U.S. DEPARTMENT OF
ENERGY

Electricity Delivery
& Energy Reliability

American Recovery and
Reinvestment Act of 2009

Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Responses

Smart Grid Investment
Grant Program

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RECOVERY ACT SMART GRID PROGRAMS

Table of Contents

Executive Summary

Smart grid technologies are helping utilities to speed outage restoration following major storm events, reduce the total number of affected customers, and improve overall service reliability to reduce customer losses from power disruptions.

Under the American Recovery and Reinvestment Act of 2009 (Recovery Act), the U.S. Department of Energy and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations.

This report presents findings on smart grid improvements in outage management from the U.S. Department of Energy's (DOE) Smart Grid Investment Grant (SGIG) program, based on the recent experiences of three SGIG projects:

- Electric Power Board (EPB), headquartered in Chattanooga, Tennessee
- Florida Power and Light Company (FPL), headquartered in Juno Beach, Florida
- PECO, headquartered in Philadelphia, Pennsylvania

All three had smart grid experience prior to the SGIG program, and used DOE funding to accelerate grid modernization and deploy new technologies that strengthen reliability and resilience to improve storm outage response. While many other SGIG projects are also realizing improvements in outage management, these three featured utilities faced one or more major storms in recent years that tested newly deployed smart grid technologies.

Major Findings

Outage management approaches that used smart grid technologies accelerated service restoration and limited the number of affected customers during major recent storms. Utilities required fewer truck rolls during restoration and used repair crews more efficiently, which reduced utility restoration costs and total outage time. Business and residential customers experienced fewer financial losses, as shorter outage time limited lost productivity, public health and safety hazards, food spoilage, and inconvenience from schedule disruptions.

The utilities deployed two key smart grid approaches: 1) distribution automation, including automated feeder switching (AFS) and fault location, isolation, and service restoration (FLISR), and 2) integrating advanced metering infrastructure (AMI) capabilities with outage management systems. They each typically focused on upgrading the feeders and substations that were most vulnerable to outages or had customers whose outage costs are highest. This practice generally involves starting out with relatively small scale deployments and emphasizes testing and evaluation before making commitments to larger scale investments. Table 1 provides a summary of the key results and benefits experienced by the three featured projects.

Table 1. Summary of Key Results and Benefits	
Improvements in Utility Storm Responses	i. Following July 2012 storms, EPB **reduced total restoration time by up to 17 hours** and prevented power loss or **instantly restored power to 40,000 customers** using AFS. ii. EPB **reduced service restoration time by up to 36 hours** and **saved an estimated $1.4 million in overtime costs** due to fewer truck rolls following a February 2014 storm. iii. PECO **avoided more than 6,000 truck rolls** and **reduced service restoration times by 2-3 days following Superstorm Sandy** in October 2012—even with smart meters deployed to only 10% of customers. iv. With smart meters 50% deployed, PECO **restored service an estimated 3 days faster,** and **automatically restored about 37,000 customers in less than 5 minutes** using AFS, following a February 2014 storm. v. FPL reports that nine AFS operations serving about 16,000 customers led to more than **9,000 fewer customer interruptions and more than 2,500 fewer upstream momentary disturbances** during Tropical Storm Isaac in August 2012—its most recent major tropical storm or hurricane.
Improvements in Grid Reliability	vi. EPB's System Average Interruption Duration Index **(SAIDI) improved 40%** and System Average Interruption Frequency Index **(SAIFI) improved 45%** from 2011 to 2014. vii. PECO's ability to "ping" meters to **remotely verify power restoration improved from about 12% to more than 95%** using the new smart meters and AMI network that replaced its former automated meter reading system. viii. FPL **reduced its number of customer minutes interrupted from 700,000 in 2012 to 200,000 in 2014 for substation transformers.** Also, 2013 marked the second consecutive year that the company achieved its best-ever overall reliability performance (SAIDI), reducing by 21% the average time a customer was without electric service.

While the featured utilities saw notable benefits from applying AFS, FLISR, and AMI, the benefits realized for a given utility will depend on a number of factors. Some regions suffer severe weather events more than others, and thus experience different costs and benefits from improved storm recovery capabilities. Each utility has its own technology starting points, local circumstances, and weather conditions, making it impossible to establish a singular course of action or best practice for applying AFS, FLISR, and AMI for outage management. Instead, each utility must individually evaluate the costs and potential benefits to build a business case and investment strategy suited to its needs.

1. Introduction

Reliable and resilient grid operations are major goals of the electric power industry and federal, state, and local governments. Having the ability to recover as quickly as possible following major weather events, such as Superstorm Sandy and Hurricane Irene, provides economic and public health and safety benefits for local businesses and communities. According to a recent report, power outages that follow major storms cost the U.S. economy an estimated $35 billion to $55 billion annually.[1] In fact, weather events cause 78% of the nation's power outages and their incidence has been rising steadily since 1992.[2]

Some of the benefits of investing in smart grid technologies, tools, and techniques include faster utility responses to power outages and the ability to restore services more quickly compared to traditional outage management techniques. For example, distribution automation (DA) technologies and systems provide grid operators with greater visibility into disturbances and the ability to reroute power flows automatically, reducing the number of affected customers from downed power lines. Advanced metering infrastructure (AMI) boosts the efficiency and effectiveness of outage management procedures by pinpointing outage locations and enabling repair crews to restore services faster and at lower cost.

1.1 Role of Smart Grid Technologies and Systems in Storm Response

Distribution automation (using automated feeder switching and fault location, isolation, and service restoration) and advance metering infrastructure are two successful strategies for improving utility responses to outages following major storms.

Distribution Automation. SGIG projects are deploying AFS devices that function as smart switches and automatic reclosers, and can clear temporary faults, isolate faults, and automatically restore service to unaffected line sections without manual operation. The SGIG utilities that use AFS for FLISR operations are improving their electric reliability indices such as SAIFI and SAIDI[3] and helping to improve grid reliability and resilience.

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[1] U.S. DOE Office of Electricity Delivery and Energy Reliability. "Hardening and Resiliency: U.S. Energy Industry Response to Recent Hurricane Seasons." 2010.

[2] Evan Mills. *Extreme Grid Disruptions and Extreme Weather*. Presented by Lawrence Berkeley National Laboratory at U.S. Disaster Reanalysis Workshop, May 3, 2012. http://evanmills.lbl.gov/presentations/Mills-Grid-Disruptions-NCDC-3May2012.pdf.

[3] U.S. DOE Office of Electricity Delivery and Energy Reliability. "Reliability Improvements from Application of Distribution Automation Technologies – Initial Results." December, 2012.

To accomplish AFS and FLISR, smart switches work in combination with feeder breakers to identify faults on the distribution system, open on fault currents, and then perform switching actions instantaneously. In the absence of AFS, faults may cause a feeder breaker lock-out and require field crews to locate it, restore upstream customers, fix the fault, and restore the affected customers. (Section 1.2 discusses FLISR operations in greater detail.)

With temporary faults, customers may experience momentary outages, and with AFS they suffer few or no consequences—removing the need for truck rolls and repair crews. When faults are sustained, the smart switches “lock-out” and isolate the disturbance, and adjacent switches perform switching actions. This enables “self-healing” capabilities to isolate faulted line sections and restore services to unaffected line sections upstream and downstream of the fault, thus preventing many customers from experiencing major outages, and enabling repair crews to be dispatched to the fault’s precise location and cause. The switches communicate details of the fault to the control center so field operations can be targeted and quick.

SAIDI and SAIFI are not the only indices that measure the effectiveness of outage management practices. For example, utilities can measure the total ***avoided*** number of customers interrupted (CI) and the ***avoided*** customer minutes of interruption (CMI). Utilities also estimate savings in personnel costs due to automatic rather than manual operations (e.g., fewer truck rolls and manual switching actions).

To determine the cost effectiveness of AFS and FLISR investments, it is important to know the value of service[4] to monetize the benefits from fewer and shorter outages. A growing number of utilities are using value-of-service estimates to develop business cases for investments in advanced outage management technologies. For example, at least one SGIG project (Central Maine Power) is using a value-of-service tool[5] developed by DOE to estimate societal costs and benefits from investments in smart grid technologies and systems.

Advanced Metering Infrastructure. AMI also plays an important role in service restoration following outages. Utilities “ping” smart meters using the data communications network to verify outage status and better coordinate dispatch of repair crews to outage locations. Most smart metering systems are designed to send a “last gasp” alarm when the power goes out and send another alarm when the power comes on.

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[4] Value-of-service estimates are derived from customer surveys to determine outage costs for customers and their willingness to pay for fewer and shorter outages. These outage costs are borne by customers due to lost productivity, reduced economic output, inconvenience, and food spoilage.

[5] U.S. DOE. “Interruption Cost Estimate (ICE) Calculator.” http://www.icecalculator.com/ice/. The tool is based on outage cost estimates from value-of-service surveys of customers.

Typically, if outage alarms are not addressed within 20 minutes, customer meters are automatically pinged to assess outage conditions. For example, if power is back on, utilities can send customers text messages instructing them to turn on tripped circuit breakers. If service is not fully restored, the utilities can send field crews, and can also automatically ping neighboring meters to gauge the extent of the outage. Neighboring meters that also do not have power implies broader outages that the utility can use to prioritize restoration. When neighboring meters do have power, it is likely a local event and junior-level technicians can be sent for these types of incidents, saving more experienced line workers for widespread outages.

Many SGIG projects are integrating data from AMI systems with outage management systems (OMS) and geographic information systems (GIS). These systems arm grid operators and repair crews with information on outage locations and the extent of customers affected by the outages. These systems accelerate storm responses by focusing restoration efforts on repairs that will get power to the most customers as quickly as possible, and with lower costs from more efficient operations and fewer truck rolls.

1.2 How FLISR Results in Fewer and Shorter Outages

Figure 1 presents simplified examples (A-D) to show how FLISR operations typically work. In Figure 1A, the FLISR system locates the fault, typically using line sensors that monitor the flow of electricity and measures the magnitudes of fault currents, and communicates conditions to other devices and grid operators.

Once located, FLISR opens switches on both sides of the fault: one immediately upstream and closer to the source of power supply (Figure 1B)); and one downstream and further away (Figure 1C). The fault is now successfully isolated from the rest of the feeder.

With the faulted portion of the feeder isolated, FLISR closes the normally open tie switches to neighboring feeder(s) next. This re-energizes un-faulted portion(s) of the feeder and restores services to all customers served by these un-faulted feeder sections from another substation (Figure 1D).

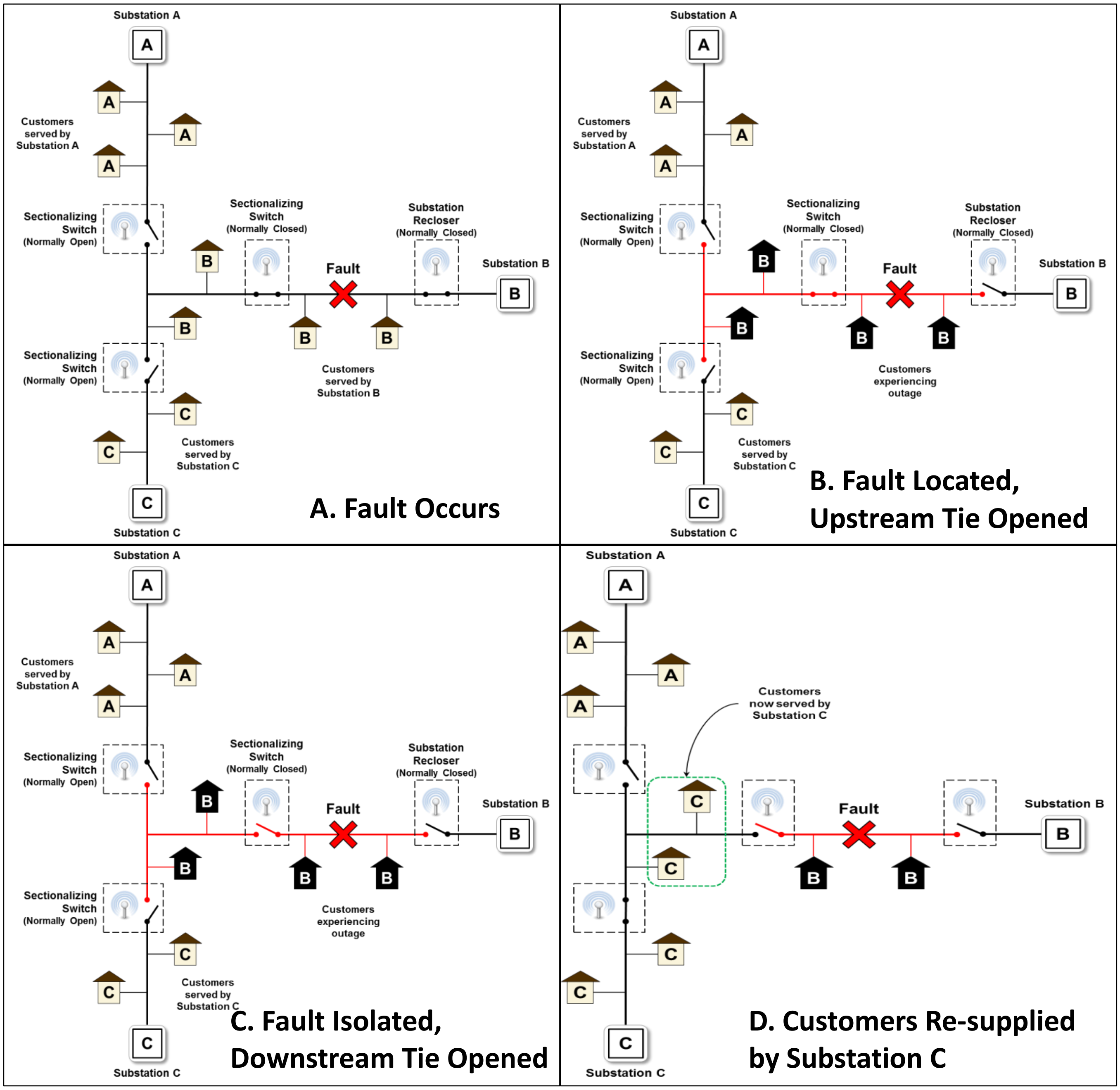

Figure 1. Schematics Illustrating FLISR Operations.

FLISR systems can operate autonomously through central control systems (e.g., DMS), or it can be set up to require manual validation by control room operators. Implementing autonomous, fully automated FLISR systems typically requires extensive validation and calibration processes to ensure effective and reliable operations. Automated FLISR actions typically takes less than one minute, while manually validated FLISR actions can take five minutes or more.

2. Overview of the Featured SGIG Projects

Three SGIG projects, highlighted below, have reported measured impacts and benefits from investments in smart grid technologies, tools, and techniques on service restoration following major storms:

- Electric Power Board (EPB), headquartered in Chattanooga, Tennessee
- Florida Power and Light Company (FPL), headquartered in Juno Beach, Florida
- PECO, headquartered in Philadelphia, Pennsylvania

2.1 EPB

EPB is a municipal utility in Chattanooga, Tennessee and has 172,000 customers, 117 substations, 3,582 circuit miles of electric distribution lines, and a summer peak demand of about 1300 megawatts. Figure 2 describes the EPB system.

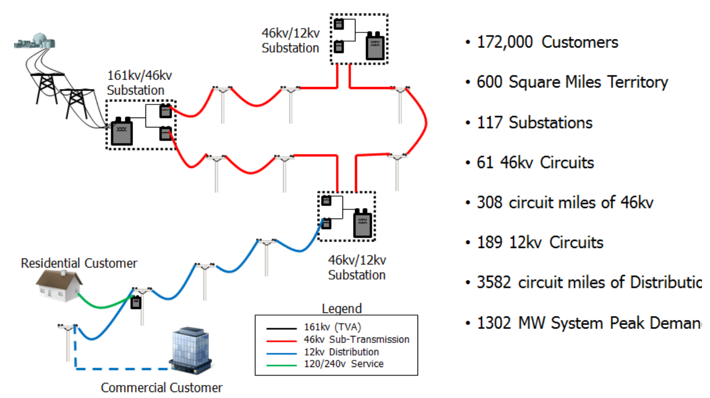

Figure 2. EPB System At-a-Glance.

EPB's SGIG project has a total budget of about $228 million, including about $112 million of DOE funding under the Recovery Act. The project involved system-wide deployment of smart meters to 170,000 customers, installation of more than 1,400 automated feeder switches, and deployment of communications and information management systems for AMI and DA operations. Smart switching communications use the utility's fiber optic network and are centrally controlled by the utility's upgraded Supervisory Control and Data Acquisition (SCADA) systems. Figure 3 shows the installation of EPB's fiber optic communications network.

The project includes AFS and FLISR operations for all of EPB's 46 kilovolt (kV) and 12 kV circuits but not the utility's underground circuits. Automation of the 46 kV circuits affects the entire service territory and the automated 12 kV circuits affect about 90% of customers. Because all of the utility's other, lower voltage circuits (4 kV), are fed by the 46 kV systems, all customers have access to DA-related benefits. The SCADA upgrade involved the utility's fiber optic network and supports an expanded number of control points and equipment installations to provide improved data and situational awareness for distribution system operators. These technologies and systems have been tested by several severe weather events. For example, in February, 2014 a severe snow storm affected 53 feeders and almost 33,000 customers. In April, 2011 Chattanooga was struck by a series of nine tornados that affected the entire service territory and 129,000 customers lost power.

Figure 3. EPB's Fiber Optic, High Bandwidth, Communications Network.

2.2 FPL

FPL is an investor-owned utility that serves 4.7 million customer accounts (the third largest in the United States) and operates more than 70,000 miles of power lines. Its parent company, NextEra Energy, Inc., operates approximately 42,500 megawatts of electric generation capacity. Figure 4 shows a map of FPL's service territory.

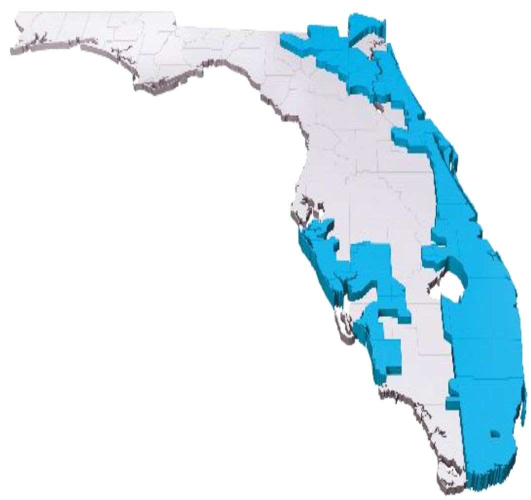

Figure 4. FPL's Service Territory.

FPL's SGIG project, the program's largest, had a total budget of about \$579 million, including \$200 million in DOE funding under the Recovery Act. FPL's total smart meter project involved deployment of about 4.6 million smart meters, DA systems for 129 circuits including FLISR operations and automated controls for voltages and reactive power management, advanced transmission systems including synchrophasor technologies and transmission line monitors, and pilot programs including customer systems such as in-home displays and time-based rate programs.

Since completing its SGIG project in the second quarter of 2013, FPL has broadly expanded the use of smart grid technologies throughout its 27,000-square mile service area. For example, through the third quarter of 2014, the company had deployed more than 1,000 automated feeder switches, avoiding more than 300,000 customer interruptions. FPL also has used the technology to detect potential issues in transformers and replace them prior to failure. To date, FPL has proactively replaced more than 1,000 distribution transformers.

In 2014, overall operational efficiencies are expected to save more than $30 million, helping FPL maintain the lowest typical residential electric bill in Florida, which is approximately 25% below the national average.

Under the SGIG project, FPL's AFS operations included several types of technologies and techniques. For example, the company installed 285 automated feeder switches covering about 23% of all feeders in Miami-Dade County as part of the project. The AFS devices function as smart switches and automated reclosers and are capable of clearing temporary faults, isolating faults, and restoring service to unaffected line sections without manual operations.

The AFS devices work in combination with feeder breakers to sense faults on the distribution system, open on fault current (thereby eliminating the need for the breaker to open), isolate the faulted section, and restore service to unaffected line sections, thereby preventing outage to customers served by the unaffected sections. Figure 5 shows an automated feeder switch deployed by FPL.

FPL is also leveraging smart line sensors, or remote fault indicators (RFI), in Miami-Dade County, and plans to accelerate RFI deployment across its distribution network in 2015. RFIs facilitate faster restoration during sustained interruptions and assist in investigation of momentary interruptions. Similar to AFS technology, the devices pinpoint fault locations and direct resources to identify and isolate damage more quickly. Integrating them into FPL's distribution management system (DMS) and mobile applications allows operators, dispatchers, and field crews to work more effectively in restoring power following unplanned outages.

As part of the grant, FPL installed more than 3,800 RFIs on 620 distribution feeders. Substation telemetry enhancements, which provide additional information from the feeder breakers on fault current values, are used by the DMS to identify fault locations. The company accomplished about 120 substation telemetry enhancements that covered more than 450 feeder relays.

As part of its SGIG-funded smart grid program, FPL installed monitoring equipment on about 745 automatic throw-over switches in Miami-Dade County to communicate data on voltages and other variables for both the primary and secondary feeders to operators in FPL's Distribution Control Center.

Figure 5. Automated Feeder Switches Installed by FPL.

The company has remote sensors on its switches that it can "ping" to confirm the feeder's operating status. The monitoring equipment enables more efficient dispatch of field technicians by quickly identifying the locations of switch malfunction.

FPL also upgraded 22 distribution substations as part of the project. Distribution substation upgrades enabled implementation of techniques that use microprocessor-based systems to gather power system data, assess equipment operating conditions, and enable application of auto-restoration and self-healing systems.

2.3 PECO

PECO is a subsidiary of Exelon Corporation serving about 1.6 million customers in the greater Philadelphia, Pennsylvania area. It operates about 500 substations and 29,000 miles of transmission and distribution lines, and has a summer peak demand of almost 9 gigawatts. PECO also owns and operates natural gas assets including more than 30 gas-gate mains and 6,600 miles of underground pipelines. Figure 6 is a map of PECO's service territory.

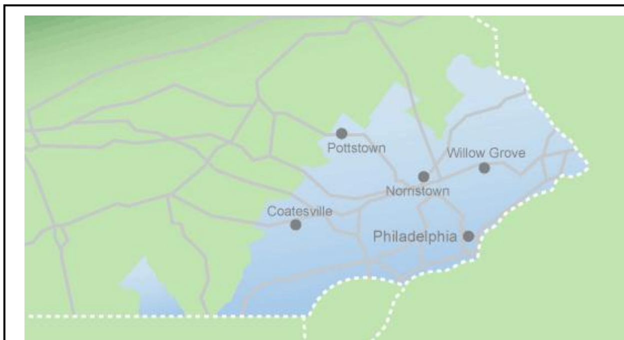

Figure 6. PECO's Service Territory.

PECO's SGIG project has a total budget of about $415 million, including $200 million in DOE funding under the Recovery Act. The project installed more than 775,000 smart meters, associated communications networks for data backhaul, about 100 automated reclosers, more than 220 smart relays, more than 60 automated capacitors, a DMS that includes smart grid data visualization and controls, customer systems such as in-home displays and web portals, and communications systems that were designed to be storm-resilient and included a backbone network of synchronous optical network fiber optic rings.

Before SGIG, PECO had installed a “first-generation” automated meter reading (AMR) system that could determine when a meter was last heard from by pinging the network. This function is used to determine whether the customer has power. During the 2014 Ice Crusher storm, slightly more than 1% of AMR meters were successful in sending power failure alarms and verifying power restoration. Typically, the success rate for AMR last-gasp outage notifications is 10%–30%; however, the abnormally low performance was attributed to the debilitating impacts of the ice storm. Under the SGIG project, PECO’s AMI network architecture was designed to be more storm resilient as each smart meter is able to communicate with several communication towers, and each tower has backup battery power at all times and backup generators available during storms. PECO developed an Advanced Metering Outage System (AMOS) which integrates AMI with the company’s outage management system (OMS). Figure 7 shows a screen shot from AMOS.

PECO is leveraging its AMI communications system for DA applications. For example, the company operates more than 1,500 automated reclosers that communicate with grid operators and control systems through the AMI communications network. PECO’s DA project includes integration of data from the reclosers with the company’s DMS.

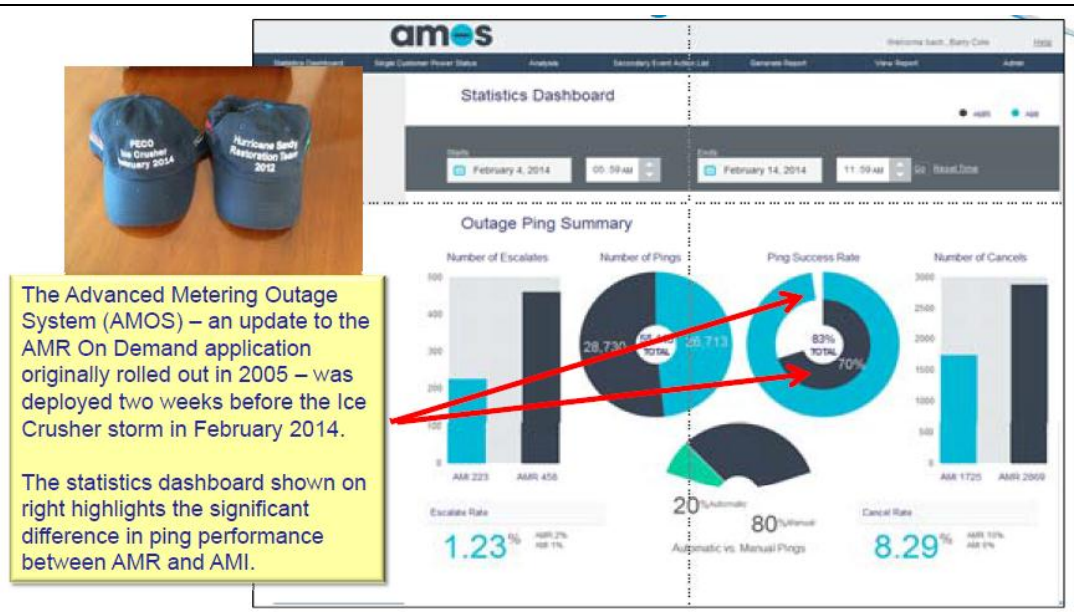

Figure 7. Screen Shot of PECO’s Advanced Metering Outage System (AMOS).

3. Project Results and Benefits

Improved capabilities for outage detection and response benefit both utilities and customers. Monetizing the value of these benefits requires utilities and decision makers to estimate the economic savings from fewer and shorter outages.

The value of customer savings from fewer and shorter outages can be monetized using estimates based on customer surveys and statistical models that are applied in value of service studies. Because these savings accrue to customers and not to utilities, they are not necessarily included in business case analysis unless societal perspectives are included.

Some utilities face regulatory benchmarks for meeting or exceeding mutually agreed upon metrics based on the IEEE's reliability indices. In these cases, reliability improvements can enable the utilities to avoid financial penalties or earn financial incentives. However, not all utilities are regulated under these types of reliability policies.

In addition to meeting reliability targets, utilities also experience operational savings from more efficient restoration practices made possible by better outage management processes from smart meters and their integration into OMS. This section presents information on these topics in two areas: (1) improvements in utility responses to specific storms, and (2) more general improvements in grid reliability indices.

3.1 Improvements in Utility Storm Responses

Storms are the biggest cause of power outages in the United States. All three of the featured utilities have been affected by major storms since the projects began and were able to assess impacts and benefits from the application of AFS, FLISR, and AMI for outage response.

EPB. The July 2012 derecho that impacted much of the Midwest also struck Chattanooga, Tennessee, affecting about half of EPB's customers. Because of EPB investments in smart switches and smart meters, the outage duration for all affected customers decreased by about half. This resulted in about **36 million fewer customer minutes of interruption (CMI) than would have occurred without the new technologies**.

Figure 8 shows the results of using smart switches and smart meters for storm restoration. The blue line shows the time it would have taken EPB to restore power to affected customers in this storm without application of AFS and AMI. The green line shows the improvement in restoration time due to these practices. Overall, **EPB's response was up to 17 hours faster due to the automated feeder switches, which restored power to 40,000 customers instantly** and allowed crews to focus on a more limited number of issues. Smart meter data also helped operators to verify outages, enabling EPB field crews to locate and fix downed lines faster and more efficiently.

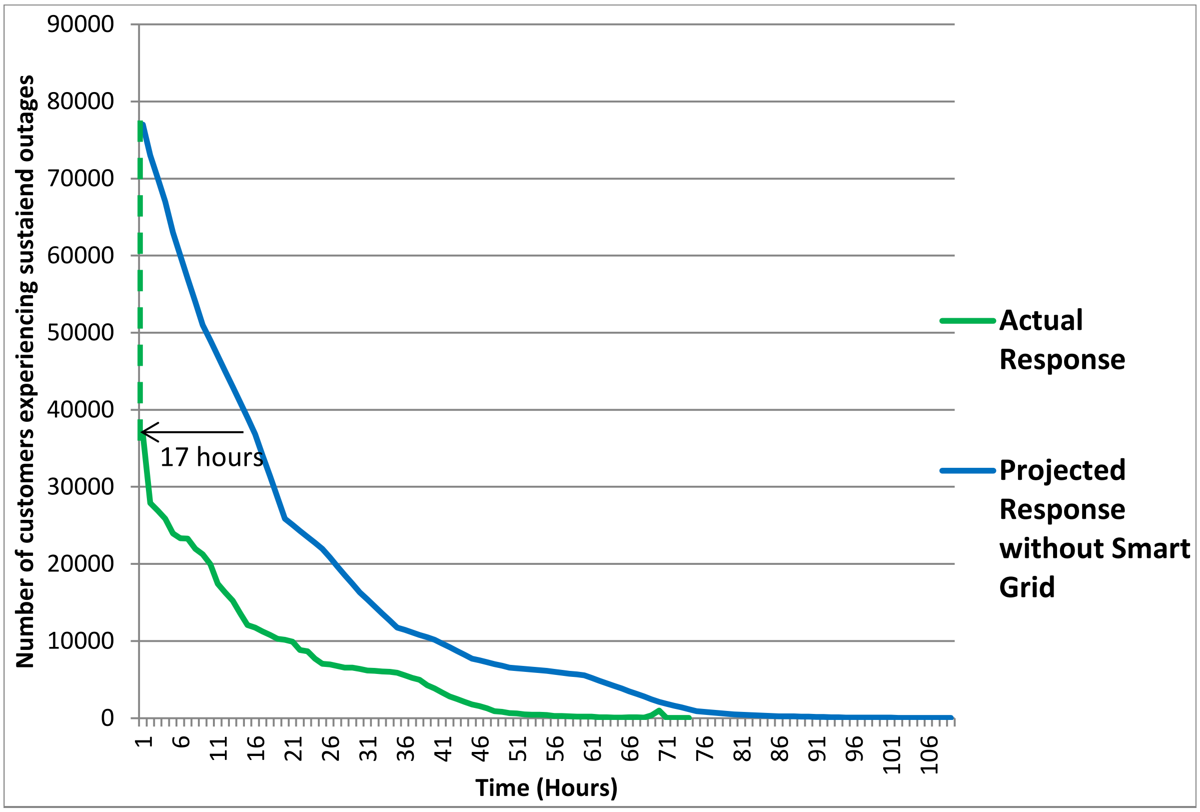

Figure 8. Improvement in Service Restoration by EPB Following a Storm in July, 2012.

EPB also experienced a snowstorm in February 2014 that affected more than 50 feeders and almost 33,000 customers. During the storm, EPB kept all of its smart switches active and did not deactivate FLISR capabilities. EPB reports that without the fault isolating capabilities of the smart switches, about 70,000 customers would have experienced sustained outages. **EPB estimates that it was able to restore power about 36 hours earlier than would have been possible without smart grid deployments**. Of those 36 hours avoided outage hours, EPB estimates about 16 were due to the self-healing actions of the smart switches, and about 20 were due to EPB's ability to "ping" smart meters, verify outage status, and redirect repair crews accordingly. EPB estimates it saved about $1.4 million in overtime costs for field crews during this storm.

Figure 9 shows a map of outage and restoration patterns from the snowstorm. The map shows the areas that were restored automatically (purple) and manually (green). Customers that were not interrupted are shown in yellow.

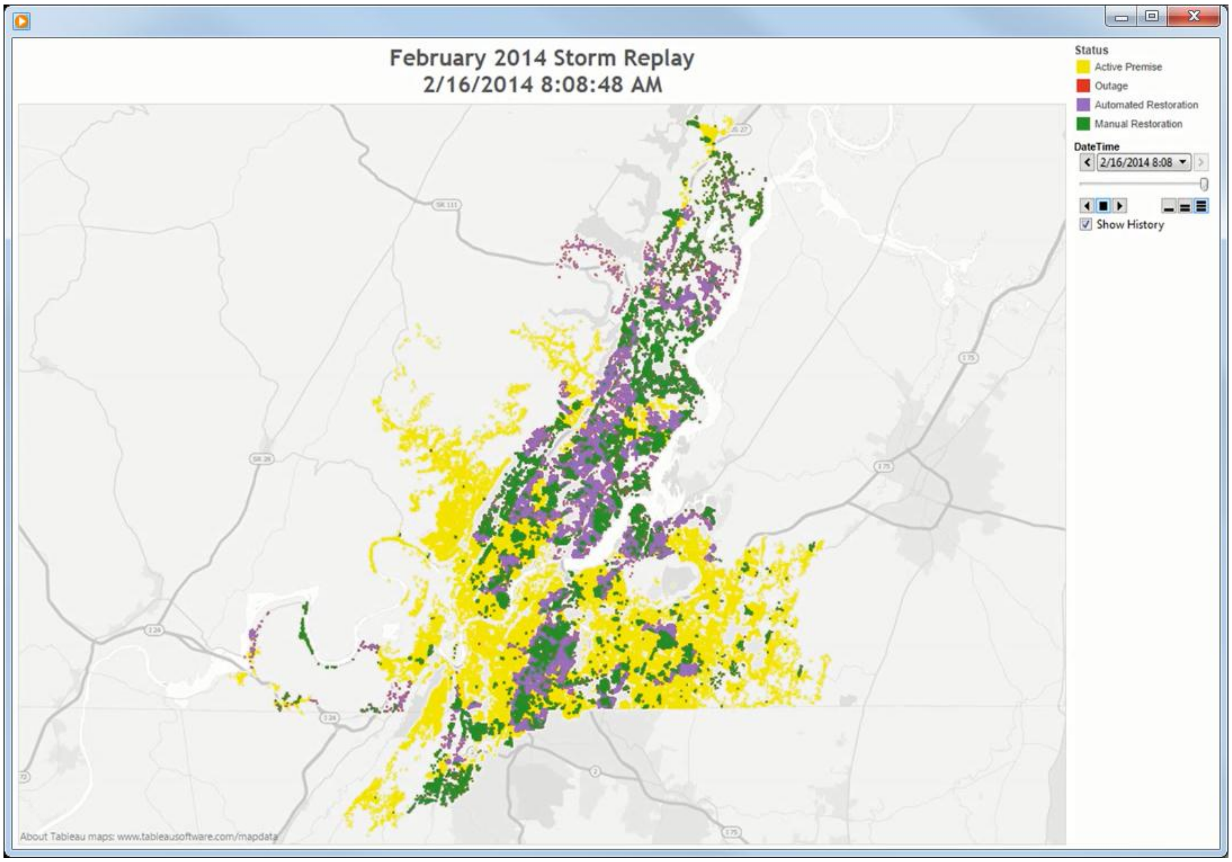

Figure 9. EPB Map of Outage and Restoration Patterns during a Snowstorm in February, 2014.

PECO. PECO has developed AMOS to more effectively integrate AMI and OMS. Before SGIG, in 2005, PECO had integrated OMS with their AMR system. The "AMR on Demand" application produced "last gasp" power outage alarms, and enabled PECO to ping the meters to verify service restoration. Unfortunately, slightly more than 1% of AMR meters were successful in sending power failure alarms and verifying when service was restored.

Using AMOS, PECO is seeing improvements. For example, in February 2014 a major storm affected significant portions of PECO's system. Although the smart meter roll-out was only 50% complete, **PECO was able to dispatch repair crews and restore services 3 days faster than they would have otherwise**. Use of AFS in response to this storm was also beneficial to customers.

For example, PECO reports that **more than 37,000 customers were automatically restored (<5 minutes) because of AFS operations**. Before the smart switches were installed, these customers probably would have been without power for 1-2 days.

PECO also reports service restoration improvements for earlier storms when the smart meter roll-out was 10% complete. Superstorm Sandy, which struck in October 2012, was the biggest storm in PECO's history and affected 70% (more than 1 million) of its customers. Smart meter operations during Superstorm Sandy helped PECO avoid more than 6,000 truck rolls due to "event cancellations," in which power restoration was confirmed by pinging meters without having to send repair crews. During storm restoration, PECO's average productivity is 2,000-3,000 truck rolls per day. By pinging meters and using that information in conjunction with OMS, **PECO was able to restore customers 2-3 days sooner than would have been possible otherwise**. Table 2 shows summary statistics for PECO's response to Superstorm Sandy.

Table 2. Summary of Benefits from PECO's Response to Superstorm Sandy	
Number of Affected Customers	~1,130,000
Number of Event Cancellations	5,077
Number of Truck Rolls Avoided or Made More Effective	6,119
Estimated Number of Fewer Days to Restoration	2-3

FPL. Tropical Storm Isaac, which struck Florida in August, 2012, is the most recent major storm to cause significant power outages in FPL's service territory. AFS and FLISR operations contributed to reductions in CI and momentary disturbances. The company reports that 9 operations serving almost 16,000 customers led to **more than 9,000 fewer customer interruptions and approximately 2,500 fewer upstream momentary disturbances**.

FPL has outfitted its first-responding Restoration Specialists with mobile technology. After completing repairs, the specialists can use the technology to remotely "ping" a meter to verify that all customers in an affected area have their power restored. This is particularly useful for identifying nested outages during events and helps to reduce outage duration for those customers.

Since Isaac, FPL has installed more than 3,800 remote fault indicators at strategic grid locations covering 620 feeders. These devices are expected to facilitate faster restoration during sustained interruptions and assist in investigation of momentary interruptions. FPL is working to improve OMS and distribution management system operations to better pinpoint fault locations and causes and accelerate restoration responses. The company equips hurricane evacuation centers with meter-pinging capabilities so that customers can find out when power has been restored at their homes and businesses.

3.2 Improvements in Grid Reliability Indices

SAIFI and SAIDI are among the standard reliability indices used by the electric power industry to monitor system performance. Figure 10 shows how these **reliability indices have improved for EPB during the time period in which AFS, FLISR, and AMI were deployed and operating**. SAIFI is a measure of how often the average customer experiences a sustained interruption, and the figure shows about a 45% reduction from 2011 to 2014. SAIDI is a measure of the total duration of the interruptions and the figure shows about a 40% reduction over the same time period.

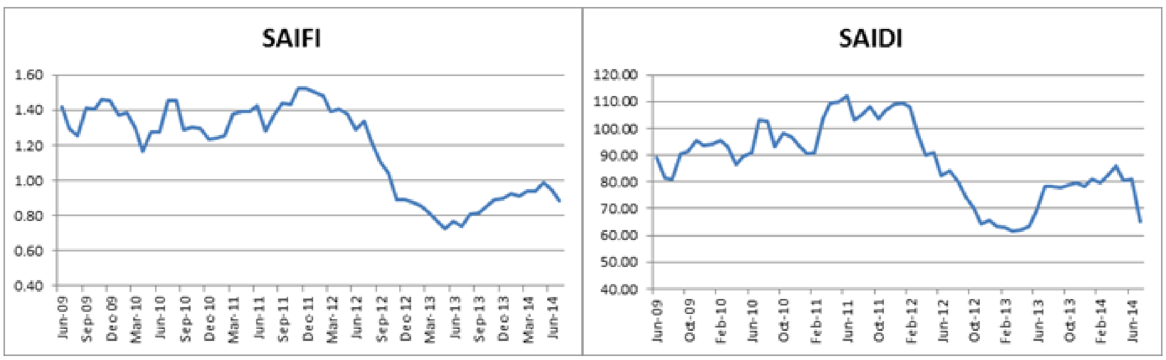

Figure 10. SAIFI and SAIDI Improvements for EPB, 2009 – 2014.

The electric power industry also uses estimates of the customer interruptions (CI) ***avoided*** and customer minutes of interruption (CMI) ***avoided*** to measure benefits from improvements in reliability. Figure 11 shows improvement in CI avoided during the time period in which AFS, FLISR, and AMI technologies and systems were deployed and operated by EPB.

FPL also markedly increased the average annual customer minutes of interruption avoided by 5.1 million minutes from 2012 through the third quarter of 2014. This was achieved, in part, due to the absence of major storms, as well as AFS and FLISR operations. The company used technologies that led to reductions in the frequency of outages.

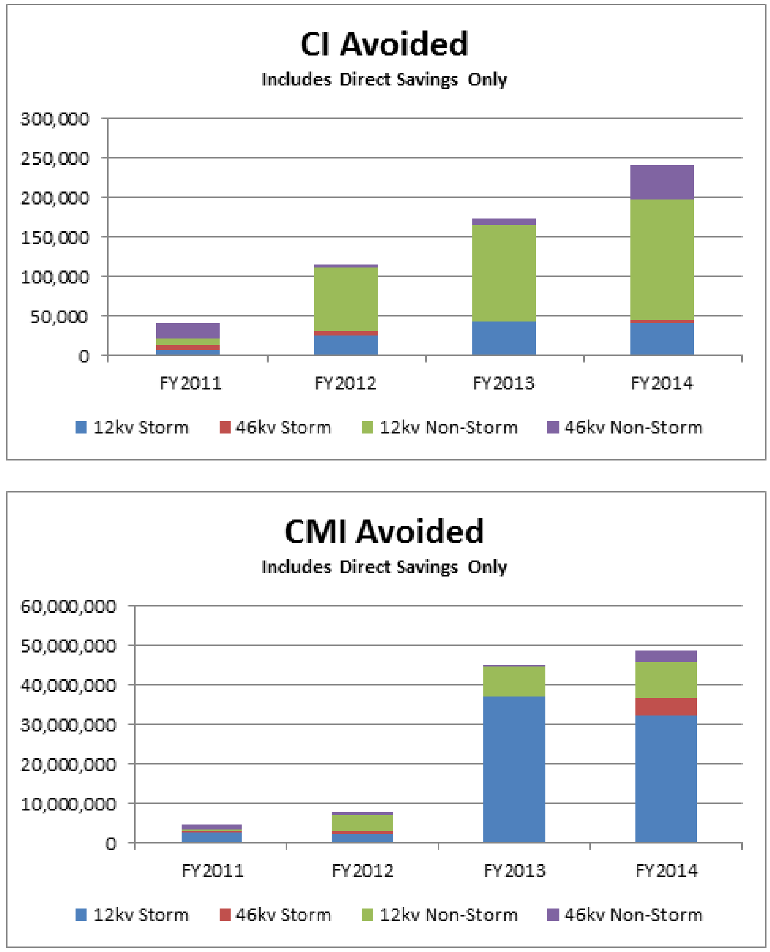

Figure 11. CI and CMI Improvements for EPB, 2011 - 2014.

FPL's Transmission Performance and Diagnostic Center (TPDC) and its System Control Center remotely monitor critical transformers and feeders for faults. Transformer failure can cause extended interruptions. The company uses smart grid technology to help predict transformer equipment failure. For example, in September 2012, the TPDC detected a potential transformer fault. FPL tested and replaced the unit, **preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs**. Through the third quarter of 2014, FPL had proactively replaced more than 1,000 distribution transformers, preventing potential unplanned outages for an estimated 10,000 customers.

PECO also observed improvements in avoiding outages due to AFS operations. For example, after a tree fell on a power line that had a feeder equipped with an automatic recloser, the recloser tripped and more than 100 customers lost power. Without the recloser, another 1,400 upstream customers also would have lost power.

Pinging smart meters is also used to assess outage impacts. Table 3 shows the improvements in PECO's capabilities to identify which customers lost power during outages and verify when power was restored after moving from AMR to AMI. The table shows that **PECO's ability to ping**

meters to verify power restoration improved from about 12% to about 95% following AMI deployments.

Table 3. Performance of AMI versus AMR for Pinging Meters During Outages		
Performance Factors	**AMR**	**AMI**
Power Failure Alarm Success Rate	10-30%	88.5%
Power Restoration Verification Success Rate	12.5%	95.2%

4. Lessons Learned and Future Plans

All three utilities are in the process of learning how to better apply AFS and FLISR and how to use AMI to support service restoration and improve storm responses. Many of the devices being used for these purposes are new or are being applied in novel ways. There is no one way to achieve the goals of faster service restoration, better reliability, or building a more resilient grid; utilities are applying different technologies in ways that make sense for their specific system configuration. Deploying smart grid technologies *system-wide* for outage reduction purposes will require additional testing and experience along with further business case analysis, as the technology's cost-effectiveness may differ for each feeder group.

The lessons learned cover technologies and systems, and business strategies and processes. Future plans include efforts to refine and expand demonstrably cost-effective applications, while at the same time testing new approaches to a limited extent to better understand the technical performance and cost-effectiveness of the technologies and systems being deployed.

4.1 Lessons Learned about Technologies and Systems

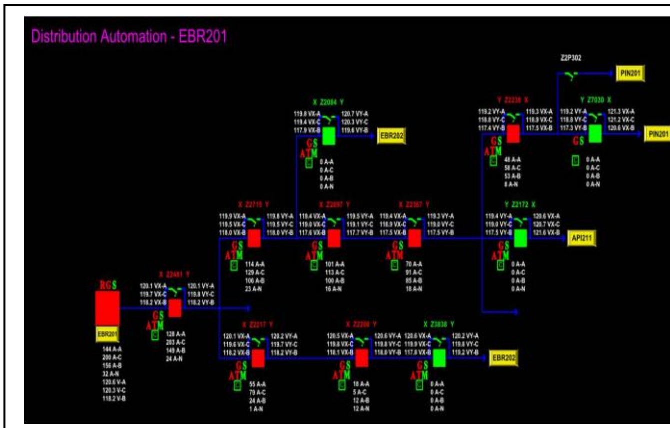

Figure 12. Example of Pole Top Telemetry Data Display at EPB.

Communications networks are foundational investments that can serve multiple existing and future smart grid applications. One of the core technologies for both DA and AMI are communications networks that are capable of processing large volumes of data from smart meters and feeder switches and accomplishing automated controls. The three utilities are attempting to realize synergies in their communications strategies. For example, FPL and PECO installed single networks to communicate with all end-point devices including smart meters, smart switches, and reclosers. The aim is to leverage resources and minimize training requirements, vendor interactions, information technology interfaces, software solutions, and systems integration requirements. EPB installed an ultra-speed, high bandwidth, fiber optic network which provides services beyond those for electric grid applications. Figure 12 shows a data display from pole top telemetry at EPB.

The utilities learned that there is value in leveraging communications capacity to serve multiple smart grid applications, but that detailed planning is need to ensure that implementation proceeds smoothly and the devices and software operate as intended. In leveraging resources, the utilities were able to use the same networks for backhauling load data from smart meters to meter data management systems and for pinging meters during outages to determine which customers were without power.

New AFS technologies required testing and adjusting to optimize capabilities. AFS technologies presented a number of common problems for all three utilities, but were commonly resolved by testing operational experience. Several of the utilities reported problems with the initial performance of the field devices, which required additional coordination with vendors and training for engineers and field crews. These problems diminished over time as the utilities gained experience operating the equipment. With experience, one of the utilities found it beneficial to change switching strategies and use less complex approaches to reduce the number of problems and boost overall effectiveness.

Extensive operational experience with FLISR technologies is needed before wider system deployment. Implementing FLISR capabilities also provided lessons learned for the utilities. For example, PECO determined it was best to turn off FLISR capabilities and revert to manual switching when the system faced extreme storms. This is because automatic switching reconfigures circuit boundaries, which can complicate the coordination of field crews. The utilities believe this is another indicator of the need for them to gain further experience with the equipment before expanding FLISR to other areas of the system.

Smart grid technologies produce large volumes of data that require additional processing capabilities. As with other smart grid applications, the utilities found difficulties managing large volumes of data from the switches, reclosers, and other field devices. Data processing, warehousing, analysis, and visualization tools were needed, and these required significant resources and planning to develop. Tools for summarizing the data and turning it into actionable information for grid operators are paramount and need to be considered in in the implementation process. Grid operators appreciated having visualization techniques and dashboards, and these were useful for supporting outage management operations.

4.2 Lessons Learned about Business Strategies and Practices

A foundational issue is the need for consistent methods to evaluate the responses of utilities to major storms in terms of metrics and tools. For a variety of reasons—including differences in regulatory guidelines, technology mixes, business incentives, and the nature of weather-driven events—the three utilities each apply different metrics and approaches. The lack of standard metrics can make it difficult to measure and compare the benefits from investments in AFS, FLISR, and AMI for outage management in a consistent manner across utilities. In addition, because weather events are random, predicting future storm impacts and benefits for inclusion in forward-looking business cases can be difficult.

For example, the February 2014 snowstorm that affected EPB occurred on a weekend. Had the storm arrived on a weekday, there would have been lower overtime costs and the savings from fewer truck rolls would have been lower. Thus, the savings for improvements in outage management can be hard to estimate before the investments take place, as assumptions about weather events and other factors can turn out to be inaccurate. As a result, business cases need to contain contingencies that reflect uncertainties in the weather, timing, and other factors. To build a business case, it is important for utilities to collect data, no matter what metrics are used, to document impacts and benefits and provide information decision makers can use for business case analysis.

Using smart grid technologies and systems for accomplishing AFS, FLISR, and AMI for outage management often requires new training staff and revised business processes. The utilities discovered they needed to strengthen project management systems and develop and manage business process improvements. One effective technique involved the use of cross-functional teams, representing all affected departments such as information systems, electric distribution, and corporate planning. This approach helped the utilities to coordinate activities and share resources more effectively.

4.3 Future Plans

The three utilities have plans to continue investments in smart grid technologies, tools, and techniques to improve storm response capabilities and reliability, build resilience, lower costs, and improve customer services. The key areas of DA and AMI are expected to play important roles. Top priorities include further efforts to integrate data and systems from the deployment of these technologies using meter data management system (MDMS), OMS, DMS, and GIS.

For example, EPB reports that the deployment of DA equipment is part of EPB's plan to more fully automate its distribution system. Moving forward, EPB expects data from the smart switches to provide information on real-time loadings on all of EPB's transformers so that demand can be better calculated and planned for, thus utilizing existing capital assets more effectively.

FPL is exploring how to tie new fault location capabilities to substations to minimize customer interruptions and improve power quality by addressing voltage flicker issues. The company also plans to strengthen the integration of the company's GIS and OMS.

Additionally, FPL is accelerating its extensive use of automated switches, including AFS and Automated Lateral Switches (ALS). ALS technology is a key part of FPL's unprecedented program to reduce the number of momentary outages—those lasting less than one minute. In addition to increasing its AFS deployment beyond the 1,000 already installed, the company plans to deploy as many as 10,000 ALS throughout its distribution system in 2015 and expects to further expand deployment in ensuing years.

PECO plans to improve its ability to respond to "nested" outages, which can occur within major events, and often can go unnoticed. PECO is using its AMI systems to identify which customers are not restored after initial restoration actions have been completed. If some customers remain out of power, it indicates that there may be nested faults. PECO is enhancing development of AMOS to help identify and resolve these types of issues. It is also working on making information from AMOS graphically visible to field crews to improve the outage restoration responses.

PECO is also planning enhancements that will better use smart meter data to create virtual transformer models and maps. Overloads can be easily identified and remediation can be scheduled before actual failure.

5. Where to Find Additional Information

To learn more about national efforts to modernize the electric grid, visit the Office of Electricity Delivery and Energy Reliability's **website** and **www.smartgrid.gov**. DOE has published several reports that contain findings on topics similar to those addressed in the three projects featured in this report. Web links are provided in Table 4.

Table 4. Web Links to Related DOE Reports	
SGIG Program, Progress, and Results	**i.** Progress Report II, October 2013 **ii.** Progress Report I, October 2012 **iii.** SGIG Case Studies
SGIG Analysis Reports	**iv.** Application of Automated Controls for Voltage and Reactive Power Management – Initial Results, December, 2012 **v.** Reliability Improvements from Application of Distribution Automation Technologies – Initial Results, December, 2012
Recent Publications	**vi.** Smart Meter Investments Yield Positive Results in Maine, February 2014 **vii.** Smart Meter Investments Benefit Rural Customers in Three Southern States, March 2014 **viii.** Control Center and Data Management Improvements Modernize Bulk Power Operations in Georgia, August 2014 **ix.** Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York, August 2014 **x.** Automated Demand Response Benefits California Utilities and Commercial & Industrial Customers, September 2014 **xi.** New Forecasting Tool Enhances Wind Energy Integration in Idaho and Oregon, September 2014 **xii.** Customer Participation in the Smart Grid – Lessons Learned, September 2014 **xiii.** Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas, September 2014 **xiv.** Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs, October 2014