peak Pricing (opt-in)

Key Targeted Benefits

- Reduced Operating and Maintenance Costs
- Improved Electric Service Reliability and Power Quality
- Reduced Distribution Line Losses

that provide customers with energy usage information. The smart meters provide FirstEnergy with data used for more detailed load profile analysis and demand forecasting.

- **Distribution automation and volt/VAR optimization systems:** FirstEnergy implemented a centralized software tool for DA system control of automated feeder devices for 64 distribution circuits. Technology upgrades included supervisory control and data acquisition (SCADA) displays for substation breakers and field devices. The tool enables integrated voltage control and reactive power from capacitor controllers, line capacitor switches, load tap changers, and regulators for 46 circuits and facilitates optimization of distribution circuit voltages, increasing efficiency and improving power quality.
- **Time-based rate programs:** Project partner Cleveland Electric Illuminating Company (CEI) offered peak-time rebates and opt-in critical peak pricing in conjunction with the AMI deployment. Peak-time rebates offer a financial incentive for electricity customers to lower their peak demand, while critical peak pricing provides a higher on-peak price signal to induce demand reductions. Both options involve day-ahead notifications of higher on-peak prices/rebate opportunities.
- **Advanced electricity service options:** CEI customers participating in the consumer behavior study were provided with in-home displays, programmable communicating thermostats, and direct load-control devices (see Consumer Behavior Study below). These technologies facilitate two-way information exchange and enable customers to better manage their electricity use and bills.
- **Direct load-control devices:** FirstEnergy installed almost 38,000 units and supporting communications infrastructure throughout Jersey Central Power & Light Company's (JCP&L) and Metropolitan Edison Company's (Met-Ed) service territories, allowing the utilities to control air conditioner settings remotely. Participating customers received financial incentives in exchange for allowing the utility to raise thermostat set points by either six degrees or nine degrees.

Consumer Behavior Study

This study involves more than 34,000 CEI customers. Various rate and enabling technology combinations were tested to assess load impacts and customer acceptance in a randomized control design with treatment and control groups. Rate programs were two opt-out peak-time rebate options and an opt-in critical peak pricing option. FirstEnergy deployed enabling technologies to support the study: power switches, in-home displays, and programmable thermostats (either utility-controlled or customer-controlled, depending on customer preference). Customer energy usage information is available through a Web portal. Notification methods included email, phone, and text messaging. Deployment for the study is complete, but the project is still conducting results analysis.

Benefits Realized

- **Improved distribution system reliability:** The distribution automation capabilities include remote restoration, which reduces the number of customer minutes interrupted. The interaction between the energy management system (EMS), automated reclosers, and grid sensors enables the EMS to model grid status and evaluate potential power restoration options. The EMS can automatically select and execute the optimal restoration plan to improve distribution system reliability and decrease outage duration.

- **Improved power quality:** The distribution management system coordinates the operation of automated capacitor banks and voltage regulators to optimize power quality and to reduce energy losses in the distribution system.
- **Lowered peak demand:** Pennsylvania and New Jersey have lowered peak time power usage with direct load-control devices adopted by their customer through their voluntary integrated distributed energy resource (IDER)/direct load-control program. During forecasted peak demand times, the load-control devices cycle appliances that are heavy energy users, such as air conditioners.
- **Increased customer engagement:** Direct load-control and a pilot time-based rate program provided service options to customers, providing information they could use to assess their energy usage and associated costs.

Lessons Learned

Through the grant-funded deployment, FirstEnergy identified many best practices and opportunities for improved implementation experience in the future. Examples include:

- Test alternative baseline calculations.
- Employ a smoothing strategy to reduce snapback on company-controlled devices.
- Test network communications design rigorously before equipment installation.
- Collaborate with vendors to modify design and operations.
- Be prepared for integration of real-time solutions (e.g., integrating DA and volt/VAR control systems onto the existing EMS system), as this effort is often more complex than initially anticipated.

Future Plans

FirstEnergy will continue its smart grid efforts through the following:

- Substantiate operating impacts, including maintenance cost reductions, improved reliability, and reduced carbon emissions.
- Complete analysis of pilot network communications technologies (DA, VVO, AMI, and IDER), and assess them for potential cross-cutting applications.
- Evaluate scalability of all tested smart grid technologies to larger customer populations.
- Rank order capital projects to modernize the utility distribution system.
- Continue assessing cybersecurity risks and developing suitable mitigation plans in accordance with industry standards.

Florida Power & Light Company

Energy Smart Florida

Scope of Work

The Florida Power & Light (FPL) project is deploying advanced metering infrastructure (AMI), distribution automation, new electricity pricing programs, and advanced monitoring equipment for the transmission system. AMI supports two-way communication between FPL and its 3 million consumers receiving smart meters associated with the DOE grant, providing detailed information about electricity usage and the ability to implement new electricity pricing programs. New distribution automation devices expand the functionality of FPL's distribution system to increase reliability, reduce energy losses, and reduce operations and maintenance costs. Synchrophasor and line monitoring devices help increase the reliability and security of the transmission system.

Smart Grid Features

- **Communications infrastructure:** Includes a 900 MHz wireless mesh network for two-way communication between smart meters and access points on the grid. Various public and private communication networks are used between access points and FPL's advanced metering infrastructure head-end systems. Distribution automation devices use the same communication networks as AMI. FPL's smart meters include 2.4 GHz radios which support ZigBee-based communications with future in-home energy management devices.
- **Advanced metering infrastructure:** Includes 3 million smart meters provided for FPL's customers. AMI supports automated meter reading, enhanced outage response and notification, and improved theft-of-service detection. With more detailed and timely data on peak electricity usage, FPL can improve its load research, analysis, and forecasting capabilities, enabling the utility to more accurately plan possible capacity expansion and capital investments in the future.

At-A-Glance

Recipient: Florida Power & Light Company
 State: Florida
 NERC Region: Reliability Coordinating Council
 Total Budget: \$578,963,325
 Federal Share: \$200,000,000

Project Type

Advanced Metering Infrastructure
 Customer Systems
 Electric Distribution Systems
 Electric Transmission Systems

Equipment Installed

- 3 Million Smart Meters
- 250 Home Area Networks
- 250 In-Home Displays
- Distribution Automation Equipment for 129 of 3,124 Circuits
 - Automated Distribution Circuit Switches
 - Automated Capacitors
 - Automated Voltage Regulators
- Equipment Condition Monitors
- 45 Phasor Measurement Units
- 60 Distributed Energy Resources Interface
- Transmission Line Monitoring System

Time-Based Rate Programs

- Critical Peak Pricing

Advanced Transmission Applications

- Angle and Frequency Monitoring
- Post-Mortem Analysis
- Wide-Area Monitoring
- Voltage Stability Monitoring
- Improved State Estimation
- Event Detection
- Disturbance Analysis

Key Targeted Benefits

- Reduced Electricity Costs for Customers
- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs
- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Equipment Failures and Theft
- Reduced Greenhouse Gas Emissions
- Reduced Truck Fleet Fuel Usage

- **Advanced electricity service options:** Include FPL's In—Home Technology Pilot, which tests emerging in-home technologies in the homes of 500 volunteer customers and assesses whether a proposed new critical peak pricing incentive (subject to approval by the Florida Public Service Commission) is effective in helping customers change their energy habits. The free, voluntary pilot includes 250 in-home displays and 250 home area networks, which include home energy controllers. One segment of home area network participants (10 customers) also receive smart appliances, including washers, dryers, dishwashers, hot water heaters, and refrigerators.
- **Time-based rate programs:** Include a pilot implementation of critical peak pricing.
- **Distribution automation systems:** Include the installation of 230 automated feeder switches, capacitor automation equipment, voltage regulator automation equipment, and transformer condition sensors. These improvements enhance distribution system reliability, reduce outage restoration time, improve circuit voltage regulation, and improve the operational efficiency of the distribution system.
- **A wide-area monitoring system:** Using synchrophasor technologies provides FPL with improved real-time information on the operation and reliability of the transmission system. This delivers greater visibility into system performance and accelerates system restoration.

Timeline

Key Milestones	Target Dates
AMI infrastructure installation begins	Q3 2009
Distribution intelligence installation begins	Q2 2010
Transmission intelligence installation begins	Q2 2010
Enterprise-wide predictive and diagnostic centers upgrade begins	Q1 2011
Enterprise-wide predictive and diagnostic centers upgrade complete	Q1 2012
Distribution intelligence installation complete	Q1 2012
AMI infrastructure installation complete	Q1 2012
Transmission intelligence installation complete	Q2 2012
In-home technology pilot complete	Q4 2012

Iowa Association of Municipal Utilities

Smart Grid Thermostat Project



Scope of Work

The Iowa Association of Municipal Utilities (IAMU) Smart Grid Thermostat project involves the deployment of advanced metering and customer systems for eight participating municipal utilities. The project aims to reduce peak demands and utility operating costs. The project deploys about 5,450 smart meters, 5,400 programmable communicating thermostats, and direct load-control devices to: (1) allow customers to view and control their energy consumption at their convenience through a Web portal and (2) allow the participating utilities to manage, measure, and verify targeted demand reductions during peak periods.

Smart Grid Features

- **Communications infrastructure:** Includes an advanced network system for smart meter communications and future integration with other smart grid technologies. The communications systems are being selected by IAMU and participating utilities in a competitive solicitation. These communication systems provide participating utilities with two-way information feedback capabilities to collect data from, and send signals to, smart meters in the project. A separate wireless network supports communications between the utilities and direct load-control devices and programmable communicating thermostats.
- **Advanced metering infrastructure:** Includes deploying smart meters to about 5,400 residential, commercial, and industrial customers. These meters provide capabilities for a variety of current and future customer electricity price and service options. Operational cost savings come from the automation of meter reading and customer service tasks.
- **Direct load-control devices:** Deployed by the project include approximately 200 direct-load control switches and approximately 5,200 programmable communicating thermostats. These devices provide direct load-control options for utilities and customers to reduce electricity consumption of heating and cooling equipment during periods of peak demand. The load-control activities enable the participating utilities to better manage peak loads, lower wholesale power costs, and reduce the need for peak generation units.

At-A-Glance

Recipient: Iowa Association of Municipal Utilities

State: Iowa and Kansas

NERC Region: Midwest Reliability Organization

Total Budget: \$12,531,203

Federal Share: \$5,000,000

Key Partners: Algona Municipal Utilities, Atlantic Municipal Utilities, Cedar Falls Utilities, Rockford Municipal Utilities, West Point Municipal Utilities, Kansas City Board of Public Utilities, Maquoketa Municipal Utilities, and Breda Municipal Electric System

Project Type

Advanced Metering Infrastructure
Customer Systems

Equipment

- Approx. 5,450 Smart Meters
- AMI Communication Systems
 - Meter Communications Network
 - Backhaul Communications
- Customer Systems for Approx. 5,400 Customers
 - Customer Web Portal
 - Approx. 200 Direct Load Control Devices
 - Approx. 5,200 Programmable

Key Targeted Benefits

- Reduced Truck Fleet Fuel Usage
- Reduced Greenhouse Gas and Criteria Pollutant Emissions

- **Advanced electricity service options:** Offered through the project include a customer Web portal that enables the customers to better manage their electricity use through remote control and setting of programmable communicating thermostats.

Timeline

Key Milestones	Target Dates
AMI deployment begins	Q4 2010
Customer systems deployment begins	Q4 2010
AMI deployment complete	Q4 2013
Customer systems deployment complete	Q4 2013



Kansas City Power & Light

Green Impact Zone SmartGrid Demonstration

Scope of Work

Kansas City Power & Light (KCP&L) and its partners are demonstrating an end-to-end SmartGrid—built around a major SmartSubstation with a local distributed control system based on IEC 61850 protocols and control processors—that includes advanced generation, distribution, and customer technologies. Co-located renewable energy sources, such as solar and other parallel generation, will be placed in the demonstration area and will feed into the energy grid. The demonstration area consists of 10 circuits served by one substation across two square miles with 14,000 commercial and residential customers. Part of the demonstration area contains the Green Impact Zone, 150 inner-city blocks that suffer from high levels of unemployment, poverty, and crime. Efforts in the Green Impact Zone will focus on training residents to implement weatherization and energy efficiency programs to reduce utility bills, conserve energy, and create jobs. KCP&L's SmartGrid program will provide area businesses and residents with enhanced reliability and efficiency through real-time information about electricity supply and demand. It will enable customers to manage their electricity use and save money.

Goals/Objectives

- Implement and demonstrate a next-generation, end-to-end SmartGrid.
- Demonstrate, measure, and report on the costs, benefits, and business model feasibility of the demonstrated technologies.
- Identify issues and gaps in technological standards.

Key Milestones

- 14,000 smart meters deployed (June 2011)
- Smart end-use implementation (June 2012)
- Complete smart distribution DMS and smart substation implementation (September 2012)
- Test to demonstrate integrated system operational (July 2013)
- Deploy smart generation, & smart DR management system (July 2014)

Benefits

- Energy efficiency improved
- Energy costs reduced
- Power reliability increased
- Greenhouse gases reduced
- Energy security strengthened.

At-A-Glance

State: Missouri

Total Project Value: \$49,830,280

DOE/Non-DOE Share:
\$23,940,112/\$25,890,168

Equipment Installed

- KCP&L Corporate LAN & Fiber WAN
- DataRaker Meter Data Analysis SW License
- Midtown Substation 12kv Equipment
- Distribution Grid 12kv Poles, Wires, and Equipment

Partners

- Siemens Energy Inc.
- Open Access Technology International Inc.
- eMeter Corporation
- Exergonix Inc.
- Intergraph Corporation
- Landis+Gyr
- Tendril

National Rural Electric Cooperative Association

Enhanced Demand and Distribution Management Regional Demonstration

Scope of Work

National Rural Electric Cooperative Association (NRECA) is demonstrating smart grid technologies with 27 cooperatives in 11 states across multiple utilities, geographies, climates, and applications including low-density areas, low-consumer-income areas, and service areas prone to natural disasters. NRECA will conduct studies in advanced volt/volt-ampere reactive for total demand; generation and transmission-wide (G&T) demand response over advanced metering infrastructure (AMI); critical peak pricing over AMI; water heater and air conditioning load control over AMI; advanced water heater control and thermal storage; consumer Internet energy usage portal pilots; consumer in-home energy display pilots; time-sensitive rates pilots; multiple AMI integration at G&T co-ops; distribution co-op meter data management system applications; and self-healing feeders for improved reliability. Installations will be implemented in four successive tranches, each of four months' duration. A study will be conducted at the conclusion of each tranche to improve the study plan, alter the type of data collected if necessary, and to assess the type of equipment installed and its configuration. This information will be shared across the co-op community.

Objectives

- Installation of 131,720 smart meter modules; 18,480 demand response switches; 3,958 in-home displays/smart thermostats; 2,825 ZigBee gateways; 169 volt sensors; and 247 fault detectors
- \$641,000 annual savings using two-way AMI
- \$400,000 annual savings implementing conservation voltage reduction.

At-A-Glance

States: Alaska, Colorado, Georgia, Hawaii, Illinois, Iowa, Kentucky, Louisiana, Minnesota, New York, North Carolina, and Wisconsin

NERC Region: Western Electricity Coordinating Council

Total Project Value: \$67,864,292

DOE/Non-DOE Share:
\$33,932,146/\$33,932,146

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment Installed

- Smart Meters
- Distribution Fault Locators
- Distribution Capacitor Banks with Controllers
- Enterprise SCADA Hardware

Partners

- SAIC
- Power System Engineering Inc.
- Cigital Inc.
- Silver Spring Networks, Inc.

Key Milestones

- Design and engineering plan completed (September 2010)
- Cybersecurity plan completed (December 2010)
- Study data systems design completed (January 2011)
- Asset tracking system online (March 2011)
- MultiSpeak interfaces completed (December 2011)
- Multi-tenant MDM study completed (October 2013)
- Advanced volt/var study completed (October 2013)
- Final technical project report (August 2014).

Benefits

- Electricity costs reduced
- Power quality improved
- Greenhouse gases reduced 1.5%–2%
- System reliability improved 5%–7%
- Energy security strengthened.



Pecan Street Inc.

Energy Internet Demonstration

Scope of Work

Pecan Street Inc. is developing and implementing an Energy Internet at the 711-acre Robert Mueller mixed-use development in Austin, Texas. Smart grid systems that form the foundation of this project include home energy monitoring systems, a smart meter research network, energy management gateways, distributed generation, electric vehicles with Level 2 charge systems, and smart thermostats. These technologies will be integrated into a smart grid that links 1,000 residences (including 250 newer, green-built homes, 250 homes at least 10 years old that were not green-built, and 140 apartments), 25 small commercial properties, and three public schools. More than 200 of the residential participants will acquire rooftop solar photovoltaics (PV) and 75 homes will acquire electric vehicles with Level 2 charging systems through this research trial. The project will also integrate 50 residences with smart water and smart gas meters. Through the use of Pecan Street's home energy monitoring systems, customers can view their energy use in real-time at the device level, set and track utility bill budgets, have software manage electricity use of individual appliances, and sell energy back to the grid; cars connected to the grid can be powered with solar energy and help level loads; and utilities can store power and deliver it when needed. The project team will also develop and test advanced data acquisition and management structures that will transform big energy data into useful information within a secure environment.

Objectives

- Move toward an efficient, zero net carbon community while creating green collar jobs, cost effectively expanding the use of clean energy, and providing customers with greater control over their electric usage and environmental impact while saving money.
- Create plug-and-play open deployment platforms for new technologies and electricity services.
- Promote replicability and scalability.
- Lower peak demand, transmission and distribution costs, capital expenditures, power interruption costs and energy costs.

At-A-Glance

State: Texas

Total Project Value: \$24,657,078

DOE/Non-DOE Share:
\$10,403,570/\$14,253,508

Equipment Installed

- Energy Monitoring Systems
- Smart Thermostats
- Smart Water Meters
- Smart Meters
- Smart Appliances
- Batteries
- Electric Vehicles
- Level 2 Electric Vehicle Charging Stations
- Solar Panels

Partners

- University of Texas at Austin
- Austin Technology Incubator
- Austin Energy
- City of Austin
- National Renewable Energy Laboratory
- Environmental Defense Fund

- **Key Milestones**

- Deploy utility-side systems (March 2012).
- Deploy customer-side smart grid systems and technologies (September 2012).
- Deploy electric vehicles in volunteer participant homes (September 2012).
- Open pike powers commercialization lab (June 2013).

Benefits

- Lower utility bills.
- Reduce greenhouse gases.
- Improve power quality and reliability.
- Increase power supply efficiency.



PECO

Smart Future Greater Philadelphia

Scope of Work

PECO's Smart Future Greater Philadelphia project includes deployment of advanced metering infrastructure (AMI) and distribution automation assets. AMI supports new electricity pricing programs for customers and pilot programs, such as in-home devices that provide energy information and energy usage control. Distribution automation (DA) helps PECO improve service to customers and reduce energy loss by managing circuit voltages. These systems help PECO improve operational efficiency and service quality for customers.

Smart Grid Features

- **Communications infrastructure:** Is multi-tiered and includes a high-bandwidth fiber optics and microwave "core" network for Tier 1; a medium-bandwidth radio frequency "backhaul" for Tier 2; a low-bandwidth radio frequency "field area network" for Tier 3; and supports home area networks for Tier 4. The project includes installing 368 miles of fiber optic cable connecting 71 substations for the Tier 1 core network and providing new digital communications for existing system telemetry, voice, and protection applications; the Tier 2 wireless backhaul network connecting Tier 3 to Tier 1; and a Tier 3 network providing systemwide communications for AMI and DA. The new communications infrastructure supports more flexible and reliable operation of the distribution system while providing PECO the ability to add future programs and functionality for its customers.
- **Advanced pricing programs:** Will educate customers about dynamic pricing and encourage them to take action during times of high energy prices. A dynamic pricing pilot will offer time-of-use rates to a limited number of residential and commercial accounts. PECO's plan has been developed involving input from stakeholders and the Pennsylvania Public Utility Commission (PaPUC). PECO also plans to conduct pilot demonstrations with a limited number of low-income (Customer Assistance Programs, or CAP) customers provided with smart meters and in-home displays. The pilot is designed to help CAP customers understand how much energy they use and how their usage compares

At-A-Glance

Recipient: PECO
State: Pennsylvania
NERC Region: ReliabilityFirst Corporation
Total Budget: \$415,119,000
Federal Share: \$200,000,000

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment

- More than 600,000 Smart Meters
- AMI Communication Systems
- Web Portal Access
- Distribution System Automation/Upgrades
 - Distribution Management System/SCADA
 - Intelligent Substation Upgrades
 - Feeder Monitors/Indicators
 - Automated Feeder Switches
 - Capacitor Automation Equipment

Dynamic Pricing Programs

- Time-of-Use (pilot program offered to 120k residential, 10k commercial accounts)
- In-Home Displays (pilot, 200 accounts)
- Customer Education and Communication

Targeted Benefits

- Improved Electric Service Reliability and Power Quality
- Reduced Truck Fleet Fuel Usage
- Reduced Greenhouse Gas and Criteria Pollutant Emissions

to their CAP rate monthly allowance. This information and the accompanying educational material will be designed to help these customers more effectively manage their energy consumption. On February 22, 2013, PECO filed with the PaPUC an updated Petition and revised Dynamic Pricing Plan consistent with the PaPUC Motion of September 13, 2012. The PaPUC approved the filing on May 9, 2013.

- **Distribution automation systems:** Include 100 new reclosers and communications upgrades for more than 300 existing reclosers. These devices will help reduce sustained outages and restoration times and improve operational efficiency. Systems also include intelligent substation upgrades with disturbance monitoring capabilities.
- **Distribution system energy efficiency improvements:** Include an integrated volt/var application with automated capacitor banks installed at two substations, enabling improved voltage and reactive power control on 55 distribution circuits to improve voltage regulation and reduce energy losses. A distribution management system involves integration with the other distribution automation assets to enable PECO to manage power distribution to better match customer demand.

Timeline

Key Milestones	Target Dates
Distribution asset deployment begins	Q3 2011
AMI asset deployment begins	Q2 2012
AMI asset deployment ends	Q4 2013
Distribution asset deployment ends	Q2 2014
DMS implementation ends	Q2 2014

Pepco - District of Columbia

Smart Grid Project

Scope of Work

The Pepco – District of Columbia Smart Grid project in Washington, D.C., includes distribution automation, advanced metering infrastructure (AMI), and demand response programs that involve load-control devices and time-based rate programs. The AMI installation is designed to provide customers and Pepco with detailed electricity usage information, which, when combined with the demand response programs, helps customers reduce electricity usage and peak demand. The distribution automation deployment includes substation smart devices, automated distribution circuit reclosers/switches, network and substation transformer monitors that improve the reliability of the distribution system while decreasing operations and maintenance costs.

Smart Grid Features

- **Communications infrastructure:** Involves components of the wireless AMI mesh network. The system has the capability to route traffic through the AMI meters, and Pepco is designing the system to route distribution automation traffic through battery-backed wireless communications devices. This approach ensures that distribution automation traffic remains on energized communications devices during power outages. The system uses the same backhaul communications systems to transport AMI and distribution automation data to the appropriate end points.
- **Advanced metering infrastructure:** Includes the installation of 270,000 smart meters across Pepco’s entire Washington, D.C. service territory. These meters can be used by Pepco to detect power outages and provide notification. AMI supports demand response, load-control, and time-based rate programs, and reduces the cost of meter operations.
- **Advanced electricity service options (offered through the project):** Include a Web portal for electric customers to access their consumption data and programmable communicating thermostats. The Web portal allows customers to view the data collected from their smart meters,

At-A-Glance

Recipient: Pepco Holdings, Inc.
 State: Washington, D.C.
 NERC Region: ReliabilityFirst Corporation
 Total Budget: \$92,753,369
 Federal Share: \$44,580,549

Project Type

Integrated and/or Cross-cutting Systems

Equipment Installed

- 270,000 Smart Meters
- AMI Communication Systems
 - Meter Communications Network
 - Backhaul Communications
- Meter Data Management System
- Customer Web Portal
- 25,250 Air Conditioner Direct Load-Control Devices
 - Programmable Communicating Thermostats
 - Outdoor Cycling Switches
- Distribution Automation Equipment for 19 out of 779 Circuits
 - Distribution Automation Communications Network
 - Control of 76 Automated Distribution Circuit Reclosers/ Switches
 - 41 Network Transformer Monitors
 - 14 Transformer Health Sensors/ Monitors
 - Upgrading 9 Substations with Smart Devices

Time-Based Rate Programs

- Peak-Time Rebate

Key Targeted Benefits

- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Equipment Failures and Theft
- Reduced Greenhouse Gas and Criteria Pollutant Emissions
- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs

giving them information on the amount and timing of their electricity usage, and the costs. The Web portal also provides the platform for customers to view and control the programmable communicating thermostats.

- **Direct load control devices (deployed by the project):** Allow Pepco to cycle off and on air conditioner control equipment during peak demand periods and system emergencies in the summer months. In addition to helping Pepco manage overall system demand, the 25,250 load-control devices also help customers manage their electricity costs.
- **Time-based rate programs:** Include customer options to enroll in time-of-use programs. The time-based rate program is aimed at encouraging participating customers to shift their consumption from on- to off-peak periods, thus reducing peak demand and lowering Pepco’s operating costs.
- **Distribution automation systems:** Include new automated feeder reclosers/switches and associated controllers, electronic substation relays, substation Distributed Remote Terminal Units (DRTU), and Automatic Sectionalizing and Restoration (ASR) programs. These devices work together to detect and isolate faults more precisely and reduce the number of customers affected by the power outage. Distribution automation includes installation of network transformer protector monitors, which provide real-time transformer status information such as phase currents, transformer loadings, and power factors. The project also includes installation of online dissolved gas analysis monitors on substation transformers. These devices monitor fault gases and other key parameters for timely assessments of transformer conditions. Together, these distribution automation technologies help improve reliability and operational efficiency.

Timeline

Key Milestones	Target Dates
AMI installation start	Q3 2010
Distribution automation installation start	Q2 2010
Direct load-control devices installation start	Q2 2012
AMI installation complete	Q1 2013
Distribution automation installation complete	Q4 2013
Direct load-control devices installation complete	Q4 2013

Public Service Company of New Mexico

PV Plus Battery for Simultaneous Voltage Smoothing and Peak Shifting

Scope of Work

Public Service Company of New Mexico and its partners co-located a 500kW/1MWh advanced lead acid battery with a separately installed 500kW solar photovoltaic (PV) plant to create a dispatchable distributed generation resource. This hybrid resource provides simultaneous voltage smoothing and peak shifting through advanced control algorithms and switches between two configurations, end-of-feeder and beginning-of-feeder. Data collection and analysis produce information for a wide range of applications including grid upgrade deferral. The project has also yielded modeling tools used to optimize battery system control algorithms and further the understanding of feeders with storage and distributed generation. The site is located in southeast Albuquerque.

Objectives

- Demonstrate that intermittent, renewables-based, distributed generation and storage can mitigate voltage-level fluctuations and enable peak shifting.
- Quantify and refine performance requirements, operating practices, and costs associated with the use of advanced storage technologies.
- Achieve 15 percent or greater peak-load reduction through a combination of substation-sited PV and storage.

Key Milestones

- Battery manufacture completed (May 2011)
- Finalize system control strategy and algorithms (May 2011)
- PV and battery system installed and field commissioned (August 2011)
- Demonstration and final report complete (February 2014).

Benefits

- Job creation
- Electricity costs reduced
- Grid efficiency increased
- Energy security strengthened
- Next-generation utility system advancement
- Greenhouse gas emissions reduced.

At-A-Glance

State: New Mexico

Total Project Value: \$6,113,433

DOE/Non-DOE Share:
\$2,305,931/\$3,807,502

Equipment

- Advanced Lead Acid and Ultra Batteries from East Penn Manufacturing
- S&C SMS Power Control System
- Advanced Data Acquisition System

Partners

- University of New Mexico
- Northern New Mexico College
- Sandia National Laboratories
- East Penn Manufacturing Company
- Electric Power Research Institute

Salt River Project

Advanced Data Acquisition and Management Program

Scope of Work

Salt River Project's (SRP's) Advanced Data Acquisition and Management Program involved deployment of an advanced metering infrastructure (AMI) system, a meter data management system (MDMS), and an energy management web portal for customers. The new two-way communication system relays customer electricity data to the utility, where upgraded software platforms analyze and process the data for billing and other back office systems. SRP also expanded the existing time-of-use rates to include AMI interval data for a time-of-day rate, empowering customers to help reduce peak demand on the system. Integration of the AMI and MDMS infrastructure with SRP's customer information system (CIS) has enabled full end-to-end system automation for core metering functions such as remote connect/disconnect.

Objectives

The AMI system reduces the need for manual meter reading and allows for remote diagnostics and troubleshooting of meter maintenance issues, reducing operating and maintenance costs and associated vehicle emissions. AMI also enables development of advanced electric services for customers, such as time-based rates and interval data presentment on the web portal. SRP can now monitor AMI transformer load data to measure system efficiencies and identify and isolate energy loss. In addition, AMI sub-metering is being monitored and evaluated to assess high desert temperatures' affects on customer air conditioning units and energy consumption. This information will support future SRP efforts to improve reliability and manage peak demand.

Deployed Smart Grid Technologies

- **Communications infrastructure:** IA two-way radio frequency (RF) mesh communications network was expanded across the entire SRP service territory, along with cellular backhaul, to support the AMI deployment.

At-A-Glance

Recipient: Salt River Project
State: Arizona
NERC Region: Western Electricity Coordinating Council
Total Budget: \$114,003,719
Federal Share: \$56,859,359

Project Type

Advanced Metering Infrastructure
Customer Systems

Equipment Installed

- 459,034 Smart Meters
- AMI Communication Systems
 - Meter Communications Network
 - Backhaul Communications
- Meter Data Management System
- Customer Web Portal

Time-Based Rate Programs

- Time-of-Use

Key Benefits

- Reduced Meter Reading Costs
- Reduced Operating and Maintenance Costs
- Reduced Truck Fleet Fuel Usage
- Reduced Greenhouse Gas and Criteria Pollutant Emissions

- **Advanced metering infrastructure:** SRP deployed nearly 459,000 AMI meters, a head-end system, and an MDMS. Using the new AMI system, SRP can improve distribution planning and operations, allow for development and deployment of time-based rate programs, and provide for improved outage management capabilities. SRP is also piloting smart meters on select transformers to assess transformer engineering and sizing methodologies and system loss allows customers to view their electricity consumption, trending data, conservation tips, and other information for more informed decision making.
- **Time-based rate programs:** Existing time-of-use rate programs were expanded for customers receiving new meters. The programs incentivize participating customers to shift their electricity usage from peak- to off-peak periods, reducing overall electricity costs, providing customers with greater control over their consumption and bills, and limiting the costs and emissions from adding peak generation capacity.

Benefits Realized

- **Reduced meter reading costs:** SRP is now able to remotely and reliably read over 450,000 meters using the AMI system, resulting in reduced meter reading costs for the utility.
- **Reduced operating and maintenance costs:** SRP has been able to remotely diagnose and troubleshoot a variety of meter maintenance issues that would have required field visits under the manual system.
- **Reduced truck fleet fuel usage:** Remote meter reading, troubleshooting, service connects, and service disconnects have all contributed to a reduced need for SRP to roll trucks. Additionally, operations personnel can remotely ping meters during outages to confirm service restoration rather than deploy field crews or call customers for verification.
- **Improved customer service options:** SRP can now offer its customers expanded time-based rates using interval data from the AMI system. Remote connect/disconnect enables faster response to customer requests for service. The new web portal offers customers better tools for home energy management and opportunities to lower their monthly bills.

Lessons Learned

- Change is difficult. New technology deployment that impacts all departments within the utility will create transformational opportunities and challenges; business rules and system principles will be questioned. Executive leadership, structured project management, and key stakeholder engagement are critical to project success.
- Vendors should play an active part in roadmap development. Build strong vendor relationships and attempt to align incentives for successful deployment.
- “Customer First” thinking is key to planning. Good customer communications results in a high rate of customer acceptance.
- Enterprise data and systems security must be considered early in the project timeline and fully integrated into system design and deployment efforts.
- New skill sets will be required and intellectual property developed. Piloting new technology early was of value in developing key AMI technology and data knowledge among SRP personnel.

- Realistic, achievable deployment goals should be developed in cooperation with the existing workforce, regardless of whether a utility chooses to outsource meter installations or keep the work in-house.
- Costs and logistics for the retirement of the old meters and meter reading system must be considered in project planning. This effort can be resource- and space-intensive.
- Smart grid technologies will continue to evolve, so flexibility should be built into the system where possible.

Future Plans

SRP plans to continue providing customers with reliable electricity at an affordable rate by using enabling technologies installed as part of the smart grid project. SRP aims to leverage the AMI system to transform how customers use energy and how it serves its customers through a much more interactive customer experience.

Timeline

Key Milestones	Target Dates
AMI installation start	Q3 2009
Communications infrastructure deployment start	Q2 2010
Communications infrastructure deployment completed	Q1 2013
Advanced meter infrastructure installation completed	Q2 2013

San Diego Gas & Electric Company

Advanced Data Acquisition and Management Program



Scope of Work

San Diego Gas & Electric's (SDG&E) Grid Communication System (SGCS) project includes the installation of an integrated wireless communication system.

The network covers targeted intelligent electronic devices on transmission and distribution poles and other electric assets. The project is making critical communications upgrades at substations and supporting telecom sites, expanding and optimizing the communications infrastructure to support smart grid initiatives while increasing system resiliency. The project aims to enhance reliability and reduce outage durations and operations and maintenance costs. SDG&E is implementing two-way communications and applications to (1) allow for the integration of new distribution automation (DA) equipment, (2) provide increased system visibility and identify the scope and location of outages, and (3) prepare for more intelligent end-point devices that support new forms of electric generation such as wind and solar.

SDG&E is implementing advanced high-speed wireless communications systems, optimizing and expanding SCADA, and increasing the communications fiber footprint that will allow the utility to remotely monitor, communicate with, and control transmission and distribution equipment. Additionally, the project will improve grid security, reduce operating costs, improve grid resilience, and support future smart grid technologies.

Smart Grid Features

- **Communications infrastructure:** Includes a unified wireless radio frequency (RF) network that leverages multiple technologies and backhaul equipment. Technologies and equipment were evaluated in a pilot study to allow the utility to select best-of-breed systems for full-scale deployment. Wireless backhaul solutions provide the backbone for energy management programs and allow for the integration of synchrophasor technologies, DA equipment, smart meters, smart appliances, and home area networks. This scalable infrastructure provides opportunities to add future service offerings and further optimize electricity delivery, system reliability, and customer participation.

At-A-Glance

Recipient: San Diego Gas & Electric Company

State: California

NERC Region: Western Electricity Coordinating Council

Total Budget: \$59,427,645

Federal Share: \$28,115,052

Project Type

Electric Distribution Systems

Equipment Installed

- Low-Power Wireless Communications Network
- SCADA Narrowband Internet Protocol (IP)-Based Network
- Expanded Substation Wide Area/Local Area Networks (WAN/LAN)
 - Microwave Technologies
 - FIBER JMUX Equipment
 - Substation Hardened Network Routers and Switches
- Field Broadband Device Connections
 - Unlicensed and "Lightly" Licensed Broadband Point-to-Point (PTP), Point-to-Multipoint (PTMP), and Mesh Wireless Radio Equipment
 - Distribution Automation Communications Network

Targeted Benefits

- Improved Electric Service Reliability and Power Quality
- Reduced Costs from Equipment Failures and Distribution Line Losses
- Reduced Troubleshooter Dispatch
- Reduced Service Costs for Customers
- Reduced Operating and Maintenance Costs

- **Low-power communications network (LPCN):** Involves deployment of a proprietary unlicensed 2.4 GHz wireless radio system that provides low-speed, low-power, wide area communications to enable remote monitoring of overhead and underground fault circuit indicators (FCIs), smart transformers, Federal Aviation Administration (FAA) tower obstruction lights, and other similar low-bandwidth assets.
- **Field broadband device connections (FBDCs):** At targeted locations, these support up to 80 advanced SCADA devices (high-speed SCADA devices with phasor measurement units enabled) and other high-speed intelligent electronic devices installed on 10 distribution circuits. This deployment creates a high-speed wireless radio infrastructure for future smart grid expansion.
- **SCADA optimization and enhancements:** Implementation of a narrowband internet protocol (IP)-based SCADA system to increase system capacity and enhance electric grid operations.
- **Substation communications (SubComm):** Involves expansion of SDG&E's wide area network (WAN) to connect additional substations via microwave and last-mile fiber.

Lessons Learned (to date)

- One overall technology solution may not address all communications needs for an organization. Unique service territory characteristics may require a combination of technologies for optimal network performance.
- Pilot testing with end-user devices may uncover the need for more targeted solutions.
- Utilities implementing similar projects should allow significant lead time to accommodate any zoning and permitting requirements for multiple site implementations.

Future Plans

SDG&E plans to use its newly implemented advanced wireless communications system to monitor, communicate with, and control transmission and distribution equipment. In addition, the utility will utilize and expand the new high-speed wireless communications system to support additional smart grid functionality such as microgrids, advanced battery storage, dynamic voltage controllers, falling conductor applications, high-risk fire mitigation, and photovoltaic penetration volatility.

Sacramento Municipal Utility District

SmartSacramento Project

Scope of Work

Sacramento Municipal Utility District's (SMUD) SmartSacramento Project involved systemwide deployment of advanced metering infrastructure (AMI) integrated with new and existing information technology systems, as well as deployment of distribution automation (DA) equipment on selected SMUD distribution circuits and substations. The project also involved customer programs and pilots that provide electricity usage and cost information to customers, enabling them to better control their energy usage and participate in demand response. Project scope included a field test of plug-in electric vehicle (PEV) charging stations to assess their technical performance, charging patterns, and impact on electric distribution system operations.

Objectives

The objectives of the project were to implement an AMI solution for all residential and commercial customers that would improve customer service; enable the introduction of new energy efficiency, demand response, and pricing programs; and provide tools for SMUD and its customers to reduce their environmental impact. In addition, the advanced technologies are expected to reduce operational costs. This project established a foundation on which to build future smart grid functionality.

Deployed Smart Grid Technologies

- **Communications infrastructure:** Wireless networks deployed throughout the SMUD territory provide two-way communication for smart meters, customer devices, and DA equipment. Software platforms for meter data management and analysis were installed to organize, analyze, and make AMI data accessible to other enterprise systems. These systems provide SMUD with expanded capabilities to leverage interval consumption and voltage data to improve distribution system operations and overall grid reliability.
- **Advanced metering infrastructure:** SMUD deployed more than 617,000 smart meters covering the entire service territory. This system

At-A-Glance

Recipient: Sacramento Municipal Utility District

State: California

NERC Region: Western Electricity Coordinating Council

Total Project Cost: \$307,697,792

Total Federal Share: \$127,506,261

Project Type

Advanced Metering Infrastructure
Customer Systems
Electric Distribution Systems

Equipment

- 617,000 Smart Meters
- AMI Communications Systems
 - AMI Meter Communications (RF Mesh)
 - AMI Backhaul Network (Cellular)
- Meter Data Management System
- Customer Web Portal
- Customer Systems for Nearly 10,000 Customers
 - Home Area Networks
 - In-Home Displays/Energy Management Systems
 - Programmable Communicating Thermostats
 - Direct Load-Control Devices
- Distribution Automation Equipment for 171 out of 644 Circuits*
 - Distribution Automation Communications Network (RF Mesh and Fiber)
 - SCADA Communications Network
 - Automated Distribution Circuit Switches
 - Automated Capacitors
- 80 Electric Vehicle Charging Stations
 - *128 are 12 kV, 18 are 21 kV, and 25 are 69 kV

Time-Based Rate Programs

- Time-of-use
- Critical Peak Pricing

Key Targeted Benefits

- Reduced Operating and Maintenance Costs
- Improved Electric Service Reliability
- Reduced Costs from Distribution Line Losses
- Reduced Truck Fleet Fuel Usage
- Improved Energy Management and Control Opportunities for Customers

enables automated meter reading, improved bill accuracy, remote service connect/disconnect capability, enhanced outage management, and improved theft detection. AMI data analytics improves load forecasting and capital investment planning.

- **Time-based rate programs:** SMUD has offered rate programs based on time-of-use (TOU), critical peak pricing (CPP), and TOU combined with CPP. Selected customers could opt into the new rate programs or choose to keep their existing rates. Additional customers were placed on the new rates but were able to opt out. The goal was to evaluate the relative merits of these programs in terms of load impacts, customer acceptance, and cost effectiveness. The aim was to provide customers with greater control over their electricity bills and reduce peak electrical loads.
- **Advanced electricity service options:** The project has provided enhanced web portal services and tools for customer information and energy management, control, and automation. SMUD installed nearly 10,000 residential and small commercial home area network (HAN) devices to provide customers with options to more conveniently manage their energy use. In addition, the project implemented advanced energy management control systems with automatic demand response (AutoDR) capability at customer facilities.
- **Direct load-control devices:** SMUD deployed programmable communicating thermostats and load-control switches that support load reduction or load shifting during periods of peak demand. Participating customers received financial incentives in return for allowing the utility to cycle major appliances and equipment during peak events. SMUD installed the software platform for a demand-response management system to provide more effective and centralized control of direct load-control operations and to enable two-way communication and feedback with customers.
- **Distribution automation systems:** SMUD deployed automated sectionalizing and restoration (ASR) equipment, reclosers, capacitor banks, and remote fault indicators integrated with the energy management system on 171 distribution circuits. This equipment automatically responds to power disruptions by isolating faulted sections of circuits and rerouting power to customers. SMUD has reduced the frequency and duration of outages and can more efficiently dispatch service restoration crews.
- **Distribution system energy efficiency improvement:** Efficiency is achieved through integrated voltage control from capacitor controllers and the energy management system. The capacitors improve volt/VAR control and power quality; distribution capacity is increased through reduced energy losses on the distribution system.
- **Plug-in electric and hybrid electric vehicle charging stations:** Stations that provide charging for PEVs and PHEVs have been deployed at 20 parking spaces on college campuses and 60 residences across the SMUD service territory. The charging stations include meters and monitoring equipment to evaluate performance and charging patterns and their impacts on the distribution system.

Benefits Realized

- **Reduced operating and maintenance costs:** SMUD's AMI system allowed SMUD to avoid approximately \$31,787,600 in meter operation costs from project initiation through March 31, 2014. The AMI system helped SMUD significantly reduce the need for manual meter operations, mainly through automated meter reading and automated service switching.

- **Reduced truck fleet fuel usage:** Thanks to the new automated systems, SMUD avoided an estimated 1.2 million vehicle miles from project initiation through March 31, 2013. SMUD previously used gasoline cars and light-duty trucks to read meters. Assuming 23.4 miles per gallon per vehicle, SMUD avoided consuming 51,000 gallons of gasoline.
- **Improved distribution system reliability:** The ASR system has helped SMUD reduce both the number of customers affected by outages and the duration of outages. SMUD estimates that if the ASR system had been implemented in 2007–2012, it would have reduced the impact of outage events by 37% in terms of customer-minutes interrupted (a measure of the total number of customers and the minutes they were without power), based on historical reliability performance of SMUD's distribution grid and the observed performance of the ASR system.

Lessons Learned

- Executive support is essential for successful project implementation. When implementing projects that require staffing and resources from multiple departments, executive support paves the way for cooperation between departments that may normally act in silos.
- Good communication with customers is critical to project success, especially with AMI implementations. Proactive customer communications, including the training of utility staff to make presentations and answer questions is important in the early stages of project development. As projects progress, it is important to develop tools that make it easy for customers to enroll in and exit programs and marketing materials that describe offerings and answer questions.
- Communicating with employees is important to obtain project buy-in and acquire the necessary inter-departmental support required to implement large-scale projects. Further, if employees will be displaced as a result of the project (meter readers), early communication and working to provide alternate opportunities is essential.
- Many technologies proved to be immature and some vendors overpromise and under deliver. Investigate new technologies to ensure they are ready for implementation. In a few cases, SMUD needed to close projects, for example, the controllable appliances initiative, when technologies did not provide the claimed benefits.
- Robust design and testing of the AMI network and meters is important. Testing should verify that meter reads are coming through, especially in difficult-to-read areas such as dense urban settings, where meter signals can be blocked by walls or other obstacles, and in rural areas, where meters are far apart. Verification of meter accuracy is also important for responding to customer inquiries about meter accuracy and for high bill complaints.

Future Plans

SMUD plans to continue developing its smart grid and will invest resources to implement projects that enhance customer service, improve grid reliability, and provide a reasonable return on investment. SMUD will continue to provide customers with reliable electricity at affordable rates through the implementation of additional smart grid projects that improve grid performance and provide better customer service.

Snohomish County PUD

Smart Grid Infrastructure Modernization of Electrical Distribution System

Scope of Work

Snohomish County Public Utility District, Washington, (Snohomish PUD) upgraded 42 of 85 substations with automated control capabilities to prepare the substations for full-scale deployment of distribution automation (DA) and integration of distributed energy resources. The project deployed DA upgrades to 10 targeted circuits in a 90-square-mile project area. These assets are being managed through a new distribution management system (DMS), which communicates through a wireless communication network installed in the project area. Information from the project area is then collected at the substation and transmitted back to Snohomish PUD's headquarters via the 163 miles of fiber optic cable that were also installed systemwide as part of the Smart Grid Investment Grant (SGIG) project.

Objectives

Snohomish PUD upgraded substations, deployed DA equipment, and installed supporting systems to reduce load and line losses on the system and improve service reliability for customers. The increased grid visibility realized through the addition of intelligent equipment (i.e., relays, line regulators, switches, and end-of-line meters) will support such reductions. The new DMS, DA equipment, and communications network allow the utility to monitor real-time sensor data and respond to changes in electricity demand and grid operating conditions. Snohomish PUD aims to reduce operations and maintenance costs over time and improve distribution system reliability.

Deployed Smart Grid Technologies

- **Communications infrastructure:** An expanded fiber optic network connects all Snohomish PUD substations to the energy control center supporting real-time data transfer and grid monitoring. The project also installed a dedicated wireless field area network to support the 10 circuits upgraded with DA equipment. This infrastructure supports future deployment and integration of new applications, such as an advanced metering infrastructure (AMI) and an outage management system (OMS).

At-A-Glance

Recipient: Snohomish County PUD
State: Washington
NERC Region: Western Electricity Coordinating Council
Total Project Cost: \$31,651,634
Total Federal Share: \$15,825,817

Project Type

Electric Distribution Systems

Equipment Installed

- Distribution Management System
- Distribution Automation Communications
- Network (wireless field area network)
- Fiber Optic Network Extension
- Distribution Automation Equipment for 10 of 356 Distribution Circuits
- Automated Switches/Reclosers
- Automated Regulators
- End-of-Line Voltage Meters with Telemetry
- Circuit Monitors/Fault Indicators
- 381 Intelligent Substation Relays

Key Benefits

- Reduced Operating and Maintenance Costs
- Increased Electric Service Reliability and Power
- Quality
- Reduced Distribution Loads and Line Losses

- **Distribution automation systems:** Snohomish PUD deployed automated switches, reclosers, and regulators on 10 high-priority circuits. These DA upgrades will enable a faster and more effective response to grid disturbances, reduce the frequency and duration of outages, and lower operations and maintenance costs. DA equipment has been integrated with a DMS that enables Snohomish PUD to improve safety, track abnormal operating conditions, and manage power distribution to better match customer demand. The DMS also enables more precise modeling and future integration of distributed generation resources such as solar, wind, and energy storage.
- **Substation automation:** The project upgraded electromechanical relays to digital relays at 42 substations. A total of 381 smart relays were installed throughout the Snohomish PUD territory. Communications infrastructure inside the substation was enhanced to capture and transmit valuable operational data. Part of the SGIG project was to extend the single fiber cable by 163 miles to all but one substation with redundancy provided by using protocol loop protection.

Benefits Realized

- **Reduced distribution load and line losses:** The automated voltage regulators work with DMS load/voltage management function to optimize the voltage profile over the length of the feeders. This optimization, in concert with existing capacitor banks, improves volt/var control and power quality, increasing distribution capacity by reducing load and energy losses on the distribution system.
- **Improved reliability:** The DA devices provide data for the fault isolation and service restoration (FISR) function of the DMS. Whether working in an advisory capacity or automatically, FISR can identify faulted line sections and either automatically restore power to unfaulted sections or direct operators and line personnel to the appropriate area for line isolation and repair. This improved response reduces the frequency and duration of outages as well as reducing crew and vehicle travel time.
- **Substation automation:** The installation of digital relays gives Snohomish PUD an opportunity to gain near-real-time insights as to what caused a disturbance at the substation level—or to predict what might cause one. By leveraging this new stream of data, Snohomish PUD will be able to provide a higher level of customer responsiveness and plan more accurately for system expansion and maintenance.

Lessons Learned

A fully functional end-to-end smart grid test lab was designed and installed under the SGIG project. Numerous work groups leverage the test lab to prove out and/or troubleshoot conceptual smart grid designs, applications, and equipment prior to deployment to the production environment. The test lab provides the foundation from which to make educated and informed decisions regarding future operational technology investments. Being able to see

how software systems from different vendors with diverse development backgrounds actually work together in the Snohomish PUD environment has proven to be an invaluable capability. Interoperability testing and validation is critical prior to deploying these new systems and equipment.

Future Plans

Snohomish PUD is committed to continuing an intentional and thoughtfully crafted smart grid technology deployment throughout the distribution system. The utility will carefully evaluate information received from the intelligent DA devices in the pilot area to determine the best approach to further deploy DA. The energy controllers, dispatchers, and planners can now access real-time operating information from the DMS and from DA devices via the field area network. This capability will give Snohomish PUD options never before realized at the distribution level. Eventually having this visibility out to the “fingertips” of the distribution system will allow the utility to integrate another layer of “smart” technologies, such as advanced metering infrastructure, while effectively managing distributed generation and other alternative or customer-owned power sources.



Southern California Edison Company

Irvine Smart Grid Demonstration

Scope of Work

Southern California Edison (SCE) is conducting an end-to-end demonstration of numerous Smart Grid technologies necessary to meet state and federal policy goals for the year 2020. The Irvine Smart Grid Demonstration (ISGD) project will investigate the use of phasor measurement technology to enable deep, substation-level situational awareness. The project will also evaluate the latest generation of distribution automation technologies, including looped 12 kV distribution circuit topology utilizing universal remote circuit interrupters. Advanced Volt/VAR Control capabilities will also be used to demonstrate customer energy consumption savings through conservation voltage reduction. The project scope includes customer homes, where the integration, monitoring, control, and efficacy of home area network devices such as energy management systems, smart appliances, energy storage, and photovoltaic systems will be demonstrated. 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 will also be assessed. DR events will use the protocol standards being adopted by Advanced Metering Infrastructure programs such as Edison SmartConnect. The project results will also demonstrate the next generation of Substation Automation (SA-3), an automation and control design based on the open standard IEC-61850. This is expected to provide measurable engineering, operations, and maintenance benefits through improved safety, security, and reliability.

Demonstration of a new auto-configuration application is intended to significantly reduce manual effort, errors, and omissions. SA-3 is designed to meet or exceed current generation North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) compliance requirements, and will demonstrate interoperability among multiple vendors and their existing equipment. ISGD's Secure Energy Network will enable end-to-end interoperability and provide the cybersecurity essential to Smart Grid development and adoption across the nation.

At-A-Glance

State: California
Total Project Value: \$79,242,416
DOE/Non-DOE Share:
\$39,621,208/\$39,621,208

Equipment

- Residential Energy Storage
- Community Energy Storage
- Solar Car Shade Battery System
- Universal Remote Circuit Interrupters
- Substation Automation and Cybersecurity Systems Infrastructure

Partners

- General Electric
- University of California, Irvine
- University of Southern California
- SunPower Corporation Electric
- Power Research Institute

Goals/Objectives

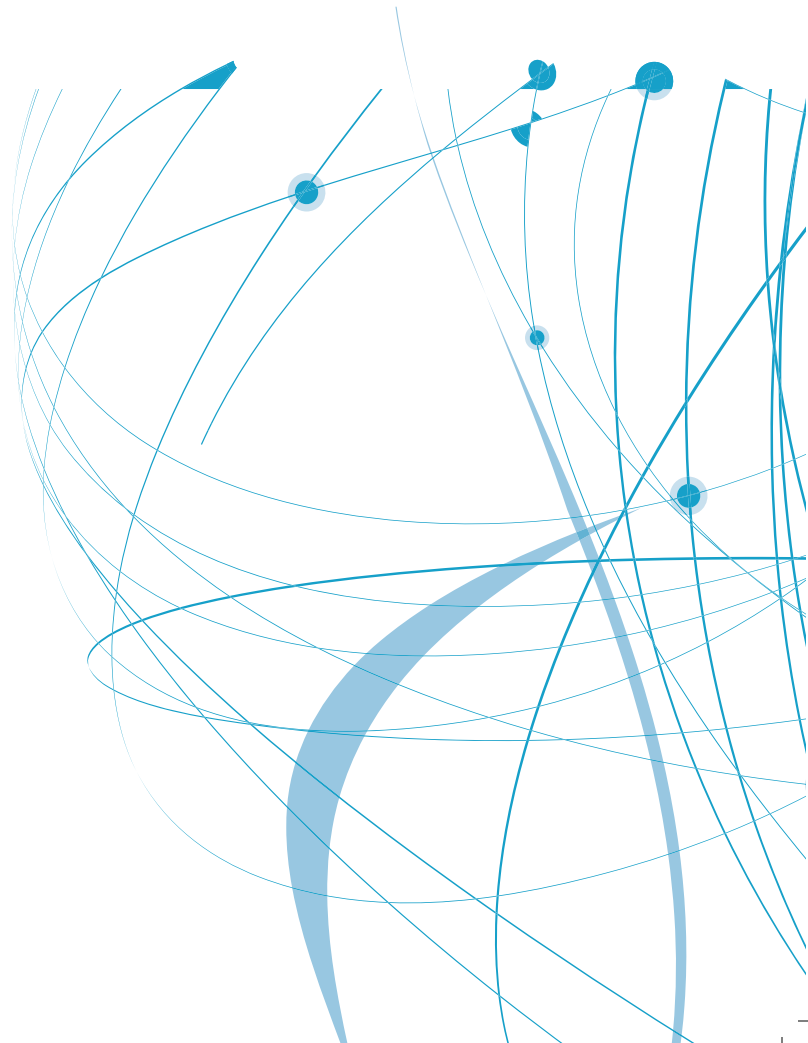
- Verify the viability of various Smart Grid technologies deployed in an integrated manner
- Quantify Smart Grid costs and benefits
- Test and validate the scalability of several Smart Grid elements
- Evaluate the ability of various Smart Grid technologies to help homes achieve Zero Net Energy status.

Key Milestones

- Completed engineering design and specifications (12/31/2012)
- Field deployment and installation complete (12/31/2013)
- Systems operations, measurement and verification complete (6/30/2015)
- Submit final technical report (12/31/2015)

Anticipated Benefits

- Advance energy independence through increased renewable energy usage.
- Reduce greenhouse gas emissions through energy efficiency, renewable energy resources, and plug-in electric vehicle integration.
- Promote open industry standards for interoperability and cybersecurity.
- Evaluate organizational capabilities needed for Smart Grid implementation.



Southern Company Services, Inc.

Smart Grid Project

Scope of Work

Southern Company Services' (Southern Company) Smart Grid Project involved integrated upgrades of the distribution, transmission, and grid management systems throughout the company's large service territory. Primary efforts included automation of significant sections of the distribution system and selected transmission lines, and installing smart monitors and relays in over 350 substations.

Objectives

The project included the deployment of new distribution technologies intended to improve the power factor at delivery and to support the ability to lower system voltage at peak load. This reduction in voltage and line losses, in turn, leads to peak load reduction, deferral of new generation capacity investments, and associated reductions in greenhouse gas emissions. New distribution and transmission automation equipment enhances system reliability through better protection from and faster responses to outages, while simultaneously lowering operations and maintenance costs. Equipment health monitors installed in substations will reduce maintenance expenses and reduce failures.

Deployed Smart Grid Technologies

- **Communications infrastructure:** The project installed new radio communications equipment and upgraded the outage management, distribution management, and supervisory control and data acquisition (SCADA) systems. A total of 141 radio towers were installed using the SCADA platform to enable real-time transmission and distribution monitoring capability for grid operators. These upgraded SCADA communications network and software platforms have enhanced grid operators' visibility into the state of the grid and their ability to react to outages and disturbances.

At-A-Glance

Recipient: Southern Company Services.

States: Alabama, Florida, Georgia, and Mississippi

NERC Region: SERC Reliability Corporation (SERC)

Total Project Cost: \$362,594,858

Total Federal Share: \$164,527,160

Project Type

Electric Distribution Systems
Electric Transmission Systems

Equipment

- Distribution Automation Equipment for 2,081 out of 4,706 Circuits
 - Distribution Management System
 - Equipment Condition Monitors
 - Automated Distribution Circuit Switches
 - Automated Capacitors
 - Automated Voltage Regulators
- Substation Automation Equipment for 359 out of 3,325 Substations
 - SCADA Communications Network
 - Smart Relays

Key Benefits

- Deferred Investment in Generation Capacity Expansion
- Improved Electric Service Reliability and Power Quality
- Reduced Operating and Maintenance Costs
- Reduced Costs from Equipment Failures and Distribution Line Losses
- Reduced Truck Fleet Fuel Usage

- **Distribution automation systems:** Of the utility's 4,706 circuits, 2,081 received new automation equipment, including automated feeder switches, regulator controls, monitors, relays, and remote fault indicators. This equipment collects and coordinates sensor data throughout the distribution grid to automatically manage power quality, avert power disturbances, and isolate outages quickly.
- **Distribution system energy efficiency improvements:** Automated capacitors and voltage regulators have been integrated with a capacitor health monitoring system. The capacitors improve volt/var control and power quality, as well as increase distribution capacity by reducing losses on the system.
- **Transmission system automation:** The project installed 545 automated switches along transmission lines as well as new monitors, relays, and breakers at 359 substations. This equipment allows Southern Company to better monitor the transmission network, react quickly to developing power disturbances, and isolate serious power outages before cascading effects occur.

Benefits Realized

- **Deferred investment in generation capacity expansion:** The Conservation Voltage Reduction (CVR) program has enabled the deferment of 400 MWs of generation. Additionally, losses have been reduced by a total of 2.65 MW, resulting in a savings of 16,735 MWh from project initiation to September 2014.
- **Improved electric service reliability and power quality:** The System Average Interruption Frequency and Duration Indices (SAIFI and SAIDI) on distribution circuits have improved by 33.7% and 35.1%, respectively, as compared to the baseline performance (the three-year average performance prior to SGIG project initiation).
- **Reduced operating and maintenance costs:** The utility has realized overall operating and maintenance savings of an estimated \$6,242,000.
- **Reduced truck fleet fuel usage:** Since project initiation, Southern Company has avoided an estimated total of 102,000 vehicle trips, resulting in 1,150,000 fewer miles driven. These reductions reduce associated operating costs and greenhouse gas emissions.

Lessons Learned

- Addition of distribution and transmission automation has resulted in improved reliability performance. Numerous instances have occurred where equipment installed through the project has resulted in avoided or reduced outage times.
- Capacitor monitoring has resulted in increased equipment reliability and real-time equipment failure notification. This is a much improved process over annual inspections.
- The use of centralized restoration gateways has provided for increased functionality of automatic restoration schemes over peer-to-peer systems.
- Distribution conservation voltage reduction programs have delivered results consistent with the theoretical results predicted in the project.

Future Plans

- Southern Company will continue to expand its smart grid program at the “speed of value”—the benefits to consumers of a new smart grid application should exceed the cost of integrating it into the grid.
- Southern Company will continue to evaluate the impact of project deliverables to determine future increased integration into the electrical grid. Southern Company will continue to implement more of the following initiatives:
 - Modernize the transmission system by upgrading, relaying, and adding digital fault recorders.
 - Expand the installation of automated line switches on transmission and distribution lines.
 - Expand automatic fault isolation and service restoration schemes on the distribution system.
- Southern Company plans to leverage data from smart devices and an existing (pre-SGIG project) advanced metering infrastructure to provide value to customers through data analytics initiatives.



Featured Reports

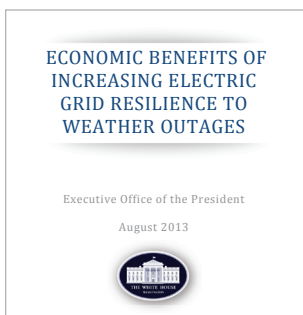
The U.S. Department of Energy has produced a variety of reports and other deliverables based on the information and data gained through the Recovery Act Smart Grid Programs. These reports include analysis, impacts, lessons learned, best practices, analytical tools, and case studies. The reports featured here and many more are available on SmartGrid.gov. The list does not include all reports that are available and more reports are expected in the future.

To download any of the publications featured here, go to www.smartgrid.gov/key-documents.



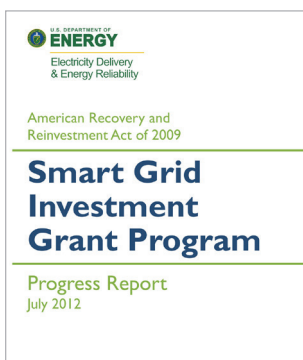
Smart Grid Investment Grant Progress Report – October 2013

This report contains information on expenditures, installations of technologies and systems, grid impacts, and lessons learned from the 99 SGIG projects as of March 31, 2013.



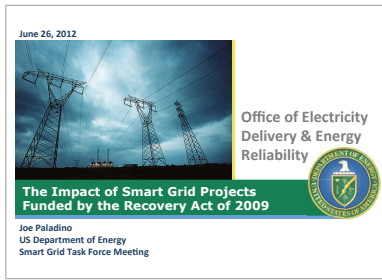
Economic Benefits of Increasing Electric Grid Resilience to Weather Outages – 2013

This report estimates the annual cost of power outages caused by severe weather between 2003 and 2012 and describes various strategies for modernizing the grid and increasing grid resilience. Over this period, weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of \$18 billion to \$33 billion.



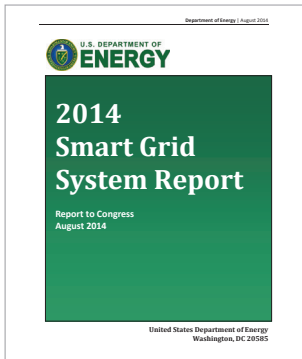
Smart Grid Investment Grant Progress Report – July 2012

The Smart Grid Investment Grant (SGIG) program is a \$3.4 billion initiative that seeks to accelerate the transformation of the nation's electric grid by deploying smart grid technologies and systems. This report provides a summary of the SGIG program's first 3 years of progress, initial accomplishments, and next steps.



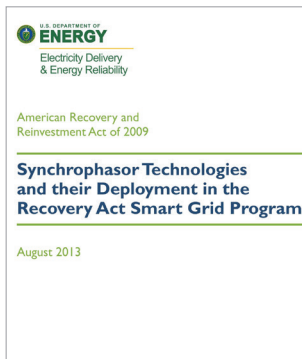
U.S. Department of Energy - The Impact of Smart Grid Projects Funded by the Recovery Act of 2009 – June 2012

A presentation that summarizes the Recovery Act Smart Grid Programs including the technologies deployed, the expected impact on the electric power industry, and information on DOE's methodologies for analyzing and categorizing the impacts of these projects.



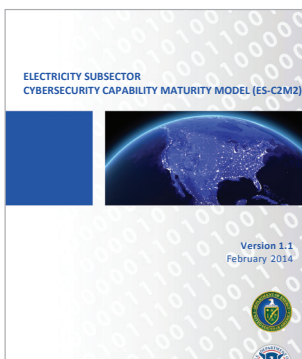
2014 Smart Grid System Report - August 2014

The Department of Energy has developed this biennial report to Congress in compliance with legislative language set forth in Section 1302 of the Energy Independence and Security Act of 2007. This report is designed to provide an update on the status of smart grid deployments nationwide, technological developments, and barriers that may affect the continued adoption of the technology.



Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs – August 2013

This report describes, for the non-specialist, synchrophasor technologies, systems, and related software applications, and the basic aspects of the Recovery Act-funded projects that are deploying synchrophasor technologies and systems. The report was prepared for DOE by Oak Ridge National Laboratory (ORNL).



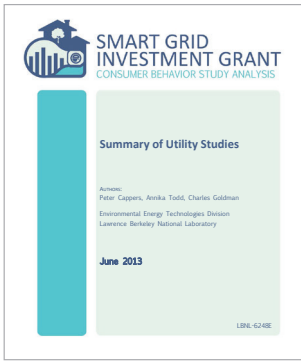
Electricity Subsector Cybersecurity Capability Maturity Model – May 2012

The Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) allows electric utilities and grid operators to assess their cybersecurity capabilities and prioritize their actions and investments to improve cybersecurity, and combines elements from existing cybersecurity efforts into a common tool that can be used consistently across the industry.



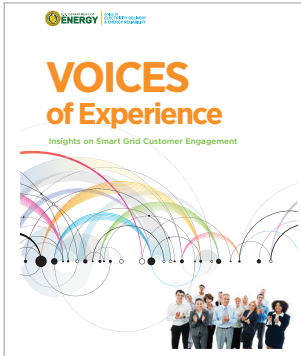
Quantifying the Impacts of Time-Based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines – July 2013

This report offers guidelines and protocols for measuring the effects of time-based rates, enabling technology, and various other treatments on customers' levels and patterns of electricity usage. Although the focus is on evaluating consumer behavior studies (CBS) that involve field trials and pilots, the methods can be extended to assessing the large-scale programs that may follow.



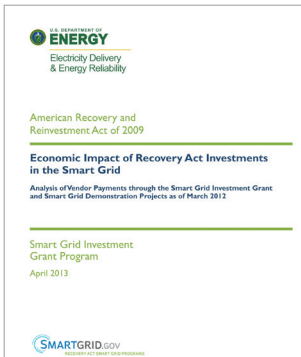
Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies – June 2013

This report provides a description of 10 utilities that undertook 11 experimentally designed Consumer Behavior Studies (CBS) under the SGIG program. The studies proposed to examine a wide range of topics of interest to the electric utility industry.



Voices of Experience|Insights on Smart Grid Customer Engagement – July 2013

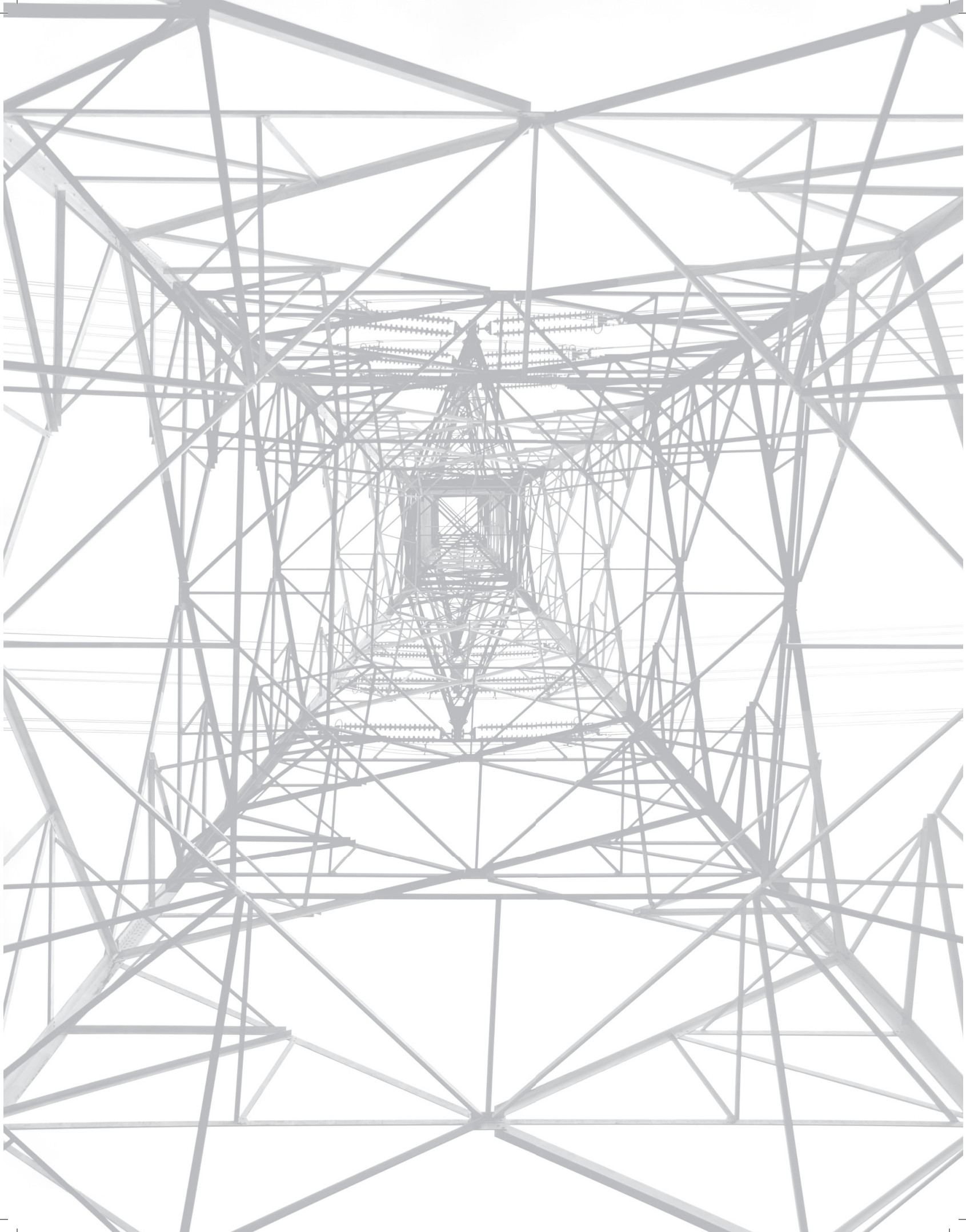
This document is the result of a nine-month effort to compile information on the successful approaches used by utilities to engage customers regarding smart grid technology deployments. Voices of Experience|Insights on Smart Grid Customer Engagement (the Guide) provides practical advice in the form of “industry insights” from utilities that have implemented smart grid projects to educate and engage their customers.



Economic Impact of Recovery Act Investments in the Smart Grid – April 2013

This study analyzes the economywide impacts of the American Recovery and Reinvestment Act of 2009 funding for smart grid project deployment in the United States. The time period of the investments analyzed cover expenditures from August 2009 to March 2012, which encompasses nearly 3 billion dollars in publicly documented expenditures.





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