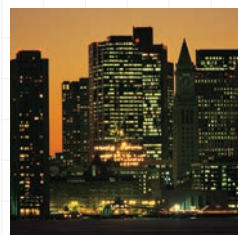
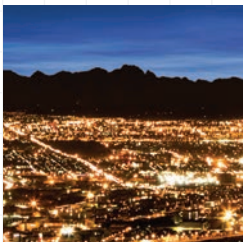
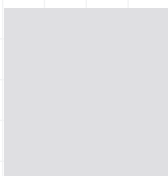


VOLUME II

INNOVATIONS ACROSS THE GRID

PARTNERSHIPS TRANSFORMING THE POWER SECTOR



The Edison Foundation

INSTITUTE for
ELECTRIC INNOVATION



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VOLUME II

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PARTNERSHIPS TRANSFORMING THE POWER SECTOR

December 2014

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The IEI Partner Roundtable is a select group of innovative technology companies dedicated to advancing smart technologies with electric utilities. The roundtable is a platform to share information, ideas, innovations, and results as utilities and technology companies work together.

“The process of integrating new resources, planning and optimizing the grid platform, and providing customer solutions is continuous, real-time, and evolving.”

Introduction

The electric power distribution grid is an evolving plug-and-play platform for integrating new energy services and technologies. Public policies, new technologies, innovation, and consumer needs are driving the transformation of the power grid. The significant investments being made in grid technologies, data analytics, distribution system sensing and monitoring, and controls to enhance operational efficiency and to integrate new resources are clear indicators of the significant changes that are happening across the electric utility industry.

Through a series of case studies documenting “real world” projects, *Innovations Across the Grid (Volume II)* shows how the distribution grid platform is evolving in real-time to continuously meet three critical needs:

- To integrate new energy resources;
- To optimize the distribution grid platform; and
- To provide customer solutions.

Evolving Distribution Grid Platform

Over the past decade, U.S. utilities have been integrating increasing amounts of large-scale variable renewable energy resources into the grid each year, and this is expected to continue. More recently, utilities have started to integrate more distributed energy resources, such as rooftop solar photovoltaics (PV), storage, and other distributed resources onto the grid. This integration requires transforming the distribution system from a one-way delivery network to a much more complex, actively controlled network.

As energy resources at the edges of the grid continue to grow, the nation’s power grid is becoming more distributed, decentralized, and complex. Chapter 1 provides roughly 20 case studies detailing the development and integration of both large-scale and distributed solar, microgrids, battery storage, and community solar, as well as the monitoring and forecasting needed for the successful integration of these resources.

Utilities are investing in and upgrading their distribution systems with the goals of creating grid optimization and a more open,

Evolving distribution grid platform.



flexible, multi-point distribution network (or platform). This involves the convergence of information technology (IT) and operations technology (OT) systems; the connection of legacy assets and systems with new ones; and the deployment of smart meters, smart sensing, and automated control technologies; along with other investments that provide visibility into the grid. Overall, and with the continuous addition of new technologies, the grid is evolving to become more digitized and data-driven.

Chapter 2 showcases more than 20 case studies that highlight projects underway aimed at grid optimization and flexibility, including enhanced grid reliability and operational efficiency; grid intelligence and self-healing; substation automation; and outage management.

Today, electricity powers nearly every facet of everyday life, and the relationship among electric utilities and customers is evolving. Customers expect more from their electricity providers. More communication methods are available to connect customers and utilities in real-time. Utilities are offering more payment and communication options to better serve their customers; different ways to manage energy use; more rate options to capture dynamic conditions; and other services behind the customer's meter. The case studies in Chapter 3 focus on customer solutions, such as energy tracking, smart pricing, bill alerts, outage communications, and BYOT – bring your own thermostat.

As demonstrated in the case studies throughout the book, the intersection of new energy resources, grid optimization, and customer solutions is creating new services for customers, new processes for utilities, and new interfaces among customers, energy resources, third-party providers, and utilities.

- The distribution grid will provide and enable more “value” to customers as new assets and services are added to it. For example, utility-provided integration of distributed energy resources and grid resource management are becoming increasingly sophisticated as a result of new technologies and data analytics. These new resources also require new tools to optimize overall system efficiency and energy use.
- Managing and optimizing the distribution grid platform mean developing the capability to manage all grid assets and business systems to achieve greater reliability, resiliency, and energy optimization. This is a major undertaking and requires significant investment. First, connecting OT and IT will lay the foundation for a smarter distribution system. Second, enhancing data analytics and real-time optimization capabilities across all assets will ensure a reliable, resilient, safe, and affordable grid.

Innovations Across the Grid (Volume II) shows the wide range of projects underway as the new distribution grid fully emerges. However, the process of integrating new

resources, planning and optimizing the grid platform, and providing customer solutions is continuous, real-time, and evolving.

The Future is Now: Electric Utilities Operate the Plug-and-Play Grid

Electric utilities operate and provide services on the plug-and-play grid platform today. Oracle Co-Founder Larry Ellison basically calls the electric utility industry *the best plug-and-play industry in the world*. The current grid is already the platform for basic services and ensures that electricity is reliable, affordable, secure, and increasingly clean. The evolving grid will expand this plug-and-play platform for new services and technologies to “plug” into. This means, for example, seamlessly integrating new energy resources, such as rooftop solar PV, storage, demand resources, and electric vehicles, into the grid. While the concept and result are simple, the technology and expertise to connect and to operate the system reliably at the distribution level are not. Much planning and investment are needed to make this operate seamlessly and efficiently.

Electric utilities are indispensable to the scaled deployment of grid-related assets and technologies, because only utilities have end-to-end platform visibility to ensure system reliability, resiliency, and power quality. However, this new business environment relies increasingly on utilities

collaborating with two key partners: with **technology companies** to bring innovative products and services to the market and to set and deploy standards, and with **regulators** to define appropriate new business models for the plug-and-play grid platform.

Today’s power grid is evolving from a one-way centralized power delivery system to a more open, flexible, multipoint digitized network (or platform) with a collection of technologies and assets, some controlled by the utility and some not. Discussions about the evolving distribution grid are unfolding across the country. Much of the dialogue is driven by the need to integrate increasing amounts of distributed energy resources and to make the overall operation of the grid more efficient than it is today.

Managing the evolving and integrated distribution “grid of things” will require utilities to continue to invest in upgrading and modifying their distribution systems.

The case studies in *Innovations Across the Grid (Volume II)* give you a glimpse into how electric utilities are doing just that.



Lisa Wood

Executive Director,
Institute for Electric Innovation
Vice President, Edison Foundation

"It's a future where the grid we operate serves as the platform to interconnect and enable all of the emerging energy technologies our customers want to pursue – in other words, a 'grid of things.'"

Foreword

The speed of change in personal technology has catapulted the expectations of the general consumer into a different dimension. Perhaps you've heard the comedy bit that lampoons an airline passenger for getting upset when the onboard Wi-Fi stops working. How quickly we've taken for granted that we can fly comfortably at hundreds of miles an hour and be connected to anything we'd want to know, read, or watch while we're doing it.

Our customers' expectations around energy are changing in similar ways. Increasingly, there's a desire for energy products and services that are clean, personalized, flexible, perfectly reliable, affordable as ever, and – it goes without saying – safe.

The question is: Is the power grid, once considered by the National Academy of Engineering as the greatest engineering achievement of the 20th century, capable of meeting the evolving expectations of the 21st century?

The short answer is absolutely yes – if we focus our investments in the right way. The longer answer is explored in the pages that follow: 55 case studies that show ideas in action for modernizing America's power grid, all of which give me optimism for the future of utilities.

At PG&E, we have a unique vantage point on this exciting time in history. The world's biggest names in technology – from Apple to Google – are based in our backyard; California's clean-energy policies are among the most progressive in the nation; rooftop solar installations and electric vehicle sales here far outpace anywhere else in the country; and all of this comes on top of California's longstanding leadership on energy efficiency.

For our part, PG&E has embraced this spirit of innovation with advancements on smart meters, fleet electrification, renewable generation, and other areas. As you'll see in the case studies that follow, electric utilities across the country are rising to these same challenges and helping to write a new chapter for our industry. It's a future where the grid we operate serves as the platform to interconnect and enable all of the emerging energy technologies our customers want to pursue – in other words, a "grid of things."

It's a future where energy technology and information technology converge and create a whole new set of opportunities. Think of a homeowner with solar panels selling excess power to a neighbor and brokering the deal with smart meters and cell phones.

Because of the interconnectivity this type of grid provides, we not only add tremendous value to those individual technologies, we also add value to the grid itself. In fact, I'd argue the grid of the next 100 years will be just as relevant and essential, if not more so, than it has been over the last 100.

Of course, a lot of work needs to be done to achieve this vision. *Innovations Across the Grid (Volume II)* captures the scope of that work by organizing it into three areas: new energy resources, grid optimization, and customer solutions. These areas are right on target for where we need to focus our efforts.

But I challenge us to also think in the bigger picture about three key groups of people who are critical to our success.

The first is our customers. Their needs and expectations must remain the principal driver behind our pursuits. So it's imperative that we invest in better understanding those needs and expectations – and anticipating how they might change 10 to 15 years down the line.

The second is non-traditional partners. Unlike the past, where innovation in the utility industry typically came from within, much of it today is coming from elsewhere. So building the best grid for our customers will require utilities to reach out and work together with these co-innovators in energy.

The third is our employees. As important as outside partners will be, the internal culture

has to move first. This means rewarding innovation, investing in training, and recruiting the right talent. The workforce of the future will look and think differently, and judging by the case studies in this volume, that's already happening.

Going forward, if utilities can continue the type of innovation demonstrated here, I have every confidence the electric grid will meet the demands of the 21st century. If done well, most people will simply take it for granted, a lot like Wi-Fi on a jetliner.

Chris Johns

President, Pacific Gas and Electric Company
Co-Chair, IEI Management Committee

“The U.S. power grid, for most customers and most applications, is amazingly 'plug and play' in a way that is still aspirational in the IT world.”

Foreword

A canard has it that Thomas Edison would still recognize today's power grid. The implication is that not a lot has changed in the way electricity is generated and delivered to customers over the last 100 years. Zut alors! Nothing is further from the truth!

While Edison would surely recognize the dedication, skill, and innovation of the men and women who work in the power sector today, he would be astounded by the major transformations that have changed – and continue to change – the grid.

Just a year ago, the Edison Foundation's Institute for Electric Innovation (IEI) released *Innovations Across the Grid*, which offers an accessible, practical handbook of utility technology projects that are producing value for companies and their customers across the country. It was quickly adopted as a sourcebook for good ideas in areas such as grid optimization, resiliency and restoration, customer engagement, and energy management.

So much has happened over the past year, and companies are eager for a fresh volume of forward-looking and practical ideas. Projects have come off the drawing board and are being implemented. Both companies and vendors are developing clearer views of how the future may develop – with a premium on optionality.

And, we have a better understanding, based on experiences in diverse settings, of the costs, benefits, and challenges of integrating new kinds of resources onto the grid.

Importantly, policymakers and regulators are engaging more frequently – and in ways that are more operationally and financially focused than was the case just a few years ago.

Innovations Across the Grid (Volume II) addresses:

- The role of technology in the evolving power grid;
- How to integrate new resources onto the grid; and
- The importance of understanding and engaging energy consumers, who are no longer “passive ratepayers.”

So much has happened within IEI as well. Our meetings, held in conjunction with the Edison Electric Institute's conferences, provide fabulous insight into forward-looking projects and innovative ideas, as well as great discussions among electric company leaders and technology partners. During each meeting, we do a deep dive into a specific set of issues. In addition to “sustaining” projects, we also are taking a hard look at emerging and potentially “disruptive” developments. And, IEI has published

a timely series of case studies and summaries that provide accessible insight into key developments.

Mid-year, we convened industry and technology leaders at a retreat designed to look over the horizon at the range of scenarios for how the industry might evolve (and how IEI should keep evolving to best serve its stakeholders). We particularly focused on the “platform grid.”

The U.S. power grid, for most customers and most applications, is amazingly “plug and play” in a way that is still aspirational in the IT world. It smoothly and seamlessly enables countless consumer and commercial applications. Our customers don’t need a tri-fold accordion manual of instructions, printed in small or tiny gray type. It’s already a great platform.

An evolving platform grid is the foundation for integrating new supply and demand resources, for customer-facing solutions, and for optimizing the energy value chain from end-to-end. The evolving “Internet of Things” is, and will be, powered on the platform grid.

The U.S. Department of Homeland Security (DHS) identifies 16 critical infrastructures in areas such as communications, education,

health care, agriculture, transportation, and emergency services. According to DHS, the energy sector is unique because, “Without a stable energy supply, health and welfare are threatened, and the U.S. economy cannot function.” Energy is “uniquely critical because it provides an enabling function across all critical infrastructure sectors.” See DHS Energy Sector Overview, <http://www.dhs.gov/energy-sector>.

That’s a big responsibility, and our industry serves critical stewardship roles, powering our economy and providing essential infrastructure and services to virtually every citizen, business, government, and non-profit entity in America. As our companies fulfill this responsibility, we need sustainable approaches to network evolution, workforce development, and other key areas. We need smart and sustainable business plans and policies to support them.

Innovations Across the Grid (Volume II) is full of ideas that are working for utilities and their technology partners as they design and build the grid that will provide essential service for the next century.

Bob Rowe

President and CEO, NorthWestern Energy
Co-Chair, IEI Management Committee

The
utility grid *is a*
national asset.

“The nation’s power grid is becoming increasingly dependent on renewable energy and is evolving into a more distributed, more decentralized, and more complex grid.”



New Energy Resources

The U.S. electric power grid is increasingly integrating new energy resources – both large-scale and distributed. Public policies are driving the exponential growth in both renewable energy and distributed energy resources as carbon-free resources for generating electricity. Over the past decade, wind-generated electricity has increased 10-fold and now represents about three percent of all of the electricity generated in the United States. Similarly, over the past five years, solar-generated electricity has grown exponentially. As a result, electric utilities nationwide are integrating increasing amounts of large (utility-scale) wind- and solar-generated electricity onto the power grid each year.

At the same time, utilities are beginning to integrate more supply-side distributed energy resources, such as rooftop solar, community solar, microgrids, and energy storage, onto the grid along with the more traditional demand-side resources such as energy efficiency and demand response. As energy resources at the edges of the grid continue to grow, the nation's power grid is becoming more distributed, more decentralized, and more complex.

The case studies in this chapter detail the development and integration of both large-scale and distributed solar, microgrids, energy storage, and community solar, as well as the monitoring, forecasting, and resource management that are needed for the successful integration of these resources. The examples that are featured demonstrate how utilities are:

- Utilizing rooftops, utility poles, and landfills/brownfields for large-scale, grid-connected solar projects;
- Acquiring distributed resources, such as energy efficiency, demand response, distributed generation, and solar, to meet anticipated growth in electricity demand;
- Expanding access to solar by developing community-solar projects that give all customers the option to purchase solar energy;
- Using demand response as an ancillary service to support renewable energy integration;
- Using forecasting tools to integrate solar and wind for improved grid operations;
- Integrating energy storage; and
- Developing grid-friendly solar photovoltaics (PV) plants with voltage regulation, power controls, and ramp-rate controls.

New Energy Resources Trends

The exponential growth in renewable energy over the past decade, the continued growth in energy resources at the

edges of the grid, and the expectation for continued growth into the future are indicators of the grid's evolution. As a result, utilities are developing new approaches for developing and successfully integrating a range of new energy resources, as well as evaluating, testing, and demonstrating energy storage projects. The case studies in this chapter focus on three key areas – renewable energy development; resource management and integration; and energy storage.

1. Renewable Energy Development

U.S. utilities are developing both large-scale and distributed renewable energy resources, as well as integrating variable renewable resources owned by third-parties and customers, while maintaining power quality and system reliability.

More recently, utilities have started to use a variety of approaches for developing community-based solar projects by leasing large rooftops for installation of solar arrays; directly developing the solar resource in a community solar garden; and partnering with the military on military bases.

2. Resource Management

As large-scale renewable energy and energy resources at the edges of the grid continue to grow, utilities are developing approaches to manage these resources successfully.

-
- Avista is demonstrating economic dispatch of customer-owned distributed energy resources.
 - Hawaiian Electric developed a solar- and wind-integrated forecasting tool for short-term renewable energy forecasting to address its large penetration of renewables.
 - PNM Resources is using the Electric Power Research Institute's OpenDSS software to more accurately analyze the impacts of distributed generation on the grid.

3. Energy Storage

Several projects are underway to demonstrate the viability of both distributed and utility-scale energy storage. Without a doubt, successful and cost-effective energy storage is transformative for the power sector.

- The AES Battery Integration Center, hosted by IPL, is focused on accelerating the adoption of utility-scale energy storage systems.
- Pacific Gas and Electric Company is testing and demonstrating a variety of grid-scale storage functions, including wholesale market participation and integration of renewable energy resources.
- Portland General Electric's *Salem Smart Power Project* demonstrates storage as a solution for integrating solar PV.
- Southern California Edison is evaluating storage for large-scale utility projects to improve the flexibility and reliability of the next generation grid.

Conclusion

The case studies in this chapter clearly demonstrate two things. First, the nation's power grid is becoming increasingly dependent on renewable energy and is evolving into a more distributed, more decentralized, and more complex grid. Second, the role of electric utilities is both to develop renewable resources – both large-scale and distributed – as well as to integrate new energy resources into the power grid successfully and seamlessly. This is a continuous, real-time, and evolving process.

“Working with Washington State University, Avista has integrated the university’s advanced building energy management system into its distributed energy resource management system, allowing for precise and automated dispatch of customer-owned resources.”



Avista Utilities

Economic Dispatch of Distributed Energy Resources

Technology Partner(s)

ecobee

Integral Analytics

Spirae

Washington State
University

Project Highlights

- 4,000 events dispatched in first eight months to customer-owned distributed energy resources (DER).
- Four-quadrant value quantification to insure value to utility and each participant is clearly understood before dispatch of an event.
- Predictive scheduling based on four-quadrant value quantification for automated dispatch of events.
- Real-time value validation allows for real-time reconciliation of scheduled event and actual transactions per participant.

Project Description

As part of the larger ARRA-funded Pacific Northwest Smart Grid Demonstration Project, Avista implemented a distributed energy resource management system (DERMS) that can automate dispatch of customer-owned distributed energy resources, including demand response. Retail customers in Pullman, Washington that signed on to the project received a smart thermostat supplied by ecobee. The DERMS can adjust the thermostat temperature set points in increments of one-degree with a maximum of four-degrees. Customers receive \$100 per year as incentive for participating, in addition to the savings that accrue from adjusting the thermostat to a more efficient temperature set point. The DERMS determines real-time energy value for each asset (in this case, the thermostat) to schedule the highest-value asset for dispatch in a manual, semi-automatic or, fully automatic mode.

Working with Washington State University (WSU), Avista has integrated an advanced building energy management system (BEMS) with the DERMS. The BEMS is composed of five asset tiers that can be dispatched to either reduce load or generate energy. The five tiers include air handlers within 39 buildings (tier 1), nine chillers (tier 2), two natural gas generators (tiers 3 & 4), and one diesel generator (tier 5). The BEMS provides availability and capacity of each tier, every 5 minutes, to the DERMS. The DERMS creates auto-correcting forward-load-projections and asset availability based on historical data. For example, if the call to shed load via the air handling system was

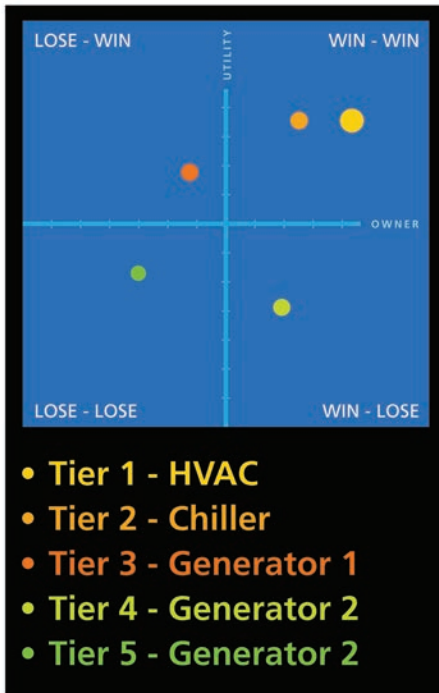
consistently being manually overridden by a building occupant, then the DERMS would learn from this trend and develop more accurate asset availability projections.

The BEMS understands the constraints of individual assets. The predicted load data, predicted asset availability, fixed and variable power supply costs, and system constraints create a real-time four-quadrant validation algorithm. This algorithm determines the value of dispatching a particular asset for the utility and the customer, which results in a win-win, win-lose, lose-win, or lose-lose outcome. Given a parameter for acceptable and desired outcomes, the system automatically schedules assets for dispatch. Afterward, the results are reconciled with the schedule to insure that the services delivered were accurately assessed.

The system went live in March 2014. As of October 2014, more than 1,000 events have been initiated. What's unique about this system? First, the forward prediction of asset capacity is sufficiently accurate for dispatch. Second, customers have complete control of the BEMS. And third, the real-time value quantification allows both the utility and the customer to understand any gain or loss.

Thanks to the flexibility of the BEMS, customers are also realizing tangible savings independent of the DERMS. WSU is using \$150,000 less electricity per month. And residential thermostat customers have saved between 4.5 percent and 9.0 percent in reduced energy consumption. Finally,

A sample four-quadrant value validation plot for various distributed resources.



data from both WSU and thermostat customer systems can be used to identify further cost-effective efficiency opportunities. Avista used this diagnostic capability to identify two thermostat participants that had malfunctioning heat pumps. Once the repairs were made, these customers saved an average of \$200 per month.

Avista is assessing the opportunity to use the DERMS to leverage customer-owned assets across the service territory. The initial focus is customer standby generation that can be leveraged as non-spin reserves. Given the anticipated growth of renewable generation and distributed energy resources, future areas of focus include industrial and commercial customer assets that can be leveraged to balance localized capacity, peak, and operational needs with the intent to offset capital investment.

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Company Description

Avista Utilities is involved in the production, transmission, and distribution of energy. We provide energy services and electricity to 365,000 customers and natural gas to 325,000 customers in a service territory that covers 30,000 square miles in eastern Washington, northern Idaho, and parts of southern and eastern Oregon, with a population of 1.5 million. Avista Utilities is an operating division of Avista Corp. (NYSE: AVA). For more information, please visit www.avistautilities.com.

“Dominion’s Kitty Hawk office is continuing a long tradition of research and development on the North Carolina coast with the construction of a micro-grid research project.”



Dominion North Carolina Power

North Carolina Microgrid Demonstration and Research Project

Technology Partner(s)

Aeolos
UGE
Windspire

Project Highlights

- Project will demonstrate and assess the installation, operation, and integration of wind turbines, a solar PV array, an integrated battery, a fuel cell, and an existing diesel generator into a facility-level microgrid.
- Four unique wind turbine systems will generate up to 13 kW and enable performance assessment of various turbine configurations.
- Solar array of 24 ground-mounted 250 watt PV cells will produce up to 6 kW of power and 7 MWh of energy annually.
- Integrated battery array of 53 individual 25 KW lithium-ion cells with a storage capacity of 75 kWh.

Project Description

In early 2012, Dominion North Carolina Power started the process of scoping a research project that would study the behavior and performance of integrating several renewable generators with an existing diesel generator to serve part of the building load for the utility's office facility in Kitty Hawk. The project, commissioned on July 25, 2014, consists of installing four wind turbines, a solar-power array, and an integrated battery in a microgrid as part of a three-year demonstration project for renewable generation.

The four wind turbines, each of which will be of a different design, manufacture, height, and configuration, will collectively be capable of generating over 13 kW. Each turbine's unique cut-in wind speeds, blade configuration, capacity factor, and annual energy production capability will allow the utility to assess the relative performance and efficiency of these turbines.

The solar array consists of 24 ground-mounted 250 watt photovoltaic cells capable of producing up to 6 kW of DC power and over 7,000 kWh annually at an upfront cost of approximately \$35,000. The project will also include 53 25 kW lithium-ion batteries with a storage capacity of 75 kWh and protective equipment and controls that allow for the charging and discharging of a battery storage system.

The project will not be tied directly to the grid. Energy harnessed at the site will reduce the amount of grid electricity used at the Kitty Hawk district office.

In 2015, Dominion plans to complete the addition of a 3 kW fuel cell to the project. An engineering study is currently underway. As part of Dominion's renewable energy efforts, the research project will open the possibility of developing similar technologies at other company locations.

Project Contact

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Company Description

Dominion North Carolina Power is a subsidiary of Dominion (NYSE: D), one of the nation's largest producers and transporters of energy, with a portfolio of approximately 27,500 megawatts of generation. Dominion operates one of the nation's largest natural gas storage systems and serves retail energy customers in 15 states. For more information about Dominion, visit the company's website at www.dom.com.

“The Solar Partnership Program allows Dominion Virginia Power to gain experience in operating distributed solar generation and also offers unique partner opportunities with customers.”



Dominion Virginia Power

Solar Partnership Program

Technology Partner(s)

Antares Group, Inc.

Aquion Energy

ViZn Energy

Project Highlights

- Launched in late 2012, Dominion Virginia Power's Solar Partnership Program will construct and operate up to 30 MW of company-owned solar facilities on leased rooftops, public, and commercial properties.
- The program will study impacts and assess benefits of distributed solar (PV) generation on heavily loaded, lightly loaded, and conservation voltage reduction circuits.
- Community-based distributed solar model creates opportunities for community engagement and education.
- 6 MW (DC) in service or in final stages of completion by year-end 2014.

Project Description

Launched in late 2012 in support of Chapter 771 of the 2011 Virginia Acts of Assembly, the Solar Partnership Program is a multi-year pilot program designed to expand Dominion Virginia Power's (DVP's) understanding of community-based solar energy. The study will assess the impact and benefits of solar power while supporting and encouraging solar energy growth in Virginia. Through the program, DVP will construct and operate up to 30 megawatts of company-owned solar facilities on leased rooftops or on the grounds of commercial businesses and public properties. When fully implemented, the program will generate enough power for up to 7,500 homes.

The Solar Partnership Program allows DVP to gain experience in operating distributed solar generation while also offering unique opportunities to partner with eligible business customers with suitable facilities for solar installation. For the purposes of the program, DVP has identified two host-site participant groups. The majority will consist of larger sites which can accommodate distributed solar generation greater than 500 kW. The company will also partner with approximately four smaller sites capable of accommodating less than 500 kW, located on public or community buildings/sites for demonstration projects. These smaller installations provide opportunities for customer outreach and education on solar technologies. An educational program will coincide with solar installations on secondary-level academic facilities throughout the state and



[Solar Partnership Installation at Old Dominion University's Student Center.](#)

will provide train-the-trainer opportunities to expand local faculty and student knowledge on the operation of solar-powered systems. DVP is also planning to study electrical storage at one Solar Partnership Program site as renewable generation and its associated technologies become more prevalent in Virginia.

Over the course of the program, DVP plans to partner with twenty to thirty commercial, industrial, and academic customers. Each of these selected sites must meet one or more of the study objectives to participate in the program. DVP has identified four key study objectives for the Solar Partnership Program.

- Determine the effects of solar distributed generation on circuit loading, analyze the peak demand reduction benefits to the distribution system, and collect the necessary data to develop a distributed solar generation load model for the company's distribution planning process.
- Quantify the reduction in line losses from distributed solar generation at various points on the distribution system.

-
- Study the operational impact of “high saturation” solar distributed generation on a single circuit.
 - Assess the potential for solar distributed generation to improve conservation voltage reduction (CVR) performance.

Solar Partnership Program projects utilize three key categories of circuits in order to study the impact of solar generation on the electric distribution grid. Categories include: heavily loaded circuits, lightly loaded circuits, and CVR circuits. Using sites selected on targeted circuits allows DVP to determine the effects of distributed solar generation on circuit loading, analyze the peak demand reduction effects to the distribution system, and collect the necessary data to develop a distributed solar generation load model for the company's distribution planning process. DVP will collect solar photovoltaic (PV) data to develop a PV capacity and energy report

model for each site and do circuit assessments at each location for load reduction, voltage profile, loss reduction, and other circuit variables. With a sufficient number of solar sites, DVP plans to forecast future solar generation impacts at the system level for the four study objectives.

As of September 2014, Dominion has completed two projects, including a 521 kW (DC) system on a heavily-loaded circuit at Canon Environmental Technologies in Gloucester, VA (which is currently the largest rooftop solar system in Virginia) and the first demonstration site at Old Dominion University in Norfolk, VA. A project located at the Prologis Concord Distribution Center in Sterling, VA was announced in July and will exceed 800 kW on two adjacent rooftops. Additional projects are under construction with a total of 6 MW (DC) expected to be in service or in the final stages of completion by year-end 2014.

Project Contact

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Project Manager

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Company Description

Dominion Virginia Power is a subsidiary of Dominion (NYSE: D), one of the nation's largest producers and transporters of energy, with a portfolio of approximately 27,500 megawatts of generation. Dominion operates one of the nation's largest natural gas storage systems and serves retail energy customers in 15 states. For more information about Dominion, visit the company's website at www.dom.com.

"Georgia Power is partnering with the U.S. Army to bring 90 MW of solar generation to Fort Benning, Fort Gordon, and Fort Stewart by the end of 2016."



Georgia Power

Utility-Scale and Distributed Solar Implementation

Project Highlights

- Over 800 MW of voluntarily developed, utility-scale solar, the largest solar portfolio of any investor-owned utility in the U.S.
- Three 30 MW U.S. Army solar projects to be completed by end of 2016.
- Two rate options for eligible net-metered customer-generated solar power.
- Customer solar decision tools available online.

Project Description

Georgia Power has a long history of innovation including real time pricing, solar energy research, and support for the development of the state's solar industry. Georgia Power's strategy towards developing solar within the state has been implemented under the regulatory construct of Georgia's statutory integrated resource planning (IRP) process. This IRP process results in meeting customers' energy needs in a reliable and economic manner.

The first large solar program Georgia Power implemented was the Large Scale Solar program, approved by the public service commission (PSC) in 2011 to purchase up to 50 MW of solar power by 2015 with a 30 MW project cap. Georgia Power signed 20-year power purchase agreements in December 2011 for 49 MW of solar energy with two developers in Georgia. The additional 1 MW was added shortly thereafter. The price Georgia Power pays for the solar energy was developed using the company's long-term avoided energy cost plus a capacity credit based on the operational characteristics of solar energy.

In late 2012, the PSC approved the Georgia Power Advanced Solar Initiative (GPASI). This initiative added to the existing Large Scale Solar initiative, creating the largest voluntarily developed solar portfolio of any investor-owned utility. Under GPASI, Georgia Power will add 210 MW of solar capacity in long-term PPAs through two efforts – the Utility Scale Program (120 MW) and the Distributed Generation Program (90 MW).

The PSC recently approved procurement of 525 MW of additional solar capacity as part of Georgia Power's 2013 IRP: 425 MW of utility scale and 100 MW of distributed generation. This 525 MW segment is known as GPASI Prime. The GPASI and GPASI Prime utility scale program pricing is based on competitively bid proposals, whereas distributed generation PPAs will pay prices at or below the current projections of long term avoided costs of the company.

The PSC recently approved Georgia Power's announcement to partner with the U.S. Army to bring 90 MW of solar generation to U.S. Army bases in Georgia. Scheduled to be completed by the end of 2016, the Georgia Power owned facilities are expected to be the largest solar generation installations operating on any U.S. military base. The 30 MW facilities at Fort Stewart, Fort Benning, and Fort Gordon will be brought online at or below the projections of long term avoided cost; and bring the Army nine percent closer to its commitment to President Obama to deploy one gigawatt of renewable energy by 2025.

Georgia Power customers who generate their own solar electricity have the option to sell some or all of that electricity to Georgia Power. Customer solar generators are eligible to sell their electricity as a Qualified Facility (QF), under the Renewable & Non-renewable Tariff (RNR), or under the Solar Purchase Tariff (SP) dependent upon the generating facility's size. Georgia Power will purchase energy from solar generating

facilities as a QF or through the RNR tariff at the company's solar avoided cost. The SP rate is used to supply the Green Energy Program. A price of 17 cents per kWh was set several years ago for the SP rate to spur the market and has been such a success that there is a waitlist.

Georgia Power is committed to providing the tools customers need to make informed decisions about solar power. Customers

can visit the Georgia Power website to learn how solar power works, the cost and potential savings, and important factors influencing solar production. Another valuable resource for customers is the Solar Consultants located in every region in Georgia. These Georgia Power employees are energy experts and are there to provide answers to customers' questions about solar power or other energy related needs.

Project Contact

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Company Description

Georgia Power is the largest subsidiary of Southern Company (NYSE: SO), one of the nation's largest generators of electricity. Value, reliability, customer service, and stewardship are the cornerstones of the company's promise to 2.4 million customers in all but four of Georgia's 159 counties. Committed to delivering clean, safe, reliable, and affordable energy at rates below the national average, Georgia Power maintains a diverse, innovative generation mix that includes nuclear, 21st century coal and natural gas, as well as renewables such as solar, hydroelectric, and wind. For more information, visit www.GeorgiaPower.com and connect with the company at Facebook.com/GeorgiaPower and Twitter.com/GeorgiaPower.

"As Germany continues to increase the share of renewable energy over the coming years, possibly reaching upward of 50 percent by 2030, demand response provides transmission system operators with a tool to help integrate renewables and manage the grid."



German Transmission System Operators Amprion & Tennet

Demand Response as Ancillary Service in Germany

Technology Partner(s)

EnerNOC

Project Highlights

- Germany currently has 88 GW of intermittent renewable energy resources (RES), often representing more than 30 percent of capacity, creating gigawatt-order fluctuations in generation.
- Bi-directional demand response has been successfully integrated in the German market, providing transmission system operators (TSOs) with secondary control reserve capacity (SRL) and tertiary or minute reserve (MRL).
- SRL and MRL have been successfully delivered simultaneously to stabilize the grid and to help integrate intermittent renewable resources.
- Advanced demand management technology captures sub-minute meter data and makes data available in real-time to support reliable, fast-response resource delivery.

Project Description

In many energy markets in Europe – as well as in some U.S. markets – increasing shares of fluctuating renewable energy resources create the need for flexible capacity to balance the grid. Intelligent aggregation of individual demand-side resources can provide a reliable source of capacity. Developments in demand management technology create demand response (DR) performance levels that equal or exceed that of generators. DR has been recognized in Europe as an important approach to stabilize the grid and integrate intermittent renewable energy sources (RES). The recently published European Commission’s Energy Efficiency Directive outlines clear and specific requirements for EU Member States to encourage DR programs. And European transmission system operators (TSOs) increasingly welcome the participation of DR as a grid-balancing ancillary service in their reserve programs.

DR as an ancillary service is already beyond the pilot phase and in full-scale implementation in Europe. The German market in particular offers an interesting look at how that country’s drive to transform its generation mix towards renewables is creating new opportunities for DR to become an essential part of the grid. High penetration of intermittent RES and the market’s requirement to prioritize dispatch of RES have created a dynamic grid in Germany, with large fluctuations in supply, making supply-side-only adjustments difficult and expensive to implement.

By enacting controlled demand-side adjustments, German TSOs have new tools and possibilities for grid stability and management. In the U.S. and Canada, DR in non-regulation reserves typically focuses on curtailment, providing synch reserves, and under frequency load shedding. Despite a number of existing regulatory challenges, bi-directional demand response has successfully been integrated in the German power market through EnerNOC’s sophisticated real-time technology, providing TSOs with secondary control reserve capacity (SRL) and tertiary or minute reserve (MRL).

Since early 2014, EnerNOC, via Entelios AG, has been demonstrating how both SRL and MRL are successfully delivered simultaneously to stabilize the grid and to help integrate intermittent RES. EnerNOC’s architecture enables DR response times of less than five minutes and delivery according to a dynamic, real-time signal from the TSO. EnerNOC has been providing aggregated DR resources to German TSOs specifically, and European TSOs generally, employing demand management technology with the capability to aggregate loads, on-site generation, and industrial process storage to capture sub-minute meter data and make that data available in real-time to support reliable, fast-response resource delivery.

Simultaneous deployment of both SRL and MRL DR resources is important. Germany currently has more than 80 GW of RES installed on its system, often representing

much more than 30 percent of system capacity. There are hours and days where the amount of wind and solar power on the system almost exceeds the amount of power the entire country can use. As a result, TSOs must manage gigawatt-order fluctuations in generation. As Germany continues to increase the share of renewables over the coming years – reaching upward

of 50 percent by 2030 – these fluctuations are projected to require the ability to ramp up and ramp down baseload power plants at a rate of 12 GW in a quarter hour. Facing more frequent, steeper, and higher ramps, DR provides TSOs with a proven tool to help effectively integrate renewables and manage the grid.

Project Contact

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Company Description

Amprion operates the largest extra-high voltage transmission system in Germany. The key task of its some 900 employees is to transmit electricity at competitive prices safely and reliably any time. The system connects power plants with the load centres and at the same time is an important pillar of the German and European transmission grid. Our transmission system is an important hub for electricity trading between Northern and Southern as well as Eastern and Western Europe.

TenneT is a leading European electricity transmission system operator (TSO) in the Netherlands and in a large part of Germany. We ensure a reliable and uninterrupted supply of electricity for the 41 million end-users in the markets we serve. We aim to meet our stakeholders' needs by being responsible, engaged, and connected.

“Routinely operating with 40 percent or more penetration of renewables on the grid, renewable forecasting is a strategy for Hawaiian Electric to ‘see and manage’ non-dispatchable renewable generation variability.”



Hawaiian Electric
Maui Electric
Hawai'i Electric Light

Hawaiian Electric Company

Solar and Wind Integrated Forecasting Tool (SWIFT) for Grid Operations

Technology Partner(s)

AWS Truepower

Project Highlights

- First utility to operationalize a solar and wind integrated forecasting tool (SWIFT) and targeted network of over 50 remote sensors optimized for renewable energy forecasting.
- Consistent bird's-eye view of wind and solar conditions across 5 islands.
- 24/7 access to near real-time delivery of 15 minute wind and solar production look-ahead forecasts.
- Provides CIM compliant, real-time probabilistic forecasts for short term (next 6 hours) and long-term (up to next 48 hours) for EMS integration.
- Integrates physics-based numerical weather prediction, statistical prediction models, local sensor data, and satellite imagery to deliver comprehensive system visibility.

Project Description

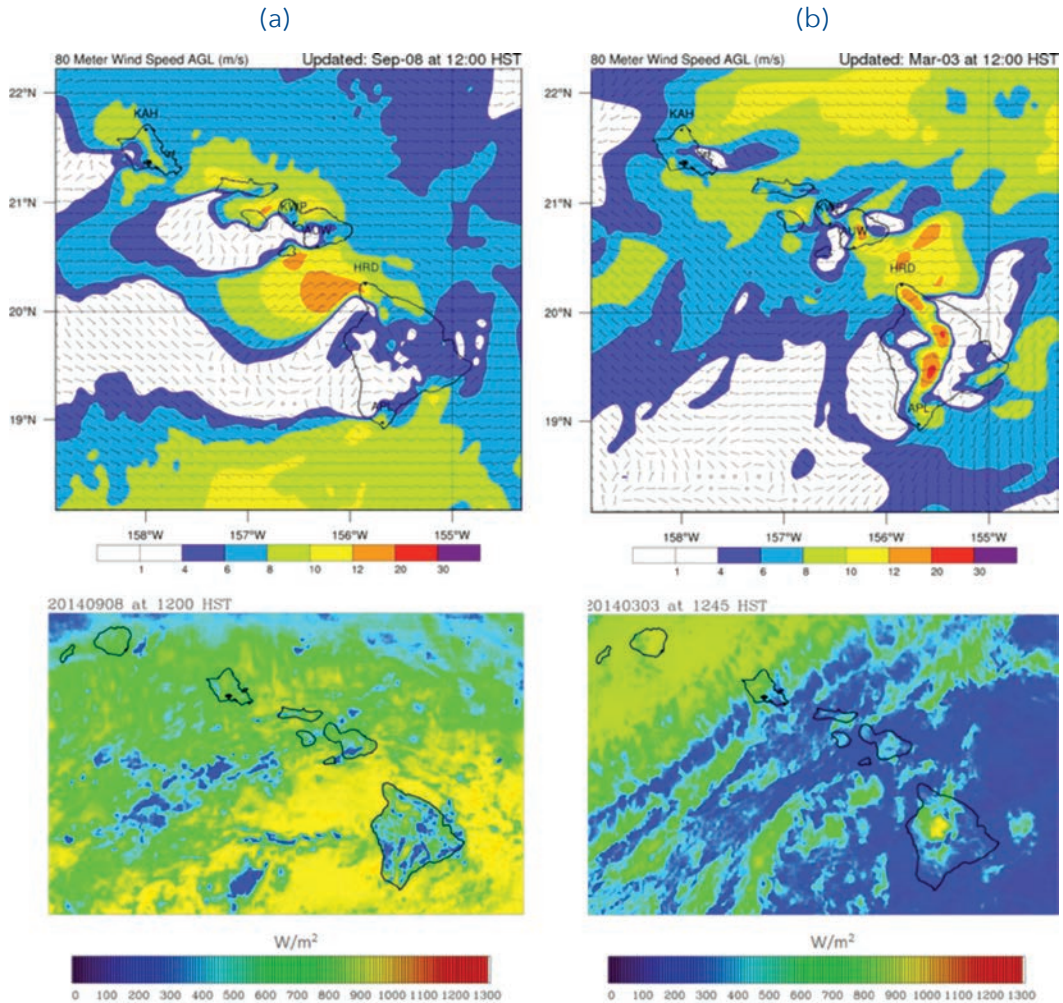
Hawai'i is blessed with an abundance and diversity of renewable resources. With strong clean energy policies and favorable renewable production incentives, the Hawaiian Electric Companies are now contending with penetrations of renewable generation, including distributed resources, that are among the highest in the country. With over 300 MW of nameplate distributed photovoltaic (PV) solar generation installed on O'ahu, the capacity of behind-the-meter PV systems is now greater than the largest central station generating unit.

Routinely operating with 40 percent or more penetration of renewables on the grid from wind, geothermal, hydro, biomass, and solar, system operators faced real-time challenges balancing the "ups and downs" of variable renewable energy generation. To address these challenges, system operators on the Island of Hawai'i identified renewable forecasting as a strategy to "see and manage" non-dispatchable renewable generation variability on islanded systems without the backup capabilities of an interconnected mainland grid. Hawaiian Electric is working with AWS Truepower, a New York-based renewable energy development consultant and forecasting service provider, to customize an ensemble of renewable energy forecasting methods and observational targeting techniques providing reliable short-term renewable energy forecast information that can provide visibility to system operators to better manage non-dispatchable renewable generating resources. A multi-phase project over the past several years focused on:

- Improving physics-based numerical weather prediction (NWP) and terrain models for Hawai'i's complex terrain and unique tropical marine environments;
- Deploying and maintaining a local sensor network sited to specifically gather wind and solar resource information (rather than airport weather condition) to improve renewable forecasts and support field verification studies for Hawai'i; and
- Operationalizing a "15-minute look-ahead" capability and probabilistic forecasts for both wind and solar into utility operations and planning.

The solar and wind integrated forecasting tool (SWIFT) currently uses a network of more than 50 state-of-the-art, remote monitoring sensors specifically sited to provide maximum benefit for short-term renewable energy forecasts within our service territory. SWIFT is providing utility staff with valuable information on prevailing wind and solar conditions through both visualization tools and data. Graphical displays present an overall, bird's-eye view of wind and solar conditions over all the islands and detailed energy production forecasts for specific facilities or aggregates of those facilities within the service territory. Physics-based models use information from the National Weather Service ("NWS"), GOES satellite imagery for cloud prediction, as well as data from the network of targeted wind and solar sensors deployed across the islands to correct for local weather and terrain conditions.

Bird's eye view of integrated wind (top) and solar (bottom) information comparing (a) normal trade conditions to (b) variable conditions for wind and solar.



When fully integrated into the EMS, SWIFT will provide system operators the ability to quickly assess and be aware of prevailing wind and solar conditions and prior performance trends. Key features of SWIFT include the 15 minute “look-ahead” forecasts for the next 6 hours (short-term) and up to 48 hours (long-term) used in operational planning. Wind forecasts include

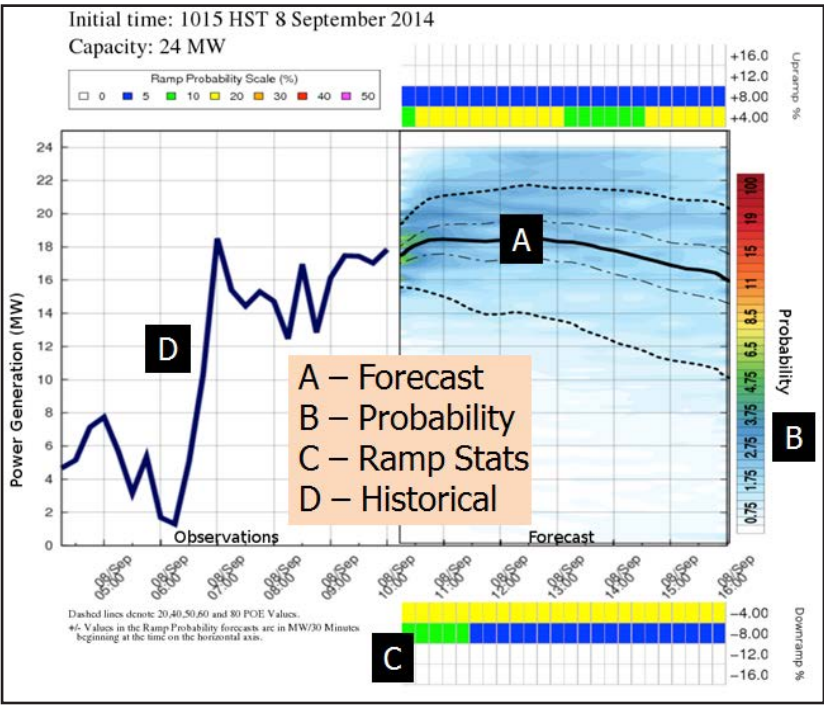
data on speed, direction, and energy, and are provided for specific wind facilities at 80 meter elevation, the typical hub height of modern wind turbines. Real-time solar irradiance forecasts and energy production for both utility-scale solar facilities and roof-top distributed PV resources are accounted for in forecasts to inform real-time operations and dispatch decisions.

System operators found tremendous value in SWIFT during recent hurricanes Iselle and Julio. SWIFT forecasts provided real-time updates tracking not only the location but also the duration of the storm.

Going forward, the project will focus on training staff to use and seamlessly integrate forecast information into operational tools including the energy management system (EMS). As part of a U.S. DOE Sunshot

award, the Hawaiian Electric Companies are working with AWS Truepower, EMS vendors including Siemens and Alstom, and data integrators Referentia Systems Inc. and DNV GL to enhance operational awareness by combining information on variable renewable generation with associated grid conditions. These efforts will provide new tools for real-time decision making and smarter grid operations.

SWIFT probabilistic wind and solar forecast displays. The probabilistic forecast contains (A) the most probable forecast for the next 6 hours and 4 confidence levels (dotted lines); (B) a probability distribution in the forecast; (C) probable ramp rate and MW threshold levels (i.e. probability that the ramp rate will exceed the specified threshold); and (D) past 6 hours historical production for reference.



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Company Description

Hawaiian Electric and its subsidiaries, Maui Electric and Hawai'i Electric Light, serve the islands of O'ahu, Maui, Lāna'i, Moloka'i and Hawai'i, home to 95 percent of the population of Hawai'i. Hawaiian Electric's parent company is Hawaiian Electric Industries (NYSE: HE).

In a changing world, the Hawaiian Electric Companies are taking the lead in adding renewable energy and developing energy solutions for its customers to achieve a clean energy future for Hawai'i. For more information, visit www.hawaiianelectric.com

***"In just over one year,
IPL has gained experience
in the deployment and
operation of six different
energy storage systems."***



Indianapolis Power & Light Company

AES Battery Integration Center

Technology Partner(s)

AES Energy Storage

Project Highlights

- Indianapolis Power & Light Company's (IPL's) AES Battery Integration Center provides a platform for the utility to accelerate the adoption and implementation of energy storage systems.
- Developed a qualification process to validate rapid, large-scale deployment capabilities of battery and power control systems from multiple manufacturers.
- Since the center's 2013 launch, four energy storage systems have been qualified, with an additional two systems to be qualified in 2014 and eight to be qualified in 2015.
- Validates the Advancion™ energy storage array aggregation controls, targeting 99.9 percent equivalent availability factor.

Project Description

In late 2007, Indianapolis Power and Light (IPL) hosted the world's first utility-scale lithium-ion based energy storage system, Carina, a two megawatt unit which operated at an IPL substation, proving the viability of battery-based energy storage. IPL continues to be a leader in energy storage by hosting the AES Battery Integration Center. Commissioned in September 2013, the mission of the center is to accelerate the adoption of utility-scale energy storage systems (i.e., hundreds of megawatts). It does so by qualifying battery and power conversion systems to the Advancion™ standard while serving as a testing and validation facility for the Advancion Digital Control System (DCS).

The Advancion architecture allows large, multi-hundred megawatt arrays to be built by replicating smaller units of storage. An Advancion array is built by replicating the smaller units (nodes) until the desired array capacity is reached. These arrayed nodes combine to provide unparalleled reliability, surpassing the availability of most conventional power plants. While a typical power plant may have an availability factor of 95 percent and be considered an excellent performer, this translates to 18 days of downtime per year; arrayed storage can achieve data-center-like availability, surpassing 99 percent to 99.9 percent availability factor with fewer than nine hours of downtime per year.

The Advancion DCS is a tiered, standards-based control system which manages an array, its nodes, and its components. The

DCS allows for safe multi-operator management of single or distributed arrays or fleet of arrays. Maintenance teams have appropriate local access to manual operations modes and critical functions, like lock-out-tag-out, while operations teams retain supervisory access from central locations. The Advancion DCS incorporates a Market Dispatch Unit, which provides operational rules and algorithms tuned to comply with all major markets and control areas.

In less than one year since its commissioning, the AES Battery Integration Center completed the qualification of four energy storage systems, with two additional systems due to be completed by the end of 2014 and seven more in queue for 2015. Each qualified system, either a battery system or a power conversion system, has been certified for use in an Advancion array. Certified battery and power conversion systems are interoperable and interchangeable.

In the development of the center, IPL has gained first hand experience in design and operation of energy storage systems through oversight of facilities engineering, development of safety procedures, fire detection and prevention systems specification, environmental controls monitoring, and relay protection and metering configuration. Few utilities have gained this valuable experience with multiple systems vendors. In just over one year of operations, IPL has gained experience in the deployment and operation of six different energy storage systems.

The integration center experience has prompted and emboldened IPL to investigate the development of multiple energy storage projects to provide a variety of services on a cost competitive basis. Projects currently under consideration include

multiple reliability projects for commercial and industrial customers, distribution feeder stability support in critical locations, and generator capacity enhancement.

Project Contact

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Company Description

Indianapolis Power & Light Company (IPL) is an electric generation, transmission, and distribution company and part of The AES Corporation, a Fortune 200 global power company with operations in 20 countries over five continents. IPL provides retail electric service to more than 470,000 residential, commercial, and industrial customers in Indianapolis, as well as portions of other Central Indiana communities surrounding Marion County. During its long history, IPL has supplied its customers with some of the lowest-cost, most reliable power in the country. For more information about the company, visit www.IPLpower.com.

"IPL has the fifth largest per capita concentration of solar of U.S. cities, with approximately 68 MW of DG connected to its grid, and an additional 30 MW expected to be interconnected in 2015."



Indianapolis Power & Light Company

Distributed Solar Generation Integration

Technology Partner(s)

ABB
Advanced Energy
GE
Schneider Electric
SMA
Solectria Renewables

Project Highlights

- Indianapolis Power & Light Company (IPL) is integrating 100 MW of distributed generation (DG) at 40 sites under contract ranging from 10 kW – 10 MW.
- 27 sites are fully operational, representing 68 MW of installed DG with an additional 30 MW coming online in early 2015.
- System protection requirements and coordination on 13 kV.
- IPL developed communication/telemetry standard integrates site-specific energy production and voltage data to operations control center.

Project Description

Indianapolis Power & Light Company (IPL) has long been a proponent of developing renewable energy resources for its customers. IPL was the first Midwestern utility to implement a feed-in-tariff for renewable fuels including solar, wind, and biomass. In 2010, IPL received permission to offer a feed-in-tariff known as the Renewable Energy Production (REP) rate to foster production of renewable energy from projects up to 10 MW in size. Under the REP rate, IPL purchases the output from the facilities based on fixed rates for 15 to 30 year periods.

Customers and developers proposed renewable projects to IPL. Based on a queuing process and a reverse auction, IPL selected 40 projects totaling approximately 100 MW of renewable energy for its REP rate offering. The projects were classified in three tiers: less than 10 kW; 10 kW-2 MW; and over 2 MW.

Integrating this amount of intermittent DG proved quite challenging and required new processes to be established to maintain excellent power quality and system reliability. Employees in multiple areas of IPL worked closely to develop efficient procedures and successfully interconnect the DG sites. Engineering experts in substation distribution and relaying, metering personnel, power quality technicians, communications specialists, operations staff, drafters, and a project coordinator met weekly to follow each project milestone.

Based on the proposed location and feeder interconnection, specific engineering site studies were performed to determine if the distribution system could reliably support each DG resource without impacting the service reliability for existing customers. Specifically, feeder loading, protection equipment, power factor impacts, fault currents, and possible voltage flicker were considered. IPL determined if there was a need for line extensions to support the interconnection along with specialty equipment, known as “static volt-ampere reactive” equipment, or a power quality relay/meter with remote alarming capabilities to mitigate potential flicker. Projects that were 500 kW-2 MW and connected at a secondary voltage required a remote shunt-trip disconnect switch for IPL to safely work on distribution lines without any chance of DG backfeed. Projects with nameplate capability over 2 MW and connected at primary voltage required an automated recloser, which ties into the IPL smart grid network. Detailed information about the energy produced and site amperages are transmitted every ten seconds to the IPL operations control centers through two-way communicating equipment designed in IPL’s DG communication/telemetry standard.

To manage the diversity across the sites, IPL developed a DG solar facility commissioning guide and site-specific operating procedures that are agreed upon by the customer/developer and IPL prior to the issuance of a formal permission to operate

letter to ensure all the requirements are met. To date, IPL has successfully integrated ten different types of inverters, each with specific characteristics and system impacts.

IPL has the fifth largest per capita concentration of solar of U.S. cities to date with approximately 68 MW of DG connected to its grid. An additional 30 MW of DG is expected to be interconnected in the first half of 2015. Real time DG output is used to assess circuit loading if switching is required for maintenance or in response to emergencies and to calculate IPL's daily load and generation forecasts. Analysis of changes on cloudy days and when snow covers existing panels

has helped IPL understand DG grid impacts. The IPL team has helped several other utilities plan how they will interconnect large-scale DG on their systems.

Solar array at Indianapolis International Airport. Image courtesy of IND Solar Farm.



Project Contact

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Company Description

Indianapolis Power & Light Company (IPL) is an electric generation, transmission, and distribution company and part of The AES Corporation, a Fortune 200 global power company with operations in 20 countries over five continents. IPL provides retail electric service to more than 470,000 residential, commercial, and industrial customers in Indianapolis, as well as portions of other Central Indiana communities surrounding Marion County. During its long history, IPL has supplied its customers with some of the lowest-cost, most reliable power in the country. For more information about the company, visit www.IPLpower.com.

“Development of utility-scale PV plants with grid-friendly features such as voltage regulation, active power controls, ramp-rate controls, fault ride-through, and frequency control is critical to grid stability and reliability.”



MidAmerican Renewables

Grid-Friendly Utility-Scale PV Plant

Technology Partner(s)

First Solar

Project Highlights

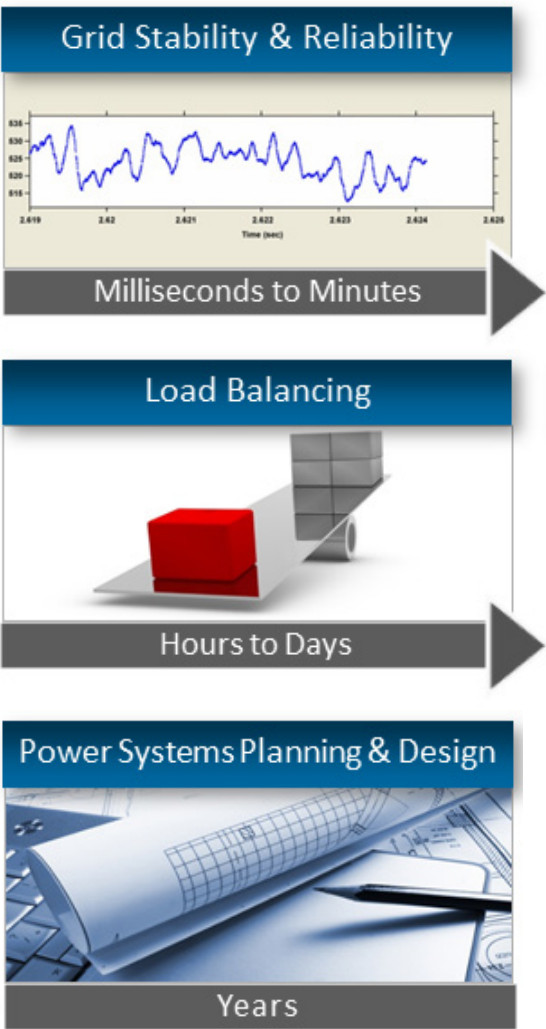
- 290 MW solar PV plant connected to 500 kV transmission line.
- Regulates voltage, power factor, and/or frequency for major transmission line.
- Intersolar North America's 2014 North America Solar Project of the Year.
- Controls active and reactive power, ramp rates, and curtails power when necessary.
- Minimizes impact of cloud cover.

Project Description

One of the world’s largest completed and operating utility-scale PV plants to date, the 290 MW Agua Caliente Solar Plant revolutionizes how solar integrates with the power grid. Agua Caliente, located approximately 65 miles outside of Yuma, Arizona, is one of the first PV plants connected to a 500 kV transmission line. First Solar designed and constructed the power plant and continues to operate and maintain the facility for owners NRG Energy and MidAmerican Renewables. Pacific Gas & Electric Company has contracted to purchase the project’s output for 25 years.

The impact of PV generation on grid reliability and stability is becoming increasingly critical, especially as solar generation grows to become a significant contributor to the grid. Deploying large utility-scale PV plants of hundreds of MW in size requires the development of “grid friendly” features such as plant-level voltage regulation, active power controls, ramp-rate controls, fault ride-through, frequency control, and others.

The impact of integrating rapidly growing PV generation on power systems, especially as it relates to grid reliability and stability, can be broadly categorized into three areas based on the time scale of grid operation. The first is related to the PV plant’s response to grid disturbances on the sub-seconds to minutes time scale. The second is related to load balancing, which is on the order of sub-hours to days. The third is related to power systems planning, which is on the order of years to decades.



Time scale of grid operations.

When compared to the inherent electromechanical dynamics of synchronous generation, PV generation responds to power electronics quite differently. In the case of Agua Caliente, a plant-level controller, designed to make the PV plant behave as a single large generator, is able to coordinate 500 individual inverters’ output to regulate the total plant’s real and reactive power output

and voltage. Similar to a large generator, plant operators can use a supervisory control and data acquisition (SCADA) human-to-machine interface to provide desired controller settings.

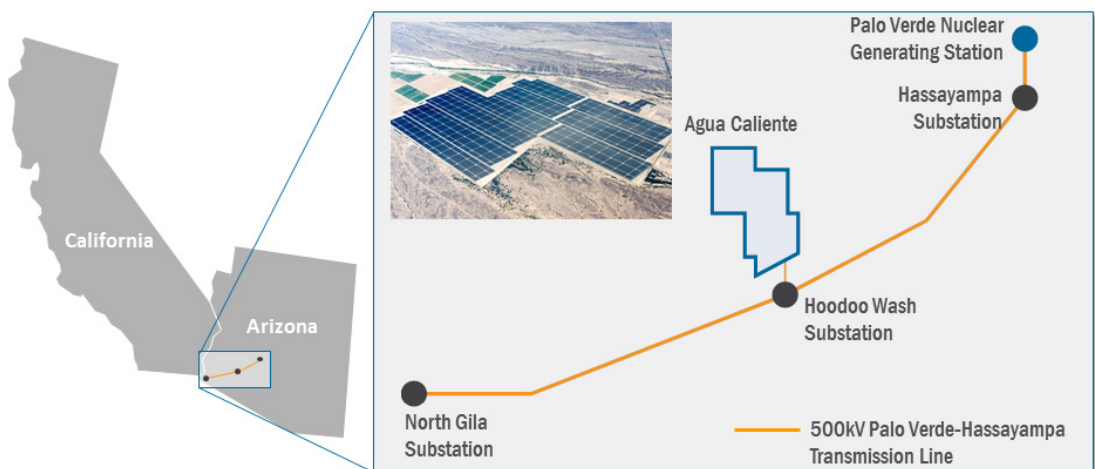
The Agua Caliente PV plant interconnects to a 500 kV transmission line that has several other generation plants on the line, including the Palo Verde Nuclear Generating Station, which is the largest power plant in the United States, with a capacity of over 3.7 GW. During normal operations, the PV plant maintains unity power factor at the point of interconnection while the active power follows the typical PV generation profile.

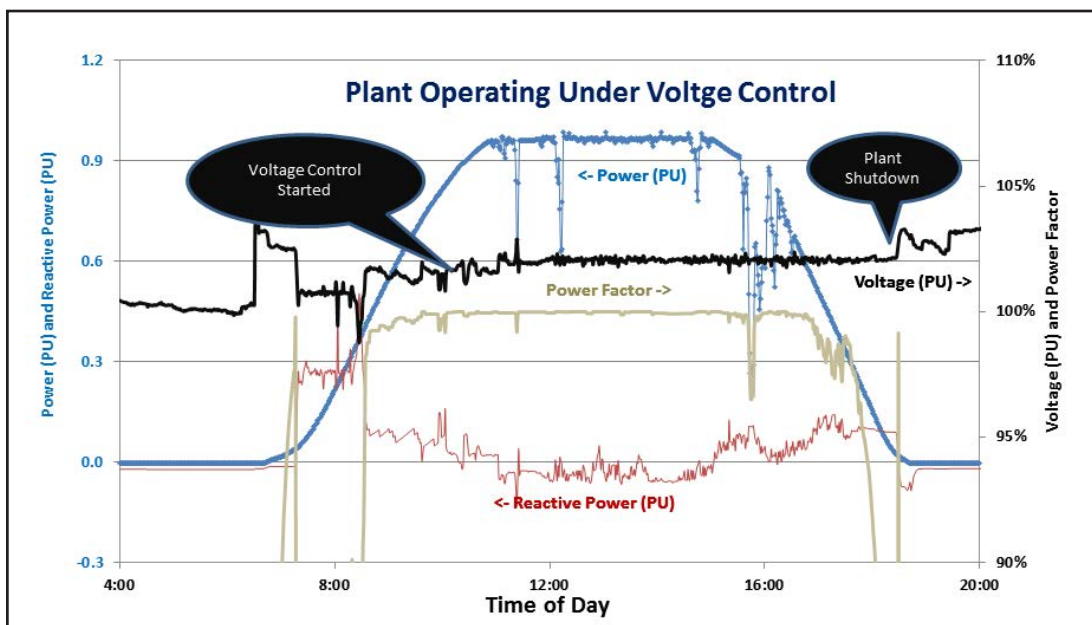
On March 21, 2014, the transmission line between the Palo Verde generating station and the Hassayampa substation was taken out of service. To avoid substantial deviation to the line voltage, the grid operator employed the “grid-friendly” features of the

Agua Caliente plant to support maintenance of the line voltage. By changing the mode of the PV plant operation, the line voltage was stabilized, and when the PV plant went off-line at sunset the line voltage started to fluctuate again.

This event provides some key lessons. First, the ability to operate the plant in various modes is critical to grid stability and reliability. Second, even though features such as voltage regulation, active power controls, ramp-rate controls, fault ride through, and frequency control may not be mandated, the value of PV plants with these features to grid operators is evident when called upon to support the grid. In summary, the development of “grid-friendly” PV plants is improving the reliability and stability of the grid, and the growing sophistication and accuracy of short-term solar generation forecasts are facilitating efficient and reliable system operations.

Agua Caliente PV plant interconnects to 500 kV transmission line in Western Arizona.





Agua Caliente PV plant supports maintenance of line voltage on March 21, 2014.

Project Contact

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Company Description

MidAmerican Renewables, LLC owns and operates wind, geothermal, solar and hydro projects in the unregulated renewables market. MidAmerican Renewables is headquartered in Des Moines, Iowa, and has offices in Phoenix, Ariz., and Calipatria, Calif. Information about MidAmerican Renewables is available on the company's website at www.midamericanrenewablesllc.com.

“Availability of solar increases the extent to which the battery can ride through an outage, and if assumptions prove correct, the grid-supported micro-grid will reduce customer service interruptions.”



NorthWestern Energy

Grid-Supported Microgrid

Technology Partner(s)

Project Highlights

- NorthWestern Energy is testing new technology to improve electric reliability through integration of grid-supported backup power, renewable generation, and battery energy storage.
- The project will determine at what price point a “grid-supported microgrid” becomes economically viable.
- The project will provide potential alternatives to improve rural reliability and develop an economic model for future scalability.

Project Description

NorthWestern Energy is siting a 40 kW photovoltaic (PV) system with battery backup on a poorly performing rural circuit tap near Butte, Montana to determine its potential to improve electric reliability and at what price point the concept of a “grid-supported microgrid” becomes economically viable. The project is designed to measure reliability improvements with an established baseline, track system efficiency through device monitoring, perform ancillary services as needed (i.e., peak load shaving), and optimize the design to develop an economic model for future scalability.

The system is sized to match about 40 percent of the average annual load for the connected customers: an 80 kW peak load capacity battery and an 80 kW inverter. When in grid-connected mode, the solar system will charge the battery and work in tandem with the battery to support the inverter’s ancillary capabilities. When solar is unavailable, the battery is supported by the grid.

In the event of a fault on the 14.4 kV line supporting the area, the microgrid enters “island” mode, and the battery provides service to approximately 13 customers on the microgrid. First, the recloser on the line opens and sends an open command signal to the automatic transfer switch noting that the fault is upstream of the recloser, prompting a switch to back up power. The battery, which remains connected to the line and to the solar PV, will support voltage and frequency services until the battery is discharged. Availability of solar increases the extent to which the battery can ride through an outage. If assumptions prove correct, the grid-supported microgrid will reduce customer service interruption metrics. During islanding the customer will experience a momentary outage when switching to A/C backup power and a second momentary outage when restoring grid-connected operations as the automatic transfer switch closes the recloser, restoring power.

40 kW PV system with battery backup grid-supported microgrid.



The project is entering the final stages of engineering design and is expected to be completed by mid-2015. NorthWestern Energy will be conducting several simulations to determine if the system is working as intended.

Project Contact

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Company Description

NorthWestern Energy provides electricity and natural gas in the Upper Midwest and Northwest, serving approximately 678,200 customers in Montana, South Dakota and Nebraska. More information on NorthWestern Energy is available on the company's website at www.northwesternenergy.com.

***“This pilot demonstrates
the concept of storage
supporting both energy
and frequency
regulation markets.”***



*Pacific Gas and
Electric Company®*

Pacific Gas and Electric Company

Battery Energy Storage System Pilots

Technology Partner(s)

NGK Insulators, LTD.

S&C Electric Company

Project Highlights

- Successfully deployed two grid-scale battery systems for PG&E.
- Developed new dispatch control system for energy storage to enable distribution support and CAISO market service multi-function use.
- First resource to participate in California's CAISO new Non-Generator Resource (NGR) energy and frequency regulation markets.
- Demonstrated exceptional accuracy following CAISO automatic generation control signal during frequency regulation.
- Successfully demonstrated smoothing of intermittent renewable (solar and wind) generation.
- Supports California mandate of 1,325 MW of cost-effective electricity storage in place by end of 2024.

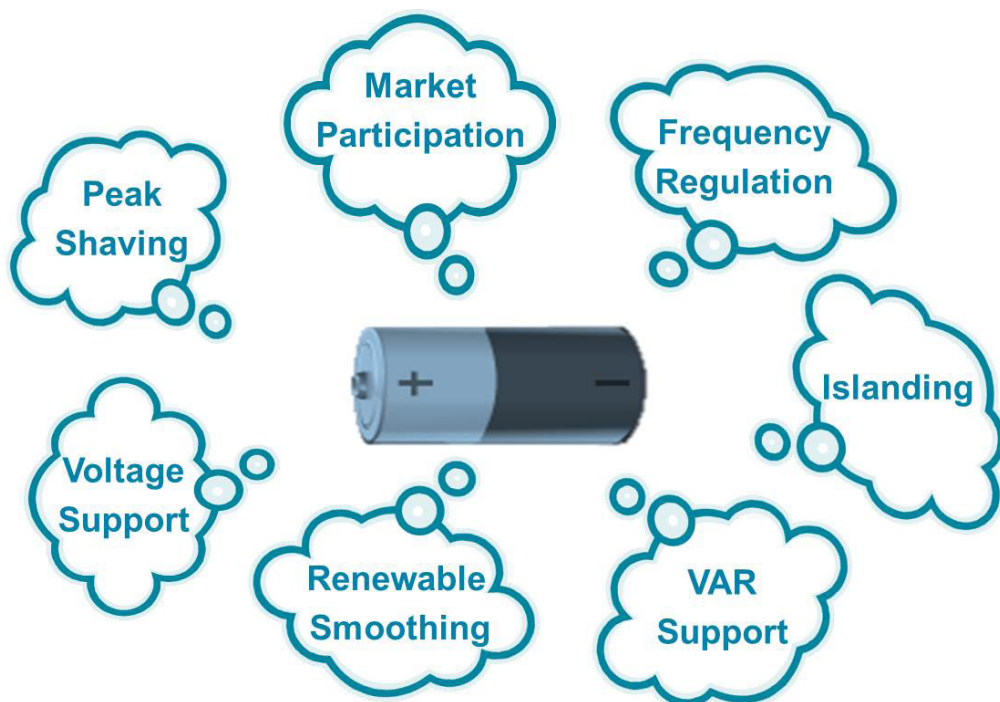
Project Description

Pacific Gas & Electric (PG&E) has deployed two battery energy storage systems (BESS) as pilot projects. The Vaca-Dixon BESS is a 2 MW / 14 MWh BESS deployed at PG&E's Vaca-Dixon Substation in Vacaville, CA. The Yerba Buena BESS is a 4 MW / 28 MWh BESS deployed at the end of a distribution feeder in San Jose, CA. Both utilize sodium-sulfur batteries supplied by NGK Insulators, LTD. of Japan. The systems are being used to test and demonstrate a variety of functionalities of grid-scale battery storage, including peak-shaving, participation in California electricity markets, integration of intermittent renewable generation, and in the case of the Yerba Buena BESS, islanding during grid disturbances.

Under a project funded by California's Electric Program Investment Charge (EPIC), PG&E is utilizing the Vaca BESS to conduct a robust exploration of participation in the California ISO (CAISO) energy and ancillary services markets, including enabling full automation in CAISO markets. Under a grant from the California Energy Commission, which also supplied some funding for the deployment of the systems, the Yerba Buena BESS is being used to study the performance of battery storage for peak shaving, improving power quality and reliability, integrating intermittent renewable generation, and participating in CAISO ancillary services markets. This work is being done in collaboration with EPRI, which is authoring reports on these functionalities along with engineer of record reports for both systems.

PG&E began operational testing of the Vaca BESS in late 2012. This testing characterized baseline system characteristics for use in evaluating resource performance over its lifetime, and confirmed that the system met or exceeded its operational specifications. Preliminary testing began with CAISO in the fall of 2013. As this was the first resource to participate in CAISO's Non-Generator Resource (NGR) market model developed for limited energy storage resources, both PG&E and CAISO used this testing to identify and resolve technical issues in scheduling and telemetry. Market operations were put on hold pending finalization of a storage interconnection process by PG&E's Electric Generation Interconnection group and deployment of a new dispatch control system developed for managing energy storage. Both were completed in July, 2014 and the resource began participating in the CAISO NGR day-ahead energy market. In September, frequency regulation was added to this participation and as of November, 2014, the resource has logged approximately 100 hours providing both regulation up and regulation down services. This is part of a project under California's EPIC program to robustly explore the real-world performance of battery storage in CAISO's NGR market, and deploy technology to fully automate battery response in CAISO markets.

The Yerba Buena BESS project began operational testing in the fall of 2013. This has included testing for its islanding functionality, in which the system can disconnect



Testing a variety of functionalities for grid-scale battery storage.

from the distribution feeder in the event of a utility disturbance or outage and supply downstream loads. Other testing has been conducted to study the system's impact on system reliability, power quality, and renewable integration under a grant from the California Energy Commission (CEC). The system will also be connected into and participate in the CAISO NGR market, and is in the latter stages of the New Resource Implementation Process for doing so. It is planned that approximately half the energy capacity of the system will be used for distribution support and half for CAISO market services.

Due to the newness of this technology and its multiple functional capabilities, bringing these projects online has required overcoming a number of organizational, technological, and financial challenges. The BESS Pilot Project team has worked closely with staff across PG&E to ensure that lessons learned from these projects inform future procurements of energy storage, particularly with regard to PG&E's upcoming request for offers (RFO) for storage, for which the team helped develop technical specifications to be provided to participants and clear definitions on how systems would be tested to verify their performance. This RFO is in

response to California’s mandate for energy storage (the first in the U.S.), requiring the state's three major investor-owned utilities to have 1,325 MW of cost-effective electricity storage capacity in place by the end of 2024. Implementing this mandate will

allow the most promising and cost-effective energy storage projects to be developed. PG&E’s allocation of the 1,325 MW is 580 MW. On December 1, 2014, PG&E issued its first of four RFOs to procure energy storage.

Project Contact

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Company Description

Pacific Gas and Electric Company is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, the company is a subsidiary of PG&E Corporation. The company provides natural gas and electric service to approximately 16 million people throughout a 70,000 square-mile service area in northern and central California.

“With penetration levels of distributed generation growing, utilities increasingly require tools that can more accurately analyze the complex impacts of such resources on the grid.”



PNM Resources

Geographic Information System (GIS) Data Converter

Technology Partner(s)

Electric Power Research
Institute (EPRI)

University of New
Mexico (UNM)

Project Highlights

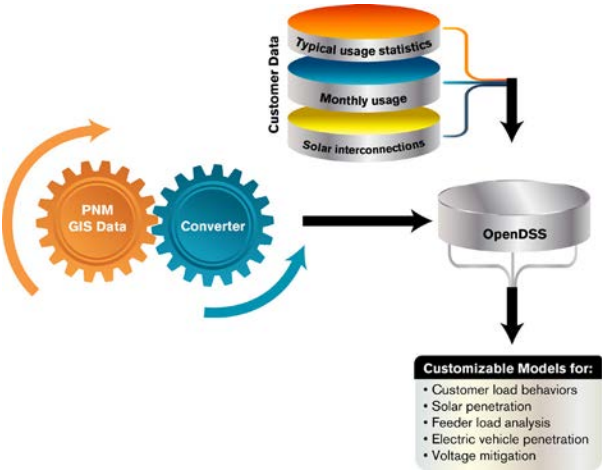
- Allows for more accurate modeling of impacts from distributed generation on PNM's utility systems.
- Converts PNM's GIS data for an entire circuit into OpenDSS in minutes.
- Analyzed 20 circuits with the most installed solar PV to understand solar impacts on different circuit types and in combination with storage, smart inverters, and electric vehicles.
- Spurred development of a new course at UNM on advanced grid technology modeling, leveraging PNM's tools and data.

Project Description

The PNM GIS Data Converter project was undertaken to automate the time consuming process of converting the company's locational and spatial data for utility assets such as transformers and relays, commonly referred to as GIS data, into the EPRI software tool OpenDSS. With penetration levels of distributed generation (DG) growing, especially solar photovoltaic (PV), utilities increasingly require tools like OpenDSS that can more accurately analyze the complex impacts of such resources on the grid. Existing analytical tools in many utilities are limited in their ability to capture the real-time behavior of DG systems, and instead view these systems in a steady state. For utilities that do not have advanced metering infrastructure (AMI), dynamic modeling provides the best approach to understanding the impacts of DG on a utility's system. OpenDSS enables this type of enhanced modeling by allowing impacts on a distribution system to be estimated in increments as granular

as a second. It also enables the analysis of interactions between the increasing number of systems on the distribution system. Although the opportunity to utilize a tool like OpenDSS is tremendous, transferring utility asset data into the program can be a cumbersome manual process. For example, it took PNM over three years to convert a single circuit's GIS data into OpenDSS. PNM, in collaboration with students at UNM, developed an application that takes the GIS information from PNM's database and converts it to a format that OpenDSS recognizes. The converter enabled replication of the GIS data for multiple PNM circuits in minutes, compared to the several years it had taken previously. Once this was completed, PNM's monthly customer usage data, statistics related to typical daily customer usage, and information from customer solar PV interconnections were loaded into OpenDSS to create detailed models. These models are now being used to analyze the 20 circuits with

GIS data conversion for dynamic distribution system modeling in Open DSS.



the most installed solar PV on the company's utility grid, identifying potential impacts on a time scale allowed by the most granular information available from the systems.

PNM also plans to use these tools to simulate adoption of other emerging technologies, such as electric vehicles, battery storage, and even smart inverters on a given circuit. For example, as PNM responds to customers' demands for electric vehicles, the modeling of various levels of electric vehicle penetration on the system will allow the company to determine grid investments and policy needs to seamlessly support these technologies, individually or in conjunction with solar PV and smart inverters. The predictive value of these models will help PNM be proactive and supportive in the face of new demands placed on the grid and new opportunities in the service territory.

As an added benefit, the collaborative effort with UNM spurred the creation of a new course for engineering students on

modeling advanced grid technologies. The students' curriculum is being created with the input of PNM's Distribution Planning and Advanced Technology departments, along with EPRI. Projects conducted by students to date have tackled several challenges with solar PV, including the development of hosting capacity metrics based on varying thresholds and parameters, reverse power flow analysis, and voltage fluctuation studies. PNM also views the collaboration with UNM as helping to develop the next generation of the utility workforce. Multiple graduates from UNM that either participated in the efforts to develop the converter, or had taken the modeling class, have been hired by PNM. EPRI's "Integration of Distributed Renewables" program is benefiting from the converter as well. The EPRI initiative provided UNM funding for a student in the modeling course to perform analysis related to their program, utilizing PNM's converter.

Project Contact

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Company Description

With headquarters in Albuquerque, PNM is the largest electricity provider in New Mexico, serving 500,000 customers in dozens of communities across the state. PNM is a subsidiary of PNM Resources, an energy holding company also headquartered in Albuquerque. For more information, visit PNM.com.

***"Smart grid technologies,
like those demonstrated
at the Salem Smart Power
Center, represent an
opportunity to enhance
the value customers receive
from the electric system."***



Portland General Electric

Integrated Energy System Demonstration at Salem Smart Power Center

Technology Partner(s)

Eaton
EnerDel

Project Highlights

- Distribution microgrid with intelligent economic dispatch and distribution management.
- 5 MW / 1.26 MWh lithium-ion battery array.
- Incorporates commercial demand response.
- Demonstrates integration of solar PV with energy storage and demand response.

Acknowledgment

PGE's Salem Smart Power Project team is pleased to acknowledge the work of its partners and suppliers on this project, especially the project staff at Battelle, located in Richland, WA, for their guidance and support in technical and administrative matters. This material is based upon work supported by the U.S. Department of Energy under Award Number DE-OE0000190.

Project Description

Portland General Electric's Salem Smart Power Center (SSPC), which opened May 2013 in Salem, Oregon, is the Pacific Northwest's only substantial microgrid and a first-of-its-kind integrated energy system. Featuring a 5 MW lithium-ion battery-inverter system that stores 1.26 MWh of energy, the SSPC is one of just two such grid-connected batteries owned and operated by an investor-owned utility.

The SSPC is comprised of thousands of battery cells that are stored in racks and wired together into a single system. Building the battery facility was challenging, but the real innovation in the project has been integrating the technologies. With many of the involved technologies new to the market, coordinating communication between the system and components was complex. Additionally, due to the high energy density of the SSPC, a unique fire control system was specially designed for the facility, including giant fans to maintain constant battery temperature.

With the foundation of a smart grid already in place – 800,000 smart meters – the SSPC demonstrates how groundbreaking technologies such as feeder islanding, distribution automation, demand response, renewable energy integration, and transactive energy controls can work together to supply more sustainable, efficient, resilient, and reliable power.

PGE has partnered with a local potato chip maker – Kettle Brand, whose factory facility generates distributed solar power – to

demonstrate the ability of the SSPC battery array to deliver high reliability to solar customers. PGE developed a custom algorithm for the project to demonstrate how the battery can combine with solar generation systems to fill in the gaps when the sun isn't shining and offer a seamless power flow. This is one of few installations completed by the utility industry to prove these concepts and demonstrate the viability of energy storage as a solution for integrating solar energy.

While the technologies used in this project are currently too costly for widespread application, PGE determined that:

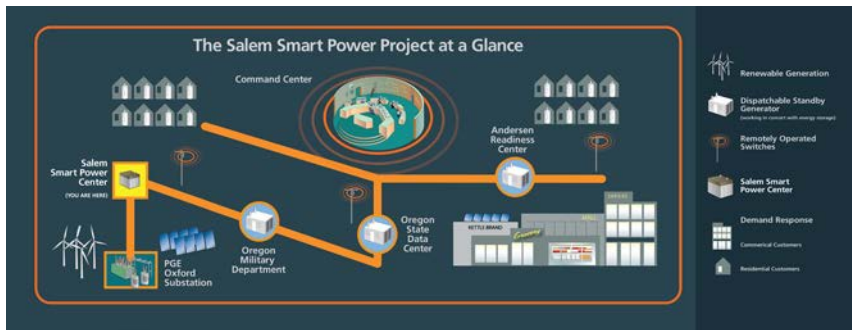
- The energy storage system is an economically viable solution for responding to frequency regulation events.
- A low-cost algorithm can be implemented for under-voltage load shedding events.
- The battery system can seamlessly integrate real-time solar energy to peak shave and firm the feeder load profile.

The project was part of the five-year, \$178 million Pacific Northwest Smart Grid Demonstration Project (PNW-SGDP) – a unique and collaborative demonstration of unprecedented technologies across five Pacific Northwest states managed by Battelle. Now complete, the key focus of the PNW-SGDP was to test how physical assets like batteries and renewable resources could partner with virtual energy assets like demand response to react to price and power supply signals.

Smart grid technologies represent an opportunity to enhance the value customers receive from the electric system. Integrating smart grid technologies into existing infrastructure continues to be a significant challenge – one that involves not only leveraging new technology, but

also making major changes in the way electricity is provided and used. In the future, PGE will continue to use the SSPC as a lab to develop and test smart grid technology, renewable energy integration, and other key features of the future electric grid.

Overview of the Salem Smart Power Project.



Project Contact

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Company Description

Portland General Electric, headquartered in Portland, Oregon, is a fully integrated electric utility that serves approximately 842,000 residential, commercial and industrial customers in Oregon. PGE has consistently delivered safe, reliable and responsibly generated electricity in northwest Oregon since 1889. We rely on several different sources to effectively balance power supply resources with customer demand which contributes to higher reliability and more stable prices for our customers. For more information visit our website at PortlandGeneral.com.

"PSE&G's 125 MW Solar 4 All Program helps New Jersey reach its solar power goals, promotes a cleaner environment, turns landfills and brownfields 'green' with solar power, and spurs job creation."



Public Service Electric and Gas Company (PSE&G)

Solar 4 All™

Project Highlights

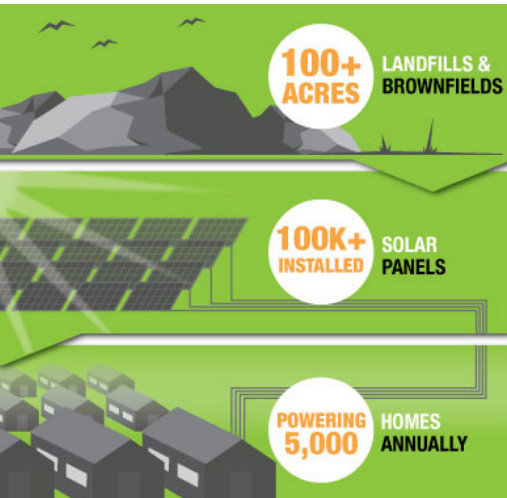
- 125 MW (DC) grid connected solar program; 80 MW (DC) in service as of October 2014.
- Largest pole-attached solar project in the world; 174,000 units.
- 24 centralized solar sites in service.
- One landfill solar farm in service; two under construction. Four brownfield solar farms in service. In total, the program has returned over 110 acres of landfill and brownfield space to good use.
- Solar 4 All™ will power more than 20,000 homes annually.

Project Description

Solar 4 All is a 125 MW (DC) program that utilizes rooftops, solar farms, utility poles, and landfills/brownfields for large-scale, grid connected solar projects. As of October 2014, 80 MW of the 125 MW total are in service.

Solar 4 All helps New Jersey reach its solar power goals, helps promote a cleaner environment, turns landfills and brownfields 'green' with solar power, and spurs economic development by creating jobs and making New Jersey a center for solar development. Since 2009, Public Service Electric & Gas Company (PSE&G) has invested more than \$480 million in the Solar 4 All program, creating more than 1,600 jobs while also benefiting PSE&G customers by connecting solar power directly into the PSE&G electric grid. Solar 4 All will eventually provide enough solar electricity to power about 20,000 average-size New Jersey homes annually.

PSE&G turns NJ Landfills into solar farms.



The 80 MW of Solar 4 All capacity that is currently in service features 40 MW of pole-attached solar and 40 MW of centralized solar. The pole-attached portion is the first and largest solar project of its kind in the world, and saves space while generating highly distributed solar energy. A 40 MW solar farm would require about 130 acres of space, or about 170 football fields, while the pole-mounted solar units occupy no real estate. More than 174,000 solar units are installed in PSE&G's electric service territory around the state.

The pole-attached initiative also includes a communications system that monitors the performance of each unit using a self-correcting mesh network. System data is used for reporting energy production and to identify under-performing units requiring maintenance. Likewise, there is a monitoring system for each of the centralized Solar 4 All solar farms, that is used to monitor the sites and measures similar parameters.

The centralized portion of Solar 4 All features 24 roof and land-mounted solar farms. Ten of these projects are built on PSE&G-owned property and the other 14 are built at third-party lease sites including four Newark Public Schools, the Community FoodBank of New Jersey, and Rider University. These third party lease arrangements help institutions unlock the economic value of unused roof and land space.

Solar 4 All is also helping to turn landfills and brownfields green. Of the 24 centralized solar projects currently in service, four are

located on PSE&G remediated brownfield sites (Trenton, Edison, Linden, and Hackensack) and one is located on a closed landfill site in Kearny. These sites provide more than 10 MW of solar capacity.

There are two additional landfill solar sites under construction – the Parklands Solar Farm in Bordentown and the Kinsley Solar Farm in Deptford. Both of these projects are more than 10 MW in size. In the spring of 2015, when the Parkland and Kinsley projects are in service, PSE&G will have returned more than 110 acres of landfill and brown-field space across the state to good use by

installing more than 106,000 solar panels, capable of generating more than 31 MW of solar power, which is enough to power about 5,000 homes annually.

PSE&G is further authorized to build two to three more landfill solar farms by the end of 2016 that will add just over 20 MW of additional solar generation to Solar 4 All. The program will also support 3 MW of solar generation through pilot programs featuring unique solar technologies centered on energy storage, innovative parking lot solar applications, and grid-reliability/storm preparedness technology.

Project Contact

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Company Description

Public Service Electric and Gas Company (PSE&G) is New Jersey's oldest and largest regulated gas and electric delivery utility, serving nearly three-quarters of the state's population. PSE&G is the winner of the ReliabilityOne Award for superior electric system reliability. PSE&G is a subsidiary of Public Service Enterprise Group Incorporated (PSEG) (NYSE:PEG), a diversified energy company. www.pseg.com.

"The Preferred Resources Pilot represents an innovative approach to meeting customers' electricity needs by providing reliable power from diverse resources."



Southern California Edison

Preferred Resources Pilot

Technology Partner(s)

Clean Power Research

FirstFuel

Lawrence Berkeley
National Laboratory

Navigant

Sentient Energy

Project Highlights

- SCE launched the Preferred Resources Pilot (PRP) in November 2013 to determine if preferred resources (energy efficiency, demand response, distributed generation, and energy storage) can meet over 300 MW of anticipated growth in electrical demand in a region served by two substation by 2022.
- SCE will implement an integrated grid project (IGP) in a portion of the PRP area to analyze the distribution circuit impacts of higher penetrations of preferred resources.
- By the end of 2017, the utility will evaluate preferred resources' performance capabilities to support deferral or elimination of the need for new gas-fired generation in the PRP region.
- The pilot's goal is to confirm the system availability of preferred resources to meet the reliability needs in the PRP region by 2022.

Project Description

Southern California Edison's (SCE's) Preferred Resources Pilot (PRP) is focused on supporting the company's core mission – safely meeting our customers' needs with reliable and affordable electricity – by conducting a multi-year pilot to investigate and demonstrate how the integrated use of preferred resources (energy efficiency, demand response, clean distributed generation, and energy storage) may meet the growth in electricity demand in the PRP region. The PRP region is a transmission-constrained area of SCE's service territory encompassing 250,000 customers. This area has an anticipated load growth of more than 300 MW by the year 2022. It is most directly affected by the closure of the San Onofre Nuclear Generating Station (SONGS) and will be affected should the nearby ocean-cooled power plants close in 2020 as part of California's "once-through" cooling policy. SCE seeks to meet the expected load growth through the use of preferred resources and thereby satisfy the reliability needs in the region.

The PRP seeks to design, acquire, and measure a diverse portfolio of preferred resources to meet the forecasted electricity demands in the PRP region. Successful resource acquisition requires understanding the resources' delivery capabilities in terms of meeting peak needs and accounting for the achievable resource potential. SCE's most recent market potential study estimates that through the year 2017, approximately 65 MW in potential peak demand reduction can be achieved through energy efficiency measures in targeted sectors and

81 MW reduction in potential peak demand can be achieved from demand response. It is expected that the market can fill the remaining needs with distributed generation and energy storage.

SCE launched the PRP in 2013 by reaching out to and engaging customers, energy policy makers, regulators, and electric system operators; completing a local, integrated resource plan; and developing a framework and process to measure the performance capabilities of preferred resources. In the coming years, SCE will continue to engage stakeholders, acquire preferred resources to meet the expected growth, look for innovative opportunities to improve the use of preferred resources, and quantify the grid-level contributions from preferred resources.

Results from the PRP will also inform the development of the grid of the future and contribute toward California's progressive environmental and renewable energy goals. Meeting the PRP's goal of managing the local load growth may reduce or eliminate the need to construct new natural gas plants in the PRP target area. By the end of 2017, SCE will use data collected from the pilot to evaluate preferred resources' performance capabilities to support deferral or elimination of the need for new gas-fired generation in the PRP region.

The PRP represents an innovative approach to meeting customer's electricity needs. One of its key goals, which is to manage load growth in the PRP region to net-zero solely



The Preferred Resources Pilot meets local energy needs in alternative ways.

with clean resources, is unprecedented for SCE. It also departs from SCE's past practice of procuring clean resources simply to meet state energy policy goals, adding the need to meet local reliability requirements as a driver of clean resource acquisition. Finally, it represents an additional departure from SCE's current practice of conducting

top-down, system-wide integrated resource planning to a bottom-up, targeted planning approach.

Additionally, SCE is incorporating a localized integrated grid project (IGP) in an area of the PRP target region to test advanced automation, enhanced communication networks, and grid-management systems that may enable enhanced integration of preferred resources in a

concentrated area. The information learned from the IGP will support development of the clean electric grid of the future throughout SCE's service territory.

For more information, please visit <http://on.sce.com/preferredresources> or <http://edison.com/preferredresources>.

Project Contact

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Company Description

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal, and Southern California. www.sce.com.

“The Tehachapi Energy Storage Project is one of the largest lithium-ion battery systems in the world and will allow SCE to evaluate how storing and dispatching large amounts of energy may improve the flexibility and reliability of the next-generation grid.”



SOUTHERN CALIFORNIA
EDISON[®]

An *EDISON INTERNATIONAL*[®] Company

Southern California Edison

Tehachapi Energy Storage Project

Technology Partner(s)

ABB

LG Chem

Quanta Technology

Project Highlights

- 8 MW / 32 MWh lithium-ion battery system connects a 12 kV system to sub-transmission system via 12/66 kV step up transformer.
- Uses two power conversion systems rated at 4.5 MVA each (9 MVA total).
- Contains 604 racks, 10,800 modules, and 604,800 lithium ion cells in a 6,300 square foot facility.
- The project will evaluate 13 operational use cases of battery energy storage systems for transmission, systems, and market applications.

Project Description

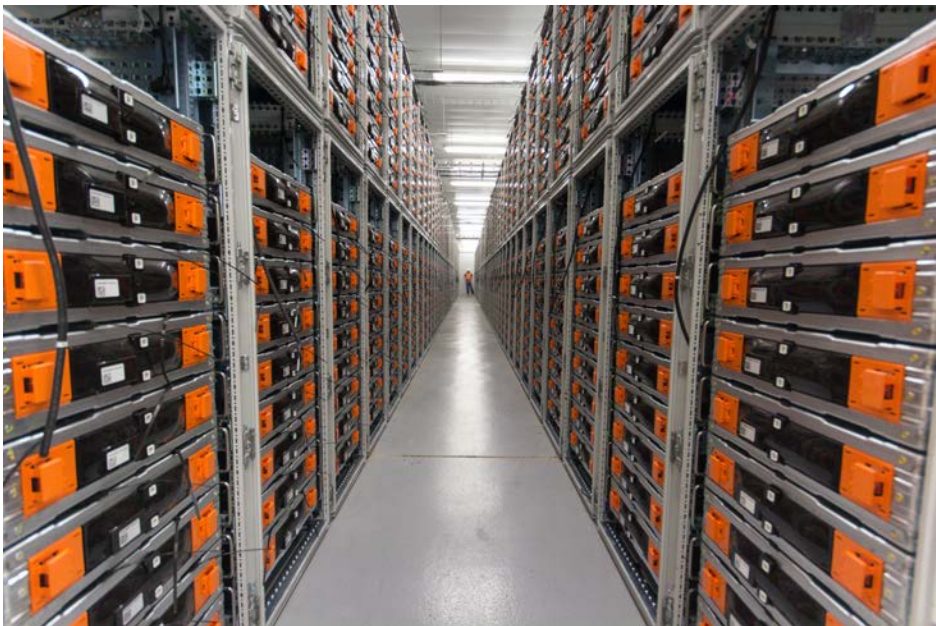
The Tehachapi Energy Storage Project (TSP), funded by SCE and the Department of Energy as part of the American Recovery and Reinvestment Act, is one of the largest lithium ion battery systems in the world, with 8 MW of power and capable of storing 32 MWh of energy.

Located at Monolith Substation, in Tehachapi, CA, TSP is a demonstration to further SCE's understanding of energy storage, evaluate the capability of utility-scale lithium-ion battery technology and smart inverters to improve grid performance, and assist in the integration of variable renewable energy resources. The area is part of the Tehachapi Wind Resource Area, currently capable of delivering over 2,000 MW of renewable energy. Though lithium-ion

battery technology has been tested at a smaller scale and is currently being used in hybrid and electric vehicles, it has not been widely deployed for large scale utility purposes. The ability to store large amounts of energy will help SCE improve the flexibility and reliability of the next-generation grid.

Thirteen operational uses of the battery energy storage system are being evaluated. There are three general evaluation categories: transmission uses, system uses, and California Independent System Operator (CAISO) market uses. The transmission uses evaluate the ability of the battery system to resolve capacity and stability issues on transmission systems, especially those with interconnected wind resources. System uses provide for a means of meeting the system

SCE Tehachapi battery array.



electricity needs with stored energy. The CAISO market uses evaluate the ability of the battery system to provide benefits to the grid in ways that meet specific needs of the system operator.

Several of the operational uses may be used to explore the practical business implications associated with evaluating grid-connected lithium-ion battery energy storage. Specifically, the project demonstrates the ability of lithium-ion battery storage to minimize the need for fossil fuel-powered back-up generation.

One innovative idea employed over the course of this project has been the development of a fully functioning “mini-system” at SCE’s lab in Pomona. The Pomona mini-system has two racks of batteries, as compared

to Tehachapi’s 604 racks. This mini-system has allowed SCE both to test all functionality of the system for safety and operational readiness in a controlled lab environment before implementing the full version into service on the grid, and to test new control and operating schemes that are not dependent upon conditions in the field. The mini-system allowed the utility to fine-tune the system before installation, shortening the commissioning process.

TSP is one of a number of battery storage testing projects that SCE is undertaking. Results will allow SCE to better understand the technology and how it may be deployed as the utility moves towards meeting the California requirement for SCE to procure 580 MW of energy storage by 2020.

Project Contact

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Company Description

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation’s largest electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal, and Southern California. www.sce.com.

***"The Bright Tucson
Community Solar
Program democratizes
access to solar energy. A
block of solar energy costs
\$3 per month, less than a
premium cup of coffee!"***



Tucson Electric Power

Bright Tucson Community Solar Program

Technology Partner(s)

University of Arizona

Project Highlights

- Community solar program empowers Tucson Electric Power (TEP) customers to purchase solar energy "blocks" of 150 kWh at a rate that adds just \$3 per month to electric bills.
- Launched in 2011, the program has grown quickly, from 532 customers purchasing 334 MWh of solar energy in the first year to 1,200 customers who purchased over 3,300 MWh of solar energy in 2014.
- Community solar democratizes access to solar, eliminates cost-shifting to non-solar customers, costs less than rooftop solar, and is regarded favorably by regulators and elected officials.

Project Description

Tucson Electric Power’s (TEP’s) Bright Tucson Community Solar (BTCS) program, launched in 2011, offers most residential and business customers an easy and affordable way to meet their electric needs with locally generated solar power. TEP’s community solar program has two core components. First, the utility sites, procures, and manages the solar photovoltaic (PV) project, determining the location and scale of the project. Second, residential and commercial customers are eligible to purchase solar energy from that project and can choose the amount to purchase.

In developing BTCS, one of TEP’s goals was to offer a solar program to its residential and commercial customers, especially those who could not or did not want to participate in rooftop solar. This includes customers who live in condominiums or apartments, customers in single family homes unsuited to rooftop solar, customers who find the upfront costs of rooftop solar prohibitive, customers who don’t want to make a long term commitment to solar, and others. Basically, BTCS was designed to be

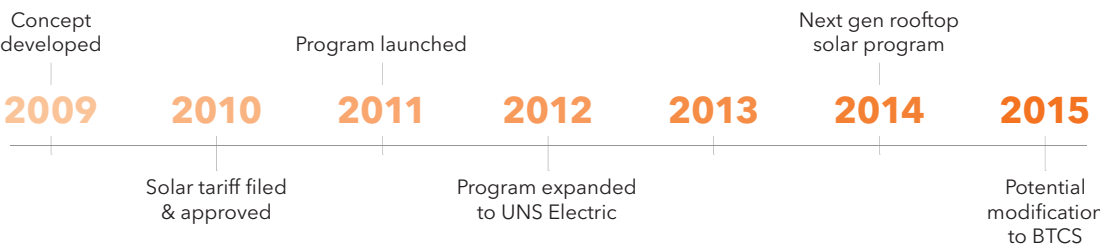


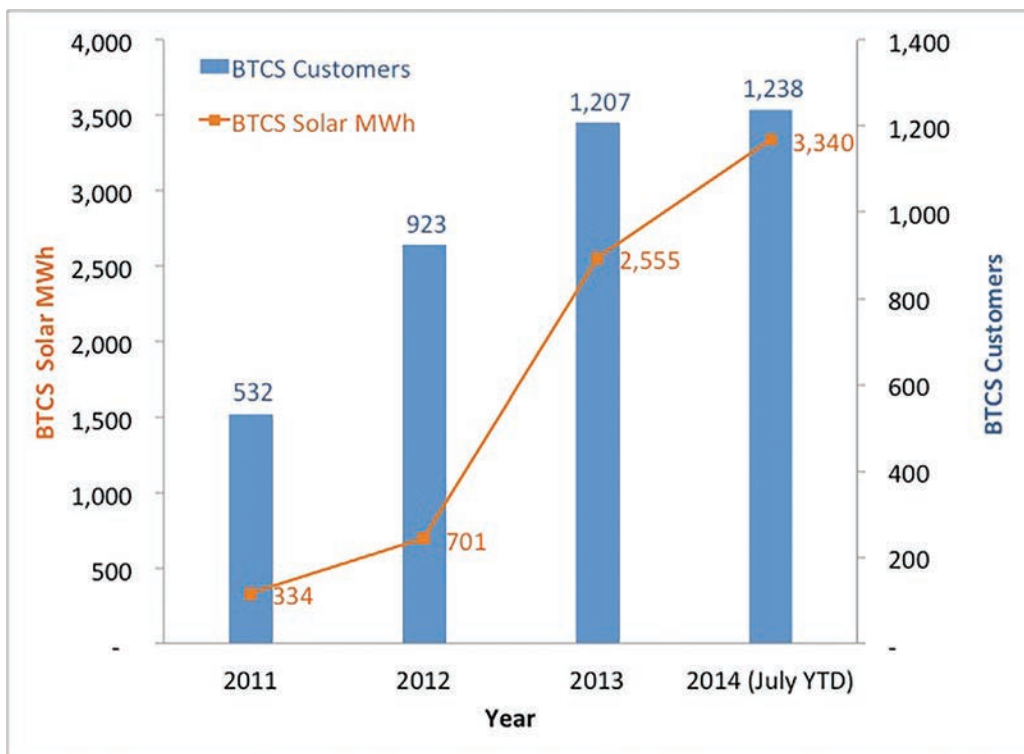
Community solar at University of Arizona Science and Technology Park.

a solution for the diverse set of customers in the Tucson area. But, the program has evolved and is now also an innovative and cost-effective solution for larger customers, including municipal governments.

Under BTCS, customers purchase solar energy “blocks” in 1 kW increments equal to 150 kWh for just \$3 a month through a solar tariff that adds about 2 cents per kWh to the customer’s average rate, giving all customers access to solar energy at very reasonable prices. Customers can subscribe up to their average monthly kWh consumption. For example, a customer with an average monthly consumption of 900 kWh would be eligible to purchase as much as 6 blocks

TEP's Bright Tucson Community Solar (BTCS) Program Timeline.





The BTCS Program grew from 334 MWh in 2011 to 3,340 MWh by July 2014 through customer purchases of blocks of community solar energy.

of solar energy for a premium of \$18 per month or as little as a single 150 kWh block of solar energy each month. When a customer purchases a block of solar energy, the customer receives an offsetting discount to the fuel and purchase power charge as well as the renewable surcharge on the monthly bill. Customers that purchase solar under the BTCS program are not under a contract and are free to drop out of the program at any time.

Critical to the success of BTCS was its extensive community involvement, including the development of TEP's 1.6 MW solar

project at the University of Arizona Science and Technology Park, which offered the first blocks of solar for sale.

The BTCS program has a wide range of customers – residential customers, commercial customers, and communities. BTCS acquired 532 customers in its first year, who purchased a total of 334 MWh of solar energy. Customer engagement has increased rapidly over the past three years. Today BTCS boasts over 1,200 customers who purchased over 3,300 MWh of solar energy in 2014 – a 10-fold increase in just three years.

TEP found that program marketing drove customer engagement in the program. Going forward, TEP believes that BTCS should include an on-bill presentation of the benefits of the program. A lesson learned so far from BTCS is that some customers did not understand the value of BTCS because it was not clearly represented on the monthly billing statement. TEP intends to modify the bill presentation to make it more customer-friendly.

Summary of Key Advantages of Community Solar

- Community solar democratizes access to solar
- Community solar eliminates the cost shift to non-solar customers
- Community solar costs less than rooftop solar
- Community solar is regarded favorably by regulators and elected officials

Project Contact

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Company Description

Tucson Electric Power provides safe, reliable power to more than 414,000 customers in southern Arizona. TEP and its sister company, UniSource Energy Services, are among a family of utilities owned by Fortis, Canada's largest investor-owned gas and electric utility holding company. Fortis completed an acquisition of UNS Energy, TEP's and UES' parent company, in August 2014. To learn more, visit tep.com.

“Through an innovative partnership that will help the U.S. Army achieve its renewable energy and energy security objectives, TEP will provide Fort Huachuca with cost-effective solar power in an expedited fashion.”



Tucson Electric Power

Fort Huachuca Solar Power Project

Technology Partner(s)

E.ON Climate and
Renewables

Project Highlights

- 17.2 MW fixed PV array, with plans for future expansion beyond 20 MW.
- TEP will finance, develop, own, and operate the system at Fort Huachuca U.S. Army base in Sierra Vista, AZ.
- The PV system will help the U.S. Army achieve its renewable power and energy security goals without increasing energy costs.
- TEP will retain renewable energy credits for compliance with Arizona's renewable energy standard.

Project Description

Tucson Electric Power (TEP) is developing a large solar array to serve Fort Huachuca, a U.S. Army base in Sierra Vista, Arizona, through an innovative partnership that satisfies the Army's energy security and green power objectives while addressing utility challenges posed by distributed generation systems.

Base officials originally sought to own a large-scale photovoltaic (PV) system in support of the U.S. Army's goal of deploying one gigawatt of renewable energy by 2025. The development cost was prohibitive, though, and buying the output of such a system through a third-party lease would have increased the base's annual energy expenses by an estimated \$2 million. In light of these and other factors – including the prospect that a distributed generation (DG) system at the base would shift the recovery of fixed utility service costs to other customers – TEP developed an alternate approach to addressing the base's energy needs. TEP collaborated closely with the U.S. Department of Defense and the Army's Office of Energy Initiatives (OEI) (formerly the Energy Initiatives Task Force, or EITF) to establish a unique solution that allows both Fort Huachuca and TEP to achieve their green energy goals while mitigating impacts on other customers.

TEP will finance, own, and operate the system, combining its output with other grid resources to reliably serve all of the base's electric needs without any change to

existing rates. In this way, Fort Huachuca will achieve its renewable energy goals at no additional cost while TEP preserves its role as the base's electric service provider.

This first-of-its-kind partnership will deliver numerous benefits for the U.S. Army, Fort Huachuca, TEP, and its customers:

- By leveraging a seven-decade relationship with TEP as its electric provider, Fort Huachuca can count on the streamlined development of a high-quality renewable energy resource from a stable, trusted provider.
- Because TEP will own and operate the solar array, the entire system will be tied to the utility's existing substation through a single interconnection on the utility's side of the meter. When combined with energy storage and other future enhancements, an array thus configured will provide the base with unique energy security enhancements that would be unavailable through a third-party system.
- TEP will continue to serve Fort Huachuca's entire load, maintaining its exclusive relationship with a key customer and retaining revenue that would have been lost if the base reduced its consumption of grid power through use of a third-party DG system. Because TEP will preserve its ability to recover its fixed service costs through the base's existing rates, those costs will not be shifted to other customers, a common consequence of third-party DG systems.

- The Fort Huachuca project facilitates TEP's continued expansion of cost-effective, utility-scale PV systems. Because TEP will retain the renewable energy credits (RECs), the system will help the company comply with Arizona's Renewable Energy Standard.

A typical third-party DG project could not have delivered such broad benefits. To achieve them, TEP and the Army's OEI developed a collaborative contracting approach that could serve as a model for other utilities. Through delivery orders issued under its Area-wide Public Utility Contract with the General Services Administration (GSA), TEP is able to deliver energy and regulated energy management services to Fort Huachuca, thereby authorizing TEP's development and operation of the PV system. Through three successive 10-year term delivery orders with the GSA, the

parties ensured that TEP will continue to provide electric service to Fort Huachuca at rates approved by the Arizona Corporation Commission. The Department of Defense also entered into a 30-year easement with TEP authorizing the company's use of the land needed for the PV system and the interconnection facilities. While TEP was the first utility in the nation to employ this new contracting approach, it need not be the last. In fact, TEP and OEI designed this model so that it could easily be replicated at other military installations with a utility as the sole energy provider.

TEP has overseen design and construction of the system through a contract with E.ON, a partner on other successful solar power projects. The first 17.2-megawatt (MW) phase of the fixed PV system is expected to be complete by the end of 2014, with plans for future expansion beyond 20 MW.

Project Contact

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Company Description

Tucson Electric Power provides safe, reliable power to more than 414,000 customers in southern Arizona. TEP and its sister company, UniSource Energy Services, are among a family of utilities owned by Fortis, Canada's largest investor-owned gas and electric utility holding company. Fortis completed an acquisition of UNS Energy, TEP's and UES' parent company, in August 2014. To learn more, visit tep.com.

“Today’s distribution grid is evolving from a one-way, centralized power delivery system to a more open, flexible, multi-point system with a collection of technologies and assets.”



Distribution Grid Optimization

The U.S. electric power grid is evolving into a platform for integrating new energy services and technologies. This includes integrating greater amounts of renewable energy and distributed energy resources, providing customer solutions, and optimizing the power grid itself.

Today's distribution grid is evolving from a one-way, centralized power delivery system to a more open, flexible, multi-point system with a collection of technologies and assets, some controlled by the utility and some not. Managing the evolving distribution "grid of things" will require utilities to invest in upgrading their distribution platforms.

In the U.S., capital expenditures in the power sector are expected to total more than \$90 billion per year for the next several years. And, in the future, more of those capital expenditures are expected to be allocated to the distribution system and less to generation, signaling the growing importance of the distribution grid.

The case studies in this chapter demonstrate how utilities are investing in and upgrading their evolving distribution systems with an aim toward grid optimization.

Examples demonstrate that:

- Investments in field sensory equipment and communications and control technologies are giving utilities the ability to collect and channel information more quickly into integrated network management systems;
- Better integration of network operations information from end-point devices, such as smart meters, is providing notifications to field service restoration crews, helping them to avoid and to reduce customer outages;
- Faster fault location and intelligent, sectionalizing switches are allowing for rerouting of power flows, enabling the grid to self-heal;
- Data analytics and machine learning are helping utilities to identify power theft and feeder failure and to perform risk-based, preventive maintenance at substations; and
- Optimized voltage through integrated volt/VAR control is providing energy and capacity savings.

Grid Optimization Trends

Utilities are improving grid operational efficiency by integrating their systems, deploying smart sensing and automation technologies at points on the distribution grid, and continuously evolving the grid platform itself.

1. Systems Integration

Utilities are connecting legacy assets and systems and are integrating new systems as

they emerge. The convergence of information technology (IT) and operations technology (OT) systems is critical for scalability of the grid platform.

- Enel has integrated 11 source systems, including the billing system, outage management system, meter data management system, validated theft case data, Google for address verification, and other systems to improve operational efficiency and to reduce non-technical losses through advanced power fraud detection.
- Many utilities are integrating their automated metering infrastructure (AMI) and outage management systems (OMS) to improve outage management and restoration services.
- Utilities are integrating sophisticated weather forecasting models to develop predictive analytic capabilities. For example, DTE Energy is using a system that integrates hyper-localized weather forecasting models with the electrical distribution network to predict damage location and outage severity more accurately to optimize crew placement and to begin repair work sooner.

2. Point Solutions

Utilities are deploying instruments and sensors to fix known trouble spots, to advance a specific capability, or to provide visibility into a specific section of the grid. These point solutions are often a step in the evolution of an intelligent grid platform and can be leveraged once other system components are in place.

-
- For instance, Con Ed is using a high-powered digital X-ray instrument for in-service inspections of high-voltage underground transmission feeders. The digital X-ray, far clearer than conventional X-rays, allows Con Ed to identify compromised feeder joint components easily and to prevent electrical failure.
 - Conservation voltage reduction schemes, such as those underway at BGE, improve voltage and power factor management on the distribution system while reducing peak demand and energy consumption.

3. Intelligent Platform

As the grid becomes digitized and data-driven, the value of data to systems operations and situational awareness is dependent upon its relevancy, accuracy, time to process, and ability to communicate.

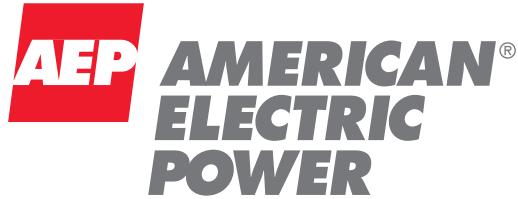
- The ability to communicate data in an effective manner is central to the success of CenterPoint Energy's Intelligent Grid project. Since 2011, CenterPoint has installed 750 intelligent grid switching devices on circuits in Houston and has fully automated 31 substations, avoiding nearly 100 million outage minutes. Key to this achievement are the wireless, secure telecommunications networks built by CenterPoint to transmit the smart meter power status notifications and execute remote switching commands.
- Economic interoperability of assets is fundamental to optimizing the distribution network. This challenge is a

long-standing one for utilities that purchase assets from multiple vendors. Duke Energy is working with a growing coalition of leading technology vendors to develop interoperability among disparate hardware, software, and communications systems. Duke's approach is unique in that it is using a field message bus that translates data into one common language and allows data to be easily shared among validated peers. This peer-to-peer communication allows data to be delivered quickly where needed without having to rely on a centralized management system. Rapid delivery of data is important to deal effectively with the variability of distributed energy resources, and Duke is demonstrating the value of interoperability and reduced latency for effective edge of network optimization.

Conclusion

Reliability and power quality remain key performance metrics for the power grid. As today's power grid evolves from a one-way, centralized power delivery system to a more open, flexible, multi-point system with distributed resources at the edges of the grid, optimizing the power grid means managing a grid that is much more dynamic, more decentralized, and more data-driven. That presents both challenges and opportunities.

"AEP's Asset Health Center tool transforms the conventional, time-based maintenance approach of asset sampling to one that acts upon specific, real-time equipment monitoring to build a smarter and better-performing grid."



American Electric Power

Asset Health Center Improves Infrastructure Decisions; Builds Smarter Grid

Technology Partner(s)

ABB

Project Highlights

- System-wide analytical tool judges the performance and longevity of transmission assets.
- Time-based maintenance of assets will be displaced by one that acts upon specific, real-time conditions of equipment.
- Risk of failure calculation is being completed for over 5,400 transformers, 3,000 circuit breakers, and 300 batteries.
- Benefits include better operational performance, financial outcomes, compliance, and safety.

Project Description

AEP and other utilities confront two major questions about decades-old infrastructure assets. How much longer will they last? When should they be replaced?

Getting answers has been elusive because of a blizzard of data from inspection reports and sensors and the long time needed to organize data into information for decisions. AEP Transmission has solved the dilemma by developing a system-wide analytical tool, the Asset Health Center (AHC), to judge the performance and longevity of assets and determine whether the lives of diminishing assets should be extended or ended for replacement.

An AEP review of infrastructure assets revealed that more than a third of its power transformers were 50 years old or greater, and nearly 20 percent topped 60 years. The report stated that the pace at which these assets either fail or need costly care to extend their lives will accelerate. Such findings called for a new approach to evaluating equipment end-of-life decisions.

AEP Transmission outlined the AHC concept in 2007. After further development with ABB, a leading power and automation company, AEP launched development of the industry's first system-wide AHC in late 2012. The AHC is a fully-fledged assessment tool that tracks asset health, predicts asset performance, and drives decision-making about asset management. AEP integrated analytical technologies created by ABB with AEP Transmission's supervisory control and data acquisition

(SCADA) system, integrated station information system (ISIS) database (a 15 year old application that will be replaced by the IPS Energy software package in early 2015), and operational and diagnostic expertise. AEP Transmission's Advanced Transmission Studies team leveraged the field operational and diagnostic expertise of the organization's Transmission Field Services (TFS) to formulate transformer and circuit breaker AHC algorithms.

By combining historical and recent data, the AHC clarifies the current performance and condition of each asset. That information enables TFS to focus its resource deployment on O&M or asset replacement. Specifically, AHC benefits customers and shareholders by helping the utility:

- Reduce the consequences of equipment failures (and outages) with real-time asset condition data, predictive analytics, and risk modeling.
- Achieve system reliability, power availability, high-quality performance, and compliance goals.
- Optimize workforce productivity and safety by targeting maintenance where it is most needed.
- Synthesize data to prioritize asset replacements/investments.

The AHC software will be deployed in successive phases over several years. In the first phase, 15 major substations containing hundreds of extra-high voltage (EHV) transformers, breakers, and batteries became fully monitored by the AHC

software. Phase 2, completed in September 2014, conducted a risk of failure calculation for over 5,400 transformers, 3,000 circuit breakers, and 300 batteries. Phase 2 also saw the implementation of monitoring data from transformer gas monitors, loading, and temperatures into the AHC software for over 75 transformers. An asset replacement dashboard was also created in Phase 2. In June 2014, AEP recorded their first prevented transformer failure due to the AHC project.

Future phases will include partial discharge monitoring data, bushing health monitoring data, and fault file data and an asset maintenance dashboard. The entire AEP

fleet of transformers, circuit breakers, and batteries will eventually be monitored and assessed through AHC algorithms and software.

The AHC project has enjoyed system-wide support and collaboration because it affects most AEP Transmission business units and is projected to improve operational performance, financial outcomes, compliance, and safety. The AHC transforms Transmission's conventional, time-based maintenance approach of asset sampling to one that acts upon specific, real-time conditions of equipment in a timely and direct fashion. Monitoring the health of key assets builds a smarter and better-performing grid.

Project Contact

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Company Description

Headquartered in Columbus, Ohio, AEP is one of the largest electric utilities in the U.S., serving over 5 million customers in 11 states. AEP Transmission, a division of AEP, operates a transmission system of more than 40,000 miles – the largest in the nation. It supplies about 10 percent of the demand in the Eastern Interconnection, and 11 percent of the demand in ERCOT, covering much of Texas. The backbone of AEP's transmission network is its 2,100 miles of 765 kV lines, more miles of 765 kV transmission lines in service than all other U.S. electric utilities combined. For more information visit AEP at www.aep.com.

“Conservation voltage reduction at BGE provides additional demand and energy savings to customers through improved voltage control enabled by modern software, hardware, and communication solutions.”



An Exelon Company

Baltimore Gas & Electric

Implementation of Conservation Voltage Reduction

Technology Partner(s)

ABB
Beckwith Electric Co.
Black & Veatch
Lindsey
Manufacturing Co.
OSI
Silver Spring Networks
Structure
Utilidata

Project Highlights

- Improved voltage and power factor management on the distribution system.
- At full deployment, estimated 85 MW reduction in peak demand and 251,000 MWh reduction in energy consumption.
- Supports EmPOWER Maryland state goal to achieve 15 percent reduction in per capita electricity demand and consumption by 2015.
- Novel capacitor-only algorithms allows CVR deployment on substations with de-energized tap changers.
- Implementation of single-phase capacitor switching algorithms allows CVR at locations with voltage imbalances.

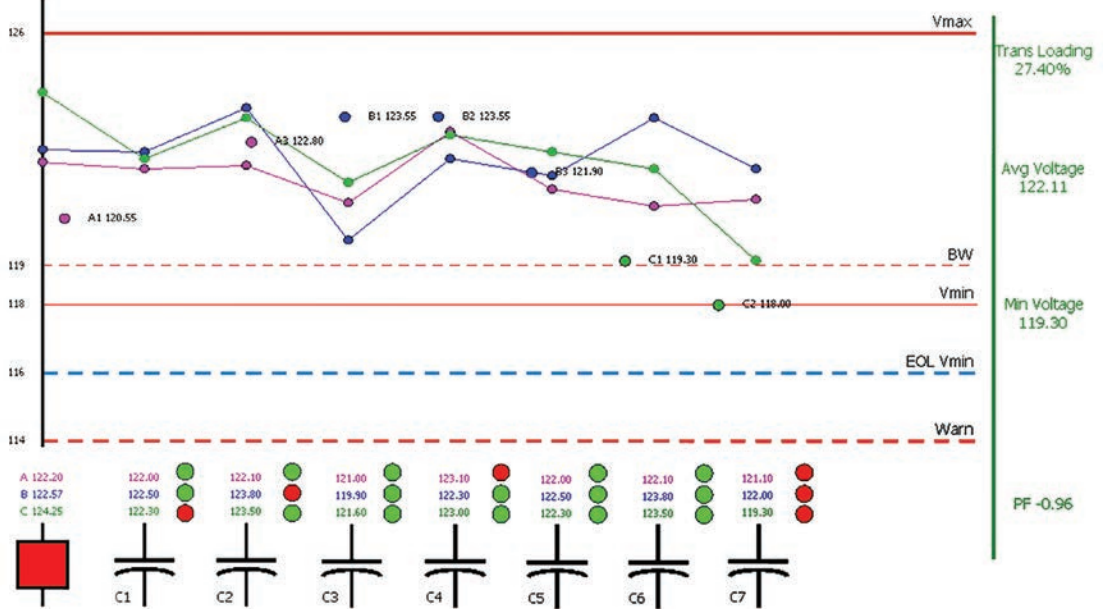
Project Description

The goal of conservation voltage reduction (CVR) is to operate distribution feeders at the lower end of the prescribed voltage range, reducing electric demand and energy consumption compared to operating at the midpoint of the prescribed voltage range. The goal of CVR implementation at BGE is to provide additional demand and energy savings to customers through improved voltage control enabled by modern software, hardware, and communication solutions. To achieve these results, BGE predominantly utilizes distribution transformers with de-energized tap changers (DETC), and relies on distribution capacitors to control both voltage and reactive power. This approach results in a more gradual voltage drop across the distribution feeder and lower overall distribution voltages, compared to traditional voltage control utilizing load tap changing (LTC) transformers. The energy and demand savings from BGE's CVR program will contribute towards the goals set in the 2008 EmPOWER MD legislation to achieve 15 percent reduction in per capita electricity demand and consumption by 2015, compared to 2007 levels.

BGE has been piloting CVR since 2012 to test various CVR algorithms and components, and to estimate projected electric demand and energy savings. Full scale CVR deployment started in 2014 with the

initial focus on deploying enterprise level head-end software and implementing CVR at substations equipped with LTCs or voltage regulators covering approximately 10 percent of BGE's distribution system. The deployment across the remainder of the system equipped with DETC transformers is expected to continue until 2019. The project will install a total of approximately 4,800 capacitor bank controllers, 9,600 overhead and pad-mount voltage sensors, 150 voltage regulators, and 50 head-end feeder monitors, and will utilize select advanced metering infrastructure (AMI) end-of-line voltages as control points for the CVR algorithm.

AMI is one component enabling effective implementation of the BGE CVR program. The AMI system supports monitoring of customer voltages to ensure acceptable customer voltages are maintained as CVR is implemented. BGE plans to utilize the Silver Spring Networks UtilityIQ® Power Monitor tool to provide localized monitoring for voltage sags/swells at the customer meter. Power Monitor reduces network traffic and delivers data directly to the CVR head end over a common MultiSpeak interface. In addition, BGE partnered with Black & Veatch to develop a voltage analytics tool to allow historical data tracking, spatial presentation, and reporting of meter voltage data based on BGE requirements.



Operation of single-phase capacitor bank switching.

The key to the success of the BGE CVR program is the design and implementation of the capacitor-only CVR algorithm, utilizing single-phase capacitor switching and re-sequencing of capacitor switching order with the goal of minimizing the average feeder voltage. Because the lowest phase dictates the operation of the algorithm, traditional three-phase operation of capacitor banks may limit the ability of the CVR algorithm to adjust the voltage while maintaining all three phases within the allowable range. Single-phase control is enabled by the installation of capacitor bank controllers

and voltage sensors. Single phase capacitor bank control allows the CVR algorithm to be applied to each phase individually, establishing better voltage balance between phases and allowing additional energy savings. BGE's single-phase capacitor-only CVR algorithm has been piloted and successfully tested, and has been implemented within the OSI head-end software.

CVR factor represents the percentage change in energy or demand resulting from a 1 percent reduction in voltage. Based on estimates from pilot data covering nine

distribution circuits, the CVR energy factors were calculated to be 1.0 for residential feeders and 0.6 for commercial and industrial feeders. At full deployment, overall energy savings are estimated to be 251,300 MWh annually (0.86 percent of total energy use on feeders where CVR is deployed),

and overall peak demand reduction is estimated to be 85 MW (1.17 percent of peak demand) at full deployment. These savings will contribute toward the EmPOWER Maryland goal to achieve 15 percent reduction in per capita electricity demand and consumption.

Project Contact

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Company Description

BGE, headquartered in Baltimore, is Maryland's largest gas and electric utility, delivering power to more than 1.2 million electric customers and more than 655,000 natural gas customers in central Maryland. The company's approximately 3,400 employees are committed to the safe and reliable delivery of gas and electricity, as well as enhanced energy management, conservation, environmental stewardship, and community assistance. BGE is a subsidiary of Exelon Corporation (NYSE: EXC), the nation's leading competitive energy provider, with 2013 revenues of approximately \$24.9 billion. www.bge.com.

“Since 2011, Houstonians have avoided nearly 100 million outage minutes due to the fault localization and remote switching capabilities of CenterPoint’s Intelligent Grid.”



CenterPoint Energy

Intelligent Grid

Technology Partner(s)

ABB
G&W Electric
GE
Itron
SEL
Siemens
Ventyx

Project Highlights

- 761 intelligent grid switching devices installed.
- 50-70 percent faster fault localization.
- 97 million customer outage minutes avoided.
- 31 substations automated.
- Power restored to over one million customers without a phone call.
- 30 percent reliability improvement (Jan.-Sept. 2014).

Project Description

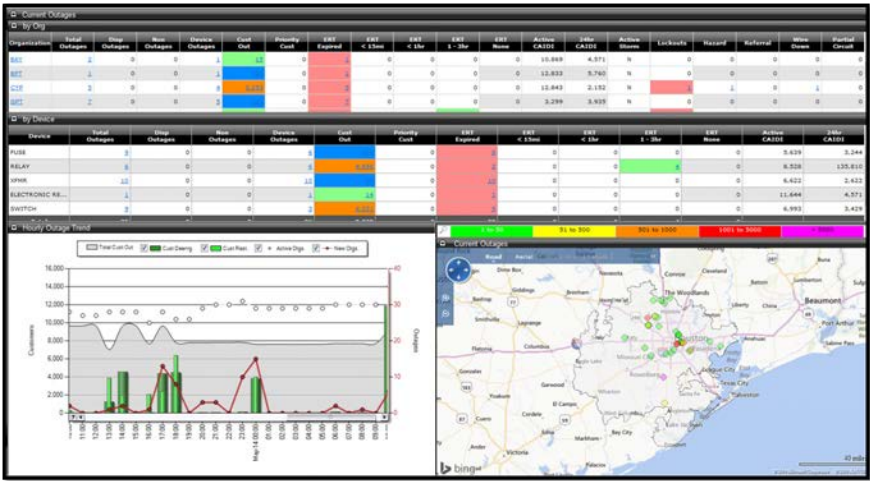
Following Hurricane Ike in 2008, the Houston Mayor’s Task Force Report concluded that a smart grid offers the best return-on-investment for improving grid resilience and enabling storm recovery, and gave the Task Force’s strongest recommendation to finding the means to accelerate CenterPoint Energy’s deployment of Intelligent Grid technology in the Houston area.

In 2009, the U.S. Department of Energy awarded CenterPoint Energy one of just six \$200 million Smart Grid Investment Grants to help fund construction of Houston’s intelligent grid and accelerate installation of 2.2 million smart meters in greater Houston. Construction on the project began in 2010 and will continue throughout the decade. By mid-2012, CenterPoint Energy had completed installation of smart meters throughout greater Houston.

Through the meters’ power-off notifications (PONs), the company can identify the scope of power outages (e.g. fuse, transformer, or single meter) 50 to 70 percent faster than by depending on customer phone calls. In fact, using smart meters and the intelligent grid, CenterPoint Energy has now restored power to more than one million customers without a single phone call. Moreover, the company’s new power alert service notifies over 400,000 enrolled customers by text, email, and/or phone call when their power goes out along with an estimated time of restoration, followed by crew status updates and confirmation of restoration.

Houstonians are also benefiting from the fault localization and remote switching capabilities of the Intelligent Grid. Currently, over 750 intelligent grid switching devices have been installed on circuits across Houston, and 31 substations have

Visual and graphical representation of outages in CenterPoint Energy’s service territory.



been fitted with automation equipment. As a result, 280,000 customers on Intelligent Grid circuits have avoided nearly 100 million outage minutes since 2011, when the intelligent grid began being used to localize outages and reroute power. In the first nine months of 2014 alone, when Intelligent Grid automation has been used, reliability has improved by 30 percent.

To enable the two-way communication at the heart of the Intelligent Grid, CenterPoint constructed a secure, redundant wireless telecommunications network to transmit PONs and power restored notifications (PRNs) as well as execute remote switching commands.

CenterPoint Energy will soon launch an advanced distribution management system, which will act as the Intelligent Grid's "brain" to better plan, engineer, and operate the grid. Faster, more accurate information about outage types and locations will make dispatching service crews more efficient, reducing outage durations while improving reliability and customer service.

In the years ahead, CenterPoint Energy will continue to extend the Intelligent Grid across the company's greater Houston electric service territory to meet the demand for a reliable and resilient electricity delivery system in the 21st Century.

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Company Description

CenterPoint Energy's electric transmission and distribution unit serves over 2.2 million metered consumers in a 5,000 square-mile area including Houston, the nation's fourth largest city and a consistently growing market. As a regulated "wires" utility, we neither generate power nor sell it to end-use consumers. We instead own, operate and maintain the poles, wires and substations that safely and reliably deliver electricity from power plants to consumers. With over 3,700 miles of transmission lines and 49,000 miles of distribution lines, we deliver electricity on behalf of 75 retail electric providers.

“The objective of the Energy Infrastructure Modernization Act is to improve system performance through accelerated investment in programs that address aging distribution infrastructure, storm hardening, and expand smart grid technology.”



An Exelon Company

Commonwealth Edison Company

Distribution Automation

Technology Partner(s)

G&W Electric

S&C Electric Company

Silver Spring Networks

Project Highlights

- 1,400 distribution automation (DA) devices installed since 2012.
- 2,600 DA devices targeted for installation by 2016.
- 375,000 avoided customer outages since 2012.
- New mesh communication network enhances security of the network.
- DA devices connected to supervisory control and data acquisition (SCADA) system to provide situational awareness and control of distribution grid.

Project Description

On October 27, 2011, the Illinois General Assembly enacted the Energy Infrastructure Modernization Act (EIMA), setting in motion a \$2.6 billion investment by ComEd to strengthen and modernize the state’s northern electric grid. The objective of the EIMA program is to improve system performance through accelerated investment in programs that address aging distribution infrastructure, storm hardening, and expand smart grid technology.

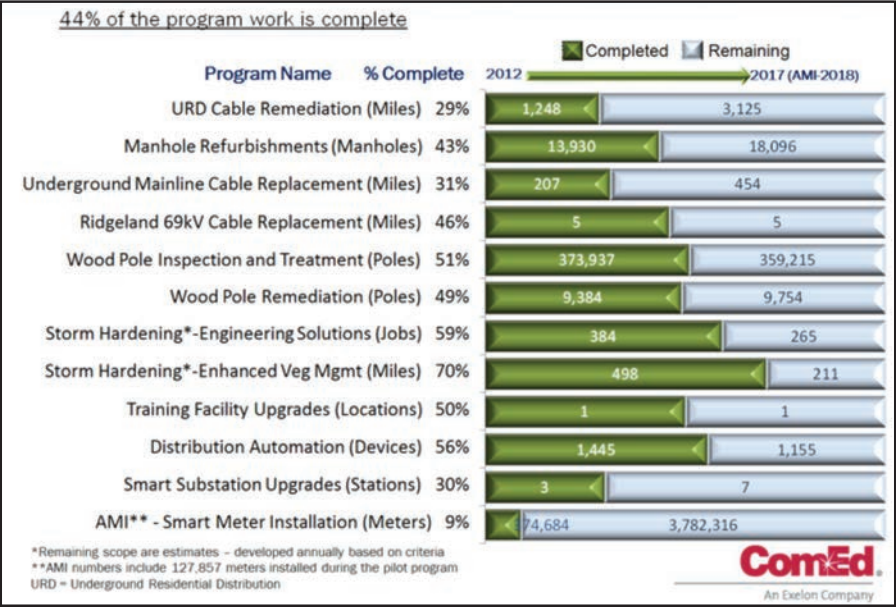
A key component of smart grid technology is distribution automation (DA). DA technology uses “sectionalizing” devices and remote communications to detect issues on the distribution system and automatically re-route power to minimize the number of customers impacted by outages. This is commonly referred to as

the “self-healing” nature of a smart grid. ComEd’s DA program includes installation of 2,600 DA devices between 2012 and 2016, as well as the necessary secure communications infrastructure.

At the end of 2011, ComEd initiated a pilot project to evaluate the addition of a newer generation of loop scheme “sectionalizing” devices. For the pilot, ComEd chose the Viper-ST reclosers from G&W Electric fitted with SEL-651R1 recloser controls. The pilot consisted of seven reclosers installed in three different schemes across the company, including a mixed scheme with existing reclosers.

A distribution automation scheme consists of one or more normally closed switches with at least one normally open switch

EIMA Status - program inception to Date through July 2014.



installed at a “tie” point between two or more distribution feeders. The technology automatically re-routes power around a problem, often with no noticeable interruption of service, and reduces the number of customers affected by an outage, as well as expediting restoration, emergency response, and the execution of switch orders.

ComEd and the vendor worked together to test the new systems and develop training modules. The pilot was rapidly followed by a system-wide deployment in 2013, installing over 400 of the new devices.

By June 2014, more than 1,400 devices were installed, and on June 30th, multiple tornadoes and strong winds reaching 110 miles per hour struck the service territory. These storms brought approximately 80,000 lightning strokes across the service

territory, and caused severe damage to electrical infrastructure, knocking down multiple poles and power lines. There were nearly 430,000 customer outages across the ComEd service territory. Without the 1,400 DA devices made possible through EIMA, there would have been approximately 60,000 more customer outages. Over half of the avoided customer outages were a result of the devices installed through EIMA.

To-date, DA devices installed through EIMA have avoided 375,000 customer outages. Fewer customer outages from DA and reliability benefits from other EIMA investments have resulted in ComEd’s best year-end reliability performance (0.99 SAIFI) and customer satisfaction rate on record.

Project Contact

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Company Description

Commonwealth Edison Company (ComEd) is a unit of Chicago-based Exelon Corporation (NYSE: EXC), the nation’s leading competitive energy provider, with approximately 6.6 million customers. ComEd provides service to approximately 3.8 million customers across northern Illinois, or 70 percent of the state’s population. For more information visit ComEd.com, and connect with the company on Facebook, Twitter, and YouTube.

“The Chicago Superconductor project will connect several of Chicago’s Central Business District substations with a superconductor cable system at 12 kV to enhance the electric grid. The total cable length is approximately 3.8 miles – the largest superconductor cable system in the world.”



An Exelon Company

Commonwealth Edison Company

Resilient Electric Grid Superconductor Project

Technology Partner(s)

American Superconductor (AMSC)

Department of Homeland Security (DHS)

Project Highlights

- Planned 3.8 mile superconductor cable system is largest in the world.
- 10-12 fold increase in carrying capacity of traditional cable circuits.
- Increased resiliency of grid serving Chicago's Central Business District.
- Improved restoration/blackstart times.
- Decreased power losses.

Project Description

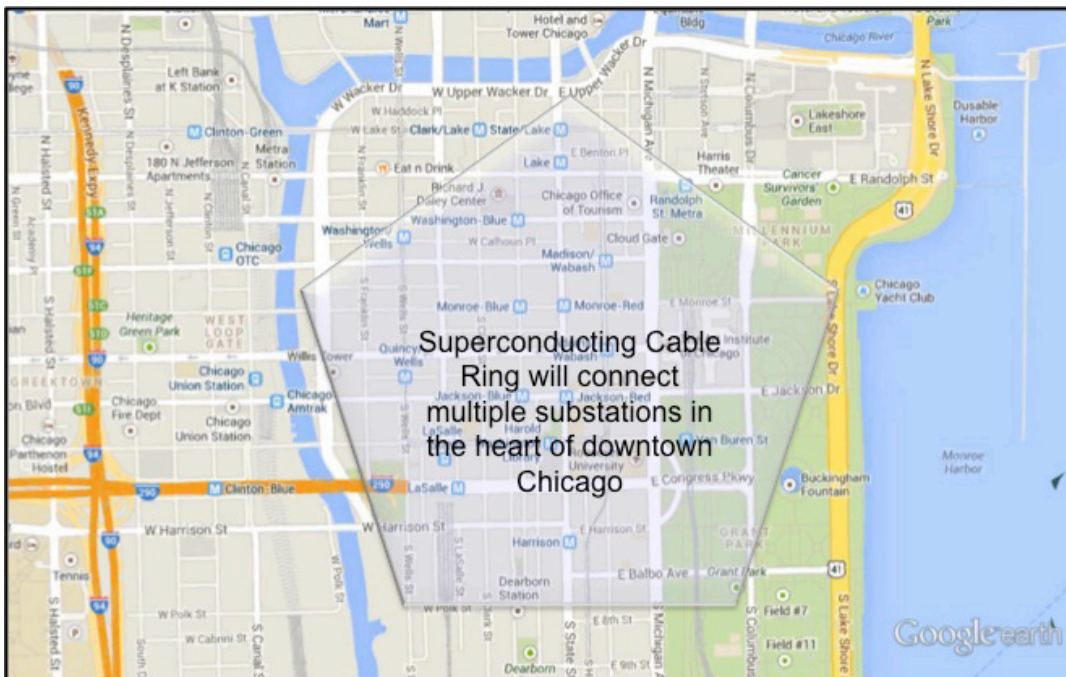
In 1913, Dutch physicist Heike Kamerlingh Onnes of Leiden University won a Nobel Prize in physics for his research in superconductivity. In 1911, he discovered that by cooling mercury using liquid helium to -452°F , its electrical resistance goes to zero. The main benefit of superconducting wire is that it has nearly 200 times the current-carrying capability as a similarly sized wire of traditional conductors, such as copper. In addition, it can be designed with inherent fault-current-limiting capabilities that are not possible with conventional conductors.

In the 100 years since the discovery of superconductivity, many breakthroughs have occurred, and there have been several

successful superconducting cable demonstrations at voltages up to 138 kV across the world. Earlier this year; the first commercial implementation of superconducting cable was completed in Essen, Germany, where a 1 km long, 10 kV, superconducting cable was installed to interconnect two substations for grid reliability purposes.

In July 2014, American Superconductor (AMSC), a global energy solutions provider, jointly announced with ComEd that the utility agreed to develop a deployment plan for AMSC's high-temperature superconductor technology and build a superconducting cable system that will strengthen Chicago's electric grid. The Resilient Electric Grid (REG) effort is part of the U.S. Department

Downtown Chicago "Loop" area.



of Homeland Security (DHS) Science and Technology Directorate's work to secure the nation's electric power grids and improve resiliency against extreme weather, acts of terrorism, or other catastrophic events.

The Chicago Superconductor project will connect several of Chicago's Central Business District substations with a superconductor cable system at 12 kV to enhance the electric grid. The total cable length is approximately 3.8 miles, making this installation the largest superconductor cable system in the world. This project will serve as a platform to scale the use of superconductor cable systems worldwide.

The cable will be installed in a conduit and manhole system using conventional methods and pulling equipment. The superconductor cable, due to its low resistance,

can carry as much power as twelve conventional 12 kV feeders. The single triaxial superconductor cable design can be installed in a single duct reducing the size of the duct package required. The triaxial cable, including the cryostat pipe, has a diameter around six inches. A cryogenic cooling system will be installed to maintain the liquid nitrogen temperatures around 70° Kelvin (-334° F).

ComEd is partnering with AMSC and DHS to perform a 6 month feasibility study as part of a 4 year project that would lead to the superconducting cable loop installation in the heart of downtown Chicago. Given the significant level of external funding and the size and scale of the project, one of the project goals is to significantly reduce the cost of manufacturing and installing superconductor cable systems.

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Company Description

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“Digital x-ray technology helps Con Edison reduce the inspection time and better identify incipient electrical failures across 800 miles of underground transmission cables.”



Consolidated Edison Company of New York

Digital X-Ray Technology

Technology Partner(s)

VJ Technologies

Project Highlights

- Innovative new technology improves x-ray imaging of underground transmission feeders, allowing non-intrusive in-service inspections.
- Enables enhanced x-ray image quality and digital archiving.
- Reveals hidden defects in underground equipment, avoiding outages.
- Eliminates use of radioactive elements, improving crew safety.

Project Description

Consolidated Edison Company of New York (Con Edison) has the largest underground transmission system in North America, including about 800 circuit miles of transmission cables. The majority of the system is comprised of high-pressure pipe-type feeders, which comprise hundreds of cable sections connected by splices (joints) in underground manholes. If a joint fails, it leads to a very costly and time-consuming repair or replacement that requires extensive feeder outage time. Therefore, feeder joints must be inspected periodically for signs of damage or future failure.

In the past, the only feasible way to inspect feeder joints without service disruption has been the use of conventional x-ray imaging, utilizing radioactive isotope Cobalt-60, which requires special safety precautions, with film as the imaging medium. There are several limitations to this approach, including difficulties in interpreting the image, limited dynamic range, lack of digital image for review and archiving, and the long delays associated with analog image transfer and inspection.

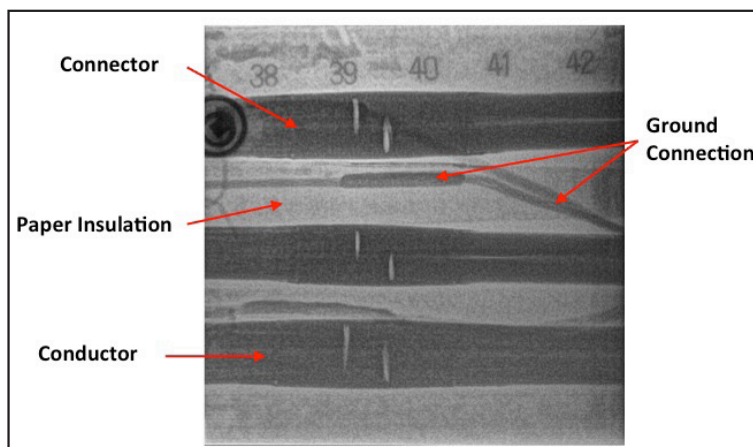
The engineering team at Con Edison has demonstrated and qualified an innovative high power digital x-ray instrument that can be used for non-intrusive in-service inspections of high voltage underground transmission feeders. The digital x-ray provides clearer images and details of the internal components/material of a joint that are used to assess its condition.

Despite the disadvantages of conventional technology, Con Edison still uses conventional x-ray to identify and quantify cable joint movement due to the relatively low cost per single film. The non-intrusive digital x-ray technology is used when conventional x-ray inspection results identify joints that require more thorough inspection.

The digital x-ray technology uses a cathode ray tube as a source and digital image capture device, eliminating the radioactive source and chemical processing of films. It is also able to digitally transfer and enhance captured images. The Con Edison team, working with VJ Technologies, has developed a technique to optimize x-raying high voltage underground transmission joints while maximizing the viewing window.

The digital x-ray technology started as an R&D project in 2011 and developed to a service contract after extensive laboratory and field tests proved the sensitivity and effectiveness of the digital x-ray inspection to identify cable joint mechanical and electrical condition.

Use of the digital x-ray technology in two cases has resulted in the identification of incipient electrical failures. In one case, a 345 kV joint was identified for internal inspection, and in the second case a 138 kV joint was identified for internal inspection. In both cases, after the joints were opened, extensive electrical damage was observed.



Transmission cable splice x-ray.

It was verified that if these joints have been left in service, they would have experienced electrical failures.

Today, Con Edison has established a joint inspection program based on digital x-ray technology, which involves periodic

inspection of underground transmission feeder joints (every 6–12 months) that have been previously identified as requiring periodic inspection. Con Edison will continue their effort to improve the digital x-ray methodology and technique to increase its effectiveness and reduce inspection time.

Project Contact

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Company Description

Consolidated Edison Company of New York (Con Edison), a regulated utility, provides electric service in New York City (except for a small area of Queens), and most of Westchester County. The company provides natural gas service in Manhattan, the Bronx, and parts of Queens and Westchester. Con Edison also owns and operates the world's largest district steam system, providing steam service in most of Manhattan.

“By reducing the risk of a large network outage, improving operational flexibility, and enhancing reliability, dual-feeder circuit breakers support Con Edison’s 3G System of the Future initiative.”



Consolidated Edison Company of New York

Dual-Feeder Circuit Breaker

Technology Partner(s)

ABB

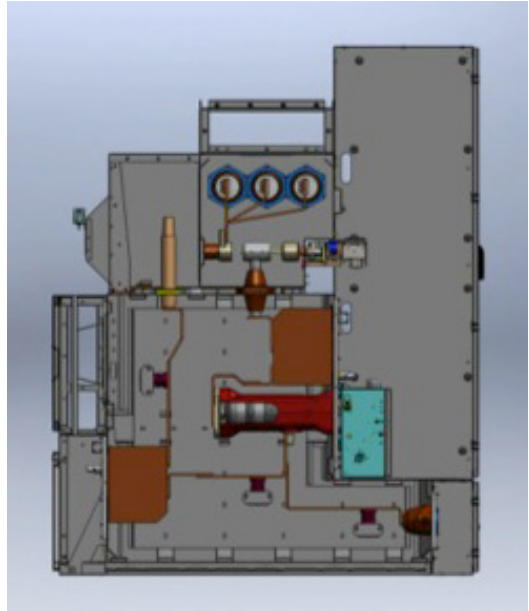
Project Highlights

- New compact breaker technology improves utilization of existing substation footprint.
- Potential to expand substation breaker capacity of 45 percent of Con Edison 27 kV substations.
- Improves operational flexibility.
- Enables network reliability enhancement.
- Reduces risk to field crews.

Project Description

The need for electricity will continue to increase in Consolidated Edison Company of New York's (Con Edison's) service area, but the space available for building new substations is scarce. Associated new distribution lines will also be difficult to route because of an already-crowded underground environment that accommodates dense concentrations of telephone lines, optic fiber, subways, water and sewer lines, and energy delivery systems. Con Edison has undertaken a long-term initiative, called 3G System of the Future, with the goal of producing new design and build approaches for substations and electric distribution installations in urban settings. The 3G designs are based on the strategy to defer or minimize costs, maintain reliability and customer service, increase asset utilization, reduce street congestion, increase operational flexibility, and reduce the risk of a large network outage. Dual-feeder circuit breakers support the 3G System of the Future design concept of reducing the risk of a large network outage, improving operational flexibility, and enhancing reliability. In May, 2014 Con Edison installed a compact dual-feeder breaker at one substation that supplies demand in Brooklyn, NY. This is the first installation of this new breaker technology on the Con Edison distribution network.

The driver of this project is enhancing the reliability in one of the fast growing Brooklyn networks. In order to improve the reliability of the network, the conventional



Built-in ground and test device in dual-feeder circuit breaker.

method is to add a new medium-voltage feeder with the associated station breaker for protection in order to supply the load area. Some of the existing substations cannot accommodate the space to install a new breaker position within the existing footprint of the substation. Expanding the existing substation, which may also require the acquisition of nearby real estate and extending the substation electrical bus, is highly costly and often not feasible. The innovative dual-feeder circuit breaker technology was developed in order to create new feeders for distribution networks within the boundaries of the existing substation.

This project succeeded by installing two new compact SF-6 insulated breakers within the boundaries of an existing single

air-insulated breaker at the substation. The dual-feeder breaker installation improves the reliability of the network by maintaining the existing medium-voltage feeder and installing an additional breaker in order to protect and establish a new feeder.

The new compact circuit breaker technology is equipped with a built-in ground and test device, remote control capability, and a viewing window for field verification. These innovative features eliminate the need for lifting a heavy separate testing device that is required for processing the medium-voltage class feeder during a fault. The elimination of a separate ground and test device

will enhance safety and improve feeder restoration time because the new feeder breaker can be visually verified through a viewing glass and grounded by the push of a button. The new SF-6 breaker was designed to maintain all required safety protocols which are needed to process the medium-voltage feeder during a fault.

Approximately 45 percent of Con Edison's existing 27 kV substations can accommodate the installation of dual-feeder circuit breakers. The successful demonstration of this new technology paves the way for new substation construction in the future.

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Company Description

Consolidated Edison Company of New York (Con Edison), a regulated utility, provides electric service in New York City (except for a small area of Queens), and most of Westchester County. The company provides natural gas service in Manhattan, the Bronx, and parts of Queens and Westchester. Con Edison also owns and operates the world's largest district steam system, providing steam service in most of Manhattan.

"To improve system reliability, DTE Energy is working with IBM to develop an Outage Prediction and Response Optimization system that more accurately predicts damage location, occurrence time, and outage severity of future weather events in order to optimize preparation and crew placement."



DTE Energy

Leveraging Hyper-Localized Weather Forecasting for Distribution System Damage Prediction

Technology Partner(s)

IBM

Project Highlights

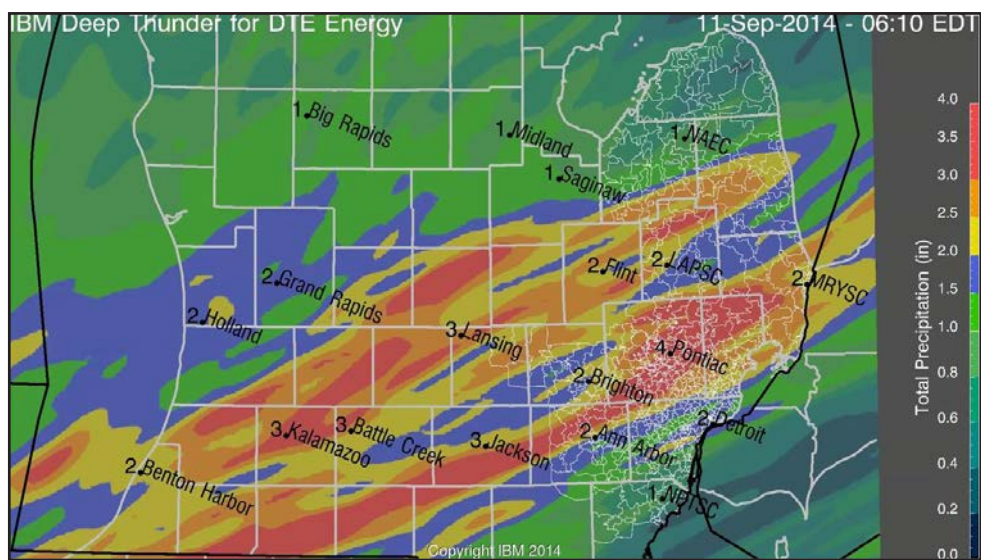
- Enabled a predictive engine that correlates damage history with weather features at the sub-station level, and incorporates weather forecasts from IBM's Deep Thunder hyper-localized weather forecasting system 72 hours into the future for the DTE service territory.
- Optimizes utility response to outage events to reach maximum restoration up to 24 hours earlier than current practices.
- Operationalizes weather forecasts for utility use.
- Ongoing accuracy validation and optimization of damage prediction engine based on occurring events.

Project Description

At DTE Energy, the reliability of electrical power delivered to customers and customer satisfaction with DTE Energy’s ability to provide uninterrupted services motivates the effort to innovate. To improve system reliability, DTE Energy is working with IBM to develop a system that integrates hyper-localized weather forecasting models with the electrical distribution network damage history and asset health characteristics to more accurately predict damage location, occurrence time, and outage severity of future weather events in order to provide utilities an opportunity to optimize preparation and crew placement planning and to begin repair work sooner. This ongoing damage prediction project is called Outage Prediction and Response Optimization (OPRO).

Fundamentally, OPRO is a correlation engine that matches weather features with damage outcomes from actual historical data to predict future damage based on forecasted weather. DTE is leveraging the IBM Deep Thunder weather system to provide ‘hyper-localized’ weather forecasting for the DTE service territory and OPRO to predict damage to the distribution system at the sub-station level up to 72 hours in advance of the actual conditions occurring. The weather features provided to DTE from Deep Thunder are in ten minute intervals over a 72-hour period for each specific feature (wind gusts, storm intensity, precipitation rate, etc.), at a precision level of as little as a single square kilometer.

IBM Deep Thunder hyper-localized weather interface.



The desire is to support decision making at DTE by understanding the magnitude of expected impact, the location of the damage within the DTE service territory, and the time range within which damage will occur. It is anticipated that the results from OPRO will support utility decision making around three dimensions of repair planning: impact magnitude (as measured by class from 'no impact' through 'catastrophic'), location (by quadrant) within the service territory, and timing (relative to scheduled crew shifts). In this way, DTE Energy expects to construct a flexible application of both the value delivered through a hyper-localized weather forecasting system (Deep Thunder) and a damage correlation engine (OPRO) to the utility's distribution operations business processes.

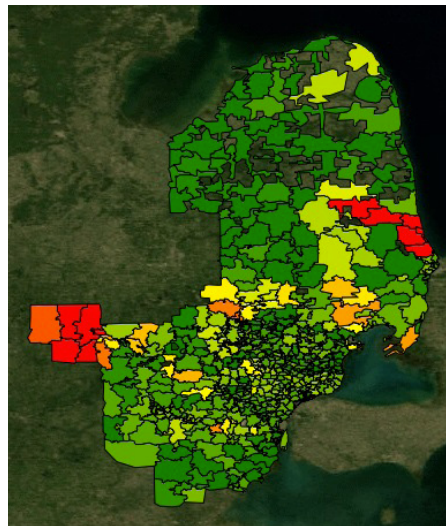
OPRO development has achieved the 'establishment' phase and is entering into the 'operational' phase. The primary focus in this phase is to validate the accuracy of the current model, and incorporate on-going damage events to improve the accuracy of the model through the upcoming winter, spring, and summer storm seasons. While the utility does scrutinize the accuracy of the Deep Thunder forecasts at the 'hyper-localized' level, DTE's real focus in this phase is the efficacy of the damage prediction engine from OPRO at the business operational level – described as magnitude class, quadrant location, and shift onset. This is precisely where DTE stands

relative to the overall development of the project. Early indications support the accuracy of location and timing, with the greatest challenges related to forecasting event intensity levels.

One area of particular attention for DTE and IBM in further innovation of this technology is to leverage the power of unstructured data in the form of human experience. DTE believes there is a rich degree of experiential understanding within their existing workforce of the impact of specific weather conditions to the distribution system. It is DTE's and IBM's desire to facilitate application of that knowledge base by building modeling features into OPRO to apply 'what if' conditions to the damage correlation engine underlying OPRO. These features are in development with IBM now, with expected availability in the 2nd quarter of 2015. Although DTE is just launching into the stage of validating real-time operational results, the utility is quite pleased that the foundational platform to leverage historical experience has been made functional, and that the promise of a high value business result is deemed to be plausible. OPRO provides the opportunity to supplant current practices and allow DTE to deploy maximum restoration levels 24 hours earlier during a weather event to shorten the duration of customer power outages.

OPRO is one component of DTE Energy's partnership with IBM and other operating utilities called the Smarter Energy Research

Institute (SERI). The underlying principle of SERI is to augment utility companies with capability and capacity for sustained research to solve important, persistent matters of concern to the business operation. In addition to OPRO's work in grid damage prediction, DTE has also elected to pursue research projects with independent value to DTE in the areas of logically inferred distribution connectivity and asset health. DTE intends to further leverage the research from connected distribution model and asset health projects for deeper insights with OPRO's damage prediction model moving forward.



OPRO substation-level risk display.

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Company Description

DTE Energy is one of the nation's largest diversified energy companies. Headquartered in Detroit, Michigan, DTE Energy is involved in the development and management of energy-related businesses and services nationwide. Its operating units include an electric utility serving 2.1 million customers in Southeastern Michigan and a natural gas utility serving 1.2 million customers in Michigan. The DTE Energy portfolio also includes non-utility energy businesses focused on power and industrial projects and energy trading. Information about DTE Energy is available at dteenergy.com, twitter.com/dte_energy and facebook.com/dteenergy.

“Advanced asset visibility supports asset management and operations strategy, helping DTE Energy make strategic decisions about how to allocate capital investments across the network.”



DTE Energy

Sensors for a Predictive Grid in the Motor City

Technology Partner(s)

Tollgrade
Communications, Inc.

Project Highlights

- Implementation of 81 smart grid sensors and predictive grid analytics platform at 9 substations and 24 feeders within DTE Energy's service area.
- Low-cost sensor solution captures real-time fault current and waveform data.
- Integrated into existing Tropos wireless network.
- Disturbance signature analysis and predictive analytics improve capital investment decision making, decrease unplanned outages, and improve outage response.
- Inductively powered sensors are lightweight and easy to install with hot-stick.

Project Description

In order to improve system reliability by predicting and preventing outages, to increase situational awareness, to help safely restore power more quickly after outages, and to inform capital investments around aging assets, DTE Energy sought a low-cost solution to get more real-time reliability data out of its distribution grid, particularly on poorly performing and older legacy circuits.

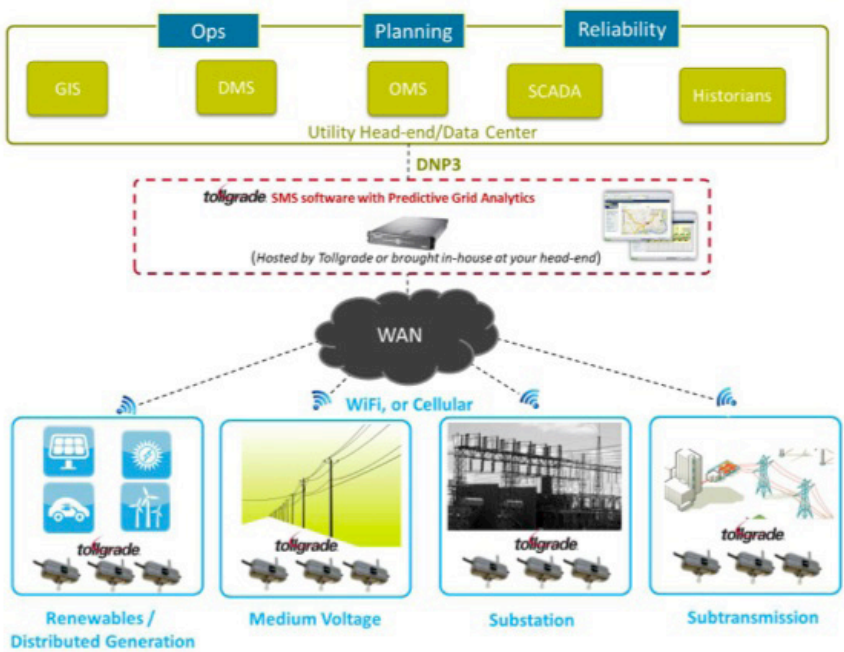
Wanting to move away from traditional Fault Current Indicators (FCIs), it was important to DTE to incorporate real-time fault data with waveform capture that could be analyzed to identify precursors to grid outages and alert crews to line disturbances. Equally important was the impact of installation and maintenance requirements. DTE

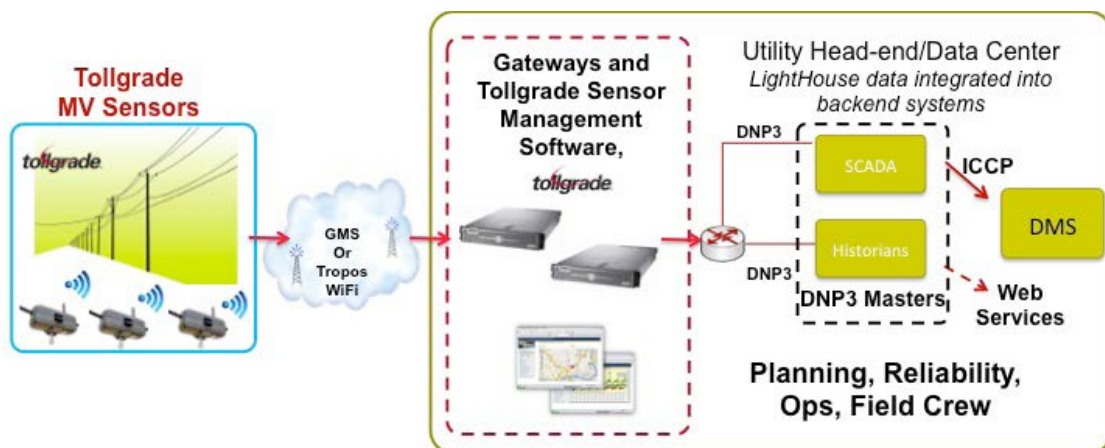
Energy needed to find a battery-free and maintenance-free solution that was easy to install and would not require circuits to be shut down during installation.

Finally, DTE Energy, like most North American utilities, found retrofitting old substations could be as expensive as building a new substation. By finding a less expensive monitoring solution with built-in wireless communications, the utility could provide planners and asset managers with the critical data they needed, without having to rebuild substations.

In response to these needs, DTE Energy installed 81 Tollgrade Smart Grid Sensors and the Predictive Grid® Analytics platform at 9 key substations and 24 feeders within

Tollgrade LightHouse architecture.





Integration of sensor data with multiple DTE Energy systems.

its distribution network. The Tollgrade solution offered a number of advantages, including light weight; easy installation with a hot-stick; inductive power from the monitored line (requiring no batteries or solar panels); near-zero maintenance; an average 20 year lifespan; and easy integration with DTE Energy's existing Itron smart meter and ABB Tropos wireless mesh networks.

When a storm hits, information from the sensors can be used to improve crew safety by showing the status of the load on the portion of the grid they are working on. By knowing what portions of the network are de-energized, crews can more safely work on the network. Once repairs are complete, crews get confirmation that power is successfully restored.

Tollgrade's medium voltage sensors gather real-time data using DNP3 protocol and send it to the LightHouse Sensor Management System (SMS) software for analysis

from where it is pushed to DTE Energy's data historian, geographical information system (GIS), and distribution management system (DMS). By integrating these systems, DTE Energy has achieved enhanced situational awareness about grid conditions, fault prediction, and real-time diagnostics.

Currently, DTE Energy is completing the integration of the LightHouse platform into its pre-existing wireless mesh network, provided by ABB Tropos, as part of its Itron advanced metering infrastructure (AMI) system. By using the predictive grid analytics capabilities of the LightHouse software, DTE Energy can start identifying disturbance precursors to avoid outages. Cost savings occur not only in reduced drive times and crew overtime, but in other unexpected ways as well. For example, instead of long lead times and costly substation upgrades, now it takes only a few thousand dollars to monitor a substation remotely.

Additionally, the ability to integrate LightHouse into the existing wireless RF mesh network saves money by leveraging the communications infrastructure that the company had already deployed.

Before LightHouse, DTE Energy did not have a good way to monitor its legacy network in real time. Advanced asset visibility supports asset management and operations strategy, helping DTE to make more strategic decisions about how to best allocate capital investment across their network.

In June 2014, DTE Energy and Tollgrade worked with the Clinton Global Initiative to make a “Commitment of Action” that pledges to bring comprehensive grid modernization in Detroit. The commitment, entitled “Building a Predictive Grid for the Motor City,” will show how other utilities can take the same proactive measures DTE Energy is standardizing, to decrease the number of outages, decrease customer minutes without power, improve crew safety and save money.

Project Contact

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Company Description

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“Recognizing the challenges from distributed energy resources and interoperability, Duke Energy created a way to make assets interoperable using a low-cost, open-source solution while enabling new ways to optimize the grid with distributed energy resources.”



Duke Energy

Field Message Bus Interoperability and the Coalition of the Willing Project

Technology Partner(s)

Accenture
Alstom Grid
Ambient Corporation
Echelon
S&C Electric Company
Verizon Wireless

Project Highlights

- Demonstrated interoperability between field devices from six vendors.
- Created a “publish and subscribe” architecture for a field message bus.
- Created voltage management and solar-smoothing algorithms that produced improved voltage quality and tighter demand and generation following.
- Demonstrated operational efficiency gains such as reduced latency of communications and increased resiliency.

Project Description

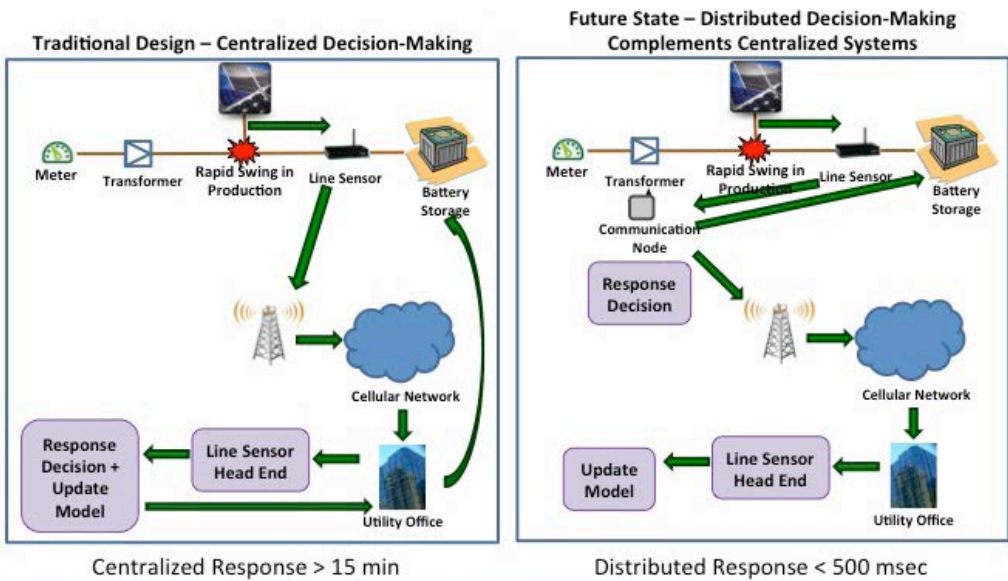
Integrating distributed energy resources (DERs) such as photovoltaics, battery storage, advanced demand response, plug-in electric vehicles, and smart appliances causes a wide variety of issues with power sector infrastructure. DERs can cause reverse power flow, create safety issues, and make the electric grid unstable. However, proper management and optimization of DERs can enable a stronger, more efficient power grid; an opportunity to sell additional products and services to customers; and a safer electrical infrastructure. Current infrastructure cannot react fast enough to sudden changes from DERs. For example, as clouds pass by overhead, a solar panel can change from full energy production to zero and back to full production in a matter of seconds. Traditional utility infrastructure takes minutes to respond. At Duke Energy, slow response times limit the ability to optimize these assets and requires significant financial investment by the utility in protective equipment to limit problems inherent in the variability of distributed resources.

Another huge challenge for utilities is getting assets to be interoperable in an economic way. Today, only assets purchased from a single vendor can be relied upon to be interoperable. Yet, no vendor makes assets for every use case, and neither does any utility purchase all assets from only one vendor. Often, utilities purchase expensive, proprietary software to force different vendors' assets to work together. However,

such solutions are expensive, and these implementations tend to make information technology infrastructure costly and difficult to maintain. In fact, Duke Energy utilizes thousands of vendors and purchases hundreds of different assets, making interoperability a significant challenge.

Recognizing the challenges from DERs and interoperability, Duke Energy employees created a way to make assets interoperable using a low-cost, open-source solution while enabling new ways to optimize the grid with DERs. The solution is called the field message bus. The field message bus is ubiquitous in modern communications, used by companies like Facebook and LinkedIn, and found in Apple and Android smart phones. Simply put, a field message bus is a piece of software that translates data into one common language and allows data to be easily shared among peers.

Translation of data is important to enable interoperability because each asset speaks a different "language" per se. Translation allows each asset to understand each other, regardless of who made the asset. Similarly, sharing data on a peer-to-peer basis is critical to interoperability because it allows data to be quickly delivered where needed without having to rely on a centralized "parent" system to tell the data where to go. And rapid delivery of data is important to deal effectively and economically with variable DERs.



Demonstrating the value of distributed intelligence and interoperability.

Led by Duke Energy, a coalition of six companies, including Accenture, Ambient, Alstom Grid, Echelon, S&C Electric, and Verizon demonstrated the interoperability of hardware, software, and communications. Duke labeled this effort the “Coalition of the Willing”. Each company’s products and services are linked together using an open-source, standards-based field message bus. Each company exposed data locally to the field message bus via a standards-based interface to create interoperability, increase functionality, and create greater value. The field message bus provides support for distributed applications that are wirelessly connected to assets in the field at the grid edge.

Duke Energy has successfully demonstrated the field message bus in lab and field trials installed at the McAlpine substation in Charlotte, N.C. Duke Energy has successfully connected a distribution management system, smart meters, communication nodes, cellular modems, capacitor controls, battery management systems, solar inverters, and transformers from multiple vendors. The use of this type of technology enabling interoperability between devices was achieved in four weeks and for under \$1,000, dispelling the notion that interoperability is too expensive and will take too long to achieve. The solar-smoothing algorithm was able to closely follow the volatility of the PV by reducing the analysis

and response times for injecting a battery from over one minute to under one half second. Using the field message bus, the data from these devices can now be shared locally without requiring costly integration, providing for more efficient decisions with lower latencies. Changes in equipment status can be backhauled to higher-priority systems to update system models or make more complex decisions.

Duke's response from industry, manufacturers, and the media has been very positive. So much so that Duke's second phase of coalition work will include 28 companies focused on providing more interoperable solutions.

Project Contact

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Company Description

Duke Energy is the largest electric power holding company in the United States, supplying and delivering energy to approximately 7.2 million U.S. customers. Duke Energy has approximately 57,500 MW of electric generating capacity in the Carolinas, the Midwest, and Florida - and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C., Duke Energy is a Fortune 250 company traded on the New York Stock Exchange under the symbol DUK.

“Local optimization in grids with large amounts of distributed energy resources will be a key feature in future power grids and in tomorrow’s smart cities.”



Électricité Réseau Distribution France (ERDF)

Nice Smart Solar District

Technology Partner(s)

Alstom

Saft

Project Highlights

- Large-scale integration of PV and energy storage.
- Distribution grid optimization and islanding operation.
- 2.5 MW of solar generation, 1.5 MW of electricity storage, 3.5 MW of load shedding capacity, and 2,500 smart meters.

Project Description

The Nice Smart Solar District (Nice Grid) is situated in an “electrical peninsula” near Carros, located in the southeastern region of France. It is one of the six smart grid demonstration projects funded by the European Union’s Grid4EU program. The project commenced in 2011, and is expected to be completed in 2016. It brings together an industry consortium led by Électricité Réseau Distribution France (ERDF), Alstom, Électricité de France (EDF) and Saft.

Nice Grid consists of seven solar districts, each represented by one secondary substation. Hundreds of customers will be able to participate in the demonstrations via 2,500 smart meters. The system will include distributed resources that will provide 2.5 MW of solar generation, 1.5 MW of electricity storage, and 3.5 MW of load shedding capacity.

Électricité Réseau Distribution France (ERDF) has to integrate these distributed energy resources (DER) into its daily grid and commercial operations. In this regard, there are key tasks. The first is how to manage the smooth injection of decentralized and intermittent renewable energy into the distribution grid. The project will integrate storage systems and deploy centralized demand management to accomplish this task. The second task is how to enable consumers to become active participants in the local energy balance via load shifting. The project will include design and validation of a new model of interactions between energy actors: consumer, commercial

aggregator, and the distribution system operator. The third objective is to demonstrate how to operate a small pocket of the low voltage network in islanding mode during a limited period of time. ERDF will be able to route energy to where it is needed, and end users will be able to voluntarily control their energy consumption and monitor usage via smart meters. In this way, the Nice Grid project will demonstrate the impact of lowering energy demand and reducing CO₂ emissions, while maintaining the quality and security of the network.

Nice Grid is using Alstom’s Distributed Energy Resource Management Solution (DERMS) to interconnect smart homes, smart industrial buildings, energy storage, and a large number of solar panels, gathering them into a single integrated localized part of the power grid. The DERMS will allow for more optimized energy consumption and production in the grid while islanded or in grid-connected mode. The DERMS is an integral part of the Network Energy Management (NEM). Most distribution networks today are unable to accommodate new types of bi-directional energy flow in distribution grids. However, local optimization and balance between production, consumption, and storage appears to be the right approach to avoid massive investments in the distribution networks.

The Nice Grid project addresses issues that utilities in the U.S. and other parts of the world expect to face due to higher penetrations of photovoltaic systems and other

DERs. Local optimization in grids with large amounts of DERs will be a key feature in future power grids, and important components in tomorrow's smart cities. The NEM and DERMS deployed at Nice Grid are examples of the innovative solutions for energy management that will be designed based on a decentralized and multilayer architecture, where local intelligence and optimization can ensure system level reliability, resilience, and security of supply.

Nice Grid will also study the feasibility of operating a low voltage feeder (e.g., with 20 customers and 250 kW of demand) portion of the grid that is only supplied by solar generation and batteries, and managed by a power converter with no rotating machines to determine the performance of zero or low inertia grid systems. Currently, the NEM is capturing actual operational data and key performance indicators in Nice Grid. ERDF will publish preliminary results from the project in 2015.

Project Contact

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Company Description

ERDF manages the public electricity distribution network for 95 percent of continental France. Every day, its 36,770 employees oversee the operation, maintenance, and development of a nearly 1.3 million km network. www.erdf.fr.

“Leveraging investments in analytical algorithms, machine learning, data integration, and cloud-scale infrastructure, Enel is successfully identifying anomalous meter activity.”



Enel

Improving Smart Grid Reliability and Operational Efficiency

Technology Partner(s)

C3 Energy

Project Highlights

- C3 Revenue Protection, C3 Predictive Maintenance, and C3 Residential systems deployed to 1 million meters in Italy. Planned deployment to 32 million meters across Italy, and 40 million meters worldwide.
- Machine learning delivers 93 percent accuracy in identifying cases of theft and meter malfunction.
- 50+ billion rows of data from 11 source systems integrated, normalized, and aggregated.
- Machine learning will improve grid reliability from 41 minutes SAIDI by predicting feeder failures.

Project Description

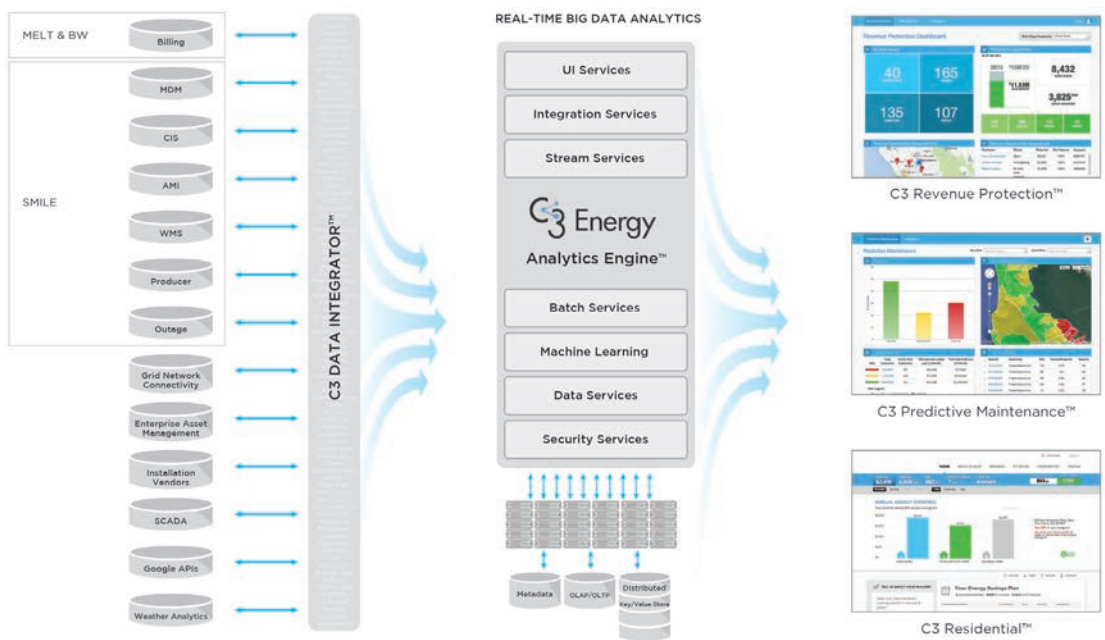
Enel, the largest power company in Italy and the second largest in the world, is deploying C3 Energy smart grid analytics solutions as its software platform for enabling smart grid and smart city services. Enel was the first utility in the world to replace traditional electromechanical meters with digital smart meters. By 2006, Enel had installed 32 million smart meters across Italy; Enel has since deployed a total of 40 million smart meters, representing more than 80 percent of the total smart meters in Europe.

Like other utilities, Enel has been experiencing non-technical loss, including energy loss due to power theft; a cost typically subsidized across the customer base. To more efficiently address this energy loss, rectify malfunctions or unsafe conditions,

and capture additional revenues, Enel deployed C3 Revenue Protection across one million meters in Italy. Implemented in less than eight months, C3 Revenue Protection ultimately identified 93 percent of Enel's non-technical loss cases through the initial deployment. The solution also identified new leads with similar patterns of theft or malfunction.

For the project, C3 Energy integrated, normalized, and aggregated over 50 billion rows of data from eleven utility source systems, including the billing system, work order system, outage management system, producer system, meter data management system, validated theft case data, external weather data, and Google for address verification.

C3 Energy's analytics system architecture.



Leveraging investments in analytical algorithms, machine learning, data integration, and cloud-scale infrastructure, Enel deployed 55 unique, sophisticated meter theft and malfunction analytics that identified anomalous meter activity. Enel is leveraging these analytics to execute rule-based and machine learning algorithms to unlock insight from both batch and streaming data. Machine learning is the ability for computers to learn without being explicitly programmed. C3 Energy solutions leverage advanced machine learning analytics to continuously improve algorithms and generate increasingly targeted and accurate results.

The initial deployment proved that the C3 Energy platform could readily handle Enel's smart grid data processing and aggregation needs. Based on the results from the one

million meter demonstration, Enel and C3 Energy are working to expand the deployment across Enel's power distribution network in Italy, which services 32 million smart meters. In a subsequent phase, Enel and C3 Energy expect to deploy these capabilities broadly across Enel Group's distribution network reaching a total of approximately 40 million installed smart meters.

In addition to C3 Revenue Protection, Enel is leveraging C3 Energy's platform and deploying additional applications to expand on what will be the largest deployment of a SaaS smart grid analytics solution. Moving forward, C3 Energy and Enel are enabling a step change in smart grid reliability and operational efficiency through predictive grid maintenance and advanced power fraud detection using C3 Energy smart grid applications.

Project Contact

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Company Description

Enel is Italy's largest power company and Europe's second listed utility by installed capacity. It is a leading integrated player in the power and gas markets of Europe and Latin America, operating in 32 countries across 4 continents, overseeing power generation from over 95 GW of net installed capacity, and distributing electricity and gas through a network spanning around 1.9 million km to serve approximately 61 million customers.

“Through the use of new smart devices, data analytics, and network communications technology, FPL is building a more intelligent and flexible electric grid.”



Florida Power and Light Company

Optimizing the Smart Grid to Enhance Service Reliability

Technology Partner(s)

GE

Landis+Gyr

S&C Electric Company

Sentient Energy

Silver Spring Networks

Project Highlights

- Received \$200 million grant from U.S. Department of Energy.
- Installed 4.6 million smart meters and more than 11,500 intelligent devices on the electric grid ahead of schedule.
- Achieved average annual reduction of 5.1 million minutes of customer power interruptions.
- Proactively created more than 40,000 outage tickets using smart meter information.
- Expected operational savings of \$30 million in 2014.

Project Description

In March 2013, Florida Power & Light Company (FPL) completed its \$800 million Energy Smart Florida program. The program was funded, in part, by a \$200 million grant from the U.S. Department of Energy in 2009. Since then, FPL has invested in further expanding smart grid technology throughout its system.

In 2014, these investments, including 4.6 million installed smart meters, continue to enhance service reliability while giving customers unprecedented control over their energy costs. FPL is re-engineering the way it operates the electric grid. Its substantial investments are helping the company deliver reliable and affordable electricity while creating the foundation for new, innovative energy services.

By year-end 2013, FPL had installed more than 11,500 intelligent devices on its electric grid and added enhanced digital technology to all of its nearly 600 substations. The new sensors and monitors, installed on transformers, breakers and battery banks, are helping the company determine the health of its equipment, predict potential issues before they disrupt service to customers, and restore power faster following outages.

FPL continues to see ongoing improvements and productivity savings, including an average annual reduction of 5.1 million minutes of power interruptions. Overall operational efficiencies in 2014 are expected to produce savings of more than \$30 million.

FPL's major grid optimization developments during the past year include:

- Automated Feeder Switches (AFSs) – FPL's extensive deployment of automated feeder switches has proven to be a productive investment. Located at key points along the grid, these switches identify and isolate faults and, if necessary, automatically reroute power around problem areas. This technology also helps pinpoint the fault location, enabling faster restoration – meaning fewer and shorter outages for customers. Through Q3 2014, FPL had deployed more than 1,000 automated switches, avoiding more than 300,000 customer interruptions.

FPL also is leveraging smart line sensors, or fault current indicators (FCIs), in Miami-Dade County, and plans to accelerate deployment across its distribution network in 2015. Similar to AFS technology, these devices pinpoint fault locations and direct resources to identify and isolate damage more quickly. Integrating them into FPL's distribution management system and mobile applications allows operators, dispatchers, and field crews to work more effectively in restoring power following unplanned outages.

- Restoration Spatial View (RSV) – The company's restoration specialists can now view extensive network information on iPads using FPL's "Restoration Spatial View" (RSV) application. This tool puts smart grid data into the hands of field crews. Developed in-house, RSV

combines outage tickets, weather information, electrical network information, time sensor data, customer energy consumption and voltage, restoration crew location, meter status, and more – all layered onto a map view on an iPad.

RSV uses smart meter information and telemetry from substation and distribution automation devices to provide a holistic view of the customer experience. It incorporates features like restoration confirmation, which allows restoration crews to confirm the power status of all smart meters affected by an outage before they leave the area. This has helped FPL identify embedded outages, resolve problems on the first visit, avoid unnecessary truck rolls, reduce repeat calls from customers, and improve customer satisfaction.

- Proactive Outage Ticket Creation – FPL has developed new tools to automatically detect many outages and begin

restoring power before customers call to report them. In the past, a customer reported an outage and an FPL customer service representative asked questions to identify the problem and its location. Today, internally developed software uses smart meter data to proactively generate outage tickets without customer input. Since the start of system deployment (June 2013), FPL has proactively created more than 40,000 tickets representing more than 500,000 customers.

- Proactive Transformer Replacement – FPL uses smart grid technology to help predict transformer equipment failure. The company's algorithm identifies transformers with high voltage readings over more than 48 continuous hours, ruling out temporary voltage spikes related to switching or equipment issues. To date, the company has proactively replaced more than 1,000 distribution transformers, preventing

FPL's Integrated Grid.



potential unplanned outages for an estimated 10,000 customers. Pre-planned transformer replacements have also improved workforce productivity and reduced employee overtime.

Today, FPL remains committed to developing new smart devices, data analytics, and network communications technology to

build a more intelligent and flexible electric grid. The next step in the company's network modernization is to expand the scale and scope of its digital footprint, further enhancing service reliability and operational efficiencies that will help FPL maintain low bills for residential customers.

Project Contact

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Company Description

Florida Power & Light Company is the third-largest electric utility in the United States, serving approximately 4.7 million customer accounts across nearly half of the state of Florida. As of year-end 2013, FPL's typical 1,000-kWh residential customer bill is approximately 25 percent lower than the national average and the lowest in Florida among reporting utilities. FPL's service reliability is better than 99.98 percent, and its highly fuel-efficient power plant fleet is one of the cleanest among utilities nationwide. The company was recognized in 2014 as the most trusted U.S. electric utility by Cogent Reports, and has earned the national Service-One Award for outstanding customer service for an unprecedented ten consecutive years. A leading Florida employer with approximately 8,900 employees, FPL is a subsidiary of Juno Beach, Fla.-based NextEra Energy, Inc. (NYSE: NEE). For more information, visit www.FPL.com.

“Enhanced monitoring on the secondary network in Boston provides NSTAR with unprecedented visibility in grid operations, improving work crew efficiency and distributed energy resource integration.”



NSTAR

Urban Grid Monitoring and Renewable Integration

Technology Partner(s)

Digital Grid
Technologies, Inc.

Project Highlights

- NSTAR has installed over 10,000 sensors to monitor the secondary network in Boston, MA.
- Increased visibility into system conditions improves efficiency of work crews, eliminates blind truck-rolls, and reduces risk of manhole fires and major outages.
- Real-time and near-real-time systems data are integrated into maintenance and future capital expansion plans.

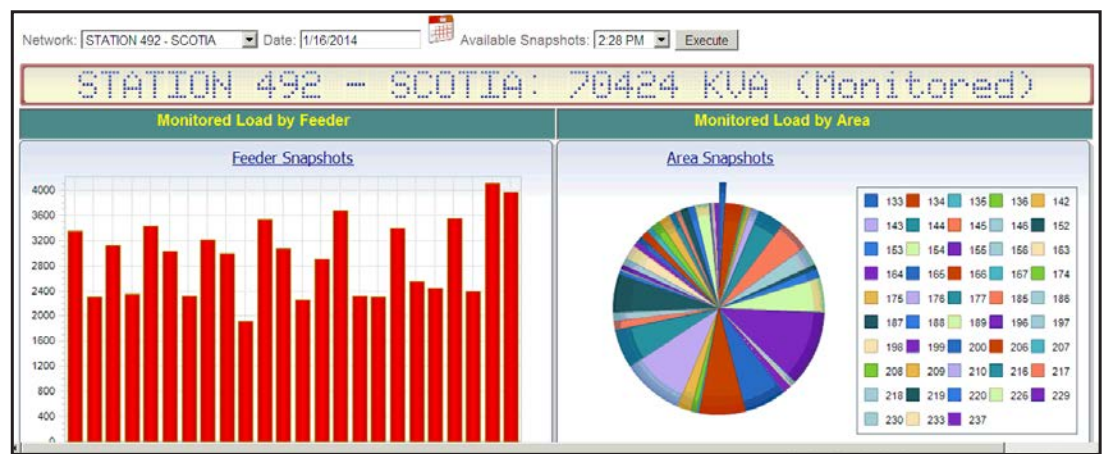
Project Description

In 2011, NSTAR, a Northeast Utilities company, launched the Urban Grid Monitoring and Renewable Integration (UGM) project to enhance network grid monitoring on the secondary network in Boston. The monitoring will provide unprecedented visibility into the operation of the grid, increasing NSTAR’s knowledge of system conditions and ability to integrate solar photovoltaics (PV), plug-in electric vehicles, and battery storage. Results and knowledge acquired from the project will benefit secondary area networks in urban areas across the country.

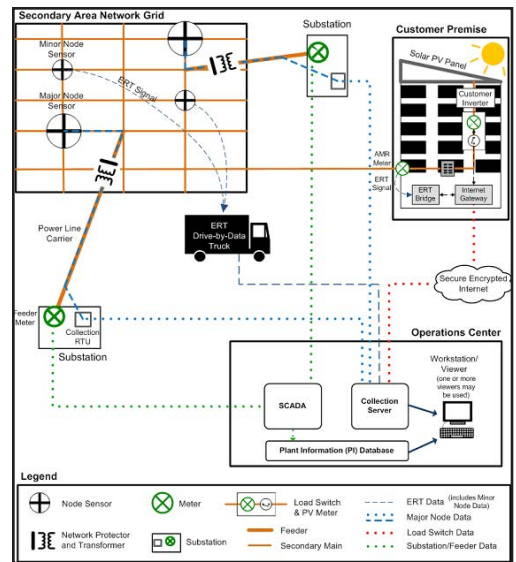
With installation completed in December 2013, information from over 10,000 sensors is collected and stored at various points in the grid, from substations to manholes. Some information is visible in real time, allowing for an operator to monitor the condition of manholes in the secondary network.

Data is informing preventative maintenance plans, making crews more efficient. For major nodes, NSTAR is monitoring approximately 150 manholes with the use of 6,480 sensors in downtown Boston. Monitoring major nodes gives real time information on manhole current (amps) and temperature, eliminating the need for blind truck-roles and preventing manhole fires and major outages. The enclosure injects a power line communication signal at the man-hole onto the secondary network. Nearby vault relays receive these packets of data and convert them into another message packet that is then injected onto the feeder cable. The substation receiver receives this message and processes data to be interpreted by the graphic interface at a central computer station.

User interface shows feeder level data.



For minor nodes, NSTAR is monitoring approximately 350 manholes through 4,386 sensors. These manholes are equipped with sensor packages that monitor current and temperature. Information is then gathered and stored in a terminal box and collected by an automated meter reading (AMR) truck. While information is not in real time, it still allows for enhanced monitoring of the secondary area network. Like major nodes, this information allows for preventative maintenance, making crews more efficient and lowering the risk for major outages, manhole fires, and the need for blind truck roles.



Transmitting secondary network grid data to operations center.

Project Contact

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Company Description

NSTAR, a Northeast Utilities company (NYSE: NU), transmits and delivers electricity and natural gas to 1.4 million customers in Eastern and Central Massachusetts, including more than one million electric customers in 81 communities and 300,000 gas customers in 51 communities. For more information, please visit our website: www.nstar.com.

“OG&E's '100 Analytics Apps' is an aspirational initiative to develop applications that utilize AMI data to create value.”



Oklahoma Gas & Electric

100 Analytics Apps

Technology Partner(s)

Silver Spring Networks

Project Highlights

- Aspirational effort to develop applications that utilize AMI data to drive value for improved operations or expanded customer offerings.
- Integrates AMI data into OMS and other applications for improved outage management and response.
- Combines AMI data with data from other applications to create system diagnostics and improve decision making.

Project Description

Since deployment of its smart grid technology platform, OG&E has been looking at ways to leverage the almost overwhelming amount of data that is available as a result. The “100 Analytics Apps” project is an aspirational effort with Silver Spring Networks to develop applications that utilize AMI data to create value for improved operations or expanded customer offerings.

OG&E has identified several potential use cases and is starting development on the first three to five apps as a proof of concept. At this point, OG&E anticipates 3-6 months to get the first few proof of concept apps into production, but expects to shorten this timeframe to roughly three months for subsequent app development by reducing labor involved with deploying the software platform.

Some example analytic applications would utilize the phase detection, power quality, and voltage data from smart meters to identify and respond to nested and single customer outages more quickly. These analytics would allow the utility to identify customer-side outages with certainty, likely eliminating over 10,000 unnecessary truck rolls annually. They would also help identify more difficult to diagnose outage situations, such as single-phasing or intermittent outages. The same data can be used to create analytic

applications for predictive maintenance, allowing OG&E to identify equipment issues before they result in an outage.

Additional analytics will be created for AMI network diagnostics. The smart grid local area and wide area networks have become a critical part of OG&E’s overall smart grid technology platform. Changing conditions on the grid (weather, load growth, change of seasons, outages, etc.) create a dynamic environment for network operations. The network requires constant monitoring and requires additional analytic applications to diagnose network problems before they significantly impact latency of data. Analytic applications can help OG&E plan and make network improvements before latency becomes a significant problem.

Other analytic applications under development will help expand customer offerings. As OG&E is able to use data and analytic applications to better understand, manage, and respond to all kinds of outages, it will be able to provide customer offerings such as outage notification, outage restoration notification, and even provide estimated time of restoration. Meter data can also be used to develop analytic applications to help commercial and industrial customers better understand what processes or equipment could be causing power factor issues, thus helping them avoid penalties.

There are virtually unlimited applications that can be developed once AMI data can be integrated with other system data and customer data. The purpose of the “100

analytics applications” aspiration is to challenge OG&E’s workforce to be creative and think beyond the obvious.

Project Contact

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Company Description

OG&E is a subsidiary of OGE Energy Corp. (NYSE: OGE), and serves more than 800,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. www.oge.com.

“Integrating smart meter data with its outage management system improves OG&E’s ability to both restore power and communicate outages to customers.”



Oklahoma Gas & Electric

Verified Service Outage

Technology Partner(s)

CGI Group, Inc.
Silver Spring Networks

Project Highlights

- Utilized smart meters to report outages and verify power restoration.
- Automatic restoration validation from meters eliminated need for customer callback system.
- Ability to ping meter from outage management system enables voltage read for any meter from mobile data units in the field.
- Benefits over first six months:
 - Restored an average of one outage incident per week before customer calls in.
 - Average of one additional fraud detection per month.
 - Average of two preventative maintenance opportunities identified per day.
 - Average reduction of 30 minutes to identify nested outages.

Project Description

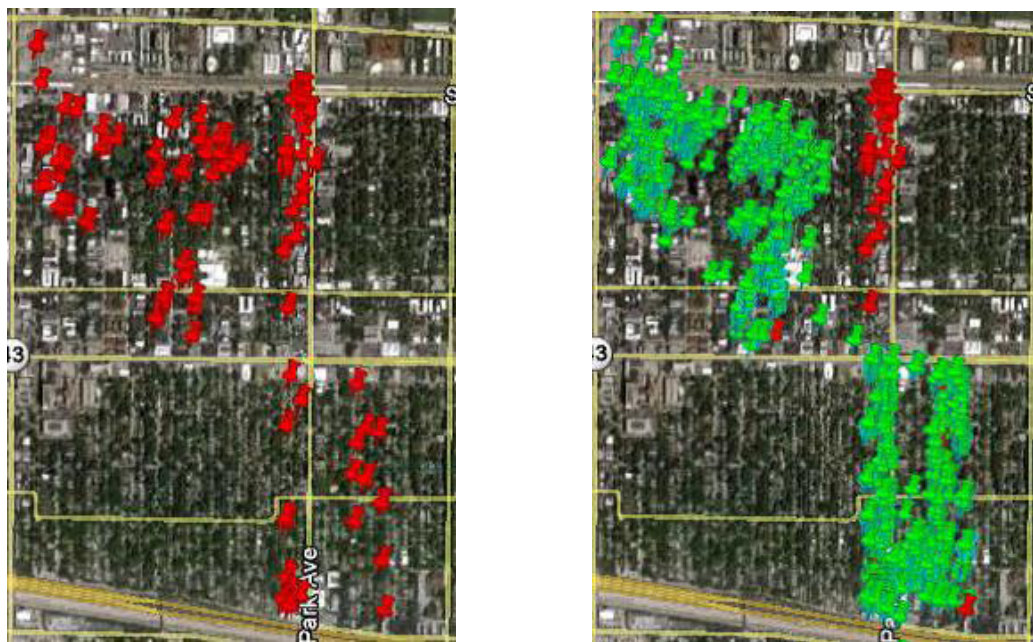
At OG&E, integrating smart meter outage data with outage management systems allows the utility to take a proactive approach to outage management. OG&E has integrated smart meter data from each meter across the entire service territory into their outage response process. During outage scenarios, OG&E utilizes smart meters for three distinct functions within the process: last gasp, power restore notification, and ping response.

When a meter loses power, it sends a “last gasp” notification to OG&E’s outage detection system (ODS). OG&E uses Silver Spring Networks’ ODS to eliminate blinks (outages less than 5 minutes) before passing the information through to their

enterprise service bus (ESB). The ESB filters the data to eliminate outage reports related to planned work, then sends the remaining data over to CGI’s PragmaLINE outage management system (OMS). The OMS analyzes the outages reported by both meters and customers to determine what device has been interrupted and creates an outage incident.

After power has been restored, the meter sends a power restoration notification to the ODS, which is then transported to OMS through the ESB to update the outage incident. Then, an automatic power restoration process pings meters that did not send a power restoration notification. Any meters that remain without power are identified as

Outage occurs at 11:00am (left). Feeders restored at 11:15am (right). Nested outages and two single customer outages remain.



a nested outage and the utility can respond, typically before leaving the premise. In contrast, prior to integrating the smart meter data into the OMS, nested outages typically went unnoticed for up to 30 minutes and often required a second truck roll. The OMS records timestamps from meters for both incident start times and energized times, which help provide a more accurate account of the incident for post-incident analysis.

The ability to manually ping meters from the OMS also enables OG&E's distribution control center to manually validate power restoration of meters. In addition, field crews now have the ability to get a voltage read from a single meter in the field through their mobile data units.

By integrating smart meter data with the OMS and providing distribution control center and field staff innovative tools to more effectively do their jobs, OG&E is improving their ability both to restore power during outages and communicate outage notifications to customers.

Project Contact

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Company Description

OG&E is a subsidiary of OGE Energy Corp. (NYSE: OGE), and serves more than 800,000 customers in a service territory spanning 30,000 square miles in Oklahoma and western Arkansas. www.oge.com.

"Since 2011, PG&E has installed intelligent switch technology on almost 20 percent of its electrical distribution circuits, avoiding nearly 50 million customer outage minutes."



***Pacific Gas and
Electric Company®***

Pacific Gas and Electric Company

Intelligent Switches: Increasing Reliability with “Self-Healing” Technology

Project Highlights

- Fault Location Isolation Service Restoration (FLISR) technology utilizes advanced feeder automation software to restore power to customers utilizing SCADA switches – in less than five minutes.
- FLISR technology installed on nearly 600 electrical distribution circuits with over 2,800 intelligent switches.
- To date, PG&E’s intelligent switch systems have avoided almost 50 million customer minutes of outage time and over 492,000 sustained customer outages.

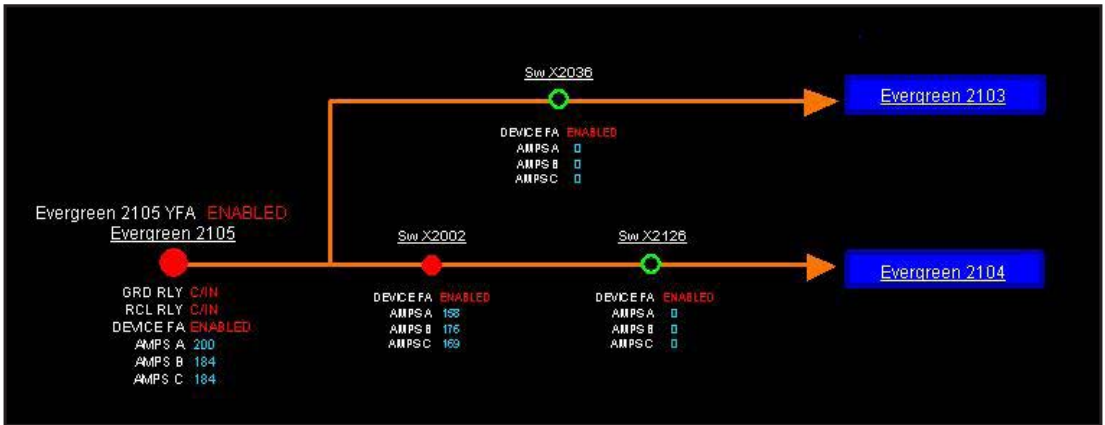
Project Description

PG&E is a leader in deploying intelligent switch systems that act to automatically restore customers' electric service in the wake of an outage. The Fault Location Isolation Service Restoration (FLISR) project began in June 2010, when the California Public Utilities Commission (CPUC) approved PG&E's three year Cornerstone Improvement Project. FLISR technology utilizes advanced feeder automation software that can identify a fault on a feeder section, automatically isolate the faulted area, and restore power to customers utilizing SCADA switches – all in less than five minutes. PG&E began implementing FLISR technology in the summer of 2011, installing detection and self-healing technology on over 500 distribution circuits by the end of December 2013. The effort continues with the installation of FLISR systems under

PG&E's 2014 General Rate Case. From 2014 – 2016, the program will expand the implementation of the FLISR system to hundreds of additional circuits across the PG&E system to improve customer service reliability.

PG&E's Cornerstone Improvement Project initially targeted 400 circuits with a goal of improving reliability. By installing new intelligent SCADA switches and incorporating existing switches into feeder automation schemes, PG&E built nearly 600 circuits with "self-healing" capability. In all, 2,800 intelligent switches and 600 substation breakers utilizing various communication mediums provide real time status to PG&E's SCADA system and feeder automation (FA) software. The FA software is continuously monitoring the system. After a fault event, the FA software will determine the location

SCADA screen of FLISR circuit and devices.



of the fault based on target information from SCADA devices, isolate the fault, and automatically reconfigure to restore customers' power.

In 2013, PG&E customers experienced the fewest minutes without electricity in company history. Smart Grid technology like FLISR played a key role in delivering this performance. PG&E has installed

intelligent switch technology on almost 20 percent of its electrical distribution circuits throughout Northern and Central California. Since the inception of the program in 2011, the self-healing technology has significantly reduced the duration of involved outages from hours to minutes, avoiding nearly 50 million customer outage minutes and saving 492,000 customers from a sustained outage.

Project Contact

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Company Description

Pacific Gas and Electric Company is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, the company is a subsidiary of PG&E Corporation. The company provides natural gas and electric service to approximately 16 million people throughout a 70,000 square-mile service area in northern and central California.

"Smart meters equipped with remote disconnect and reconnect switches have enabled PHI to reduce internal costs and improve customer service."



Pepco Holdings, Inc.

Remote Disconnect and Reconnection of Electric Service

Technology
Partner(s)

GE
Itron
Landis+Gyr
Silver Spring Networks

Project Highlights

- Pepco Holdings, Inc. (PHI) is currently enabling remote connect/disconnect capabilities for 1.4 million residential and small commercial customers with smart meters in Maryland, Delaware, and the District of Columbia.
- When fully operational, remote connect/disconnect will eliminate over 20,000 truck rolls and over 100 tons of vehicle-related CO₂ emissions annually across the PHI operating companies.
- When fully operational, PHI estimates it will realize over \$1.4 million of revenue recovery annually by reducing average past due amounts.
- Will allow customers to select a window of time for the establishment of electric service, reducing the window from a 24-hour period down to a few hours, improving customer service.

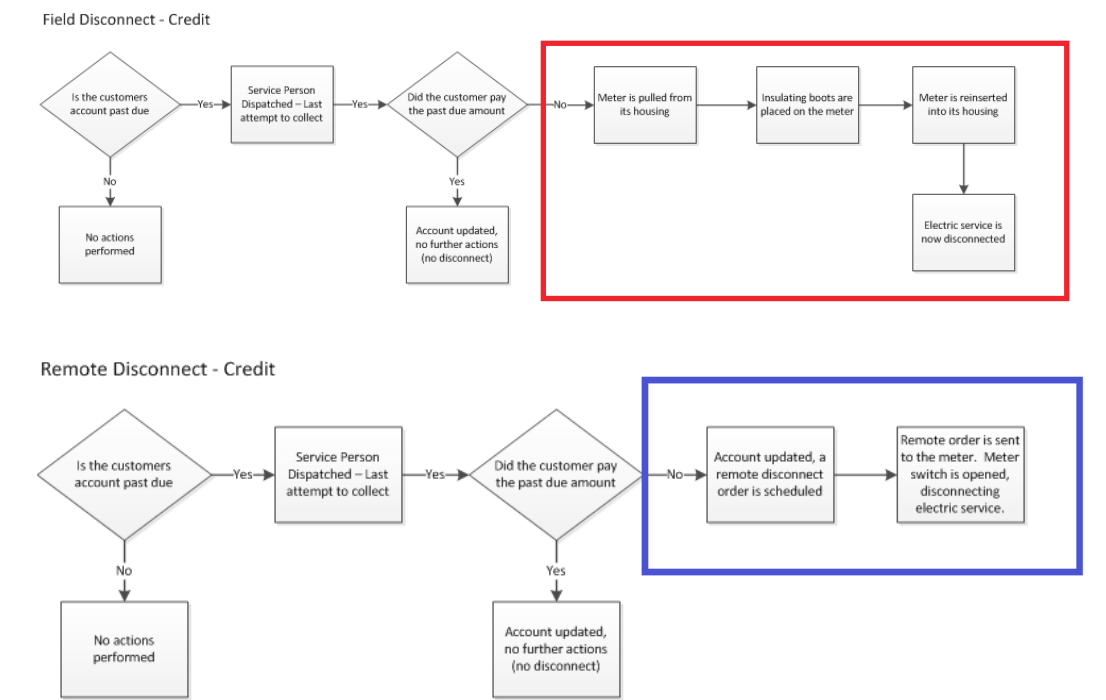
Project Description

The Pepco Holdings, Inc. (PHI) operating companies in Maryland, Delaware, and the District of Columbia are leveraging advanced metering infrastructure (AMI) for remote disconnect and reconnection of electric service. Most of PHI's 1.4 million residential and small commercial meters are equipped with a remote switch that allows PHI customer service representatives to connect and disconnect electric service without having to physically visit the customer premise. By leveraging the telecommunications network, meter orders can be processed much more quickly than if a service person had to be dispatched. The

technology, combined with updated and streamlined processes, has enabled PHI to reduce internal costs, improved customer service, and helped PHI avoid lost revenue.

By using the smart meter's remote disconnect and reconnect capabilities, PHI has reduced, and in some cases, eliminated the need to dispatch a service person when a customer moves in or out of their home. When fully operational, PHI anticipates this capability will eliminate roughly 20,000 truck rolls annually across the operating companies, reducing the companies' potential for vehicle collisions and eliminating over 100 tons of vehicle related CO₂ emissions.

An example of updated PHI customer service processes enabled by remote meter connect/disconnect capability.



In addition to not having to wait on the arrival of a service technician, customers will no longer have to wonder when their electricity will be turned on. Customers will be able to select a window of time for the establishment of electric service, reducing the wait from a 24-hour period to just a few hours.

The AMI system also helps PHI better identify and address unbilled consumption of electricity. Improving the cash collection cycle reduces outstanding past

due amounts and the average collectable amount. When the remote disconnect and reconnection capabilities are in full operation, PHI estimates it will realize over \$1.4 million of revenue recovery annually by reducing average past due amounts.

Project Contact

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Company Description

Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 2 million customers in Delaware, the District of Columbia, Maryland, and New Jersey. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI also provides energy efficiency and renewable energy services through Pepco Energy Services.

"PHI's transformer load management study demonstrates how AMI data can be leveraged to proactively manage transformer assets and prevent possible overloads, power quality issues, and long-term customer outages."



Pepco Holdings, Inc.

Transformer Load Management

Technology
Partner(s)

Itron

Oracle

Silver Spring Networks

Project Highlights

- Leveraged smart meter data to address possible overload on over 5,400 transformers.
- Optimized transformers decrease environmental disturbances and public safety issues associated with transformer failure.
- Reduced truck rolls by right sizing transformers.

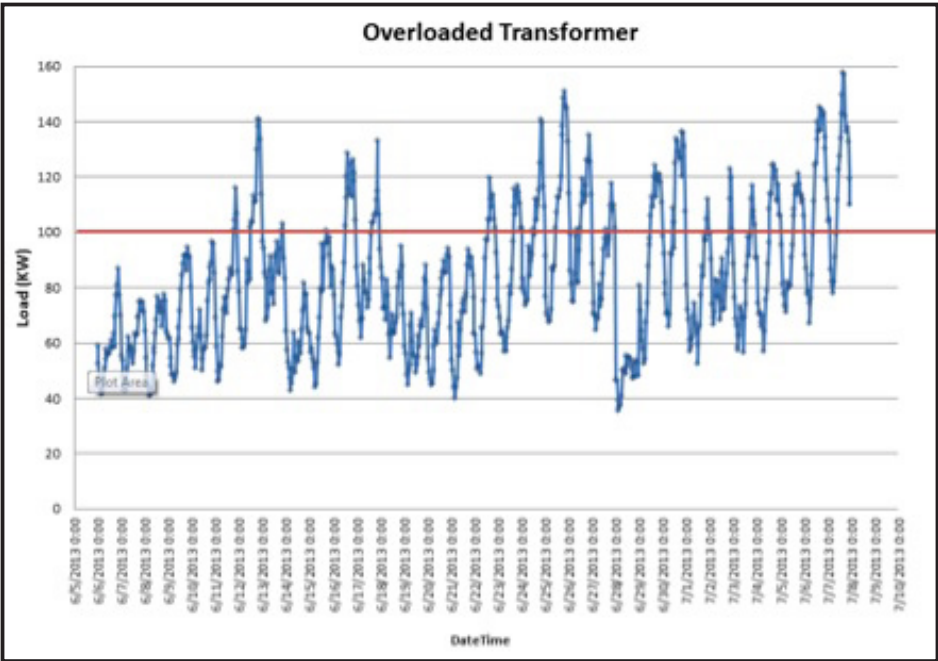
Project Description

Pepco Holdings, Inc. (PHI) has successfully used interval consumption data from their automated metering infrastructure (AMI) to build load profiles for distribution transformers on a number of feeders across their Maryland, Delaware, and District of Columbia service territories. The underlying technology supporting the AMI data was provided by Silver Spring Networks, Itron, and Oracle.

AMI meter data was aggregated to determine the hourly load on over 5,400 transformers under study. Using the load shape, peak load, and transformer nameplate capacity, PHI identified possibly overloaded transformers for field inspection.

The transformer load management (TLM) study allowed PHI to enhance customer service reliability. By proactively monitoring the load profile on transformer assets and performing replacement before failure, PHI can avoid long-term customer service interruptions and power quality issues. The TLM study also helps PHI make smarter decisions when purchasing and installing transformers. PHI uses the information from the TLM study to provide accurate load profile and peak load data for each transformer, enabling optimized sizing of the transformers. By right-sizing transformers, PHI realizes capital savings and avoids losses due to suboptimal equipment allocation.

Load profile of an overloaded transformer.



By identifying and replacing overloaded transformers, the study also reduced public safety issues, environmental disturbances and risk of property damage associated with transformer failure. In addition, proactive monitoring and replacement of overloaded transformers avoids truck rolls, which are required to respond to outages caused by overloads.

PHI plans to continue using AMI and other data from in field assets to diagnose and proactively prevent transformer overloading.

Project Contact

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Company Description

Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 2 million customers in Delaware, the District of Columbia, Maryland, and New Jersey. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI also provides energy efficiency and renewable energy services through Pepco Energy Services.

“Open standards allow SCE to automate substation configuration during the commissioning phase, reducing the process from months to minutes.”



Southern California Edison

Irvine Smart Grid Demonstration: Substation Automation Using Open Standards

Technology Partner(s)

Electric Power Research
Institute (EPRI)

GE

Space-Time Insight

SunPower Corporation

University of Southern
California

University of
California at Irvine

Project Highlights

- Open standards-based approach to substation and feeder automation and interoperability of third-party technologies.
- Engineering design and specifications completed December 2012; field deployment and installation completed December 2013.
- Scheduled completion of systems operations, measurement, and verification by June 2015.
- Implementation is part of Irvine Smart Grid Demonstration (ISGD).

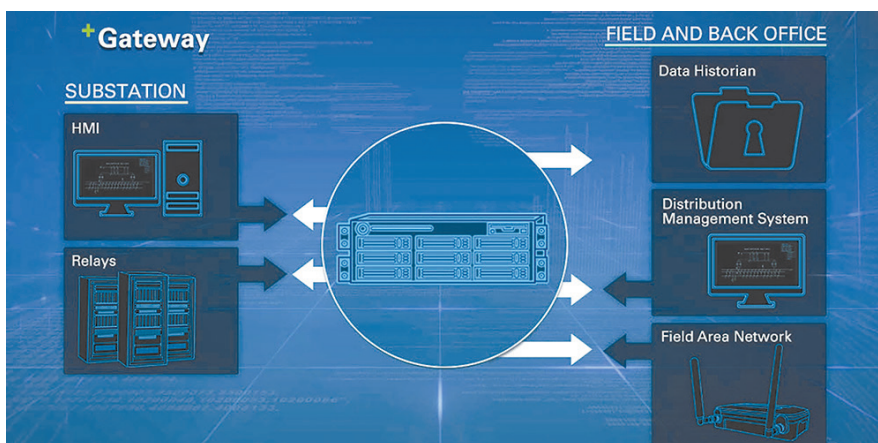
Project Description

The Irvine Smart Grid Demonstration (ISGD) implements equipment, systems, and software that will help set the direction for Southern California Edison's (SCE's) next-generation grid. ISGD has received \$39.6 million in matching funds from the U.S. Department of Energy as part of an American Recovery and Reinvestment Act demonstration grant. The project is demonstrating technologies on the customer side of the meter, in neighborhoods, on distribution circuits, in distribution substations, and in the utility back office, including home area networks, renewable energy, battery storage, electric vehicle charging, volt/VAR control, advanced circuit protection, standards-based substation automation, and the back office systems to securely integrate these systems.

ISGD is demonstrating a number of advanced substation automation and distribution automation capabilities out of MacArthur substation, including the next generation of SCE's substation automation (SA-3), an automation and control design based on the open standard IEC 61850. The IEC 61850 standard provides an internationally recognized method of communications for substation equipment protection, monitoring, and control. This flexible standard also provides simplified system configuration and integration. MacArthur is SCE's first substation to use this open standard. The standard is being supported by the UCA International Users Group, of which SCE was a founding member.

The goal of SA-3 is to transition substations to standards-based communications, automated control, and enhanced protection design. Achieving these goals will support system interoperability and enable advanced functionalities such as automatic device configuration and integration with legacy systems. The design incorporates IEC 61850-compliant software and hardware from multiple vendors.

When deploying complex systems, utilities typically procure hardware and software from a single vendor. This helps utilities avoid having to manage device interoperability, thereby mitigating deployment challenges. Open standards promote vendor competition, thereby increasing procurement options and reducing costs. Open standards also promote flexibility by allowing utilities the ability to choose best-in class devices from multiple vendors. Using open standards removes the need to engineer and configure the substation to work with unique vendor specifications, and allows SCE to automate substation configuration during the commissioning phase. This reduces a process that had taken months to one that takes minutes. An additional benefit is a reduction in the number of manual errors that would typically be anticipated during a protracted installation process. The open standards also anticipate future technological improvements; new technologies that are compliant with IEC 61850 will easily integrate with current equipment and technologies.



Secure communications between substation devices, field area networks, and back office systems are coordinated through a gateway installed in the substation.

As part of the MacArthur demonstration, a gateway was installed in the substation to provide connectivity to the distribution SCADA system as well as the distribution circuit automation. This gateway transfers standards-based messages to coordinate protection and control between substation automation and feeder automation, increasing customer reliability. This gateway also incorporates advanced cybersecurity features.

This new automation design enabled by the open standards will simplify the advanced protections and control strategies needed to incorporate distributed energy resources reliably. The lessons learned as part of this project will be freely shared with the industry to help other utilities accomplish smart grid implementations without having to start from scratch.

Project Contact

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Company Description

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal, and Southern California. www.sce.com.

“Xcel Energy is realizing multiple benefits from its improved network management system in monitoring and managing the distribution grid”



Xcel Energy

Advanced Network Management System

Technology Partner(s)

Oracle

Project Highlights

- Network management system upgrade allows Xcel Energy to quickly address outages while at the same time significantly reducing service crew hours.
- Thousands of service calls avoided, resulting in an estimated \$600,000 savings in the past two years.
- PowerFlow application determines potential system overloads, voltage issues, and suggested switching, including enhanced alert notifications for major customers.
- Identifies system areas that may be overloaded due to switching during both emergency and planned work, allowing employees to mitigate power-quality issues before executing switching in the field.

Project Description

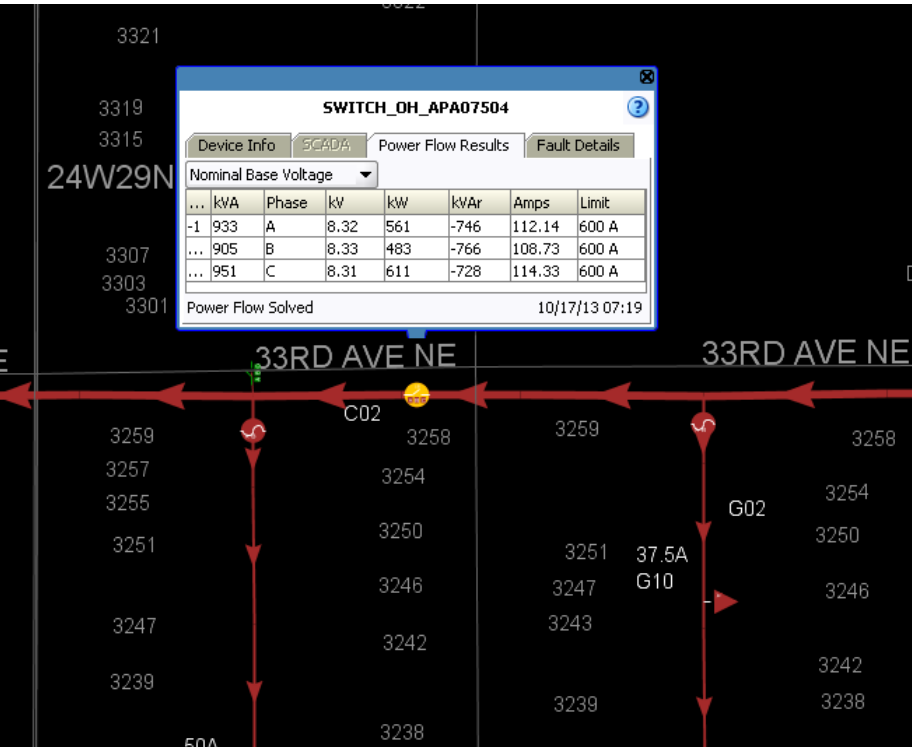
Reliability and customer satisfaction are two of Xcel Energy's main priorities, and efficient and timely management of electric outages is critical to both of those goals. Integrating new technology with the company's electric system has brought big benefits, helping to quickly address outages while at the same time significantly reducing service crew hours.

The utility industry's use of radio signals to read meters and check their functioning is not new, but Xcel Energy has taken advantage of recent developments in the technology by integrating state-of-the-art

improvements into its electric network management system (NMS). Part of the technology involves "customer pinging," which allows system operators to "ping" an individual address. This entails accessing a field controller that polls the individual customer's meter to determine if it is energized or not.

The effort can prevent sending service crews into the field unnecessarily. Minimizing the need to send crews and trucks during an outage to check on meters, that many times haven't been affected, can eliminate hundreds of unneeded trips. That saves

Power flow modeling application.



time and money while maximizing field crews' efficiency and their ability to restore service more quickly to areas in need.

What's changed is the ability to ping meters from within the NMS program. The NMS can now show all customers who called during an outage, and all available meters that can be pinged for a response. If the company pings a meter that responds with 'power on', employees can cancel the service call and check on the customer call-back information right in the existing application.

Ping responses had typically come back within minutes. With the new system, dispatchers can receive responses in as little as 30 seconds showing that a meter is on, freeing line crews to be redeployed to the next job. The technology significantly improves the cleanup of single customer outages. During major storms – with more users involved – the response time slows down a bit, and the returning percentage of usable pings also goes down. However, the company still receives enough usable pings that it can cancel hundreds of unnecessary trips during a major storm.

Throughout Xcel Energy's service territory, thousands of service calls have been avoided thanks to the improvements, saving well over \$600,000 in the past two years, and making the technology a proven critical resource in restoring service as efficiently and quickly as possible.

"Pinging" isn't the only recent improvement to Xcel Energy's NMS system. Oracle Utilities' web-based applications have helped make the NMS more familiar and user-friendly for employees. The NMS upgrade was implemented in 2012, and enhancements included important changes to the switch-plan program, which is used to isolate areas of the grid for both planned and emergency service.

In addition, the new PowerFlow modeling application allows company users to determine potential system overloads, voltage issues, suggested switching, as well as a host of other important functions, including enhanced alert notifications for major customers. The PowerFlow application allows the company to see directional flows of load, and if the company has to switch electricity flows in the system, it can determine in advance if there could be issues involved with the possible switches. PowerFlow effectively identifies areas of the system that may be overloaded due to switching during both emergency and planned work. It also identifies areas that may experience voltage issues, allowing employees to look ahead and mitigate these power-quality issues before actually executing the switching in the field.

Company teams continue to implement many of the new, additional features that the Oracle software offers, further enhancing the efficiency of the NMS in responding

effectively to outages. One major issue the technology has helped Xcel Energy with is finding errors in its connectivity model, the graphic view of the company's electric distribution system. As the connectivity model improves, so does the company's ability to predict outages. This saves Xcel Energy time in the field, improves the accuracy of switching procedures, and helps with comprehensive feeder-circuit planning for engineering.

All told, Xcel is realizing multiple benefits from the enhanced and improved NMS capabilities in managing and monitoring the distribution system.

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Company Description

Xcel Energy (NYSE: XEL) is a major U.S. electricity and natural gas company with regulated operations in eight Western and Midwestern states. Xcel Energy provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers through its regulated operating companies. www.xcelenergy.com.

“New technologies are opening the door to meeting new customer needs, and electric utilities are responding with new solutions.”



Customer **Solutions**

The relationship between utilities and customers is evolving, thanks, in part, to newer communication methods that are better connecting customers and utilities. At the same time, customer segmentation, data analytics, and customer information systems that integrate with other utility systems are providing the foundation for utilities to develop and to offer new customer solutions.

On the customer side, the proliferation of behind-the-meter distributed energy resource options is changing the way customers view and think about electricity; morphing it from a basic commodity to a lifestyle definer. Meanwhile, businesses increasingly are looking to their utilities to provide advice on their energy use and to help them achieve energy savings goals. From a technology standpoint, connected devices and the "Internet of Things" finally are making home energy management solutions accessible to the mass market.

Electric customers typically have maintained a low level of engagement with their utilities, which is something that utilities keep in mind when introducing new

products or services. A too-often cited industry statistic is that the average consumer only spends a total of six minutes each year thinking about their home energy bill and interacts with their utility providers for seven minutes a year. In spite of this low engagement, about 75 percent of customers express a high level of satisfaction with their utility providers, and the majority of customers view their utility as the source for how to use electricity more efficiently. That is very good news!

Today, new technologies are opening the door to meeting and discovering new customer needs, and electric utilities are responding with new solutions. In rolling out new customer solutions, utilities often adopt an incremental approach, enabling customers slowly to learn about the new products and services, beyond just electricity, that are offered by their electric provider. While some customers feel they already know more than enough about their electricity use, others are delighted to find new services that enable greater control and choice over their energy use.

Customer Solutions Trends

As the nation becomes more energy efficient and more focused on clean supply sources to generate energy, electric utilities are providing new customer-side solutions – new products and services – that better serve the shift in customer needs and expectations. This chapter describes

some of the solutions that electric utilities are offering their customers today, including payment and communications options and utility program engagement.

1. Payment and Communications Options

Choice is important for customers. They want to decide how they interact with and receive information from their electricity provider, as well as how they view and pay their bills. Some customers prefer a self-serve approach via online resources, while others value high-touch service. Different payment options have emerged to serve the spectrum of customer preferences, including prepay, online bill pay, and budget setting with alerts based on actual usage.

Among the ways utilities are offering customers choices:

- They are developing energy management apps, such as DTE Energy's Insight, which lets customers set monthly energy consumption goals, provides feedback on progress, suggests energy savings projects, and can display real-time energy usage on smartphones;
- Utilities are providing peer comparison and usage tracking tools, such as those offered by Duke Energy, Portland General Electric, and San Diego Gas & Electric. These are effective, low-cost solutions that are delivered in a variety of ways (e.g., online and paper) and provide benefits to customers; and

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- Many utilities are enhancing their communications around power outages and expected restoration times, which are tremendously popular customer service offerings and demonstrated by the case studies from CenterPoint Energy, Commonwealth Edison, and Southern Company.

2. Program Engagement

Electric utility programs, such as energy audits, rebates for energy-efficient appliances, and participation in energy-efficiency and demand-response programs are definitely nothing new. What is new is that utilities are putting customer engagement tools to use in order to increase adoption and retention in these programs. As a result of these efforts, customers are saving energy, and a sense of partnership is developing between the customer and the electric utility.

Recent examples include:

- Austin Energy's bring your own thermostat (BYOT) demand response program, which enables customers to buy their preferred thermostat at retail and to participate in the utility's demand response program. This is a transition from first-generation demand response or load-control programs where utilities gave away thermostats for free. Now customers engage by purchasing their own device.
- From opt-in efforts like Gulf Power's Energy Select program to holistic voluntary approaches like Pepco's Peak

Energy Savings program, and even commercial customer-focused initiatives like NV Energy's mPowered program, participation in dynamic pricing and demand response programs continues to increase as electric utilities offer better "reasons" for customers to engage in these programs and as customers gain a better appreciation of the ease and value of participating.

Conclusion

The case studies in this chapter clearly show that as the programs and services that electric utilities offer become more mainstream, they open the door for more diversified and sophisticated customer solutions that provide even more customer value.

From the customer perspective, there is a natural evolution from basic services that are provided for free or incentivized to stimulate adoption today to more sophisticated and targeted services. Now that the market is primed, proactive strategies are jumpstarting the transition toward the next phase of customer solutions.

“Allowing customers to bring their own thermostats to participate in demand response events is helping Austin Energy achieve its demand response goal of 150 MW by 2020.”



Austin Energy

Power Partner Thermostat Program

Technology Partner(s)

ecobee
EnergyHub
Nest Labs

Project Highlights

- Power Partner Thermostat program provides \$85 rebate to customers who purchase, install, and enroll one of 14 eligible Wi-Fi thermostats.
- Over 7,000 thermostats representing 10 MW of demand response currently enrolled.
- Enrollment, operation, and reporting of participating thermostats supported by three thermostat vendors: ecobee, EnergyHub, and Nest.
- Planned program expansion to 70,000 thermostats will deliver 100 MW of peak demand reduction to support Austin Energy's demand response goal of 150 MW by 2020.

Project Description

In 2001, Austin Energy initiated its residential demand response program through the distribution of over 80,000 free thermostats to residential, multifamily, and small business customers. Through a one-way radio signal, Austin Energy cycled the thermostats on-and-off during demand response events. Unfortunately, with a one-way signal it is not possible to receive data back from the thermostats or even confirm the number of active thermostats in the field. In addition, this “top-down” approach required a significant service contract to install and maintain the thermostats and also respond to customer concerns and event opt-outs.

In an effort to improve its residential demand response program, in May of 2013, Austin Energy initiated the Power Partner Thermostat or “Bring Your Own Thermostat” (BYOT) program for residential customers. Under the BYOT program, customers are encouraged to purchase one of 14 eligible Wi-Fi thermostats, install it, enroll in the program, and receive an \$85 rebate. Under the enrollment agreement, the customer agrees to allow Austin Energy to adjust the thermostat by no more than 4 degrees during demand response events and allows the customer to opt-out if they feel the conditions are unfavorable. Events are called during the demand response season from June–September for approximately 2 hours (events generally occur from 3:45 to 5:45). These events typically occur 15 times per season.

Austin Energy currently works with three vendors (ecobee, Nest Labs, and EnergyHub) to support the enrollment, operation, and reporting of the participating thermostats. Each vendor provides Austin Energy with a portal to access customer enrollment data, initiate events, and review post-event reports. Each vendor notifies customers of an event in a unique manner. Customers with Nest thermostats receive day-ahead event notification via the Nest app, while customers with ecobee and EnergyHub thermostats are notified of the event in progress on their thermostat display. Austin Energy pays each vendor an annual portal maintenance fee as well as quarterly payments for each enrolled thermostat.

By allowing customers to participate in demand response events, Wi-Fi thermostats play a significant role in helping Austin Energy achieve its aggressive demand response goal of 150 MW by 2020 and support its customers by improving system reliability and reducing transmission expenses and fuel charges billed to the customer. If Austin Energy can reduce its contribution to the ERCOT 4-coincident peak, which is the average coincident peak demand over June, July, August, and September, its share of the transmission costs will be reduced and the savings can be passed on to customers.

A significant advantage of the Wi-Fi model is that customers may opt-out of an event from the thermostat. With two-way communication and access to the vendor portal,

Austin Energy can identify the number of participating thermostats and calculate an associated savings. As an added advantage, by promoting Wi-Fi thermostats to their customers, Austin Energy is helping customers make informed decisions about their home's energy use. Homeowners can monitor and control their thermostat from anywhere, using a smartphone, tablet, or computer. Thermostats covered by the BYOT program understand the weather outside and a home's energy performance to optimize for energy savings throughout the year.

The program has been overwhelmingly successful. Austin Energy has seen customers embrace Wi-Fi thermostats at rates

beyond expectation. In the first year of the program, Austin Energy was able to meet their enrollment goals for the year within the first two months of working with vendors. Currently, Austin Energy has enrolled over 7,000 thermostats since its launch last year, representing an offset of about 10 MW of peak demand. Austin Energy believes that 100 MW of the 150 MW demand response goal can be met with the adoption and use of approximately 70,000 Wi-Fi thermostats. Critical to achieving this goal is making the Wi-Fi thermostats work in multifamily settings. The success of the program has been supported by advertising done primarily through our three vendors. Efforts are underway to expand the program to include an additional two vendors.

Project Contact

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Company Description

Austin Energy is the nation's 8th largest publicly owned electric utility. It serves more than 420,000 customer accounts and more than 1 million residents in the Greater Austin area. Operations are funded entirely through energy sales and services, and Austin Energy supports other City of Austin services with an annual transfer into the general fund of more than \$100 million. The utility operates within the ERCOT market. Austin Energy's mission is to deliver clean, affordable, reliable energy and excellent customer service.

“Overall, 82 percent of Power Alert Service enrollees are satisfied or extremely satisfied that CenterPoint is addressing their outage problems.”



CenterPoint Energy

Power Alert Service

Technology Partner(s)

Itron

Send Word Now

Project Highlights

- Roughly 493,000 alerts delivered to over 400,000 enrolled customers.
- Only 7 percent of enrolled customers call to report an outage.
- 92 percent of customers rate program registration/ use as "easy".
- 93 percent of customers find restoration alerts timely.
- 82 percent customer satisfaction.

Project Description

When power goes out, residential and business customers want answers to two questions: “Does the electric company know that my power went out?” and “When will my power come back on?”

CenterPoint Energy’s Power Alert Service (PAS), currently serving more than 400,000 registered electric customers in the greater Houston area, is a free tool that notifies customers about power interruptions at or near their home or business address and keeps them informed during the outage event. Notifications start when CenterPoint Energy believes a power outage has occurred, and they continue until the power has been restored.

Designed as a compact system which integrates six pre-existing company systems, and piloted with employees before being made available to the public, PAS uses data collected through smart meters to pinpoint the addresses affected by power outages and notify those customers through their choice of email, text, and/or phone call within minutes of a confirmed (non-momentary) outage. The initial notification includes the number of customers affected by the outage as well as an estimated time of restoration (ETR). Customers are kept informed with status updates advising them when repair crews are assessing conditions, and if needed, on-site repair crews can revise the ETR, triggering a follow-up alert to customers with the newly estimated time of restoration. The final follow-up message

includes the outage cause, such as weather, wildlife, or equipment failure.

Within ten months of becoming publicly available, more than 400,000 customers were enrolled and over 493,000 alerts were delivered by phone, email, or text. PAS gives customers assurance that CenterPoint is addressing their problems; only seven percent of PAS-enrolled customers call to report their outage – a significant reduction in call volumes. In fact, CenterPoint Energy’s use of smart meters’ power-off notification (PON) capability, which immediately alerts the company to outages, has decreased the time it takes to localize outages by 50 to 70 percent, enabling the utility to dispatch crews more efficiently to restore power for more than 875,000 customers without a single phone call.

CenterPoint Energy regularly surveys PAS users and has received positive feedback via social media. About 92 percent of enrollees find it easy to enroll in and use PAS. Indeed, auto-enrollment of some customer segments (customers can opt out at any time, but few do) has created “surprise and delight” for customers discovering the new service. Customers also praise the timeliness of the alerts, with 93 percent satisfied with the speed of the “power restored” notification. In fact, many customers report that the company informed them of an outage before a family member at home could reach them.



Power Alert Service notifies and informs customers of power delivery events.

Overall, 82 percent of enrollees are satisfied or extremely satisfied with PAS for alerting them to outages, keeping them informed, saving them from waiting on hold or navigating the automated phone system, and helping them plan around an estimated restoration time.

In 2015, CenterPoint Energy will continue to proactively roll out PAS across the company's electric customer base. Future enhancements will include increasing the number of people a customer can have notified during an event, such as a family member or landlord. PAS, which aligns

with rising expectations among regulators and customers for outage communications, can also be used to alert large numbers of customers before a major storm. Indeed, as one of the first proactive, electronic communication tools to alert electric customers

about service-related issues, PAS will eventually become CenterPoint Energy's primary method of delivering operational messages to customers in the information age.

Project Contact

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Company Description

CenterPoint Energy's electric transmission and distribution unit serves over 2.2 million metered consumers in a 5,000 square-mile area including Houston, the nation's fourth largest city and a consistently growing market. As a regulated "wires" utility, we neither generate power nor sell it to end-use consumers. We instead own, operate and maintain the poles, wires and substations that safely and reliably deliver electricity from power plants to consumers. With over 3,700 miles of transmission lines and 49,000 miles of distribution lines, we deliver electricity on behalf of 75 retail electric providers.

***“ComEd's System
Improvements Map
provides transparent
and timely information
to customers on com-
pleted and upcoming
grid improvements in
their communities.”***



An Exelon Company

Commonwealth Edison Company

System Improvements Map

Technology Partner(s)

iFactor

Project Highlights

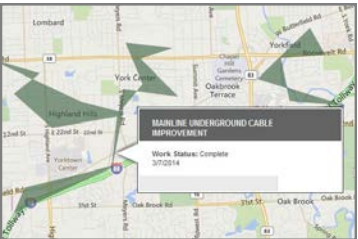
- Improved communication of system investments.
- Increased transparency and customer access to information on grid modernization.

Project Description

Under the Energy Infrastructure and Modernization Act (EIMA) passed by the Illinois General Assembly in 2011, ComEd is investing \$2.6 billion over 10 years to modernize the power system with digital technology and to replace, refurbish, and upgrade electric equipment across a northern Illinois territory that spans from Lake Michigan to the Mississippi River.

Ultimately, the grid modernization investments will help ComEd significantly reduce outages and give customers the tools to manage their energy usage and save money. In fact, ComEd's 2013 power system reliability rating of 0.99 on the System Average Interruption Frequency Index (SAIFI) was the best in company history with the fewest customer interruptions. ComEd's reliability improvements stem largely from the utility's substantial investments in building a "smart grid," implementing major power infrastructure upgrades, and optimizing workforce performance.

ComEd's System Improvements Map Display.



The map shows the general area of the work being done in each program with a customer-friendly naming convention.

To help keep customers connected and informed of the modernization investments, on June 30, 2014, ComEd launched an interactive System Improvements Map. The System Improvements Map highlights infrastructure improvements completed since the beginning of the smart grid modernization program and shows planned efforts

for the upcoming quarter. In addition, customers can view locations where tree trimming and other reliability enhancements have been completed.

The System Improvements Map provides transparency and useful information to ComEd's customers. Customers can engage with this interactive map to learn about the completed and upcoming improvements underway in their community. ComEd is excited to introduce this interactive way to display ComEd's grid modernization efforts, which include investments dedicated to system reliability; including refurbishing, replacing and upgrading system infrastructure; storm

hardening; and automation to improve the resiliency of circuits especially susceptible to storms.

Planned upgrades to the map include an expansion to the frequently asked questions section, which will further educate customers on how system enhancements will improve the reliability of the grid.

ComEd's System Improvements Map can be accessed at [ComEd.com/SmartGrid](https://www.comed.com/SmartGrid).

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Company Description

Commonwealth Edison Company (ComEd) is a unit of Chicago-based Exelon Corporation (NYSE: EXC), the nation's leading competitive energy provider, with approximately 6.6 million customers. ComEd provides service to approximately 3.8 million customers across northern Illinois, or 70 percent of the state's population. For more information visit [ComEd.com](https://www.comed.com), and connect with the company on Facebook, Twitter, and YouTube.

***"ComEd's Smart Ideas
Central AC Cycling Pilot
uses the Nest Learning
Thermostat™ to help
customers save money,
save energy, and help
the environment."***



An Exelon Company

Commonwealth Edison Company

Nest Thermostat Demand Response and Rebates

Technology Partner(s)

Nest Labs

Project Highlights

- Up to \$140 in rebates for customers who purchased a Nest Learning Thermostat™ and participated in ComEd's Smart Ideas Central Air Conditioning Cycling pilot program.
- Over 3,200 customers participated in the Nest thermostat pilot.
- Preliminary analysis shows average demand reduction of 0.79-1.08 kW per customer during two events in 2014.

Project Description

The Nest “Learning” Thermostat is a new class of thermostat that is able to learn a customer’s schedule, reprograms itself to changing room temperature, and can be controlled by a customer’s smartphone. During the summer of 2014 ComEd partnered with Nest Labs Inc. to offer up to \$140 in rebates for customers who purchased a Nest Learning Thermostat™ and participated in ComEd’s Smart Ideas Central Air Conditioning (AC) Cycling pilot program. Customers received a \$100 rebate from ComEd for signing up to participate in the pilot that features Nest’s Rush Hour Rewards™ (RHR), and an additional \$40 rebate for participating in the pilot all summer. RHR events only occurred from June 1st to September 30th, 2014 at ComEd.

ComEd signed up 3,200 customers to participate in the pilot by recruiting customers from the ComEd and Nest websites, using in store displays, posting on social media (i.e. Facebook and Twitter), e-mailing promotional materials to customers, granting interviews to magazines and television news channels, and by posting stories on blogs. The key message for the pilot was that you can use this enabling technology to save money, save energy, and help the environment.

Demand response programs such as ComEd’s AC pilot can use Nest’s RHR service to help reduce electricity demand on the hottest days of the summer. With ComEd’s pilot, Nest sends a wireless signal over the customer’s home Wi-Fi to the Nest

thermostat to adjust the customer’s air conditioner, automatically helping reduce electric demand during peak periods.

With Nest’s RHR program, a customer’s thermostat temperature is automatically adjusted around rush hours events. Before the event, the customer’s air conditioner can be controlled by the thermostat to pre-cool the home and can let the temperature raise a few degrees during the event. This helps reduce the electric demand of the home during rush hour events while still keeping customers comfortable. Customers can override the temperature during an event by simply changing the setting on the thermostat.

ComEd called two RHR events in the summer of 2014, on July 22 from 1-4 p.m. and on August 24 from 12-3 p.m. A preliminary analysis was performed based on a “base day” methodology from 136 smart meters at the customer site. Based on the analysis, the average customer demand reduction during the three hours for the two events ranged from 0.79-1.08 kW per customer. This result is similar to the results ComEd has seen from a traditional direct load control switch having a 100 percent load interruption. Pre-cooling of the home an hour before the event likely contributed greatly to the large load reduction measured in the pilot.

One benefit ComEd gained by running the Nest thermostat pilot during the summer of 2014 was to gain more experience in

leveraging the benefits of programmable communicating thermostats (PCT). Using PCTs, customers can operate their thermostat with their smart phone when they are away from home. This helps improve the customer's ability to control their thermostat while they are away from home, enabling customers to more effectively participate in demand response, energy efficiency, and dynamic pricing programs. This type of Wi-Fi-enabled technology helps put additional control into the customer's hands in a new and innovative way.

In addition, the Nest thermostat facilitates automated changes to customer's individual schedules to drive energy savings,

through a feature called the "Seasonal Savings" program. ComEd will measure the amount of energy efficiency benefits to customers from the Seasonal Savings program for a full year, starting June 1, 2014.

As part of ComEd's AMI roll-out, during the summer of 2015 customers with smart meters will be able to participate in ComEd's Peak Time Savings (PTS) program. Some of the customers that sign up in the PTS program can participate in a direct load control (DLC) pilot that will leverage a PCT device similar to the Nest device used in 2014. The experience of the Nest thermostat pilot in 2014 will directly benefit ComEd's efforts to operate their DLC pilot in 2015.

Project Contact

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New Product Development

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Company Description

Commonwealth Edison Company (ComEd) is a unit of Chicago-based Exelon Corporation (NYSE: EXC), the nation's leading competitive energy provider, with approximately 6.6 million customers. ComEd provides service to approximately 3.8 million customers across northern Illinois, or 70 percent of the state's population. For more information visit ComEd.com, and connect with the company on Facebook, Twitter, and YouTube.

"To demonstrate the immediate value from ComEd's smart meter investment, ComEd is offering its Peak Time Savings program to all customers who have smart meters."



An Exelon Company

Commonwealth Edison Company

Peak Time Savings

Project Highlights

- Peak Time Savings (PTS) is an opt-in residential demand response program available to all residential customers with smart meters.
- Bill credits of \$1 per kWh saved during select summer PTS hours.
- PTS is expected to launch enrollments in Fall of 2014 and call its first events during summer 2015. Enrollment runs annually from October–April.
- Anticipated customer participation of 3 percent in the first year, growing to 10 percent by 2020.


Project Description

Smart meters are a key part of ComEd's effort to show customers the value of a smart grid-enabled future. To demonstrate the immediate and tangible benefit to customers from ComEd's smart meter investment, ComEd will offer the Peak Time Savings (PTS) program to all residential customers who have smart meters. PTS is an opt-in demand response program that will pay enrolled customers for saving electricity during select summer Peak Time Savings events when electricity demand is high. Managing high-demand periods can help reduce the need for additional power plants as well as lower emissions, help keep down the overall cost of electricity, and lessen the burden on the electricity delivery system, all while saving customers money.

Eligible customers with smart meters installed at their homes can earn a credit on their electric bills of \$1 per kWh saved when they participate voluntarily on days with Peak Time Savings hours. ComEd will calculate each customer's baseline electricity usage, which is the expected amount of energy the customer would have consumed, and subtract the customer's metered usage to determine the rebate amount.

Peak Time Savings events will occur during summer months, from June to September. Peak Time Savings hours will typically occur for a few hours between 11 a.m. and 7 p.m. on three to five days during the summer. Customers will be notified of Peak Time Savings afternoons by phone call,

ComEd Peak Time Savings program marketing messages.



LOOK WHAT YOUR HOME'S SMART METER CAN DO FOR YOU


Welcome to PEAK TIME SAVINGS

Peak Time Savings is a program from ComEd that pays you back for using less electricity when it is most in demand. Earn a credit on your electric bill when you participate voluntarily on days with Peak Time Savings Hours.

Peak Time Savings Hours will typically occur for a few hours between 11 a.m. and 7 p.m. during the summer—when most air conditioners are on, stores are open and factories are running.

ComEd will announce **three to five** days with Peak Time Savings Hours during the summer of 2015.

Reduce your use and save!




HOW IT WORKS:

NO RISK, NO PENALTY, NO WORRIES


There is no cost to enroll in the Peak Time Savings program. And there is no penalty if you enroll and don't participate. You just won't earn a credit on your electric bill for that day and you can still participate in future Peak Time Savings Hours.

ENROLL




Enrollment is now open to participate in the 2015 summer season. You can remain in the program for as long as you like. Visit ComEd.com/PTS or call 844-852-0347.

GET NOTIFIED



ComEd will notify you on the day when Peak Time Savings Hours will occur. Choose your preferred method of notification when you enroll – phone call, text message or email. We'll notify you that morning as early as 9 a.m. or at least 30 minutes prior to the start.


REDUCE & SAVE



During Peak Time Savings Hours, use less electricity and earn a credit on your electric bill. The amount you earn will be based on your current electricity usage. See chart for examples of what you can do during Peak Time Savings Hours and how much you can potentially earn.*

| ACTIONS What can your household do during Peak Time Savings Hours? | POTENTIAL EARNINGS How much can you earn? |
|---|---|
| Delay using your dishwasher, vacuum, clothes dryer, lighting or electronics | EARN \$1 - \$3 credit on your bill |
| Take the actions above, plus set the thermostat 4 degrees higher | EARN \$4 - \$12 credit on your bill |

EARN CREDITS



When you participate, ComEd will credit your monthly bill for reducing your electricity use during Peak Time Savings Hours. A credit will appear as actual dollars off the total amount due on your next electric bill or the following bill. And you'll help reduce the need for fossil-fuel power plants which helps the environment.

text message, and email at least 30 minutes prior to the start of the event. The program will launch enrollments in the fall of 2014, and events will start in the summer of 2015.

Bi-lingual marketing campaign.

Enrollment runs annually from October to April. For 2014, the target audience is all eligible residential customers with a smart meter – approximately 335,000 customers, growing to 833,000 customers with smart meters installed in 2015. ComEd anticipates 3 percent of eligible customers will opt-in during the first year, growing to approximately 10 percent of customers by 2020.

PTS will complement the other smart grid/smart meter-enabled initiatives ComEd is offering under the Smart Grid Exchange (SGE), including the Nest pilot, appliance retailer collaborations, smart home energy management devices. Apps promoted by SGE initiatives will help customers take full advantage of PTS.

Project Contact

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Company Description

Commonwealth Edison Company (ComEd) is a unit of Chicago-based Exelon Corporation (NYSE: EXC), the nation's leading competitive energy provider, with approximately 6.6 million customers. ComEd provides service to approximately 3.8 million customers across northern Illinois, or 70 percent of the state's population. For more information visit ComEd.com, and connect with the company on Facebook, Twitter, and YouTube.

“DTE's Insight App helps customers understand and manage their energy use through a unique blend of coaching, gamification, and social elements.”



DTE Energy

DTE Insight App and Energy Bridge

Technology Partner(s)

Vectorform

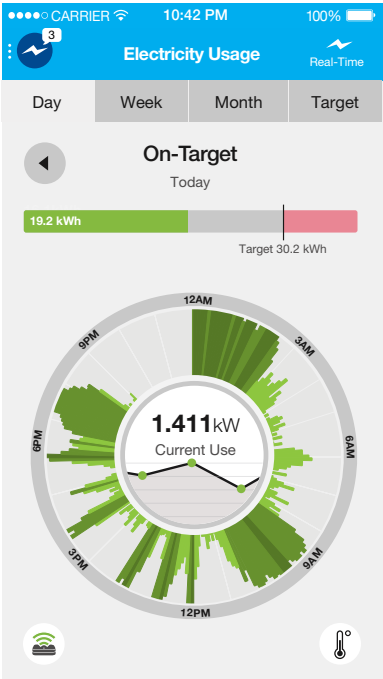
Project Highlights

- Mobile app that can display real time energy usage data on the customer's smartphone when connected to the Energy Bridge.
- Launched in July 2014 and exceeded year end 10,000 download goal in less than two months. Currently at 24,000 downloads.
- Provides views of past energy consumption including, minute by minute, weekly, and monthly trends
- Provides a platform to market energy efficiency programs.
- Anticipated 75,000-90,000 customers will actively use app over time. 23,000-27,000 MWh energy savings expected annually.
- Future opportunities for demand response, home automation, and home energy management.

Project Description

The DTE Insight app is a first-party digital lifestyle platform that engages users around discovering and improving their personal energy consumption, while providing DTE Energy with a next generation platform for a self-service customer channel that is rooted in positive customer touch points. With a unique blend of coaching, gamification, and social elements, it enables DTE customers to engage with their personal energy consumption and find ways to reduce their energy use and enjoy a comfortable home. Customers can use features in the app to identify opportunities to apply small behavioral changes that will make a big change in reducing their usage, saving energy and money.

Core current features of the Insight app help customers understand when, where, and how they are using energy. A dashboard provides a coaching engine and bird's eye view of energy efficiency performance against monthly energy consumption targets. The app includes tools for researching ENERGYSTAR products, and iPhone users can take a "Power Scan" reading of any electrical device using just its power cord, instantly seeing its energy consumption and estimating its monthly operating cost. To keep customers motivated, energy efficiency tasks and challenges are provided weekly to incentivize energy efficient behavior through reward points. Users can also view electricity consumption patterns in real-time with Energy Bridge, which allows the app to communicate



DTE Insight app.

directly with advanced meters to obtain real time data, providing minute by minute, daily, weekly, and monthly time horizons. Currently over 600 Energy Bridges have been shipped to pilot customers, and there have been requests for over 5,400.

The app was released in July 2014. Since the release, customer downloads of the app have far exceeded DTE's initial goal of 10,000 before year end. Through late October, the app has been downloaded 24,000 times. Marketing has been limited to two earned media events, radio ads, web banner ads, and mailers. More significant marketing is planned in 2015, which

will include a focused engagement campaign as well as broader advertisement on TV. The goals for the project are to have 75,000 - 90,000 customers actively use the application to generate energy savings in the range of five to ten percent. If these goals were to be accomplished, the gross energy savings would be between 23,000 and 27,000 MWh annually.

Phased roll-outs will continue to add features based on consumer feedback. In addition to verified energy savings, DTE anticipates increased customer engagement

and satisfaction. The app may also serve as a platform for future in-home energy management and demand response programs.

Future features may include:

- Natural gas consumption patterns powered by advanced meter data (late 2014).
- Community feature to connect to friends, build groups, compare energy-saving performance, and share encouragement.
- Rewards for performance, including online and retail goods and virtual avatar upgrades.

Project Contact

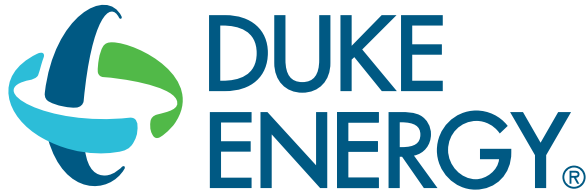
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Company Description

DTE Energy is one of the nation's largest diversified energy companies. Headquartered in Detroit, Michigan, DTE Energy is involved in the development and management of energy-related businesses and services nationwide. Its operating units include an electric utility serving 2.1 million customers in Southeastern Michigan and a natural gas utility serving 1.2 million customers in Michigan. The DTE Energy portfolio also includes non-utility energy businesses focused on power and industrial projects and energy trading. Information about DTE Energy is available at dteenergy.com, twitter.com/dte_energy and facebook.com/dteenergy.

“By providing personalized energy insights and offers based on individual customer needs, Duke Energy has developed stronger relationships with its customers.”



Duke Energy

Becoming a Trusted Energy Advisor

Technology Partner(s)

Tendril

Project Highlights

- The Duke Energy Home Energy Reports (MyHER) program is the largest of its kind in North America with 18 million paper home energy reports distributed to 1.2 million customers since 2012.
- Average energy savings of 1.53 percent per customers.
- The program has generated over 15,000 enrollments for other Duke programs.
- Less than 1 percent of customers opted out of the MyHER program.
- From March 2012 through December 2013, the program saved enough energy to provide power to more than 22,000 homes for a year.

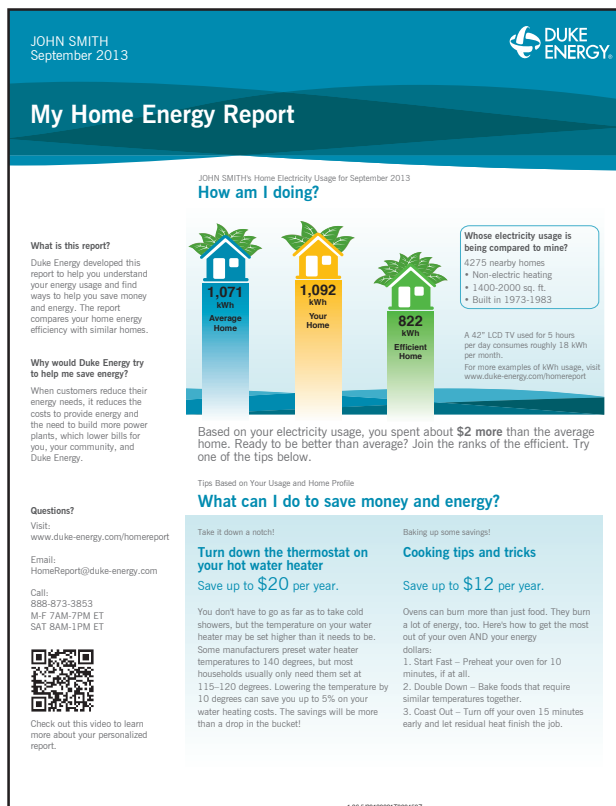
Project Description

In January 2012, Duke Energy – in partnership with Tendril – launched its Home Energy Report program (MyHER) with the goal of meeting regulatory requirements, strengthening customer relationships, and positioning Duke as a trusted energy advisor. With the MyHER program, Duke Energy wanted to look beyond simply checking a compliance box and understand how improved consumer engagement could take its business and customer relationships to the next level. In order to accomplish these goals, Duke Energy needed a robust platform that could take in and turn large amounts

of data into usable customer insights. Through Tendril's physics-based home simulation model, which leverages data such as home size, home age, heating fuel data, usage history, and local weather patterns, Duke Energy was able to deliver highly accurate insights and entice customers to act with more relevant tips and promotions.

The home energy reports are designed to increase awareness of energy usage, and engage customers with personalized recommendations and offers for reducing consumption. Each report details the

Duke's My Home Energy Report delivers specific advice to homeowners.



specific homeowner's energy usage to help determine how efficient they are in comparison to other similar households. The report then provides the homeowner with recommendations, tips, and product rebate offers that can help them save more energy.

Since its launch, Duke Energy's MyHER program has become the largest paper home energy usage insights and comparison programs of its kind in North America, resulting in the delivery of more than 18 million reports to 1.2 million residential customers across five states. From March 2012 through December 2013, the program saved enough energy to provide power to 22,000 homes for a year. This represents savings of up to 1.53 percent per customer receiving the MyHER reports.

The MyHER program has also demonstrated success in other facets of Duke Energy's business. Since the program began, Duke Energy has generated over 15,000 sales/participants for other Duke programs via the reports' free-text fields, a customizable section of each report that allows Duke to offer customers additional relevant products and services month-to-month. By providing personalized energy insights and offers that show an understanding of customers' individual needs, Duke Energy has developed stronger relationships with its customers. The MyHER program has not only initiated a valuable ongoing dialogue with consumers, but has also opened the door for Duke Energy to deliver new service offerings, which gives the utility a strong foothold in the rapidly evolving energy space.

Project Contact

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Company Description

Duke Energy is the largest electric power holding company in the United States, supplying and delivering energy to approximately 7.2 million U.S. customers. Duke Energy has approximately 57,500 MW of electric generating capacity in the Carolinas, the Midwest, and Florida – and natural gas distribution services in Ohio and Kentucky. Headquartered in Charlotte, N.C., Duke Energy is a Fortune 250 company traded on the New York Stock Exchange under the symbol DUK.

“The Energy Select program allowed program participants to take advantage of lower energy prices 87 percent of the time, delivered nearly 25 MW of reliable peak demand reduction to Gulf Power, and resulted in high customer satisfaction.”



Gulf Power

Energy Select

Technology Partner(s)

Comverge

Project Highlights

- The first fully-automated critical-peak pricing (CPP) program in the U.S.
- Nearly 14,000 enrolled participants.
- Program consists of four elements: a programmable thermostat and other enabling technology, a four-tier rate, a communications gateway, and an online portal to program enabling devices.
- Customer satisfaction rates as high as 95 percent.
- Four-tier rate offers lower energy prices than a standard rate 87 percent of the time.

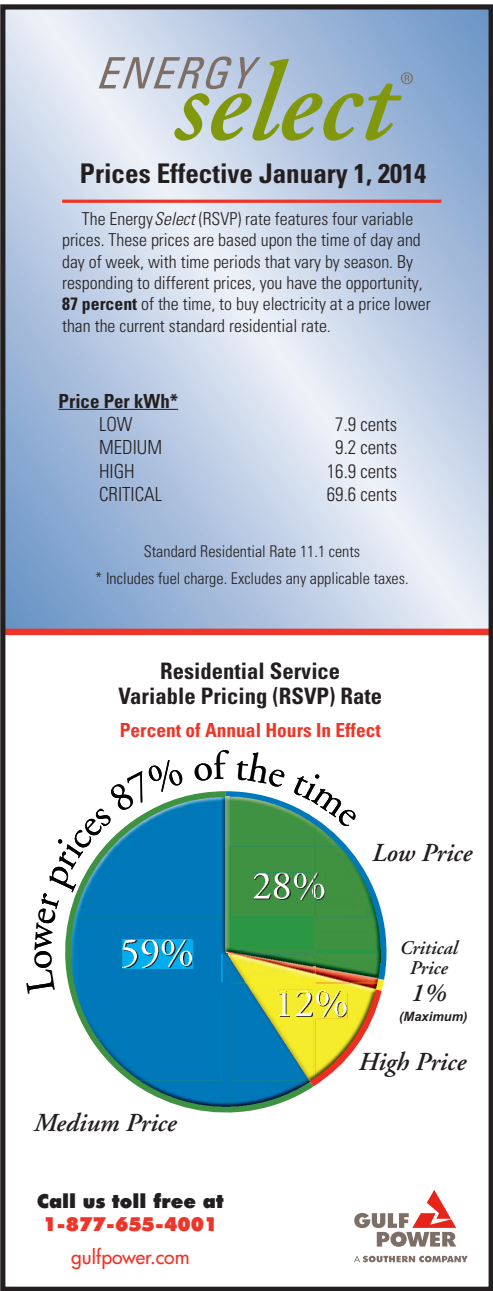
Project Description

Gulf Power Company, a subsidiary of Southern Company, is located in northwest Florida and serves approximately 400,000 residential customers. Long recognized as a leader in demand-side management (DSM) at the residential level, Gulf Power continues to drive innovation in the area of automated dynamic pricing.

The Gulf Power Energy *Select* program was initiated in 2000 and has the distinction of having been the first fully-automated critical-peak pricing (CPP) program in the country. A long-standing partnership between Gulf Power and Comverge produced what continues to be one of the largest and most successful critical-peak pricing programs. Energy *Select* attracts voluntary program participants – nearly 14,000 thus far – through cost savings, customer control, and satisfaction.

Energy *Select* consists of four elements: a price-responsive programmable thermostat and timers for customers’ water heaters and pool pumps, a rate featuring four prices (low, medium, high, and critical) for electricity, a communications gateway, and an online programming portal. Participants in the program enjoy greater control over their energy usage and the ability to pre-program their central cooling and heating systems, electric water heaters, and pool pumps to respond automatically

Gulf Power Energy *Select* rate card.



to specific pricing tiers and dynamic price signals from Gulf Power. By leveraging the web portal capabilities of Comverge's IntelliSOURCE demand response management platform, Energy *Select* participants can also monitor HVAC run-time and program changes on the go, putting them in control of how much energy they purchase, when they purchase it, and at what price.

The Energy *Select* program has resulted in customer satisfaction rates as high as 95 percent, allowed program participants to take advantage of lower energy prices 87 percent of the time, and delivered reliable peak demand reduction to Gulf Power, enabling the utility to reduce summer peak

demand for electricity by nearly 25 megawatts. The program received the 2013 Project of the Year Award from POWERGRID International and has garnered national recognition from The Wall Street Journal, Newsweek magazine, and the National Society of Professional Engineers.

Gulf Power plans to build on its vision by continuing to grow Energy *Select* program participation through active promotion of the program using direct mail, outdoor advertising, and the web. Information on the program is prominently displayed on the Gulf Power website home page.

Learn more about the program at www.gulfpower.com/energysselect.

Project Contact

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Company Description

Gulf Power Company is an investor-owned electric utility, wholly owned by Atlanta-based Southern Company. Gulf Power's service territory spans the area from the Alabama border on the west to the Apalachicola River on the east; from the Alabama border on the north to the Gulf of Mexico on the south. Gulf Power serves approximately 435,000 customers in 71 towns and communities throughout Northwest Florida. www.gulfpower.com.

“The goal of the DemandLink™ pilot is to determine whether a planned investment in distribution infrastructure can be deferred through investments in distributed energy resources such as energy efficiency and demand response.”



National Grid

DemandLink™ Pilot in Rhode Island for System Reliability Procurement

Technology Partner(s)

ecobee
2D2C Inc.

Project Highlights

- Targeted EE and DR efforts to reduce peak load on specific feeders.
- 1 MW of load relief defers 2014 substation upgrade to 2018.
- Enhanced incentives focused on air conditioning.
- Preliminary results show targeted outreach increased area EE participation by roughly 50 percent.

Project Description

National Grid's DemandLink pilot is a non-wires alternative demonstration project that aims to reduce load during peak hours on specific feeders in Rhode Island that were projected to overload starting in 2014. The goal of the pilot is to determine whether or not a planned capital investment in distribution infrastructure can be deferred through investments in distributed energy resources such as energy efficiency and demand response.

The pilot was proposed in 2011 in compliance with the System Reliability Procurement (SRP) guidelines that are in place to support the Least Cost Procurement legislation in the state. The SRP guidelines were compiled through a collaborative process involving National Grid, the Rhode Island Energy Efficiency Resource Management Council, the Rhode Island Division of Public Utilities and Carriers, as well as other agencies and advocacy groups in the state. The DemandLink pilot began operations in 2012 and will continue through 2017, with the first two years acting as a ramp-up period and the remaining four years comprising the period of deferral. Each year, as long as the need for load relief still exists, National Grid submits an updated load forecast, pilot proposal, and budget to the Rhode Island Public Utilities Commission.

The affected feeders serve approximately 5,200 customers in two towns (the southern part of Tiverton and all of Little Compton) that are predominantly residential. While a few hundred commercial accounts exist in the affected area, there are no large

commercial customers or industrial customers. The pilot's goal is to create reductions in summer peak load in the amounts of 150 kW by the end of 2014 up to 1 MW by the end of 2017.

The primary mechanisms for creating load relief on the affected feeders are targeted energy efficiency (EE) and demand response (DR). The pilot promotes existing incentives offered through the statewide EE programs (such as free home and business energy assessments) as part of its dedicated outreach campaign but also sponsors a number of incentives exclusively for pilot-eligible customers. Most of these incentives are focused on air conditioning, as air conditioning was identified early as one of the most likely drivers of demand during the peak hours of 3:30-7:30 p.m. In its first year, DemandLink offered customers a free Wi-Fi thermostat and annual bill credits if they participated in all DR events. In order to qualify for this offer, customers had to have central AC and Wi-Fi. In its second year, the pilot added incentives for plug load devices, window AC purchases and window AC recycling to broaden the eligibility pool and increase participation. The outreach and education campaign (limited to targeted groups, e.g., high energy users and recently-assessed homes) and internet ad campaign were significantly expanded in 2013 and 2014 to include multiple direct mail and email pieces, two rounds of telemarketing, and an annual community event. Telemarketing has so far produced the greatest number of leads.

Get the most out of your WiFi Thermostat and Smart Plugs.



Use the ecobee phone app to make changes to your cooling and heating programs on-the-go.



Visit your personal web portal at **ecobee.com** regularly to see when you're cooling and heating the most.



If you have put away your window A/C units for the season, plug other small appliances into the Smart Plugs to see how much electricity they're using, or to automate when they turn on and off.

DemandLink pilot energy management options.

The pilot is currently on track to meet its load relief targets, and National Grid has so far deferred construction on the distribution infrastructure investment until at least 2016.

While the DemandLink pilot is still in progress, a number of lessons around customer recruitment and retention have been learned in the first years of its implementation. First, when marketing such a program to a defined geographical area, communications touchpoints should be direct and frequent. With a finite number of eligible customers, the typical 5–10 percent participation rates seen in broad-based EE and DR programs will not create enough load

reduction. Second, diversifying both the messaging and incentives can increase participation. Different customers are motivated by different things. The best ways to broaden participation are to increase the eligibility pool and articulate all the reasons that make the pilot worthwhile. Third, minimizing the customer requirements to participate is key to motivating segments outside of the “early adopters.” Even customers who perceive value in the program may not participate if it is difficult or complicated to do so. Finally, communication should continue after the recruitment stage in order to maximize participant engagement and contentment with the program.

Project Contact

Lindsay Foley

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Company Description

National Grid USA is a regulated public utility that provides electrical service to 3.3 million customers in areas of Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The utility operates over 9,000 miles of electricity transmission. National Grid Rhode Island serves over 460,000 customers in 38 Rhode Island communities.

“NV Energy’s mPowered program offers commercial customers an integrated energy efficiency and demand response program that reduces energy and peak demand without disrupting business or inconveniencing customers.”



NV Energy

Building Energy Intelligence in the State of Nevada

Technology Partner(s)

BuildingIQ

Project Highlights

- NV Energy's mPowered program customers reduced peak HVAC power consumption by as much as 15-24 percent on demand response event days.
- Customers lowered on-going daily HVAC energy use by 10-14 percent.
- The program has so far enrolled 5.7 million square feet and 3 million square feet are in 'active optimization' mode.
- Current savings targets are 4-6 million kWh per year.

Project Description

In order to help temper the company's peak summer demand, NV Energy, which serves 93 percent of the population of Nevada, wanted to create broad-based customer engagement through its mPowered program. For Nevada, this was an opportunity to develop fully integrated energy efficiency (EE) and demand response (DR) systems that reduce energy and peak demand without disrupting business or inconveniencing customers.

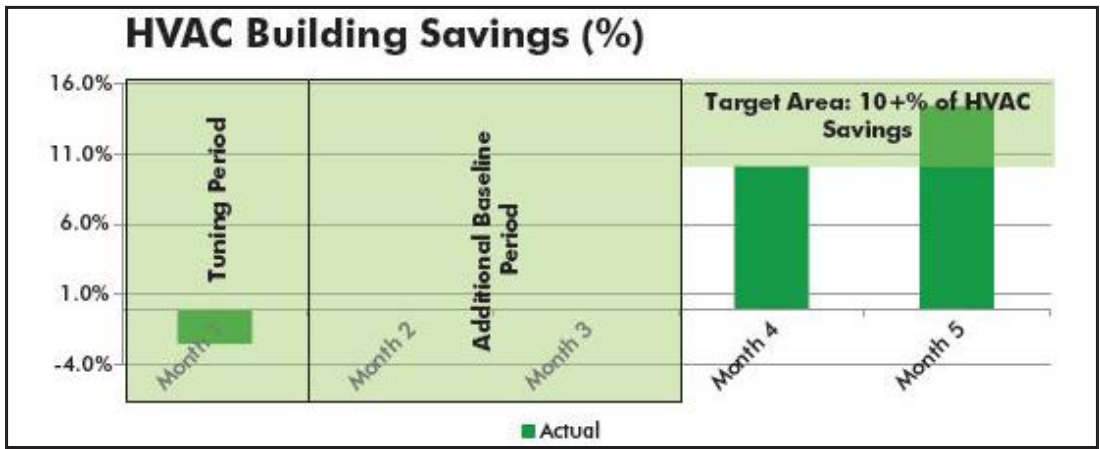
Through NV Energy's program, a growing number of buildings in Nevada have deployed BuildingIQ's cloud-based software, which incorporates Predictive Energy Optimization™, to bring a new level of intelligence and controllability to large commercial building operations, including casinos, hotels, government facilities, and office buildings. Over a four to six week period, BuildingIQ's software learns a building's HVAC energy patterns to predict consumption. Based upon these predictions, the system automatically optimizes energy usage;

HVAC controls are adjusted in real-time using BuildingIQ algorithms. The system also communicates via OpenADR with NV Energy's Demand Response Management System and manages DR events strategically in order to maintain occupant comfort.

This approach allows NV Energy to offer a demand response program to its commercial customers that will not impact occupant comfort, which is a primary concern for the gaming and entertainment industry in Nevada. The approach also allows NV Energy to use the financial benefit associated with year-round energy savings as the primary program incentive for participating in demand response events.

Since 2023, the technology and program have reduced peak HVAC power consumption in 11 commercial buildings throughout Nevada by 15-24 percent on DR event days. In 2023, NV Energy called 12 DR events, and in 2024 the company called 17 DR events.

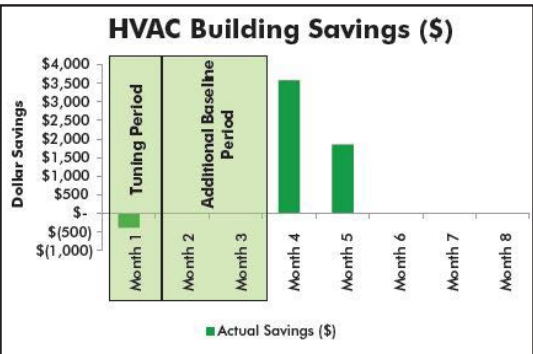
HVAC building energy savings at City Hall climbed to 14.4 percent within a few months (kWh).



The program has also significantly lowered ongoing daily HVAC energy use at these buildings by 10–14 percent.

City Hall, one of the first buildings to participate in the mPowered program, controlled 308,000 sq. ft. of conditioned office space, resulting in cumulative energy savings of 7.4 percent during the 12-month startup period, and energy savings climbed to over 20 percent in subsequent months. On average, City Hall is saving \$1,500 to \$3,500 per month on energy bills due to optimized HVAC energy usage. By utilizing BuildingIQ’s optimization software, the City of Las Vegas has become the first major city in the country to leverage this type of energy management solution.

The program continues to expand with a growing list of prominent commercial and government buildings.



HVAC building dollar savings at City Hall from HVAC energy reductions have ranged between \$1500 and \$3500 per month following the start-up period.

Project Contact

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Company Description

NV Energy, Inc. provides a wide range of energy services to 1.3 million customers throughout Nevada and nearly 40 million tourists annually. NV Energy is a holding company whose principal subsidiaries, Nevada Power Company and Sierra Pacific Power Company, are doing business as NV Energy. The company is headquartered in Las Vegas, Nevada. NV Energy was acquired by Berkshire Hathaway Energy in 2013. www.nvenergy.com.

“PG&E’s integrated marketing strategy increased awareness and resulted in a significant increase in loan applications by small- to medium-business customers.”



***Pacific Gas and
Electric Company®***

Pacific Gas and Electric Company

On-Bill Financing Marketing

Technology Partner(s)

Jacobs & Clevenger

Targetbase

Project Highlights

- Launched in 2010, PG&E's On-Bill Financing loan program has lent more than \$36.7 million to small- to medium-sized business (SMB) customers for energy efficient retrofits.
- Based on 2013 research identifying program awareness as a key barrier for SMB customers, an integrated marketing strategy increased on-bill financing loans to SMB customers.
- Loans to SMB customers increased over 600 percent between 2012 and 2014.
- 2014 SMB Customer Journey pilot targeted 50,000 SMBs that have never participated in an energy efficiency rebate.

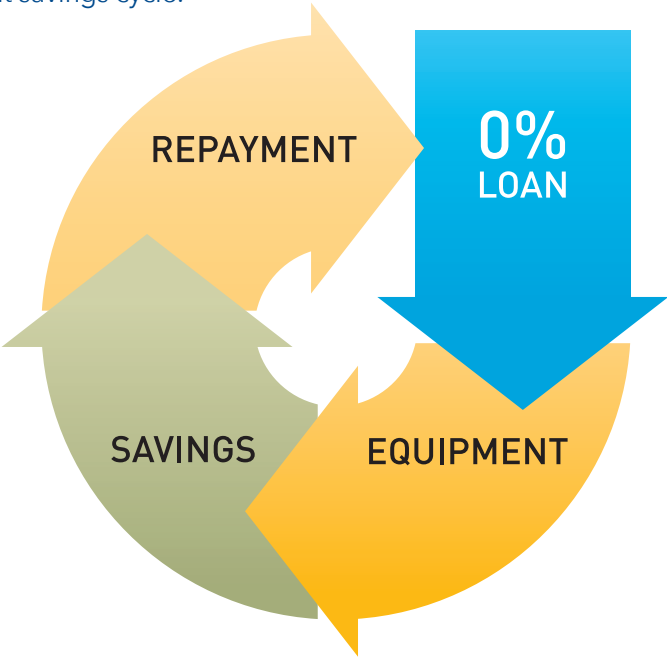
Project Description

Pacific Gas and Electric Company's (PG&E) On-Bill Financing program helps eligible business customers pay for energy efficient retrofit projects with zero percent interest. The program works in conjunction with PG&E's energy efficiency rebate and incentive programs by eliminating a key barrier to entry, which is often availability of capital. After project completion, PG&E will lend the money for the retrofit and the customer will pay the loan – interest free – through their monthly utility bills. The On-Bill Financing program launched in 2010, with a \$50.5 million revolving loan pool funded by California utility customers through the California Public Utilities Commission. To date the program has lent \$36.7 million (\$10.8 million has already

been repaid) with \$16.9 million committed for customer projects in process. Government and large business customers were first to take advantage, whereas PG&E's 390,000 small- to medium-sized business (SMB) customers required more education and awareness. Four years later, PG&E has executed a successful integrated marketing strategy targeting SMB customers, and the SMB segment is actively submitting loan applications.

In 2013, strategic marketing efforts were deployed to raise awareness of the On-Bill Financing loan program with SMBs. Before embarking on outreach, PG&E commissioned qualitative research (focus groups) with SMBs and contractors from a variety of industries. The program concept was

PG&E's equipment savings cycle.



extremely appealing to all participating SMBs, but the greatest barrier to participation was lack of awareness.

As enticing as a zero percent interest loan is, a loan isn't the focus; new energy efficient equipment and future savings are. Just as a customer doesn't visit a car dealership to secure financing, but rather to buy a car, and only learns about the available financing options to pay for it, SMB customers are primarily interested in the prospect of new equipment and future savings. PG&E approached on-bill financing with the same lens. The utility promoted the right energy efficiency product opportunities to customers, and provided on-bill financing as an enabler to closing the "sale." Using that philosophy, PG&E built a strategy to integrate the on-bill financing message into all applicable energy efficiency marketing and sales campaigns. For some efforts, financing was the key message; in others, it was a supporting message to begin broadening awareness. PG&E utilized the research findings to develop the following messaging framework:

- Messaging A - Focus on the sale. PG&E's energy efficiency financing makes it more affordable than ever for your business to save energy and money at the same time.
- Messaging B - Focus on new equipment. It's not the loan, it's what the loan makes possible: brand new energy efficient equipment to replace old and inefficient equipment and use less energy.

With the messaging and strategy established, PG&E executed on its strategic plan in 2013 and 2014. Through integrated efforts, PG&E was able to incorporate financing messages in their digital marketing, content marketing, experiential and event marketing, email marketing, sales collateral, and the 2014 SMB Customer Journey pilot, as well as other tactics.

In one specific marketing campaign, the SMB Customer Journey pilot, PG&E targeted prospects through a unique segmentation based on energy management engagement. SMB customers were divided into three categories:

- Beginner (never participated in an energy efficiency rebate).
- Intermediate (has participated in at least one rebate).
- Advanced (participated in multiple rebates or customized programs).

The pilot focused on the 'beginner' segment, creating a group of 50,000 customers in three sub-segments:

- 10,000 customers that didn't have an online account.
- 37,000 customers that had an online account but hadn't taken the Business Energy Checkup (PG&E's online assessment for SMBs).
- 3,000 customers that had taken an assessment, but had yet to participate in a rebate.

Each group had different customer experience to encourage action, with different

levels of customized or dynamic content communicated via different channels. As customers engaged, they would move from one stage to the next, ideally completing all three actions of signing up for an online account, taking an energy assessment, and ultimately applying for an energy efficiency rebate. On-bill financing was a key message in the majority of outreach. Throughout the journey, tailored energy efficiency product recommendations were delivered and customers were made aware of the fact that they could take advantage of On-bill financing to pay for it.

The SMB customer journey pilot is ongoing and results are still being analyzed, but it demonstrates one of the many ways in which we integrated financing into our marketing efforts. PG&E looks forward to building upon this integrated strategy in our 2015 outreach to continue to increase the uptake of loans for the hard-to-reach SMB population.

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Company Description

Pacific Gas and Electric Company is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, the company is a subsidiary of PG&E Corporation. The company provides natural gas and electric service to approximately 16 million people throughout a 70,000 square-mile service area in northern and central California.

***“Enabled by smart meters,
PHI’s Peak Energy Savings
Credit program provides
customers an opportunity
to earn credits on their
electric bill.”***



Pepco Holdings, Inc.

Peak Energy Savings Credit

Technology Partner(s)

Aclara

IBM

Itron

Silver Spring Networks

Project Highlights

- Pepco and Delmarva Power's AMI-enabled Peak Energy Savings program in Maryland and Delaware service areas launched full-scale in 2013.
- More than 500,000 participating customers saved over 4 million kWh of electricity and earned approximately \$5 million in bill credits.
- An additional phase-in of 5,000 residential customers in the Delmarva Power, Maryland service area occurred in 2014.

Project Description

Enabled by smart meters, PHI's Peak Energy Savings Credit program provides opportunities to customers in Maryland and Delaware to reduce their energy use for a few hours during peak usage days in order to earn credits on their electric bill. Participating customers choose two of three methods to be notified of a peak event (voicemail, email or SMS text). Notifications occur the night before the event and participation in the program is voluntary. The only requirement is that the customer has a smart meter.

Participating customers take various measures to reduce usage, such as turning off lights, delaying running the dishwasher, delaying laundry, and adjusting their thermostats. Those that reduce usage earn credits at a rate of \$1.25 per kWh saved. Customers can view their average usage online prior to the event (based on the same hours as the event), as well as check their consumption and preliminary credit after the event.



PHI's Peak Energy Savings bill credit.

In the summer of 2014, multiple events were called and approximately 500,000 customers participated, saving over 4 million kWh of electricity and earning approximately \$5 million in bill credits.

As the program matures and customers learn how to make conservation activities work for their unique situations, Pepco expects to see an increase in both the volume of customers participating as well as credits earned.

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Company Description

Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 2 million customers in Delaware, the District of Columbia, Maryland, and New Jersey. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI also provides energy efficiency and renewable energy services through Pepco Energy Services.

“SolutionOne – PHI's unified, state-of-the-art customer relationship management and billing system – will mean better service to PHI customers.”



Pepco Holdings, Inc.

SolutionOne

Technology Partner(s)

Accenture

SAP

Project Highlights

- The SolutionOne project will replace decades old legacy systems with a unified, state-of-the-art customer relationship management and billing (CRM&B) system.
- Following a 28-month design, development, testing, and training period, the new system will launch in early 2015.
- SolutionOne converts and consolidates records from 1.8 million existing customers.
- The project tested 170 interfaces that link new system with 50 other internal and external data systems.

Project Description

The SolutionOne project will enhance the daily business transactions of regulated electric and gas customers of Pepco Holdings, Inc. (PHI) by replacing two separate, decades old, command-line driven, legacy customer relationship management and billing information systems with a single, unified, state-of-the-art customer relationship management and billing system (CRM&B). The scope of the SolutionOne project is considerable; converting and consolidating data from more than 1.8 million existing customers from two legacy systems into one CRM&B will be challenging, but the end result will mean better service to PHI customers.

Recognizing that unplanned events can occur during a complex system conversion, PHI has taken steps to minimize the chances of such occurrences. To provide for a smooth transition, PHI developed guiding principles to address and mitigate risk during the process. The first guiding principle is that the quality of the implementation is paramount. PHI partnered with SAP, to provide a robust software platform that would require minimal customization, and Accenture, to provide a structured and rigorous project management approach.

Another important guiding principle for the SolutionOne project is "virtue in simplicity." A concerted effort was made to design the system architecture so that the functionality of the customer information systems remains intact while also building

in enough platform flexibility to allow for future enhancements. Working from a blank canvas invites a multitude of good ideas, but not all can or should be built. Every project decision was made with consideration to how PHI's customer care and operations team could use the tool to provide an enhanced customer experience.

After an intensive design, development, testing, and training initiative over a 28-month period, the new system is scheduled to go live in early 2015. During the development process, PHI tested approximately 170 interfaces that link the new system with about 50 other internal and external data systems. As the cutover date approaches, the project team continues with technical, operational, and business readiness trainings to maintain data quality and billing accuracy.

Every effort is being made to reduce the expected challenges to productivity and call-response times while staff gains proficiency in the new system following the launch. Training approximately 1,375 end-users for the new system includes instructor-led, computer-based, and self-practice components as the team transitions from a command-line interface to a more intuitive, point-and-click interface.

Once cutover is complete, SolutionOne will provide customer service representatives and other end-users with 21st century tools to provide prompt, effective resolution of customer inquiries. PHI plans to

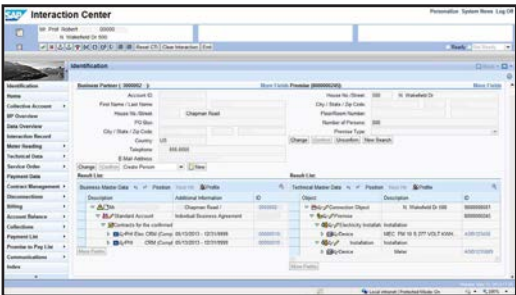
leverage a variety of communication channels, including bill inserts and social media to deliver information about the system conversion. SolutionOne represents how

collaboration across various PHI business units, technology partners, and project implementers positions the project for a quality deployment.

PHI Legacy System.



Point-and-Click SolutionOne Interface.



Project Contact

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Company Description

Pepco Holdings, Inc. is one of the largest energy delivery companies in the Mid-Atlantic region, serving about 2 million customers in Delaware, the District of Columbia, Maryland, and New Jersey. PHI subsidiaries Pepco, Delmarva Power and Atlantic City Electric provide regulated electricity service; Delmarva Power also provides natural gas service. PHI also provides energy efficiency and renewable energy services through Pepco Energy Services.

***“PGE's Energy TrackerSM
provides timely, accurate
energy information and
concrete, effective actions,
giving customers the
power to control their
energy usage and bill.”***



Portland General Electric

Energy TrackerSM

Technology Partner(s)

Aclara

Project Highlights

- Usage-to-date and forecasted bill text and email alerts.
- 5,000 alerts per month sent to customers.
- Accessed by 18 percent of customer base.
- Daily and hourly energy use charts.
- Billing period comparisons.
- Customers using Energy TrackerSM reduce energy 3 percent faster than control.

Project Description

Portland General Electric's (PGE) Energy TrackerSM makes energy tangible for customers. Deployed in 2011 following the successful installation of more than 825,000 smart meters in the Portland, Oregon metro area, Energy Tracker is an online tool that provides a window into energy use and billing data to drive proactive, cost-effective energy reduction and savings. Residential and general business customers can access their smart meter data using the same accounts that are used for billing and service requests on PortlandGeneral.com.

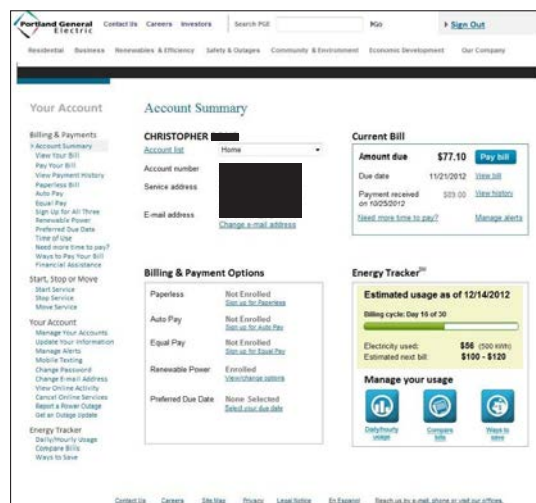
Nearly one-fifth of PGE's eligible customers have accessed Energy Tracker. Customers are able to see their usage granularly by hour down to a 15 minute interval, and they can compare one billing period to another going back 13 months. This gives customers tools to understand their energy usage and make smart changes. PGE provides tips on how to save money and reduce energy consumption, and customers are able to create a profile that helps identify a savings model appropriate for their home or business. Customers can set goals to review through Energy Tracker as usage information becomes available. This encourages active engagement that brings them back to the website, where Energy Tracker can connect them to energy efficiency programs, available incentives, and actions they can take on their own.

PGE's new text and email alerts are an opportunity to directly engage customers. These alerts provide weekly information on

usage-to-date in a billing cycle, and a forecasted bill (available to residential customers only) that gives customers time to plan their budget or reduce their energy use. Additionally, customers can sign up for an alert notifying them whether the forecasted bill exceeds their indicated budget target by mid-month. PGE is also finding success in efforts to inform and engage low income customers through local community action agencies. Agency staff are trained on Energy Tracker and show low income customers ways to reduce their energy usage and electric bill. More than 2,000 customers have opted in to these alerts, resulting in over 5,000 alerts sent per month.

Energy Tracker is a critical effort in Portland General Electric's goals laid out in the company's resource planning. Since the program launched in December 2011, customers using Energy Tracker have reduced their annual energy consumption

Energy Tracker account summary.





Energy Tracker text alert.

3 percent faster than customers not using the program, representing an additional energy savings of 332 kWh per customer on average.

PGE is committed to ongoing improvements to Energy Tracker that give customers the power to control their energy usage and electric bill. Providing timely, accurate information and concrete, effective actions to customers in a digestible fashion is key to continued success. PGE is currently undertaking a multi-year transformation of their customer service and information systems, which will make further enhancements to Energy Tracker necessary and feasible. This includes enabling more granular data, enabling future pricing and predictive programs. As one of the key avenues in which PGE communicates with customers, the utility is committed to making Energy Tracker a relied-upon tool for customers.

Project Contact

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Company Description

Portland General Electric, headquartered in Portland, OR, is a fully integrated electric utility that serves approximately 838,000 residential, commercial, and industrial customers in Oregon. We've been consistently delivering safe, reliable, and responsibly generated electricity in northwest Oregon since 1889. We rely on several different sources to effectively balance power supply resources with customer demand which contributes to higher reliability and more stable prices for our customers. For more information visit our website at PortlandGeneral.com.

“SDG&E's Manage-Act-Save program sustains customer engagement by targeting individual customer interests and motivations rather than taking a one-size-fits-all approach.”



San Diego Gas & Electric

Manage-Act-Save

Technology Partner(s)

Simple Energy

Project Highlights

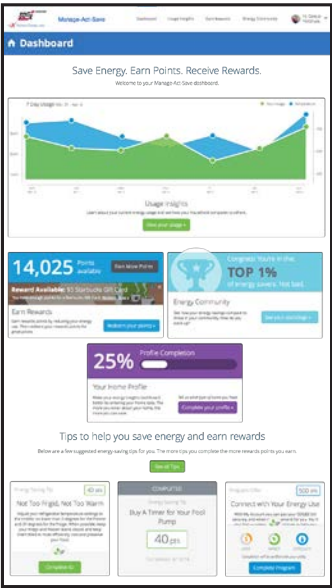
- SDG&E's Manage-Act-Save program customer engagement program, in its second year, has about 375,000 residential customers enrolled.
- Preliminary indications show approximately 4.5 percent average kWh savings per customer.
- Email open rates among active users have remained consistently above 20 percent over 16 months.
- Average visitor session on the Manage-Act-Save site lasts close to 4 minutes, showing that customers are interested and engaged with the site content.
- Program participants have completed over 134,000 energy-saving tips to date and redeemed over 23,000 rewards.

Project Description

In an effort to demonstrate value from smart grid implementations to residential customers, San Diego Gas & Electric (SDG&E) partnered with Simple Energy to deliver a customer engagement program. The Manage-Act-Save program seeks to empower about 375,000 residential customers to better manage their energy usage. It does this by utilizing data from SDG&E’s smart grid and customer information system as well as the platform’s internal continuous feedback loop of customer activity and preferences. Simple Energy’s engagement platform delivers personalized messaging to participants, encourages individual comparison and competition through gamification, and rewards customers for energy savings.

Following the successful implementations of the ‘Biggest Energy Saver’ pilot program in 2011, with roughly 100 customers, and the ‘San Diego Energy Challenge’ in 2012 that engaged 42,400 customers, SDG&E expanded the availability of Simple Energy’s customer engagement platform, branded as ‘Manage-Act-Save’, to more of its residential customers. The Manage-Act-Save program has been able to deliver sustained customer engagement and successfully motivated customers to continuously take action on the platform, even after a period of over 16 months. Average energy savings per customer is around 4.5 percent.

The Manage-Act-Save program is powered by Simple Energy software and branded as SDG&E. Paper reports are sent every-other month to customers for whom SDG&E



Manage-Act-Save dashboard view.

does not yet have email information, in an effort to drive them online for continued digital engagement through both the Manage-Act-Save website and SDG&E’s My Account. Weekly ‘Energy Insights’ emails help customers make sense of their recent energy usage and take action to save more. All communications (digital and direct mail) are personalized to the individual customer; containing micro-targeted energy-saving tips and recommended SDG&E programs based on a user’s SDG&E account and consumption data, as well as publicly available data and past website activity.

Each personalized, targeted communication drives customers online to explore the Manage-Act-Save web platform. There, customers can interact with a range of experiences.

-
- **Energy Insights** – The data-driven messages in the Energy Insights feature help customers better understand their energy consumption and conservation options and put this information into context by comparing usage relative to similar and efficient households. Weather and building information is factored to help customers understand how much of their energy usage is within their locus of control, and then motivate them with goals to encourage energy saving behaviors and activities. Finally, targeted tips and program suggestions give customers the tools to understand and save.
 - **Energy Community** – energy-saving competitions and leaderboards encourage customers to take action. Customers are empowered to engage with their energy usage in the same way that they engage with everything on the web: socially. Customers can see how they compare to other users on the leaderboard, earn virtual badges by taking certain actions, and earn entries to win prizes by saving energy.
 - **Energy Rewards** – reward points drive customers to take specific actions and increase satisfaction. Manage-Act-Save makes saving energy exciting and rewarding: by saving energy and taking action on the platform, customers earn points that are redeemable for gift cards and discounts to local and national merchants. Through a network of local stores, restaurants, and national partners, customers have a broad range of choices where they can "spend" their reward points.
- Through programs like Manage-Act-Save, SDG&E has found that different motivations work for different people and that those motivations change over time. Sustained customer engagement is achieved when utilities are able to target individual desires rather than take a one-size-fits-all approach. While some people are driven to save energy through neighbor comparisons, others are more interested in timely information delivered on their smartphone and motivated by the opportunity to compete with others and receive virtual badges and points.

Project Contact

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Company Description

SDG&E is a regulated public utility that provides energy service to 3.4 million people through 1.4 million electric meters and 860,000 natural gas meters in San Diego and southern Orange counties. Our service area spans 4,100 square miles. www.sdge.com.

“Southern Company's suite of outage communication tools provide the kind of outage information that customers want in a timely manner.”



Southern Company

Customer Outage Communications

Technology Partner(s)

iFactor

Oracle

Southern Company
Services IT (SCS IT)

Ventyx

Project Highlights

- Outage map provides individual location, county, or zip code level views of outages, number of customers impacted, estimated restoration time (ERT), and outage cause.
- Outage alerts selected by customer (text, email, voice) provide ERT, outage cause, ERT updates, and restoration notification.
- During February 2014 ice storm, Georgia Power outage map saw 860,000 hits in five days.
- Improves customer satisfaction.
- Reduces outage-related call volume.

Project Description

The relationship between Southern Company and its customers has been a major focus for years, one built on trust through consistent service. The four major operating companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, have consistently received high customer satisfaction ratings for customer service.

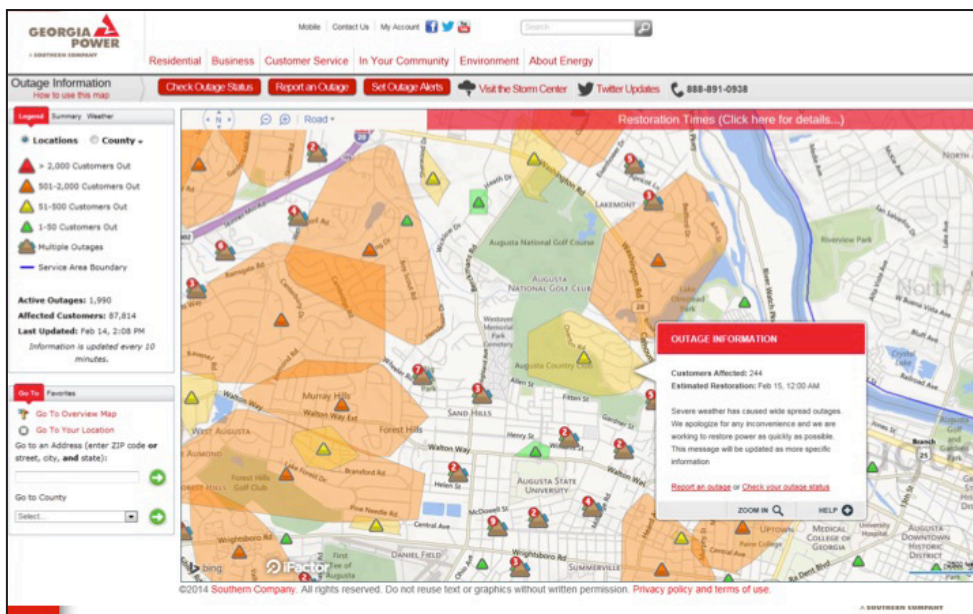
Customer and industry surveys found that customers are seeking more information about outages, in a timelier manner, and wanted it in ways beyond the traditional method of phone calls to an interactive voice response system or customer service consultant. Customers want access to outage maps on computers and mobile devices. Customers also want to receive information from the utility via text, email, or voicemail without having to request it and control which kinds of communications they receive.

Based on this feedback, Southern Company decided to expand the customer experience beyond the traditional communication channels by designing and implementing a proactive outage communications technical solution. To achieve its communication goals, Southern Company partnered with iFactor to implement a suite of communication tools, including outage maps, automated alerts, and mobile applications that maintain the look and feel of Southern Company's brand while allowing for differences according to each operating company's needs.

For Georgia Power, this project began Q3 2012 and had an operational outage map in service Q2 2013, followed by the full suite of outage alert notifications in Q4 2013. The other operating companies have deployed or are currently deploying similarly.

Outage Alerts Marketing Material.





Outage Map – February 2014 Ice Storm.

The outage communication systems were developed and deployed by cross-functional teams with membership from multiple departments, including distribution, marketing, customer service, legal, and corporate communications. Using customer feedback as the measuring stick, every aspect of the customer experience was reviewed from web site layout, internal system links, outage messages, legend and thematic map colors, terms and conditions, and FAQ links.

The key technologies involved in the solution are:

- Outage Management System (OMS): Oracle's NMS application suite acts as the source for all outage information.

- Outage Map, Outage Alerts (text/email/voice), and Outage Mobile App: iFactor's suite of products (including Storm Center and Notifi) visualize outages and execute all proactive communications.
- Customer Preference Center (CPC): developed by SCS IT on the corporate web site, this application allows customers to input their contact information and select their preferred communication channels.
- Corporate web sites (desktop and mobile): promote the Outage Communication program, links to applications, the CPC, and other outage-related information.

An important design requirement for the project was that it must be easy to use, and that all methods of outage communications

must deliver consistent and timely outage information. With the successful integration and deployment of the project's components, these goals have been achieved. Beyond the technologies, employee education and modified work processes to support the information provided to customers are key ingredients to project success.

Acceptance of the outage communication tools, and feedback from customers, local media, and other sources has been overwhelmingly positive. As an example, during an ice storm in February 2014, the Georgia Power outage map received over 860,000

hits during a five-day period. Sign-ups for outage alerts increased three-fold during these five days compared to the previous three-month period. Throughout the 2014 summer storm season, customer and local media utilization of the outage communication tools has continued to grow. In addition, Georgia Power residential customer satisfaction surveys completed in July 2014 show the company's largest percent gains in the area of outage communication, helping propel Georgia Power into the top quartile of overall electric utility customer satisfaction.

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Company Description

Southern Company is one of the largest energy providers in the United States. Based in Atlanta, Ga., Southern Company owns electric utilities in four states (Alabama Power, Georgia Power, Gulf Power, and Mississippi Power) and a competitive generation company. Known for generating, transmitting, and distributing electricity and providing excellent customer service to its 4.4 million customers, Southern Company is also leading the nation's nuclear renaissance through the construction of the first new nuclear units to be built in a generation of Americans and the development of a state-of-the-art coal gasification plant. www.southernco.com.

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