COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Duke Energy Kentucky, Inc., for (1) a Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief.	)	Case No. 2016-00152

DIRECT TESTIMONY OF

DONALD L. SCHNEIDER, JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

April 25, 2016

TABLE OF CONTENTS

PAGE

ATTACHMENTS:

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald L. Schneider, Jr., and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Director, Advanced Metering by Duke Energy Business Services LLC, a service company subsidiary of Duke Energy Corporation (Duke Energy), and a non-utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes. I have been registered as a professional engineer with the State Board of Registration for Professional Engineers in the State of Indiana since 1995.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville in 1986. Upon graduation, I was employed by Duke Energy Indiana (then known as Public Service Indiana) as an electrical engineer. Throughout my career with Duke Energy, I have held various positions of increasing responsibility in the areas of engineering and operations, including distribution planning, distribution design, field operations, and capital budgets. Prior to working in Duke Energy's Grid Solutions organization, I was General Manager, Midwest Premise Services, responsible for managing all of Duke Energy's Midwest premise service and meter reading departments, including our service territories in Kentucky, Ohio and Indiana. In 2008, following the Cinergy Corp.,/Duke Energy merger I was promoted to a position responsible for managing the project execution for all Grid Solution projects in the field, including both advanced metering and distribution grid automation , for all legacy Duke Energy jurisdictions. In 2012, following the Duke Energy/Progress Energy merger, I took on my current role as Director, Advanced Metering with responsibility for project execution for all advanced metering projects in all Duke Energy jurisdictions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I previously provided testimony on behalf of the Company in Case No. 2012-00428, the Kentucky Public Service Commission's (Commission) administrative investigation regarding the Consideration of the Implementation of Smart Grid and Smart Meter Technologies.[1]

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss and support Duke Energy Kentucky's request for approval of a Certificate of Public Convenience and Necessity (CPCN) to replace and upgrade its metering infrastructure throughout its gas and electric service territory (Metering Upgrade). I provide background information about the Company's previous experience with an advanced metering pilot program and describe the new Metering Upgrade technologies to be deployed,

[1] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, (Order)(April 13, 2016).

including Advanced Metering Infrastructure (AMI) technology to serve electric and combination electric and gas customers and Automated Meter Reading (AMR) technology to serve gas-only customers; details of the Metering Upgrade deployment plan; and sponsorship of a cost-benefit analysis for the project. Finally, I will discuss the operational capabilities of the metering technology selected for deployment, and how this new infrastructure will have a positive impact on Duke Energy Kentucky's operations and mission to provide safe, reliable and reasonably priced utility service to its customers.

II. METERING TECHNOLOGY BACKGROUND

Q. PLEASE DESCRIBE THE SCOPE OF DUKE ENERGY KENTUCKY'S ADVANCED METERING PILOT PROGRAM DEPLOYED IN 2007.

A. Following Duke Energy Kentucky's last electric rate case, Case No. 2006-00172, Duke Energy Kentucky began deploying a limited-scale, early-generation advanced metering solution based on Power Line Carrier (PLC) technology. Rather than proceed with a full-scale, system-wide rollout, Duke Energy Kentucky decided to conduct this PLC AMI system installation as a pilot program, limiting the number of installations, to gain information about the technology before proceeding with a full scale system-wide roll out. As part of this pilot program, the Company also installed an AMR (drive-by) technology consisting of communication modules for a small subset of its gas-only meters to gain experience with that technology as well. The PLC AMI technology the Company deployed used the electrical distribution system as the communication medium for a Two-Way Automatic Communication System (TWACS) between the meter and the utility's back-office systems, allowing the Company to read meters remotely.

Around the same time as its pilot, Duke Energy Kentucky's parent corporation, Duke Energy Corp., began analyzing other technologies that enabled greater opportunities for operational enhancements than simply remote meter reading. As part of Duke Energy Kentucky's limited scale advanced metering pilot, the Company deployed approximately 13,000 gas modules and approximately 39,000 electric advanced meters in northern Kentucky for its electric and combination customers. In addition, approximately 12,000 gas-only customers received AMR gas modules. These limited scale pilot technologies are still in use today.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S EXPERIENCE WITH THE ADVANCED METERING PILOT PROGRAM.

A. Duke Energy Kentucky's experience with the advanced metering pilot, while positive, did not afford the Company, as a combination electric and natural gas utility, or its customers with the anticipated level of benefits or opportunities that are available with AMI technologies in the market today. The technology that Duke Energy Kentucky installed as part of the pilot did allow remote meter reading, but did not allow for more advanced functions like remote connection and disconnection. Further, Duke Energy Kentucky learned that the piloted technology installed was impractical for retrieval of interval electric usage data or daily data collection, as is possible with more advanced systems. This impracticality was because of the bandwidth limitations created by transmitting such data across utility power lines. The Company also discovered that the TWACS piloted technology significantly limited the ability to retrieve meter reading data during substation maintenance, outages, or seasonal switching situations where circuits were re-routed. For those circuits experiencing either an outage or a system re-routing event, even if the customer was not experiencing an outage, their consumption was not retrievable. Oftentimes, this was because the communication with the meter along the established circuit path was lost and took days to be reestablished. This resulted in lost data and prompted the Company to either attempt manual readings or develop estimated bills for customers. In those situations when the Company had resources available to deploy personnel to manually read the customer's meter on their scheduled date, and thus avoid an estimated read, it created additional customer inconvenience and safety concerns because Duke Energy Kentucky personnel were unexpectedly appearing at the customer's premise to read the meter even though a remotely read metering device had been installed. The piloted technology presented further limitations for monthly natural gas meter reading in that the gas modules required pairing to specific electric meters. When natural gas meters were changed out as part of our normal gas meter replacement program, or the modules were replaced for other reasons, the connection to the electric meter was often lost, thereby also requiring estimated natural gas readings or manual or drive-by data retrieval.

The Metering Upgrade proposed in this filing does not have those same challenges and is proven technology in that it is similar to what is currently being deployed in other Duke Energy jurisdictions, including those where the Company has combination electric and gas customers.

In order for the Company to offer its customers innovative programs and services to better control their energy consumption, Duke Energy Kentucky must upgrade its metering infrastructure through an investment in technologies that can support such developments. The Metering Upgrade enables such opportunities.

III. DUKE ENERGY KENTUCKY'S METERING UPGRADE AND ITS BENEFITS

Q. PLEASE PROVIDE AN OVERVIEW OF THE TECHNOLOGIES THAT DUKE ENERGY KENTUCKY INTENDS TO DEPLOY AS PART OF THE METERING UPGRADE, AND WHO WILL RECEIVE SUCH TECHNOLOGIES.

A. Duke Energy Kentucky proposes to upgrade the metering technology for its residential and small commercial customers, as well as any large commercial and industrial (C&I) customers that do not already have a similar advanced metering device installed. The type of metering technology will differ by customer depending on whether the customer is an electric-only customer, a combination electric and gas customer, or a gas-only customer. The technology for electric-only customers will be an AMI solution. For combination electric and gas customers (combination customers), the technology will consist of an AMI electric meter and an AMI gas module attached to their existing gas meter. Usage data from these gas modules will be collected through nearby electric AMI meters. In areas where Duke Energy Kentucky only provides gas service (gas-only customers) the Company will not have the electric AMI infrastructure in place to support communications for a gas AMI solution. The technology for these customers will be an AMR gas module attached to their existing gas meters. The Company will read the AMR gas modules remotely by driving past the customer's premise. Exhibits 3 and 4 to Application are the specifications to the meter and module devices to be installed as part of the Metering Upgrade. Exhibit 5 is a network diagram showing how those meters and modules communicate with one another and the Company.

Q. PLEASE EXPLAIN WHY SOME OF DUKE ENERGY KENTUCKY'S LARGE C&I CUSTOMERS ARE NOT INCLUDED IN THIS METERING UPGRADE?

A. Most of Duke Energy Kentucky's larger C&I customers already have a form of an advanced metering infrastructure and have had such capability for many years. This is due to the nature of their consumption and the rate structure they are under that already contemplates interval metering. For customers that already have a similar form of advanced metering, there is simply no need to replace those meters as part of this Metering Upgrade.

Q. PLEASE BRIEFLY DESCRIBE AMR TECHNOLOGY.

A. AMR technology involves one-way communication from a meter to a remote receiver either in the form of a handheld device or a drive-by device. The utility cannot send signals back to meters through AMR technology, but meter reading can be accomplished much more efficiently using AMR technology than by walking right up to a meter. The AMR technology collects usage data on a monthly interval. This CPCN seeks approval to install AMR technology on existing gas meters for gas-only customers.

Q. PLEASE BRIEFLY DESCRIBE AMI TECHNOLOGY.

A. AMI is far more encompassing than just a remotely read meter. AMI is an overarching architecture providing automated, two-way communication between an advanced utility meter and a utility's back-office systems for the purpose of measuring, collecting, and analyzing energy usage data. The overall AMI solution includes three basic components: 1) advanced meters; 2) a two-way communication network; and 3) back-office systems.[2]

Q. IS AMI A MATURE TECHNOLOGY?

Yes, AMI meters are becoming the standard for Duke Energy and for the industry as a whole. In fact, the national penetration rate for smart meters (which include two-way communications) is over 43% and continues to climb (See Attachment DLS-1, Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid, IEI Report September 2014, p. 1). An estimated 65 million smart meters will be installed nationwide by 2015 (See Attachment DLS-2, Smart Grid System Report, Report to Congress August 2014, United States Department of Energy, p. 4). Likewise, Duke Energy has installed over 1.3 million AMI meters across its other jurisdictions.

Q. HOW DO AMI METERS WORK?

A. AMI meters – often referred to as "smart meters" – have two-way communications capability and are capable of collecting interval usage data,

[2] The Metering Upgrade deployment does not include distribution automation or integrated volt/VAR control.

tamper detection, customer premises voltage levels and reactive power measurement, and net metering. The solution selected for Duke Energy Kentucky's electric operations will allow the Company to not only remotely read a customer's meter without having to deploy field personnel, but will also allow the Company to provide customers with next-day interval usage data, to collect off-cycle usage data, and to remotely disconnect and reconnect electric customers, avoiding customer appointments. Combination electric and gas customers will also be provided next-day usage data for their gas service as well.

Q. PLEASE DESCRIBE THE TWO-WAY COMMUNICATION NETWORK.

A. To make use of the advanced meters' two-way communications capability, Duke Energy Kentucky will install a neighborhood area network (NAN) and use a third-party-provided wide area network (WAN). The NAN represents the network connecting advanced meters to grid routers through a mesh architecture, as depicted in Figure A below.

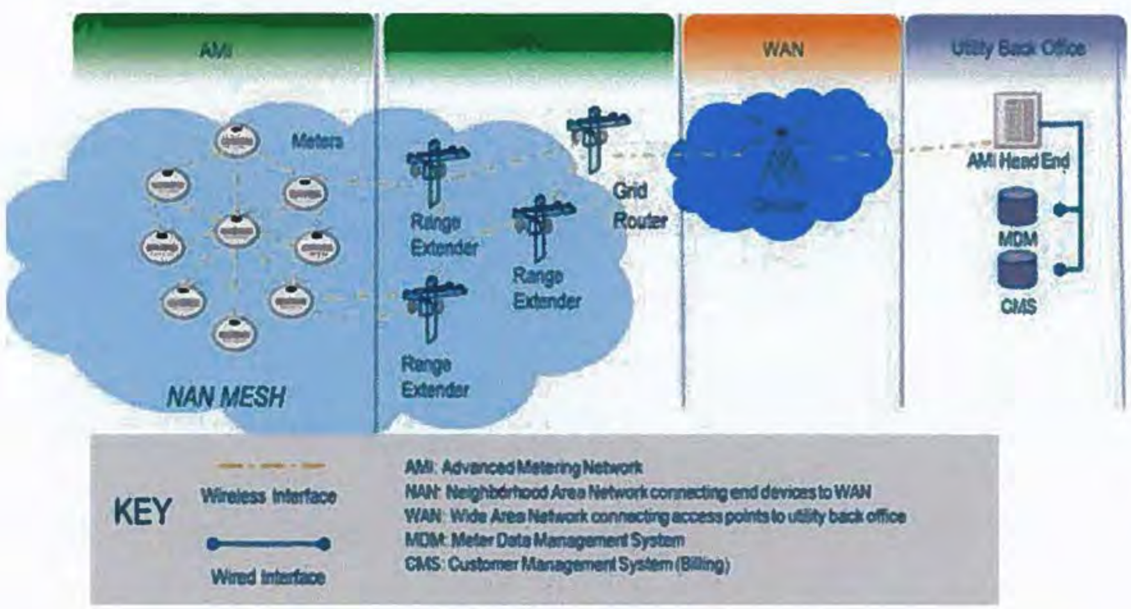

Figure "A" – AMI Solution Architecture

Advanced meters within the mesh network establish an optimized communication path to a grid router either through other meters or, in some cases, through network range extenders. Range extenders may be used to extend the mesh signal to meters that would have otherwise been outside the reach of the mesh network. All communications throughout the NAN occur using wireless radio frequency (RF) transmissions in the 900 MHz spectrum band.

Routers are the gateway between the NAN and the WAN. The WAN is the two-way communication network used to move data and instructions between the routers and the Company's back-office systems. Routers aggregate the communications from advanced meters within the NAN and transmit them to the WAN. They also communicate commands, firmware/program updates, and instructions from the WAN out to the advanced meters within a NAN. The Company will utilize secured communications over public cellular networks in Kentucky as its WAN. In cases where meters are located far enough from the NAN where it would be cost prohibitive to extend the NAN via range extenders, the Company will be installing AMI meters that contain their own cellular modem to send data back and forth over public cellular networks.

Q. PLEASE DESCRIBE THE BACK-OFFICE SYSTEMS.

A. Besides the AMI meters and communication network, the third component of the AMI solution is the back-office systems. The head-end system routes information to and from the advanced meters. The network management system monitors and maintains the health and reliability of the NAN and WAN. Finally, the Meter

Data Management system processes usage and event data from the advanced meters. Processing involves validating, editing, estimating, and packaging data for billing and other uses. Additional systems are interfaced to conduct other corporate functions, such as the Company's Customer Information System, but are not considered part of the AMI back-office systems.

Q. WHAT TYPE OF DATA WILL THE NEW AMI METERS BE SENDING TO THE COMPANY?

A. AMI electric meters will transmit interval kilowatt-hour (kWh) usage data for billing purposes as well as time-tagged event and alert data such as tamper alerts. Some electric meters will transmit voltage, amperage, phase angle, or other data, as needed. Daily interval gas usage reads will be transmitted from the gas AMI modules for combination customers.

Q. WHY IS THE COMPANY INTERESTED IN COLLECTING THESE TYPES OF DATA?

A. Interval usage data will be available for customers to view and use to make informed energy decisions such as efficiency upgrades. The data will be used by the Company for billing purposes. Various alerts will allow the Company to better manage the distribution grid, while tamper alerts and data analytics will allow for more efficient theft detection. Various system data from the advanced meters will be used to improve system models for planning purposes and improve overall distribution system operations and effieciency in terms of outage restoration. The Metering Upgrade infrastructure, together with continued investments in Distribution Management Systems (DMS) and other distribution system technologies could be integrated in the future to enable Duke Energy Kentucky to more efficiently manage its entire distribution grid and support the development of distributed energy resources.

Q. HOW WILL THE METERING UPGRADE TECHNOLOGY DIRECTLY BENEFIT DUKE ENERGY KENTUCKY'S CUSTOMERS?

A. The proposed Metering Upgrade technology is customer-focused; it enables greater convenience, control and transparency over a customer's energy consumption. AMI enabled Customers will have access to more detailed information about their hourly and daily usage patterns so they can make more informed choices regarding how they use energy.

All customers receiving the Metering Upgrade will benefit from the greater convenience that enables Duke Energy Kentucky to perform monthly or off-cycle meter reads remotely. The Company should not have to enter the customer's home or property just to read a meter. Additionally, customers will experience the convenience of not needing to schedule a site visit when they request that their electric service be switched on or off. Also, electric customers who become eligible for disconnection for non-payment will have power restored quicker through the near instantaneous remote turn-on capability, than they would if Duke Energy Kentucky had to send a technician on site. The fewer daily and monthly "truck rolls" will directly translate to cost savings through a reduction in Operations and Maintenance (O&M) expense related to meter reading that all customers will eventually experience through Duke Energy Kentucky's rates.

Finally, AMI will be integrated into our efforts to increase communications with customers about outages and restoration timelines. Duke Energy Kentucky will have the capability to ping individual meters or masses of meters to determine if customers have power. During the damage assessment phase of a storm, the mass meter pinging capability allows the Company to have a better view of where outages are located on the system. This functionality helps reduce the assessment time, thus reducing outage durations for customers. During the power restoration phase of a storm, the capability of mass meter pinging enables the Company to determine whether power has been restored to each meter before leaving an area. For example, today, if the Company restores power to a circuit that was experiencing an outage, the Company does not know whether each individual home has been restored along that circuit. It could happen that power is restored to nearly all of the homes along the circuit, but that one or two homes may continue to be without service due to some other individual issue. The Company presently has no way of knowing if that is the case until that customer notifies the Company that they are still without service, and by that time, the Company's crew may have moved on to a new area. AMI will allow the Company to know whether individual meters are back online before the Company moves on. And lastly, during the clean up phase of a storm, when the Company is clearing out single-out tickets, the capability of pinging individual meters allow the Company to make calls to customer premises to confirm if power is still out or if it has already been restored. Experience in other Duke Energy jurisdictions having AMI installed has proven this benefit to result in hundreds of reduced truck rolls, resulting in lower overall storm restoration costs.

Q. WHAT OTHER PROGRAMS AND SERVICES WILL BE AVAILABLE TO CUSTOMERS ONCE AN AMI SOLUTION IS DEPLOYED?

A. The Company has been identifying and developing a suite of enhanced basic customer services that we would like to provide as options to our Duke Energy Kentucky customers that is enabled by the Metering Upgrade. Duke Energy Kentucky Witness Sasha Weintraub Ph.D., describes the enhanced basic customer services and customer programs that the Metering Upgrade would enable and Duke Energy Kentucky customers could voluntarily choose from.

Q. HOW WILL THE METERING UPGRADE BENEFIT DUKE ENERGY KENTUCKY?

A. The Metering Upgrade is also sustainable; it enables more efficient operations and enhanced safety. In the same way that customer convenience will improve through avoiding some on-site technician visits, the capability to conduct remote meter readings and meter-related service orders will also provide a safety benefit to the technicians performing the work. In the utility industry, the customer premise work necessary to conduct meter reading and other meter-related service orders historically has some of the highest employee-related safety and injury incident rates, presenting an inherent safety concern for Company representatives by way of risk of recordable injuries and vehicle accidents. Any time a Company representative steps foot on a customer's premises, they are exposed to unknown and oftentimes unavoidable risks such as pets and potential tripping hazards. This is especially true with accessing interior meters while attempting to obtain a monthly meter reading. Advanced meter reading capability mitigates those risks. For example, in Duke Energy Ohio's service territory, by increasing the percentage of remote meter reads, the Ohio/Kentucky meter reading department witnessed a nearly 90% reduction in the number of employee recordable injuries and preventable vehicle accidents from pre- to post-AMI deployment. Duke Energy Kentucky anticipates a similar reduction to occur in its own service territory once the Metering Upgrade is complete.

The Metering Upgrade will also allow the Company to better manage its O&M expense through increased revenue capture with enhanced theft detection capability and through Duke Energy Kentucky's capability to remotely disconnect electric customers who become eligible for disconnection due to non-payment of bills. This ability allows the Company to better control its costs by no longer having to deploy personnel to perform the electric disconnection (or reconnections), and provides the Company another tool to manage customer arrearages, especially in instances where meter access has been restricted or difficult to obtain. The Company will still follow all required customer notifications prior to disconnection, but will have greater control over our costs in doing so.

Finally, the Metering Upgrade will allow the Company to identify equipment issues in a more timely fashion. Integration of AMI meters into existing distribution systems along with analytics of the AMI meter data will improve Duke Energy Kentucky's revenue capture in that the enhanced communication capabilities also provide an indication of the health of our distribution system. For example, the Company's existing electro-mechanical metering infrastructure is not capable of communicating when metering devices may be slowed, malfunctioning, or tampered with. Duke Energy Kentucky has no idea if such situations are occurring without a physical inspection of the meter. The AMI meters enable the Company to directly assess the health of the metering equipment, translating into more efficient operation of all customers' meters and less cost due to more reliable revenue capture across our customer base.

Q. YOU PREVIOUSLY MENTIONED ENHANCED THEFT DETECTION AS ONE OF THE BENEFITS OF THE NEW AMI TECHNOLOGY, PLEASE EXPLAIN.

A. The AMI technology affords greater communication with the Company, which includes various potential theft detection alerts and alarms. These alerts/alarms detect a removed meter, an inverted meter, magnetic tampering, load-side voltage on a disconnected meter, and cover removal from the meter. Once such an alert/alarm is received, the Company will be able to immediately investigate the situation. Data analytics is another tool for use in detecting theft. Having more defined analytic queries can help reduce false positives upon investigation that can often occur from just a single alert/alarm. Data analytics can look at a pattern of alerts, alarms, events and usage as opposed to a single alert/alarm. This helps result in fewer false positives upon investigation. This is another way of proactively detecting theft so it can be investigated in a more timely manner. Today, theft is typically only found upon a periodic meter inspection or during the regular monthly reading (if tampering is evident without pulling the meter). The

AMI technology provides many more tools for detecting theft, and does so in a more timely manner.

Q. WILL DUKE ENERGY KENTUCKY NEED ANY SPECIFIC WAIVERS FROM THE COMMISSION TO ENABLE THESE BENEFITS?

A. Duke Energy Kentucky is seeking, to the extent necessary, any waivers needed to implement the Metering Upgrade, including delivery of benefits that can be obtained through remote connection and disconnection of services. These waivers would include, to the extent necessary, a waiver of any requirement to conduct a manual meter reading at least annually, or an acknowledgement that the remote meter reading will constitute a manual reading under the Commission's regulations. Duke Energy Kentucky is also requesting a waiver, again, to the extent necessary, that would require inspection of metering equipment and service connections prior to initiating service to a new customer for any account that has an AMI device. The purpose of this regulation is to ensure that a new customer is not unfairly penalized for the consumption of a prior customer. Advanced theft detection and remote connection and disconnection provided by AMI meters allows Duke Energy Kentucky to know if energy continues to flow through the meter after a customer has requested to be disconnected. This would allow the Company to fully investigate the theft and address it prior to a new customer taking service at that location, ensuring that one customer will not be adversely affected by the consumption or bad acts of a prior customer. Therefore, to enable the Metering Upgrade functionality and the cost savings that can be attributed thereto, Duke Energy Kentucky is requesting waivers of these Commission regulations.

IV. DUKE ENERGY KENTUCKY'S DEPLOYMENT PLAN AND STRATEGY TO ADDRESS CUSTOMER CONCERNS

Q. PLEASE DESCRIBE THE PROPOSED METERING UPGRADE FOR DUKE ENERGY KENTUCKY.

A. Duke Energy Kentucky proposes a full-scale, system-wide advanced meter implementation across its service territory. Duke Energy Kentucky will install advanced meters for its residential and small commercial customers, as well as any large C&I customers that do not already have a similar advanced meter installed. The project will involve an 18 month phased deployment of approximately 143,000 electric AMI meters, using ITRON Open-Way technology and installation of approximately 103,000 Itron gas modules on its existing gas meters to allow remote meter reading. Of those 103,000 gas meters, approximately 80 percent (approx. 82,500 accounts) are combination customers. These combined meter accounts will receive an AMI gas module installed to their existing natural gas meter. The remaining approximately 20 percent, or 20,500 accounts, are gas-only Duke Energy Kentucky meter accounts. These gas-only accounts will receive an AMR gas module installed to their existing natural gas meter. In parallel with the meter deployment, the Company will also be installing a communications network and back-office systems to enable the functionality of the meters.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S METERING UPGRADE DEPLOYMENT PLAN.

A. The Deployment Plan Maps included as Exhibit 2 to the Company's Application provide a depiction of the service territory for deployment to electric, combination gas and electric, and gas-only customers. The deployment will start with installation of AMR modules on existing meters for gas-only customers in the southern portions of the Company's service territory. These customers – dispersed from Warsaw to Williamstown and Falmouth to Mentor – offer an opportunity to quickly realize the benefits of reduced meter reading costs by driving past these customers for reads instead of conducting them manually. Since there is no additional communication infrastructure to plan and set up for AMR, the Company can begin that deployment immediately after CPCN approval and the subsequent three-month planning and procurement period.

For the AMI deployment, the Company will need 3-6 months after CPCN approval and procurement to complete planning for the communication network before ramping up its deployment. By that point, the Company would install, on average, more than 10,000 electric meters and around 8,000 gas modules per month for 12 months and wrap up the deployment about 2 months after that. The Company will begin deployment of AMI in its more highly concentrated northern service territory, and spread out from there to less densely populated service areas.

When the deployment is complete, the newly deployed metering network is turned over from the Metering Upgrade project team to the appropriate areas of business for them to continue to monitor, manage and maintain the network. From that point forward, new electric and/or gas customer accounts and reactivation of inactive electric and/or gas accounts will receive an AMI/AMR meter.

Q. HAVE THERE BEEN LESSONS LEARNED FROM OTHER DUKE ENERGY ADVNACED METERING DEPLOYMENTS THAT WILL BE HELPFUL IN KENTUCKY?

A. Duke Energy Kentucky is proposing technology proven not only across the industry, but specifically proven by Duke Energy in other jurisdictions. Duke Energy Kentucky will thus benefit from the experiences and lessons learned from deploying the same advanced metering technology being proposed for Duke Energy Kentucky's Meter Upgrade. Because advanced metering deployments will likely continue in the Carolinas throughout the Kentucky deployment, those project teams can share experiences and lessons learned for any emergent challenges that may arise in Kentucky. Each service territory presents its own challenges for communication network optimization in terms of topography and population density, among other things. Duke Energy has extensive experience in the approaches to communication network optimization and is working with solid vendors with an even broader range of experience in that area.

Q. WHAT CHANGES WILL CUSTOMERS SEE IN THEIR SERVICE AFTER THE METERING UPGRADE IS COMPLETED?

A. The most significant change customers will experience is in the availability and access to interval usage data. Once a customer's AMI meter is installed and certified as ready for billing, he or she will be able to view interval usage data from the previous day on the Duke Energy Kentucky customer web portal. Customers will no longer require monthly walk-by meter reads, because meter reads will be remotely reported back to the Company through the AMI communication network daily. When customers move into or out of properties, we will activate or deactivate their electric service remotely, and immediately, so that they don't have to schedule an appointment with a technician. AMI also improves our outage restoration, because we can ping meters to identify the extent of an outage and verify that power is back on after repairs.

Q. HAS DUKE ENERGY EXPERIENCED ANY CUSTOMER CONCERNS WHILE DEPLOYING AN ADVANCED METERING SOLUTION IN OTHER STATES?

A. Based on experiences in Duke Energy's other jurisdictions, Duke Energy has received minimal customer concerns during our advanced mtering deployments. Over time, Duke Energy has developed or identified existing processes to address customer concerns that do arise. The few concerns that are voiced, usually are focused on one of five areas: 1) deployment communications, 2) meter and telecommunications installation, 3) service disconnection for non-access/non-response, 4) bill accuracy, and 5) smart meter installation refusal (due to concerns around data security, data privacy or health attributed to wireless RF emissions).

Q. PLEASE DESCRIBE THE CUSTOMER ENGAGEMENT AND COMMUNICATION PROCESS DURING THE METERING UPGRADE DEPLOYMENT.

A. Duke Energy has developed a thorough customer engagement and communication process for its advanced metering deployment. This process informs customers of their upcoming installation so that they have ample time to reach out to us with questions, includes an attempt to contact the customer onsite when the meter is exchanged, and calls for several attempts to reach the customer for an appointment in cases where the meter is not accessible. After a customer's meter is installed and ready for billing, the customer is informed that they can access their interval usage data via their customer web portal. The deployment team also works with local leaders to discuss the advanced metering solution and deployment methodology prior to deploying in their area. This customer engagement process used during the advanced metering rollout is a best practice, and it has garnered the appreciation of customers, regulators, and customer advocates. However, we continually monitor and adapt our outreach efforts to ensure we're responsive to our customers.

Q. WHAT IS THE COMPANY'S APPROACH TO CUSTOMER CONCERNS REGARDING DEPLOYMENT COMMUNICATIONS?

A. If customers have questions after receiving the communications described directly above, the deployment team will work individually with customers in addressing their concerns.

Q. WHAT IS THE COMPANY'S RESPONSE TO CONCERNS REGARDING METER AND TELECOMMUNICATIONS INSTALLATION?

A. Duke Energy Kentucky seeks to minimize the impact on customers from installing the new technology, so our deployment team tries to proactively communicate and respond rapidly when customers have questions or concerns about the installation. If concerns arise, our deployment team will work individually with customers to address their installation concerns.

Q. WHAT IS THE COMPANY'S RESPONSE TO CONCERNS REGARDING BILLING ACCURACY?

A. Duke Energy Kentucky will continue to perform manual meter reading until it has consistently accurate reads from the customer's new meter prior to billing from the new meter. If the old electric meter was slowed or otherwise incorrectly capturing a customer's true electric usage, the deployment team will work directly with the customer in explaining what could have led to a higher bill and then put customers in touch with the call center for more specific answers about billing accuracy.

Q. WHAT IS THE APPROACH TO DATA SECURITY (CYBERSECURITY) FOR THE METERING UPGRADE SOLUTION?

A. Duke Energy's IT security policies for the Metering Upgrade solution are based upon National Institute for Standards and Technology (NIST) guidelines for securing Smart Grid assets and risk management. The data and systems associated with every component of the advanced metering solution are secured against both internal and external security threats. During and after implementation of the advanced metering solution, periodic audits and security penetration tests will be performed to ensure the appropriate policies have been applied to defend the potentially affected systems.

Q. PLEASE EXPLAIN HOW THE DATA COLLECTED FROM THE PROPOSED METERING UPGRADE IS TREATED FROM A PRIVACY PERSPECTIVE.

A. Duke Energy Kentucky has long had privacy policies in place to protect customer information. Duke Energy Kentucky will treat data from the Metering Upgrade solution with the same level of privacy protection. Duke Energy Kentucky's customers' privacy is of the utmost concern, and the Company does not release private customer information to third parties without the authorization of the customer.

Q. SOME PEOPLE CITE HEALTH CONCERNS REGARDING SMART METERS. CAN YOU COMMENT ON THIS?

A. Based on numerous reliable studies by third party and governmental organizations, wireless smart meters – or AMI meters – do not "present a credible threat of harm to the health and safety" of customers.[3] In the United States, the Federal Communications Commission (FCC) sets limits for public exposure to RF emissions and requires that all radio communicating devices be tested to ensure that they comply with the FCC standards. The FCC public exposure limits are set at a safety factor 50 times less than the threshold for potentially adverse biological effects, and AMI meters emit low-power RF waves at a fraction of those FCC limits. We plan to include information on the safety of AMI devices in our customer communication plans.

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[3] http://www.whatissmartgrid.org/smart-grid-101/fact-sheets/radio-frequency-and-smart-meters; http://www.azcc.gov/11-4-14smartmeters11-0328.pdf; https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2011-00262; https://www.puc.texas.gov/consumer/electricity/Metering.aspx.

V. COST-BENEFIT ANALYSIS

Q. HAS DUKE ENERGY PERFORMED A CUSTOMER COST-BENEFIT ANALYSIS FOR THE METERING UPGRADE SOLUTION?

A. Yes. We have looked at estimated costs of the Metering Upgrade solution and compared those costs to estimated benefits.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH THE PROPOSED METERING UPGRADE INCLUDED IN THE COST-BENEFIT ANALYSIS.

A. As reflected in Attachment DLS-3, the estimated capital and O&M cost to deploy the Metering Upgrade solution is approximately $49 million. The electric portion of the project deployment cost is approximately $38 million. The project deployment cost of the installation of the gas modules on the existing natural gas meters is approximately $11 million. Additional costs in the cost-benefit analysis include estimated annual ongoing cost of operation of the Metering Upgrade once deployment is completed. These costs are expected to be approximately $1.2 million per year (capital and O&M total). More detailed cost information from the cost-benefit analysis can be found in Confidential Attachment DLS-4.

It should be noted that this case does not include estimates for costs or benefits associated with the enhanced basic customer services about which Dr. Weintraub testifies.

Q. PLEASE DESCRIBE THE BENEFITS THAT WERE INCLUDED IN THE COST-BENEFIT ANALYSIS SUPPORTING THE METERING UPGRADE.

A. The main quantifiable benefits from the Metering Upgrade arise from the elimination of monthly and off-cycle manual meter reads, the ability to conduct electric disconnects and reconnects remotely (i.e., avoiding truck rolls), enhanced theft detection that can be conducted through data analytics, and the availability of interval usage data that can empower customers to better understand their energy usage and save energy. In estimating these quantifiable benefits, Duke Energy Kentucky has used its experience in other jurisdictions and industry studies.

Hard to quantify benefits (or qualitative benefits) are not included in our cost-benefit analysis but are worth noting. Examples include carbon reduction from assumed energy efficiency savings due to better customer understanding of their usage, increased efficiencies with respect to outage restoration, the integration of advanced technologies such as distributed generation, energy storage and electric vehicles with our distribution system, and the ability to offer expanded options for energy efficiency and demand response programing, etc.

More detailed benefit information from the cost-benefit analysis can be found in Confidential Attachment DLS-4 to my testimony.

Q. ARE THE ESTIMATED COSTS OF THE METERING UPGRADE INVESTMENTS JUSTIFIED BY INCREMENTAL BENEFITS?

A. Yes, the cost-benefit analysis demonstrates that there are quantifiable benefits that substantially outweigh the costs of the plan. Confidential Attachment DLS-4 includes a Net Present Value (NPV) summary showing costs are justified by the benefits of the project. Outside of the details provided in the cost-benefit analysis performed, there are qualitative benefits and future functionality that will result in additional benefits going forward.

Q. HOW AND WHEN WILL CUSTOMERS EXPERIENCE THE SAVINGS FROM THE BENEFITS OF THE METERING UPGRADE INVESTMENT?

A. There are several benefit types included in the plan. The benefits attributable toward enhanced convenience and services will be available to customers upon full deployment and operation. The benefits attributable to efficiencies and cost savings will naturally flow to customers through the Company's Commission-approved rates in its next electric base rate case. For instance, the benefits associated with increased revenues from better theft detection, reduction of meter installation errors, and reduction of underperforming meters, will be reflected through the Company's base rates in a future rate case. To the extent more accurate monthly kWh and hundred cubic feet (CCF) data is obtained from remote meter readings and estimated readings caused by meter access issues are correspondingly reduced, customers will see those benefits through the monthly fuel adjustment clause (FAC) process. The Metering Upgrade will help ensure that customers are being properly billed and paying for their own kWh and CCF usage.

Another category of benefit included in the cost-benefit analysis includes customer energy savings due to the next-day interval usage data customer feedback (Prius Effect). This benefit also directly flows to customers through individual reduced energy usage that is brought about through access to the web portal, which will provide interval usage data to customers that they have never had access to before. The estimated savings for this benefit was developed based on web portal access data from our Ohio advanced metering roll-out and industry studies.

Finally, a large part of the benefits are operational cost savings gained through expense reductions related to meter reading, truck roll reductions, meter-related service order reductions, and outage assessment reductions. Smaller operational cost savings (identified as Misc. O&M Savings) include reduced estimated bills (and therefore reduced customer calls) and improved vegetation management (utilizing voltage sag data from meters). These savings will eventually be reflected in Duke Energy Kentucky's base rates once established as part of the Company's next base electric and natural gas base rate proceedings, respectively. Once in place and fully deployed, Duke Energy Kentucky's annual operating expenses will be lower than what they otherwise would be absent the Metering Upgrade.

Q. IN YOUR OPINION, ARE THE COST-BENEFIT ESTIMATES REASONABLE BASED ON YOUR REVIEW AND EXPERIENCE?

A. Yes. Duke Energy Kentucky used actual hardware costs, deployment experiences and operational experiences from other advanced metering deployments in Duke Energy jurisdictions using the same technology to develop the Metering Upgrade costs. The Company has enterprise-wide vendor pricing agreements in place for key components of the Metering Upgrade such as the meters and communication devices. Likewise, Duke Energy has experienced the benefits from advanced metering deployments in Ohio and the Carolinas to validate the benefits estimated in our cost-benefit analysis.

The accounting treatment requested by the Company, including the Company's requests for addressing the undepreciated existing metering equipment is described in the direct testimony of Peggy A. Laub. This accounting treatment is a key component of the Company's ability to proceed with this Metering Upgrade Deployment in a timely manner that will not create a financial hardship for the Company.

VI. CONSISTENCY WITH THE COMMISSION'S CONSIDERATION OF SMART GRID AND SMART METER TECHNOLOGIES

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S RECENT ORDER IN CASE NUMBER 2012-00428, REGARDING THE COMMISSION'S CONSIDERATION OF THE IMPLEMENTATION OF SMART GRID AND SMART METER TECHNOLOGIES?

A. Yes. I have reviewed the Order and participated in the case initially.[4] The Commission conducted a thorough evaluation and consideration of the merits of advanced metering and grid operations, spanning many complex areas such as proposed federal information and investment standards, customer privacy issues, opt-outs, customer education, dynamic pricing, among other issues, including local gas distribution company (LDC) participation and determine not to adopt the Energy Independence and Security Act of 2007 (EISA) Standards for Smart Grid

[4] *In the Matter of: Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, (Order)(April 13, 2016).

Investment and Information (EISA Standards).[5] The Commission's Order sets forth several policy considerations and reporting requirement for utilities as they develop advanced grid deployment strategies going forward.

Q. DO YOU BELIEVE THE COMPANY'S FILING FOR A METERING UPGRADE IS CONSISTENT WITH THE COMMISSION'S ORDER?

A. Yes.

Q. PLEASE EXPLAIN.

A. First, the Commission's Order requires utilities to provide certain basic usage information to customers through cost-effective means.[6] Duke Energy Kentucky's Metering Upgrade will do just that. Once fully deployed, the Company will be able to provide customers with detailed interval usage information next-day through the Company's web portal.

Second, the Order requires utilities to develop detailed internal procedures and policies regarding investments.[7] Duke Energy Kentucky has such investment policies, and those policies have lead the Company to proposing this investment through a CPCN application. The Company's application and supporting testimony describes the Company's existing system, our goals and vision for developing new and innovative programs and services for our customers, as well as to manage our costs. The detail of that evaluation is contained in my Attachment DLS-3 and Confidential Attachment DLS-4, that support the overall business case for this Metering Upgrade deployment.

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[5] *Id.* Order at 8 and 10.
[6] *Id.* at 8
[7] *Id.* at 8 and 22.

Customer privacy is the third area of focus outlined in the Order.[8] The Commission requires each utility to have a customer privacy policy. As the Order discusses, the investor-owned utilities (including Duke Energy Kentucky) already have established policies that are available on company websites. As I discuss above, Duke Energy Kentucky does not and will not give out customer specific information to anyone but the customer, absent customer written authorization.

The fourth area of discussion in the Order is customer opt-outs, which the Commission does not support.[9] Duke Energy Kentucky is not proposing an opt-out in this proceeding so that it is able to maximize the opportunities for cost savings and customer benefits.

The fifth area addressed in the Order involves customer education.[10] As I discuss above, Duke Energy Kentucky already has a customer education program already in place for its Metering Upgrade. Duke Energy Kentucky has maintained its Envision Center in Erlanger Kentucky which provides a "hands-on" demonstration of the capabilities of advanced grid technologies. While the Company is in the process of formalizing its broader education policy as directed by the Order, for purposes of the Metering Upgrade, a plan is already in place.

The sixth area for consideration is Dynamic Pricing.[11] Although the Order states the Commission will not require dynamic pricing be developed, it does encourage utilities to develop pilot programs for consideration. Duke Energy Kentucky currently offers optional tariffed time-of-use rates for non-residential

[8] *Id.* at 13.
[9] *Id.* at 17.
[10] *Id.* at 19.
[11] *Id.* at 22.

customers. Although the Company is not proposing any new dynamic pricing rates as part of this proceeding, the Metering Upgrade is the gateway technology to consider such offerings in the future.

The next topic of discussion reflected in the Order involves Distribution Smart Grid Components.[12] Like the overall, investment standards discussed regarding EISA, the Commission's Order does require utilities to develop procedures for Smart Grid investments that include a description of their systems, planning goals, and explanation of how such investments are considered a Smart Grid plan.[13] Duke Energy Kentucky's filing in this proceeding is a result of such a plan. The Company is preparing its formal procedures as ordered by the Commission, but that preparation of the formal procedures does not mean the current filing was by whim. The Company already has a robust planning and evaluation process for its grid investments. The Metering Upgrade solution was the result of in-depth study and business case cost/benefit analysis.

The eighth area of focus was cyber security. [14] Duke Energy Kentucky and its ultimate parent, Duke Energy, already has significant resources devoted to ensuring cyber-security that exceed what is required by both the Federal Energy Regulatory Commission and the North American Reliability Corporation standards. The Company will make the necessary certifications and presentations as required by the Commission's Order.[15]

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[12] *Id.* at 22.
[13] *Id.* at 25.
[14] *Id. at 26.*
[15] *Id.* at 29.

Q. PLEASE EXPLAIN HOW THE ORDER ADDRESSES NATURAL GAS COMPANY PARTICIPATION IN SMART GRID AND HOW DUKE ENERGY KENTUCKY IS IN COMPLIANCE.

A. The Commission's Order requires LDCs to comply with the customer privacy, education, and cyber security issues discussed. As a combination utility, Duke Energy Kentucky does in fact comply with those areas of focus addressed in the Order. The Company's application in this proceeding includes a strategy for its natural gas customers to also participate in some level of benefits in the Metering Upgrade proposed. Duke Energy Kentucky does and will continue to apply its customer education, privacy, and cyber security policies equally across both its gas and electric operations.

VII. <u>CONCLUSION</u>

Q. DO YOU BELIEVE UPGRADING THE COMPANY'S METERING INFRASTRUCTURE WILL POSITIVELY IMPACT BOTH THE CUSTOMER AND THE COMPANY'S ONGOING OPERATIONS?

A. Yes. In addition to the cost savings depicted in the cost-benefit analysis that I explained above, from an operational standpoint, Duke Energy Kentucky will function in much of the same way it does today, but in a more efficient manner as it relates to metering. The technology will provide the gateway to the various customer-focused programs described by Dr. Weintraub. The most tangible difference is that the Company will no longer have to "roll a truck" to read the customer's electric meter or to connect or disconnect their service. The Company will be able to act more quickly in establishing services to its customers and to control its costs by timely disconnecting service when customers either cancel or fail to pay their bills. Of course, Duke Energy Kentucky will continue to abide by all notice requirements required under Kentucky regulations in the latter case. But this capability will allow Duke Energy Kentucky to respond in a much faster way to meet customer demands and to better manage its uncollectible expense.

To customers, these changes will be seamless. Duke Energy Kentucky will continue to follow its system inspection and meter testing protocols in accordance with the Commission's regulations. The Company's bill format will not change.

Q. DO YOU SPONSOR ANY OF THE EXHIBITS TO THE COMPANY'S APPLICATION SUBMITTED IN THIS PROCEEDING?

A. Yes. I sponsor Exhibits 2, 3, 4 and 5 to the Company's Application. These Exhibits include the Company's deployment plan maps, technology specifications, and a diagram depicting the interaction of the Metering Upgrade devices and equipment, respectively. These exhibits were prepared at my request, and under my direction and control.

Q. WERE ATTACHMENTS DLS-1 THROUGH DLS-4 PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Donald L. Schneider, Jr., Director, Advanced Metering, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony are true and correct to the best of his knowledge, information and belief.

Donald L. Schneider, Jr.

Donald L. Schneider, Jr, Affiant

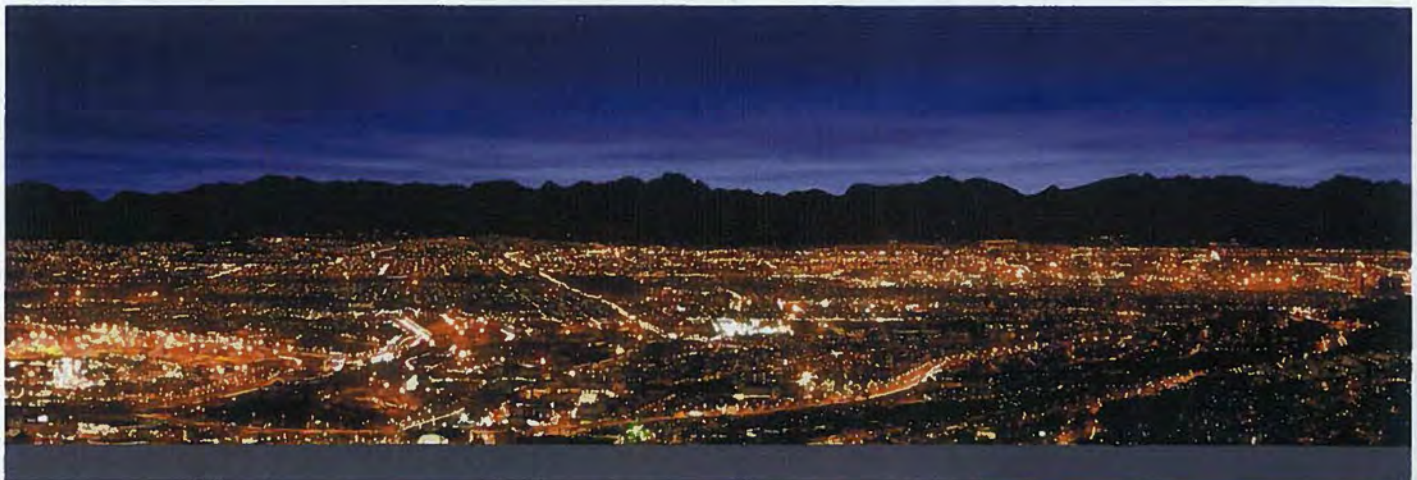
Subscribed and sworn to before me by Donald L. Schneider, Jr. on this 25th day of April, 2016.

Heather Paige Blum

NOTARY PUBLIC

HEATHER PAIGE BLUM
NOTARY
PUBLIC
MECKLENBURG COUNTY, N.C.

My Commission Expires: 1/9/2018



UTILITY-SCALE SMART METER DEPLOYMENTS:

BUILDING BLOCK OF THE EVOLVING POWER GRID

IEI Report
September 2014

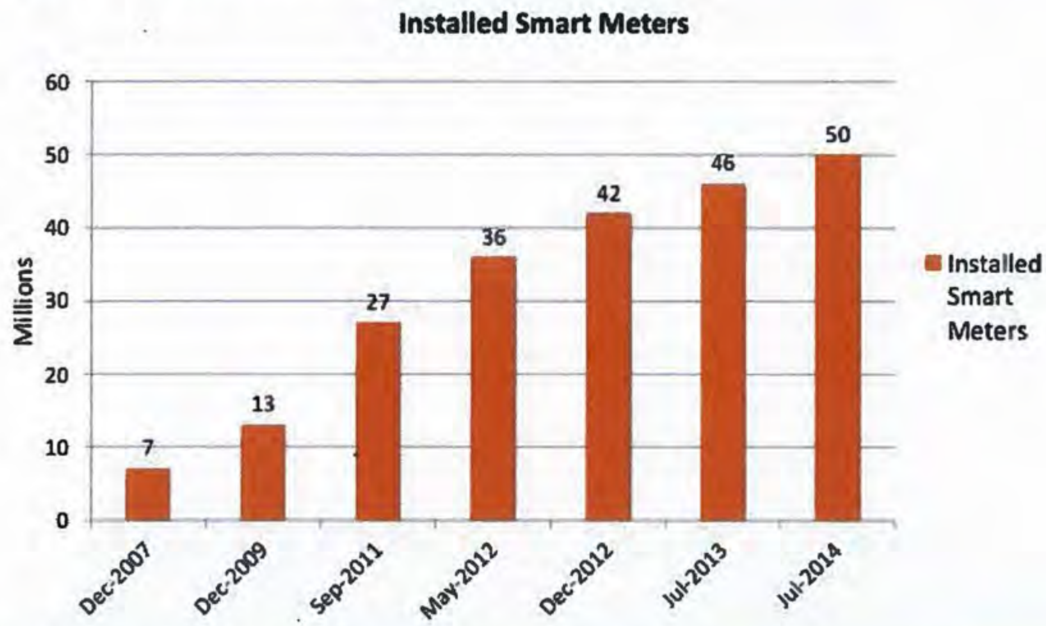
The Edison Foundation
INSTITUTE for
ELECTRIC INNOVATION

EXECUTIVE SUMMARY

Smart meters are playing a critical role in shaping the electric grid of tomorrow and enabling the integration of new technologies and innovations across the grid. As the power grid evolves into a broad platform for integrating new energy services and technologies, the ability to connect legacy assets and systems and integrate new ones is critical; smart meters are supporting this evolution. In addition, the data collected by smart meters (or automated metering infrastructure (AMI)) opens the door for greater integration of new resources and new energy services for customers.

As shown in Figure 1, as of July 2014, over 50 million smart meters had been deployed in the U.S., covering over 43 percent of U.S. homes, up from 46 million smart meters a year ago.

Figure 1. Smart Meter Installations in the U.S. Reach 50 Million

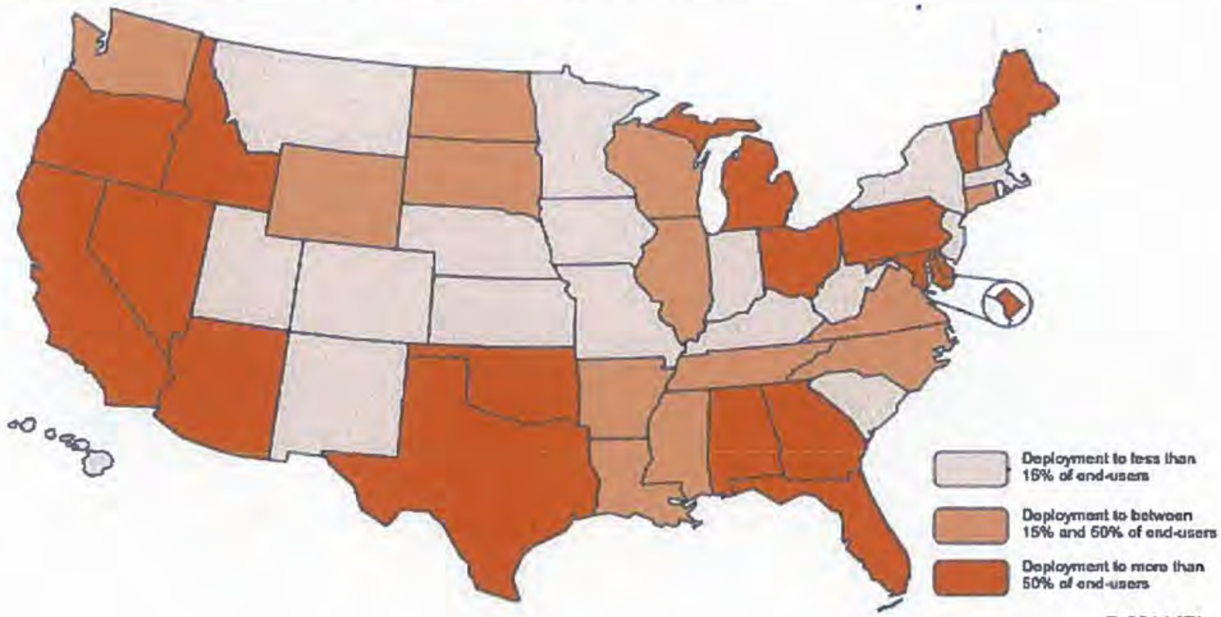


This report discusses how electric utilities are (1) integrating smart meters with their existing systems to provide enhanced outage restoration, improved distribution system monitoring, and new customer services; and (2) connecting new resources to the grid. The report also provides a synopsis of the 50 million smart meter installations by electric utilities nationwide. Figure 2 shows the expected smart meter deployments by state on a percentage basis by 2015. Thirty of the largest utilities in the U.S. have fully deployed smart meters to their customers.

A smart meter is a digital electric meter that measures and records usage data hourly, or more frequently, and allows for two-way communications between the utility and the customer.

Several states have implemented policies that allow customers to opt out of smart meters, but, to exercise this option, these customers typically pay an initial fee and a monthly opt-out fee. The number of customers that have officially requested to opt-out of a smart meter installation is extremely low.

Figure 2. Expected Smart Meter Deployments by State by 2015



Note: Figure 2 shows the extent of smart meter deployments by state by 2015 that are either completed, underway, or planned. This map does not include automatic meter reading (AMR) installations.

LEVERAGING SMART METERS

With 50 million smart meters deployed, utilities are now focused on integrating and optimizing information gathered by smart meters (and transmitted by AMI communications systems) and other investments in the digital grid to provide benefits and new capabilities to customers and system operators. The IEI 2014 Smart Meter survey highlighted a few areas where utilities are leveraging smart meters.

- ***Systems Integration.*** AMI systems integration with outage management systems (OMS) and distribution management systems (DMS) is providing enhanced outage management and restoration and improved distribution system monitoring.
- ***Integrating New Resources.*** Smart meters position the grid as a platform for the integration of distributed energy resources such as distributed generation, community solar, electric vehicles, storage, and micro-grids.
- ***Operational Savings.*** Smart meters result in operational savings such as reduced truck rolls, automated meter reading, and reduced energy theft.
- ***New Customer Services.*** Smart meters have enabled services such as automated budget assistance and bill management tools; energy use notifications; and smart pricing and demand response programs.

SYSTEMS INTEGRATION

As utilities advance towards managing the grid as an integrated network, smart meter data are increasingly combined with other streams of data for both analytical and real-time funcationality. A good example of this is CenterPoint's integration of its information technology (IT) and operations technology (OT) functions into a single function called CenterPoint Technology (CT). According to Gary Hayes, Chief

Information Officer, CenterPoint Energy, "The focus on outcomes drives collaboration across the IT/OT organizations. Operations will leverage the technologies and skills from the IT team while also incorporating operational principles in the deployment of field device technologies. This benefits the operations and reliability of all technologies supporting our Smart Grid."

Many utilities with smart meters installed are integrating their AMI and OMS systems to improve outage management and restoration services. When utility service restoration crews can see the status of the electrical network in near-real time, this helps them: identify embedded outages, resolve problems on the first visit, reduce repeat calls from customers, avoid unnecessary truck rolls, and improve customer satisfaction. IEI survey responses show that several more utilities are on a similar path and will complete the AMI-OMS integration within the next year.

We're very pleased with the integration of power outage and restoration notifications from smart meters to our outage management system and we're looking forward to building on this success and integrating more information from other grid-edge devices, and futher improving our operational efficiencies.

Utilities are also integrating AMI with DMS for distribution automation and circuit reconfiguration, Volt/VAR management, device monitoring, and predictive asset maintenance along the distribution network. "We're very pleased with the integration of power outage and restoration notifications from smart meters to our outage management system and we're looking forward to building on this success and integrating more information from other grid-edge devices, and further improving our operational efficiencies," said Karen Lefkowitz, Vice President, Business Transformation, Pepco Holdings, Inc.

INTEGRATING NEW RESOURCES

Across the U.S., utilities are connecting new resources to the power grid. In addition to providing bi-directional metering of energy flows for resources such as rooftop solar and storage, smart meters also provide greater visibility into what is occurring at the edge of the network. Grid operators are using the AMI communications network to provide situational awareness of distributed resource operations. By better understanding the dynamics of intermittent resources on the grid, utilities can manage the grid more efficiently.

Connecting AMI systems with demand response management and distributed energy resource management systems is also underway or planned. This convergence provides the foundation for integrating and managing the increasing number of distributed resources at the edge of the network.

As more distributed resources are developed, visibility at the individual or feeder-level becomes ever more important. A digital grid platform supported by AMI allows for proactive monitoring and management of distribution network conditions and the sustainable integration of new resources.

A digital grid platform supported by AMI allows for proactive monitoring and management of distribution network conditions and the sustainable integration of new resources.

OPERATIONAL SAVINGS

The most basic operational savings from a smart meter is the reduced need to send an employee in a vehicle to a customer site to read the meter. Utilities with smart meters deployed have saved several millions of dollars. In addition, the ability to remotely connect and disconnect service means that customers receive much quicker service when moving in or out of a residence. "Operational savings gained through smart meters will be passed on to customers through lower rates on their electric bills as they occur through yearly rate adjustments," said Mike McMahan, Vice President, AMI Implementation, Commonwealth Edison. "Over time, these savings will more than offset the costs of the smart meters."

Other advanced operational efficiencies empowered by smart meters include the application of data analytics to help utilities "see" what is going on in the field. By using a variety of analytical tools that cross reference customer billing and information systems with the meter data management system, utilities are identifying and resolving theft leads and unmetered current – all of this results in savings. "The implementation of advanced metering at DTE Energy continues to show positive results," said Bob Sitkauskus, General Manager, Major Enterprise Projects, DTE Energy. "Meter reading rates are at the highest levels in history, regardless of weather or traffic. Completing remote activities such as miscellaneous reads, re-connects and disconnects, along with outage and restoration notifications through the network continues to enhance customer service and distribution operations. On top of these efficiencies, customers now have access to their usage with details down to the minute, all in an effort to allow personal energy decisions."

Completing remote activities such as miscellaneous reads, re-connects and disconnects, along with outage and restoration notifications through the network continues to enhance customer service and distribution operations.

NEW CUSTOMER SERVICES

Investing in digital technologies provides utilities an opportunity to educate, learn from, and connect with the 21st century customer. With high levels of digitization all around us, it is not surprising that consumers want more control over their daily activities, including how they use energy. As the trusted energy advisor, customers expect their utilities to provide guidance on electricity matters and the majority of electric utilities have implemented multi-year plans to better serve, educate, and engage customers.

Smart meters provide a digital link between the utility and the customer and opens the door for energy management. Popular new services that utilities provide to customers include: budget setting and high usage alerts, online portals with easy to understand graphics, home energy reports, and easily downloadable energy usage data which customers can upload into their preferred app. These simple, smart services are powered by the information collected by smart meters.

Smart pricing programs are growing across the U.S., resulting in energy and bill savings for the majority of customers enrolled such programs along with increased customer satisfaction. Today, over 8 million smart metered customers in California, Delaware, the District of Columbia, Maryland, and Oklahoma are eligible to

Over 8 million smart metered customers in California, Delaware, the District of Columbia, Maryland, and Oklahoma are eligible to participate in a variety of 'smart pricing' programs.

participate in a variety of 'smart pricing' programs which reward participants for voluntarily reducing energy consumption when demand for electricity and prices are expected to be especially high. Smart pricing programs include Baltimore Gas & Electric's *Smart Energy Rewards*, Oklahoma Gas & Electric's *SmartHours*, Pepco and Delmarva Power's *Peak Energy Savings Credit*, San Diego Gas & Electric's *Reduce Your Use*, and Southern California Edison's *Save Power Day*.

Some customers are using devices like programmable controllable thermostats to respond to the price signals, while others are altering their behavior – all to take advantage of the opportunity to save money on their electricity bill. While these programs have different names and nuances, all are enabled by smart meters and, for most customers, the result is energy savings, bill savings, and increased satisfaction. "At BGE, we commend our customers on their participation in BGE Smart Energy Rewards and the great savings they are able to achieve," said Ruth Kiselewich, Director, Demand Side Management Programs, BGE. "We look forward to working with them to sustain and increase participation in each Energy Savings Day so they can save on their electric bills, help ease peak demand, contribute to improved reliability, and help make a positive impact on the environment."

IEI 2014 SMART SURVEY

Twenty utilities (representing 37 operation companies) provided responses to IEI's 2014 Smart Meter survey. These utilities account for roughly 27 million of the 50 million smart meters captured in this report. The remaining information on smart meter deployments was obtained from the Energy Information Agency's Form 826 Advanced Metering worksheet and Smartgrid.gov's project information build metrics datasheet. The data that are represented in this report were compiled from May through July 2014. This report identifies general trends and examples of how utilities are using smart meters. The report does not attempt to cover all of the ways in which utilities are leveraging investments in their smart meters. For inquires or to provide feedback, please contact Adam Cooper at acooper@edisonfoundation.net.

Summary of Smart Meter Installations and Projected Deployments

Utility Type	Meters Installed	Target Number of Meters
Investor-Owned Utilities	43,115,000	60,126,000
Municipal and Cooperative-Owned Utilities	6,963,000	9,874,000
Total as of July 2014	50,078,000	70,00,000

Smart Meter Installations and Projected Deployments by Investor-Owned Utility

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
AEP	IN, OH, OK, TX	1,199,000	2,714,000	AEP's Indiana Michigan Power (I&M) subsidiary has deployed 9,917 meters to customers in South Bend, IN; AEP Ohio has deployed 131,635 in the Columbus area; AEP Texas has deployed 1,024,849; and AEP's Public Service Company of Oklahoma (PSO) has deployed 32,538 meters. Timing for the remaining deployments will depend on specific conditions in each of the operating company subsidiaries and approval by the relevant utility commissions.	IEI Smart Meter Survey Summer 2014
Allete (d/b/a Minnesota Power)	MN	8,000	8,000	Allete plans to invest $3M and deploy 8,000 smart meters in northeast Minnesota. The utility also intends to purchase automation equipment and begin dynamic pricing program. $1.5M of the project cost is covered by federal funds.	SmartGrid.gov
Alliant Energy	IA, MN	442,300	442,300	Wisconsin Power & Light, a subsidiary of Alliant Energy, reached full deployment in 2011. Interstate Power & Light has a 1,000 meter pilot supporting the Sustain Dubuque Initiative, which fully deployed in 2010. Additional AMI deployment in IA and MN has been deferred indefinitely.	IEI Smart Meter Survey Summer 2014
Ameren Illinois	IL	0	780,000	Ameren Illinois will have 40,000 meters installed by December 2014 and anticipates 780,000 meters installed by December 2019.	IEI Smart Meter Survey Summer 2014

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Avista Utilities	WA	13,000	13,000	Avista has installed 13,000 smart meters in Pullman, WA as part of a five-state, five-year demonstration project leveraging DOE SGDG funds. Long term decisions about future deployment have yet to be made.	IEE Smart Meter Survey Q2 2013
Arizona Public Service	AZ	1,206,000	1,206,000	APS achueved full deployment at the end of May 2014.	IEI Smart Meter Summer 2014 Survey
Baltimore Gas & Electric	MD	1,150,000	1,360,000	BG&E installed 1,115,000 smart meter meters thru May 2014. Full deployment is expected by the end of 2014.	IEI Smart Meter Survey Summer 2014
Bangor Hydro-Electric	ME	120,100	120,100	BHE has fully deployed 120,100 smart meters in its service territory.	EIA Form 826
Black Hills Energy	CO	96,200	96,200	Black Hills Energy has fully installed 96,249 smart meters in Colorado and is now testing direct load control and peak time rebate offers with their residential customers.	IEE Smart Meter Q2 2013 Survey; SmartGrid.gov
Black Hills Power	MT, SD, WY	69,600	69,600	Black Hills Power has fully deployed 69,607 in its service areas across Montana, Wyoming, and South Dakota.	IEE Smart Meter Q2 2013 Survey
CenterPoint Energy	TX	2,283,000	2,283,000	CenterPoint received approval in 2008 to install an advanced metering system across its service territory. It completed deployment in July 2012, installing 2,283,012 smart meters.	IEI Smart Meter Survey Summer 2014; PUCT Docket 36699
Central Maine Power Company	ME	623,800	623,800	Central Maine Power Company completed its smart meter deployment in 2012, installing 623,790 AMI meters.	IEI Smart Meter Survey Summer 2014
Cheyenne Light, Fuel & Power	WY	39,700	39,700	Cheyenne Light, Fuel & Power completed its smart meter installation in 2011.	IEE Smart Meter Q2 2013 Survey
Cleco Power	LA	289,000	289,000	Cleco Power fully deployed smart meters across the utility's entire service territory, after receiving approval from the Louisiana Public Service Commission in 2011.	IEI Smart Meter Survey Summer 2014
Commonwealth Edison	IL	400,000	4,157,000	In June 2013, ComEd received regulatory approval for full deployment of smart meters. 400,000 smart meters have been deployed with full deployment to over 4 million customers will be complete by 2018, three years in advance of the originally scheduled 2021 completion date.	IEI Smart Meter Survey Summer 2014
Consolidated Edison	NY	4,100	4,100	Con Edison piloted a $6M smart grid program in northwest Queens. 1,500 meters will be deployed and 300 customers will test in-home displays that monitor energy usage by appliance. Intent to file for approval to expand deployments has not been announced	EIA Form 826

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Consumers Energy	MI	246,500	1,800,000	As of May 2014, 246,500 smart meters had been deployed with full deployment of 1.8 million meters anticipated by 2018.	IEI Smart Meter Survey Summer 2014
Dominion	NC, VA	223,300	2,704,000	Dominion has completed installation of 223,289 smart meters in North Carolina and Virginia. The AMI business case and full deployment plans for 2.7M meters are still under development.	IEI Smart Meter Survey Summer 2014
DTE Energy	MI	1,327,000	2,603,000	As of May 2014, 1,326,984 meters had been installed with full deployment of 2.6M expected by end of 2017.	IEI Smart Meter Survey Summer 2014
Duke Energy	FL, KY, NC, OH, SC	1,112,200	1,269,700	Duke has fully deployed 717,000 smart meters in Ohio. In other jurisdictions, Duke has achieved targeted deployments of 74,392 meters in Florida; 39,000 in Kentucky; 223,209 in North Carolina; and, 68,650 in South Carolina. An additional 157,500 meters are planned for the Carolinas by year end. Duke is still in its planning stages for deployment in Indiana.	IEI Smart Meter Survey Sunner 2014
Entergy	LA	5,100	19,800	Entergy New Orleans has installed 4,755 smart meters in a dynamic pricing pilot for low-income households in New Orleans. Entergy Louisiana has installed 300 smart meters.	EIA Form 826
FirstEnergy Corporation	MD, OH, PA, WV	56,400	2,153,000	FirstEnergy operating company Illuminating Company in Cleveland, OH installed 32,300 meters as part of a 44,000 meter pilot. In Pennsylvania, Act 129 (2008) requires electric distribution companies with more than 100,000 customers to file a smart meter technology procurement and installation plan. FirstEnergy subsidiary West Penn Power in Pennsylvania installed 23,000 smart meters as part of a pilot with full deployment starting in 2017. Pilot activities in Morgantown, WV and Urbana, MD are testing 1,140 smart meters.	EIA Form 826; SmartGrid.gov First Energy Implementation Plan (Docket M-2013-2341990)
Florida Power & Light Company	FL	4,625,000	4,800,000	FPL has fully deployed its smart meter program to residential customers. Deployment to remaining 200,000 Commercial and Industrial customers is underway with completion expected in 2015.	IEI Smart Meter Survey Summer 2014
Green Mountain Power	VT	260,600	260,600	Green Mountain Power has deployed 260,600 smart meters to customers across Vermont	EIA Form 826
Idaho Power	ID, OR	512,300	512,300	Idaho Power has fully deployed 512,348 smart meters across its service territory in Idaho and Oregon.	IEE Smart Meter Survey Q2 2013; EIA Form 826
Indianapolis Power & Light	IN	11,900	42,000	IPL has installed 11,888 meters, and does not anticipate installing additional meters. IPL intends to not fully deploy AMI to its service territory, instead pairing it with AMR meters.	IEE Smart Meter Survey Q2 2013

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Kansas City Power & Light	MO	14,000	14,000	KCP&L completed the installation of 14,000 smart meters in 2011 for its SmartGrid Demonstration project in midtown Kansas City, MO. The project includes piloting in-home displays, demand response thermostats, a web portal, and investments in distributed energy resources, distribution, and substation automation. The project concludes in 2014.	IEE Smart Meter Q1 2012 Survey; KCP&L Smart Grid Presentation
Madison Gas & Electric	WI	5,100	5,900	MGE is installing a small scale smart grid network , including 5,100 meters, EV charging stations, and in-home management systems.	IEE Smart Meter Q2 2013 Survey; SmartGrid.gov
National Grid	MA	15,000	15,000	National Grid's pilot was approved by the DPU in August 2012. 15,000 smart meters have been installed in Worcester, MA for a pilot demonstration.	EIA Form 826
NV Energy	NV	1,205,000	1,300,000	NV Energy has installed 1.2 million meters and are in the final stages of exchanging meters with major account customers. Full deployment of 1.3 million is expected by the end of 2014.	EIA Form 826
Oklahoma Gas & Electric	AR, OK	871,700	871,700	OG&E has fully installed 871,708 meters: 804,078 in Oklahoma, and 67,630 in Arkansas. Residential customers in Oklahoma can sign up for a TOU-CPP rate plan as part of the SmartHours program.	IEE Smart Meter Survey Q1 2012; SmartGrid.gov
Oncor	TX	3,302,000	3,302,000	Oncor has fully deployed 3,302,181 smart meters across its service territory.	EIA Form 861; PUCT Project 36157
Pacific Gas & Electric	CA	5,140,000	5,140,000	PG&E has deployed 5.14M meters and completed its SmartMeter Project on December 31, 2013. Customers with smart meters can participate in PG&E's SmartRate plan, a voluntary critical peak pricing (CPP) rate plan that will help manage system load during hot summer days, and receive EnergyAlerts which notify customers of when they are moving into higher-priced electricity tiers.	IEI Smart Meter Survey Summer 2014
PECO Energy Company	PA	1,227,000	1,600,000	PECO has installed 1,226,665 smart meters, and has moved up its full deployment timeline by five years, indicating 1.6M meters will be installed by the end of 2014.	EIA Form 826
PEPCO Holdings, Inc.	DC, DE, MD	1,357,000	1,360,000	PHI subsidiary Delamarva Power has reached full deployment in Delaware with 315,000 meters installed; Pepco has reached full deployment in the District of Columbia with 279,000 meters installed; and, Pepco and Delmarva Power in Maryland has reached full deployment with 763,000 meters installed. There is no active AMI project in New Jersey.	IEI Smart Meter Survey Summer 2014

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Portland General Electric	OR	841,000	841,000	PGE's smart meter program was approved by the commission in 2008; full deployment was completed by the fall of 2010.	EIA Form 826;
PPL	PA	1,438,000	1,438,000	PPL is in compliance with PA Act 129 and has fully deployed 1,438,000 smart meters in its service territory. The PA electric distribution companies are engaged in a collaborative process to develop standards and formats for electronic communication of meter data and access by customers and third parties.	IEI Smart Meter Survey Summer 2014; PA Docket No. M-2009-2092655
San Diego Gas & Electric	CA	1,406,000	1,406,000	SDG&E has fully deployed over 1.4M meters across its service territory. SDG&E is using its Itron meters for bill/usage alerts, demand response, and remote connect/disconnect, among other uses.	IEE Smart Meter Survey Q2 2013
Southern California Edison	CA	4,990,000	5,001,000	SCE has deployed roughly 5 million smart meters. Additional deployments are scheduled through 2015 to accommodate population growth. SCE's SmartConnect program uses the meters to offer Critical Peak Pricing (CPP) and Peak Time Rebate (PTR) rates to customers with enabling technology.	EIA Form 826
Southern Company	AL, FL, GA, MS	4,288,000	4,470,000	Southern Company's Georgia Power, Alabama Power, and Gulf Power (FL) are fully deployed. Georgia Power reached full deployment in 2012 and has 2,395,786 meters, Alabama Power reached full deployment in 2010 and has 1,444,882 meters. Gulf Power reached full deployment in 2012 and has 441,008 meters. Mississippi Power has installed 6,716 meters and is awaiting approval from the PSC for full deployment of 188,660 by 2018.	IEI Smart Meter Survey Summer 2014
Texas New Mexico Power	TX	162,300	240,000	In July 2011, TNMP received PUCT approval for full deployment of 240,000 meters in Texas by 2016. It is using Itron meters to facilitate outage detection/restoration and remote connect/ disconnect.	IEE Smart Meter Survey Q2 2013; PUCT Project 39772
United Illuminating	CT	145,300	350,000	United Illuminating has installed roughly 145,300 of its projected 350,000 smart meters. The company is considering expanding its use of IBM meters to natural gas customers as well.	EIA Form 826;
Unitil	MA, NH	104,000	104,000	Unitil has fully deployed 104,000 smart meters across its service territory around Concord, NH and Fitchburg, MA. It has used this technology to, among other things, implement a TOU pricing pilot.	IEE Smart Meter Q2 2013 Survey

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Westar Energy	KS	62,000	132,000	Westar piloted smart meters in its SmartStar project in Lawrence, KS and given the results is deploying meters to additional customers. Currently, Westar has 62,000 smart meters installed with another 30,000 planned by year end 2014 and an additional 40,000 planned for following year. In total, 132,000 smart meters will be installed by year end 2015.	IEI Smart Meter Survey Summer 2014
Xcel Energy	CO	23,700	23,700	Xcel Energy has completed deployment of its pilot project in Boulder, CO, as part of its SmartGridCity initiative. It has deployed 23,000 residential meters and 700 commercial meters. The utility initially planned to install 50,000 meters, but was forced to decrease the deployment due to cost overruns.	EIA Form 826
Other Investor-Owned Utilities	10 States	193,800	2,141,500	Limited deployments in 10 states by multiple operating companies account for 193,800 smart meter installations.	IEI Smart Meter Survery Summer 2014; EIA Form 826; SmartGrid.gov
Total as of July 2014		43,115,000	60,126,000		

Smart Meter Installations and Projected Deployments by Municipal and Cooperative Utility

Utility	State	Meters Installed	Target Number of Meters	Notes	Resources
Austin Energy	TX	418,900	418,900	Austin Energy's smart meter program was approved in 2008, and reached full deployment of 418,900 in 2009.	IEE Smart Meter Survey Q1 2012
CPS Energy	TX	40,000	707,000	CPS intends to install 700,000 smart meters by 2018. Its initial 40,000 meter pilot, which started in 2011, is complete. Phase two of the deployment will begin in 2014.	EIA Form 826
Los Angeles Department of Water and Power	CA	52,000	52,000	Los Angeles DWP installed 52,000 smart meters as part of its Smart Grid L.A demonstration project. Based on the success of the demonstration project, involving less than 5% of LADWP customers, the utility will consider replacing all existing meters with smart meters.	EIA Form 826; LA DWP Smart Grid L.A. website
JEA	FL	64,800	64,800	After an initial dynamic pricing pilot for 3,000 customers, JEA has now installed over 40,000 smart meters.	EIA Form 826
Nebraska Public Power District	NE	47,400	68,500	NPPD is in the process of installing smart meters throughout the state. 68,500 smart meters will be installed by 2015.	EIA Form 826
Sacramento Municipal Utility District	CA	617,500	617,500	SMUD completed full deployment of smart meters within its service territory in 2012. The overall smart grid plan includes dynamic pricing, 100 EV charging stations, and 50,000 demand response controls.	SmartGrid.gov
Salt River Project	AZ	866,000	1,000,000	Salt River Project has currently installed over 860,000 smart meters, and has scheduled to have 1M meters installed by 2013.	EIA Form 826
Tacoma Public Utilities	WA	18,100	152,000	Tacoma Public Utilities currently has over 18,000 smart meters installed and intends to fully deploy over 150,000 meters.	EIA Form 826
Tennessee Valley Authority	TN, MS	606,355	606,355	TVA currently has over 559,000 meters installed.	EIA Form 826
Other Coops and Municipal Utilities	44 States	4,231,945	6,186,945	Over 4M meters have been installed by other municipal utilities, cooperatives, and non-IOU electric distribution companies, with plans to deploy about 5.7M. These electricity providers operate in 45 states.	EIA Form 826; SmartGrid.gov
Total as of July 2014		6,963,000	9,874,000		

Smart Meter Installations by Utility Type and State (July 2014)

State	IOU Smart Meters Installed	Municipal and Cooperative Smart Meters Installed	Total
AK	-	13,267	13,267
AL	1,491,034	-	1,491,034
AR	69,055	236,599	305,654
AZ	1,061,444	1,000,316	2,061,760
CA	11,536,696	943,038	12,479,734
CO	119,949	122,177	242,126
CT	145,272	24,183	169,455
DC	279,000	-	279,000
DE	315,000	11,982	326,982
FL	5,140,843	473,857	5,614,700
GA	2,460,139	722,011	3,182,150
HI	30	29,629	29,659
IA	1,000	3,104	4,104
ID	495,000	31,343	526,343
IL	400,000	58,698	458,698
IN	21,805	17,052	38,857
KS	76,000	-	76,000
KY	41,000	66,474	107,474
LA	306,292	75,730	382,022
MA	44,119	23,043	67,162
MD	1,878,000	-	1,878,000
ME	743,914	-	743,914
MI	1,573,482	-	1,573,482
MN	8,030	52,716	60,746
MO	14,000	17,773	31,773
MS	6,829	415,126	421,955

State	IOU Smart Meters Installed	Municipal and Cooperative Smart Meters Installed	Total
MT	41	6	47
NC	223,209	279,488	502,697
ND	-	71,153	71,153
NE	-	58,788	58,788
NH	75,000	83,326	158,326
NJ	-	-	-
NM	-	19,262	19,262
NV	1,204,727	22,531	1,227,258
NY	4,100	20,581	24,681
OH	1,017,200	37,600	1,054,800
OK	850,953	103,464	954,417
OR	858,352	38,511	896,863
PA	2,687,162	11,554	2,698,716
RI	-	201	201
SC	65,771	122,386	188,157
SD	68,067	55,007	123,074
TN	-	559,430	559,430
TX	6,772,370	718,739	7,491,109
UT	-	19,983	19,983
VA	236,053	153,332	389,385
VT	260,600	44,864	305,464
WA	16,499	18,215	34,714
WI	471,919	-	471,919
WV	1,140	-	1,140
WY	42,698	24,959	67,657
Multi-state	30,726	161,749	192,475
Total as of July 2014	43,114,520	6,963,247	50,077,767

About the Edison Foundation Institute for Electric Innovation

The Edison Foundation Institute for Electric Innovation (IEI) focuses on advancing the adoption and application of new technologies that will strengthen and transform the power grid. IEI's members are the investor-owned electric utilities that represent about 70 percent of the U.S. electric power industry. The membership is committed to an affordable, reliable, secure, and clean energy future.

IEI promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEI also identifies policies that support the business case for the adoption of cost-effective technologies.

IEI is governed by a Management Committee of electric industry Chief Executive Officers. In addition, IEI has a Strategy Committee made up of senior electric industry executives and more than 30 smart grid technology company partners.

Visit us at: **www.edisonfoundation.net**

About The Edison Foundation

The Edison Foundation is a 501(c)(3) charitable organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide. Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people. The Edison Foundation provides knowledge, insight, and leadership to achieve its goals through research, conferences, grants, and other outreach activities.

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The Edison Foundation
INSTITUTE for
ELECTRIC INNOVATION

U.S. DEPARTMENT OF ENERGY

2014 Smart Grid System Report

Report to Congress
August 2014

United States Department of Energy
Washington, DC 20585

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Message from the Assistant Secretary
Office of Electricity Delivery and Energy Reliability

I am pleased to present the *2014 Smart Grid System Report*, which is intended to provide an update on the status of smart grid deployment nationwide, technological developments, and barriers that may affect the continued adoption of the technology. The past few years have seen acceleration in the deployment of digital smart grid sensing, communication, and control technologies that improve electric grid reliability, security, and efficiency. This is in part due to the $9 billion public-private investment in smart grid projects committed through 2015 under the American Recovery and Reinvestment Act of 2009. Along with significant near-term progress, these projects continue to deliver unprecedented data on real-world benefits, costs, and best practices that can inform future investments.

The adoption of smart grid technologies varies across the nation and depends on many factors including state policies, regulatory incentives, load growth, and technology experience levels within utilities. There is a need to share cost, benefit and performance data, as utilities and regulators work to determine the value of the technology and determine appropriate investment strategies. It is essential that the industry effectively shares lessons learned and best practices along the way, especially as new challenges emerge in this transformative time. In addition, the adoption of renewable and distributed energy resources is on the rise; growing interest in resilience and microgrids has resulted from extreme weather events; and the role of utilities is evolving as customers also become energy producers. These future demands will require a faster-acting, flexible, and sophisticated grid that maintains high reliability and efficiency while integrating new capabilities. This report describes the challenges and opportunities that will shape the next several years of grid modernization.

Pursuant to statutory requirements, this report is being provided to the following members of Congress:

- **The Honorable Joseph Biden**
  President of the Senate
  Vice President of the United States of America
- **The Honorable John Boehner**
  Speaker of the House of Representatives
- **The Honorable Barbara A. Mikulski**
  Chairwoman, Senate Committee on Appropriations

- **The Honorable Richard C. Shelby**
  Ranking Member, Senate Committee on Appropriations
- **The Honorable Harold Rogers**
  Chairman, House Committee on Appropriations
- **The Honorable Nita M. Lowey**
  Ranking Member, House Committee on Appropriations
- **The Honorable Dianne Feinstein**
  Chairman, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations
- **The Honorable Lamar Alexander**
  Ranking Member, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations
- **The Honorable Mike Simpson**
  Chairman, Subcommittee on Energy and Water Development
  House Committee on Appropriations
- **The Honorable Marcy Kaptur**
  Ranking Member, Subcommittee on Energy and Water Development
  House Committee on Appropriations
- **The Honorable Fred Upton**
  Chairman, House Committee on Energy and Commerce
- **The Honorable Henry Waxman**
  Ranking Member, House Committee on Energy and Commerce
- **The Honorable Ed Whitfield**
  Chairman, Subcommittee on Energy and Power
  House Committee on Energy and Commerce
- **The Honorable Bobby L. Rush**
  Ranking Member, Subcommittee on Energy and Power
  House Committee on Energy and Commerce
- **The Honorable Mary Landrieu**
  Chairwoman, Senate Committee on Energy and Natural Resources

- **The Honorable Lisa Murkowski**
  Ranking Member, Senate Committee on Energy and Natural Resources

If you have any questions or need additional information, please contact me or Mr. Christopher Davis, Principal Deputy Assistant Secretary for Congressional Affairs, at (202) 586-5450 or Mr. Joe Levin, Associate Director of External Coordination in the Office of the CFO at 202-586-3098.

Sincerely,

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

Figure 1. Smart grid technologies are being applied across the electricity system, including transmission, distribution and customer-based systems

Source: Courtesy of Florida Power & Light Company

Executive Summary

The U.S. electric grid is undergoing significant transformation from the application of digital technologies as a result of policies encouraging the growth of renewable and distributed energy resources, emphasis on resilience due to extreme weather events, and increasing involvement of electricity customers and businesses in both managing and producing energy. Since 2010, large public and private investments totaling over $9 billion made under the American Recovery and Reinvestment Act of 2009 (ARRA) have advanced smart grid technology deployments, providing real-world data on technology costs and benefits along with best practices. Deployments are delivering results, where we are seeing improvements in grid operations, energy efficiency, asset utilization, and reliability.

The smart grid involves the application of advanced communications and control technologies and practices to improve reliability, efficiency, and security which are key ingredients in the ongoing modernization of the electricity delivery infrastructure. Figure 1 illustrates where smart grid technologies are being applied across the electric grid, including transmission, distribution, and customer-based systems.

Progress in smart grid deployment is being made in many areas:

- Advanced metering infrastructure (AMI), which comprises smart meters, communication networks, and information management systems, is enhancing the operational efficiency of utilities and providing electricity customers with information to more effectively manage their energy use. An estimated 65 million smart meters will be installed nationwide by 2015, accounting for more than a third of electricity customers.

- Customer-based technologies, such as programmable communicating thermostats for residential customers and building energy management systems for commercial and industrial customers, work with smart meters to make energy usage data accessible and useful to customers. At Oklahoma Gas and Electric, the coupling of AMI with time-based rates and in-home displays is reducing peak demand to an extent that will potentially enable the utility to defer the construction of a 170 MW peaking power plant. Also, utility and state efforts are addressing the privacy concerns of electricity customers, and businesses are offering new energy management services to customers.

- The integration of sensing, communications, and control technologies with field devices in distribution systems is improving reliability and efficiency. Smart grid applications enable utilities to automatically locate and isolate faults to reduce outages, dynamically optimize voltage and reactive power levels for more efficient power use, and monitor asset health to guide maintenance. For example, the City of Chattanooga was able to instantly restore power to half of the residents affected by a severe windstorm on July 5, 2012 (from 80,000 affected customers to less than 40,000 within 2 seconds) using automated feeder switching. In addition, utilities are upgrading and integrating computer systems to improve and merge grid operations and business processes.

- The deployment of advanced sensors and high-speed communications networks on transmission systems is advancing the ability to monitor and control operations at high-voltage substations and across the transmission grid. For example, synchrophasor technology provides data 100 times faster than conventional technology from the placement of phasor measurement units (PMUs) throughout the transmission grid and permits grid operators to identify and correct for system instabilities, such as frequency and voltage oscillations, and operate transmission lines at greater capacities. In one application, the Western Electricity Coordinating Council has determined that it can increase the energy flow along the California-Oregon Intertie by 100 MW or more using synchrophasor data for real-time control—reducing energy costs by an estimated $35 million to $75 million over 40 years without any new high-voltage capital investments. Public-private ARRA investments in synchrophasor technology will result in more than 1,000 networked PMUs deployed by 2015, up from 166 in 2009.

Progress is also being made in instituting cybersecurity measures and advancing interoperability among devices and systems. Government and industry are actively developing tools, guidance, and resources necessary to develop robust cybersecurity practices within utilities. Government and industry experts are also advancing interoperability through standards development, testing, and supporting policies. Continued coordination for standards and independent testing is needed to streamline new technology integration.

The rate of smart grid technology adoption varies across the nation and depends largely on state policies, regulatory incentives, and technology experience levels within utilities. It will take time to adequately assess and validate the costs and benefits of the technology for utilities, their customers, and society. Improved efficiencies in operations and energy use and in reliability are already being realized where smart grid technology is deployed. Hence, sharing effective deployment practices and methods for valuation across the industry and government jurisdictions will remain an important task.

In addition, smart grid technologies are required as new demands on the electricity delivery system are requiring that it function in ways for which it was never originally designed. Traditionally, utilities managed a fairly predictable system in terms of the supply and demand of electricity with one-way flow from large, centralized generation plants to customers. The modern grid is becoming much more complex and will need to handle:

- Variable power from renewable energy resources that are located within transmission and distribution systems,
- Two-way power flows from distributed energy resources and other assets, such as rooftop solar panels, electric vehicles, and energy storage devices,
- The active management and generation of energy by utility customers and businesses other than utilities, and
- Advanced communications and control technologies with "built-in" cybersecurity protections.

The integration of these technologies and practices will require a faster-acting, more flexible grid and new business and regulatory approaches. There will be a need to maintain reliability, especially as consumers and third-parties become more involved in the management and generation of electricity. Also, long-term investment strategies will be needed to effectively balance competing demands for reliable, efficient, secure, and affordable electricity delivery.

2014 Smart Grid System Report

Table of Contents

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I. Legislative Language

The U.S. Department of Energy (DOE) has developed this biennial report to Congress in compliance with legislative language set forth in Section 1302 of the Energy Independence and Security Act of 2007, wherein it directs the Secretary of Energy, through the Assistant Secretary of the Office of Electricity Delivery and Energy Reliability, to:

> *"...report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. The report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid"* (42 USC Section 17382).

This report is designed to provide an update on the status of smart grid deployments nationwide, technological developments, and barriers that may affect the continued adoption of the technology. The report has been reviewed by the Federal Smart Grid Task Force, a group of 11 agencies, chaired by DOE, that meets to coordinate federal smart grid activities and includes representatives from the National Institute of Standards and Technology (NIST), the Federal Energy Regulatory Commission (FERC), and the U.S. Department of Homeland Security.

II. Introduction

The U.S. electric grid is undergoing significant transformation from the introduction of digital technologies, policies encouraging the growth of renewable and distributed energy resources, and increasing engagement of electricity customers and businesses in both managing and producing energy. Since the writing of the last biennial *Smart Grid System Report* in 2012, large public and private investments made under the American Recovery and Reinvestment Act of 2009 (ARRA) have advanced smart grid technology deployments, providing real-world data on technology costs and benefits along with best practices. Deployments are delivering results, where we are seeing improvements in grid operations, energy efficiency, asset utilization, and reliability.

The smart grid involves the application of digital technologies and information management practices and is a core ingredient in the ongoing modernization of the electricity delivery infrastructure. The rate of smart grid technology adoption varies across the nation and depends largely on state policies, incentives, and technology experience levels. Today, we see a growing number of utilities that have begun successful smart grid deployments and are now grappling with a new set of technical, regulatory, and financial challenges that mark an industry undergoing change. In many cases, utilities have begun with small-scale tests and pilot programs before moving to larger-scale deployments to appropriately evaluate the technology and ensure management and regulatory approval for continued investment.

To help characterize the current smart grid environment, this report provides a concise overview of the following:

- **Smart Grid Deployment Status:** Smart grid deployment progress and emerging benefits, specifically in advanced metering infrastructure, customer systems, transmission, and distribution.
- **Cross-cutting Technologies:** Government and industry activities to ensure progress in communications, cybersecurity, and interoperability.
- **Trends and Challenges Shaping Future Deployment**: An evolving understanding of technology costs and benefits, the integration of distributed energy assets and resources, and changing business and regulatory approaches that meet requirements for a more sophisticated, reliable grid involving greater participation by customers and third parties in energy management and generation.

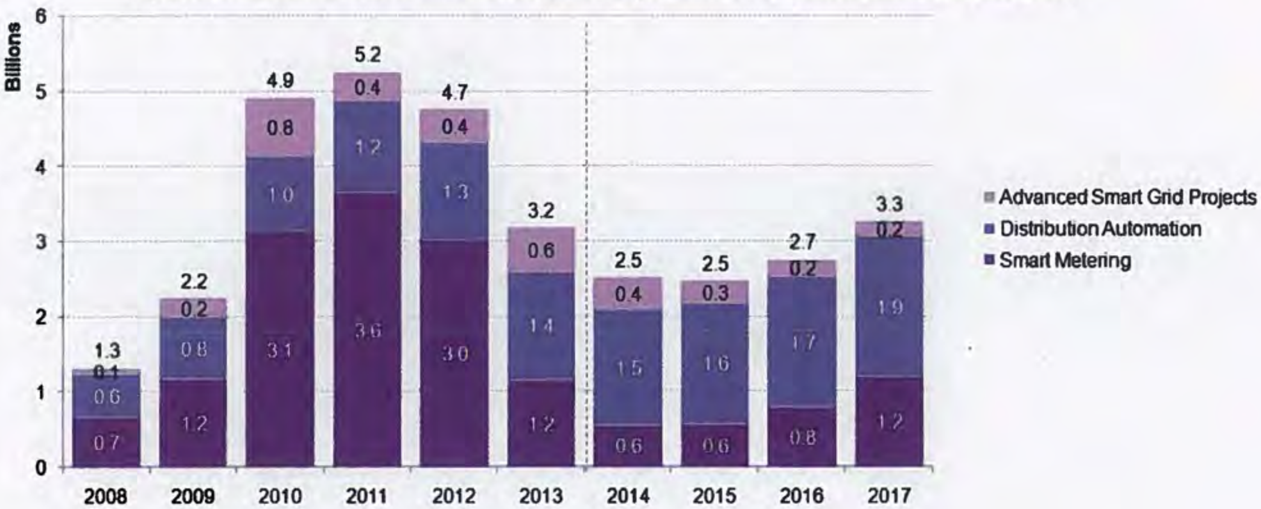
III. Smart Grid Deployment Status

Smart grid systems consist of digitally based sensing, communications, and control technologies and field devices that function to coordinate multiple electric grid processes. A more intelligent grid includes the application of information technology systems to handle new data and permit utilities to more effectively and dynamically manage grid operations. The information provided by smart grid systems also enables customers to make informed choices about the way they manage energy use.

The electricity industry spent an estimated total $18 billion for smart grid technology deployed in the United States during the 4-year period of 2010 through 2013 (BNEF 2014). Smart grid investments under the ARRA accounted for nearly half—approximately $8 billion—during the same time frame (DOE 2014a).

As shown in Figure 2, annual smart grid spending nationwide hit a high of $5.2 billion in 2011, coincident with peak deployment spending from the cost-shared ARRA projects, and is now declining toward an annual level of $2.5 billion expected in 2014 (BNEF 2014). The decline in investment is largely due to reduced spending for advanced metering infrastructure (AMI), which was heavily influenced by ARRA funding. However, industry analysts expect annual spending on distribution system smart grid technologies to gradually increase from $1.2 billion yearly in 2011 to $1.9 billion in 2017, with decreased spending ($3.6 billion in 2011 down to $1.2 billion in 2017) for AMI (BNEF 2014). In comparison, total capital investments by investor-owned utilities (in 2012 dollars) in electricity delivery systems averaged $8.5 billion annually for transmission system upgrades and $17 billion annually for distribution system upgrades from 2003–2012 (EIA 2014).

Figure 2. Baseline U.S. Smart Grid Spending 2008-2017 (Historical and Forecast)



Source: BNEF 2014

As of March 2013, joint federal and private expenditures under ARRA totaled $6.3 billion from the 99 Smart Grid Investment Grants (SGIG), which represent the largest portion of ARRA investments. Between 2009 and 2015, DOE and the electricity industry will jointly invest more than $7.9 billion in the SGIG projects, which involve more than 200 electric utilities and other organizations to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid operations, benefits, and utility impacts (DOE 2013a). In the same time frame, an additional $1.6 billion in cost-shared funding will support energy storage demonstrations and regional demonstrations to assess emerging smart grid concepts (DOE 2014a). Another $100 million in federal funding has supported 52 smart grid workforce training projects in the same time frame (DOE 2014a).

Estimates of overall spending required to fully implement the smart grid vary. The Electric Power Research Institute (EPRI) estimates that spending of $338-$476 billion over a 20-year period is required to fully implement the smart grid, including preliminary estimates of $82-$90 billion for transmission systems and substations, $232-$339 billion for distribution systems, and $24-$46 billion for consumer systems (EPRI 2011). The Brattle Group estimates that total transmission and distribution investment may need to reach nearly $900 billion (nominal) by 2030 to meet forecast electricity demand (Brattle Group 2008).

To get a more detailed understanding of current smart grid status, the following sections provide an overview of deployment in four key technology application areas—AMI, customer systems, distribution, and transmission—along with emerging benefits from recent deployments.

Advanced Metering Infrastructure (AMI)

Technology Adoption

AMI encompasses smart meters, the communications networks that transmit meter data to the utility at regular intervals (hourly or shorter), and the utility office management systems (such as meter data management systems) that receive, store, and process the meter data. Usage data from AMI systems can also be sent directly to building energy management systems, customer information displays, and smart appliances. About 46 million smart meters are in place in the United States today (IEE 2013). An estimated 65 million smart meters will be installed nationwide by 2015 (IEE 2012), accounting for more than a third of the approximate 145 million U.S. meters (of all types) in use today (EIA 2013b; FERC 2013). ARRA project deployments will contribute more than 16 million smart meters when they are complete in 2015 (DOE 2013a).

Nearly 75% of AMI installations to date have occurred in only 10 states and D.C., where on average more than 50% of customers now have smart meters (DOE 2013b). AMI investments have been driven largely by state legislative and regulatory requirements for AMI, ARRA funding, and by specific cost recovery mechanisms in certain regions. AMI requires significant investment, and adoption barriers remain for utilities where the business case for AMI is not clear and where prior investments in older metering technology (such as automated meter reading) may present stranded costs. Concerns over meter safety, costs, and consumer privacy protections are being addressed, and enhanced consumer education is a key part of the solution.

Benefits

AMI enables a wide range of capabilities that can provide significant operational and efficiency improvements to reduce costs, including:

- Remote meter reading and remote connects/disconnects that limit truck rolls.
- Tamper detection to reduce electricity theft.
- Improved outage management from meters that alert utilities when customers lose power.
- Improved voltage management from meters that convey voltage levels along a distribution circuit.
- Measurement of two-way power flows for customers who have installed on-site generation such as rooftop photovoltaics (PV).
- Improved billing and customer support operations.

Real benefits, such as improved operational efficiencies, are being observed where AMI is deployed. For example, Central Maine Power Company has deployed smart meters to its 625,000 customers and has reduced its meter operations costs by more than 80% with annualized savings of about $6.7 million—due largely to fewer service calls, resulting in about 1.4 million fewer annual vehicle miles traveled (DOE 2013a). Projects under ARRA estimate operational cost savings from 13% to 77%, depending on the nature of legacy systems, the particular configuration of the utility service territory, system integration requirements, and customer densities per line mile (DOE 2013a).

Customer-Based Systems

Technology Adoption

AMI technologies can provide customers with detailed information and greater control over energy usage when coupled with residential customer technologies—including programmable communicating thermostats, web portals, and in-home displays—and business and industrial technologies that include building or facility energy management systems. Customer-based systems enable and support demand-response and time-based rate programs that promote more efficient customer energy use, in alignment with widespread federal, state, and local energy-efficiency policies.

Commercial and industrial markets for energy management systems are more established than residential markets, yet they are all expected to grow significantly as advanced technology and greater access to information permit customers to more effectively manage their electricity use and save money. ARRA projects mostly targeted small-scale, residential deployments of technologies and pricing programs. ARRA project recipients installed 623,000 customer-based devices by October 2013—a small percentage of customers when compared to the 14.2 million smart meters installed at that time (DOE 2013a).

The advancement of AMI and customer-based devices improves the effectiveness of time-based rate programs—including time-of-use (TOU) rates, critical peak pricing (CPP), critical peak rebates (CPR), and variable peak pricing (VPP)—where feedback to customers about their energy usage and better control technology encourages consumers to adjust their consumption based on price. This results in reductions in peak or overall electricity use. Time-based rate programs are growing—FERC estimates 2.1 million residential customers participated in 2012, nearly double the 2010 amount—but still reach only a small fraction of total customers (FERC 2012). Pilot programs conducted under ARRA projects aimed to quantify potential savings under time-based rates and determine customer preferences; the Sacramento Municipal Utility District, for example, is shifting all customers to a default time-of-use rate by 2018 based on the success of their pilot program (DOE 2013a, SMUD 2013).

While the application of customer-based technologies and time-based rate programs generally lags the deployment of smart meters, many utilities are beginning to actively engage their customers as smart meters and AMI make new information on electricity usage available to consumers (DOE 2013d). However, the availability of this personal electricity usage data has raised consumer concern over privacy and protection of their individual data. NIST, the Smart Grid Interoperability Panel (SGIP), and several states are addressing privacy policies and practices that more adequately secure personal data. At least eight states have now adopted rules governing third-party access to customer usage data (FERC 2013).

In addition, industry organizations are now working with NIST, DOE, and their states to make smart meter energy usage data available to customers in a standard, usable format. Standardizing the format of usage information paves the way for new customer services, such as energy management cell phone applications and web tools or home energy-efficiency reports. DOE, NIST, and the White House Office of Science and Technology Policy (OSTP) launched Green Button, now an industry-led effort to simplify and standardize smart meter data and provide it in a secure and easy-to-read format. Currently, 48 electricity suppliers committed to provide Green Button data to more than 59 million homes and businesses (OSTP 2013). Some utilities have partnered with third-party service providers to develop customer "apps" that use energy use data to alert customers to potential cost savings from efficiency improvements or alternative rate programs (FERC 2013). Based on a December 2013 Presidential Memorandum, federal agencies are now required to use Green Button, where available (OSTP 2013).

Benefits

Deploying AMI with customer-based systems and time-based rates can reduce electricity demand during peak periods to improve asset utilization and defer new capacity needs. Peak demand reductions can exceed 30% depending on the rate design and type of customer system (DOE 2013a). For example, Oklahoma Gas & Electric (OG&E) decided to offer a VPP/CPP rate to all its customers based on pilot results that reduced peak demand by at least 70 megawatts (MW) in one year. With a current goal of achieving 20% participation, OG&E hopes to reduce peak power requirements by 170 MW and thereby defer the construction of a peaking power plant planned for 2020 (DOE 2013a). Ongoing efforts to evaluate this and other utility programs must continue to explore the factors that determine the potential magnitude of savings associated with customer-based technologies and the relevant design considerations that affect customer response, acceptance, and retention.

Distribution System Upgrades

Technology Adoption

Grid modernization within the distribution system includes the deployment of sensor, communications, and control technologies that, when integrated with field devices within circuits, permit highly responsive and efficient grid operations. Smart distribution technologies enable new capabilities to automatically locate and isolate faults using automated feeder switches and reclosers, dynamically optimize voltage and reactive power levels, and monitor asset health to effectively guide the maintenance and replacement of equipment.

Industry analysts indicate that investments in distribution automation technology are now exceeding those in smart metering and will continue to grow (BNEF 2014). More than half of the ARRA projects are deploying distribution automation technologies across 6,500 circuits, representing about 4% of the estimated 160,000 U.S. distribution circuits (DOE 2013a). ARRA projects have invested about $2 billion as of March 2013 in distribution automation to deploy field devices, such as automated feeder switches and capacitors, and to integrate them with utility systems that manage data and control operations (DOE 2013a).

In addition, utilities are beginning to upgrade and integrate their computer systems for managing distribution grid operations including meter operations and customer support, outage management, automated operations within substations and distribution circuits, and asset management. The impetus for advancing and integrating distribution management systems comes from the significant inflow of new data from field devices, such as smart meters and sensors on equipment and lines that provide utilities with enhanced understanding of grid status and new capabilities for planning and operations. As utilities begin to apply this information, increased coordination between departments is becoming possible along with greater collaboration between field operations and business processes, including customer interactions. In addition, advanced distribution systems allow greater degrees of automation, including both centralized and distributed control schemes.

Emerging technologies, such as energy storage and solid-state (power electronics) devices are also being introduced to better manage power flows. These devices along with more sophisticated information management and control systems are needed to provide the flexibility and reliability required to manage distributed energy resources (with two-way flows of power) and to support resilient operations that might incorporate, for example, automated switching and microgrids.

Benefits

Distribution automation technologies can enhance reliability and resilience while improving operational efficiencies. ARRA projects that deployed automated feeder switches are reporting up to 56% shorter and 11%–49% less frequent outages, with fewer affected customers. The City of Chattanooga was able to instantly restore power to half of the residents affected by a severe windstorm (a derecho) on July 5, 2012 (from 80,000 affected customers to less than 40,000 within 2 seconds) using automated feeder switching; beyond avoiding outage damages to residents and businesses, the utility saved $1.4 million as it was able to restore power more quickly (DOE 2013a).

Distribution automation technology can also improve energy efficiency. Many utilities are now beginning to apply smart grid technologies to dynamically optimize voltage and reactive power levels in certain distribution circuits. Where applied specifically to achieve lower voltage levels for conservation voltage reduction (CVR) purposes, smart devices are achieving on average 2.2% energy reductions and 1.8% peak load reductions per distribution circuit (DOE 2014c). Several ARRA projects are applying CVR within their distribution systems; one utility is expecting to obtain 200 MW in peak demand reduction by automating capacitor banks on their lines (DOE 2012a). Extrapolating from the results observed in CVR projects, it is estimated that significant energy efficiency gains are possible—by as much as 6,500 MW of peak demand reductions nationally (PNNL 2010). Yet many utilities still face a lack of incentives for applying CVR practices and regulatory cost recovery challenges, as application of the technology results in reduced utility revenues.

Transmission System Upgrades

Technology Adoption

Transmission system modernization includes the application of digitally based equipment to monitor and control local operations within high-voltage substations and wide-area operations across the transmission grid. Synchrophasor technology, which uses devices called phasor measurement units (PMUs) to measure the instantaneous voltage, current, and frequency at substations, is being deployed to enhance wide-area monitoring and control of the transmission system. Synchrophasor data are delivered in real time to sophisticated software applications that permit grid operators to identify growing system instabilities, detect frequency and voltage oscillations, and see when the system exceeds acceptable operating limits—allowing them to ultimately correct for disturbances before they threaten grid stability. Additionally, synchrophasor data enable improved coordination and control of generators, including renewable resources (e.g., wind power plants), as they interact with the transmission grid.

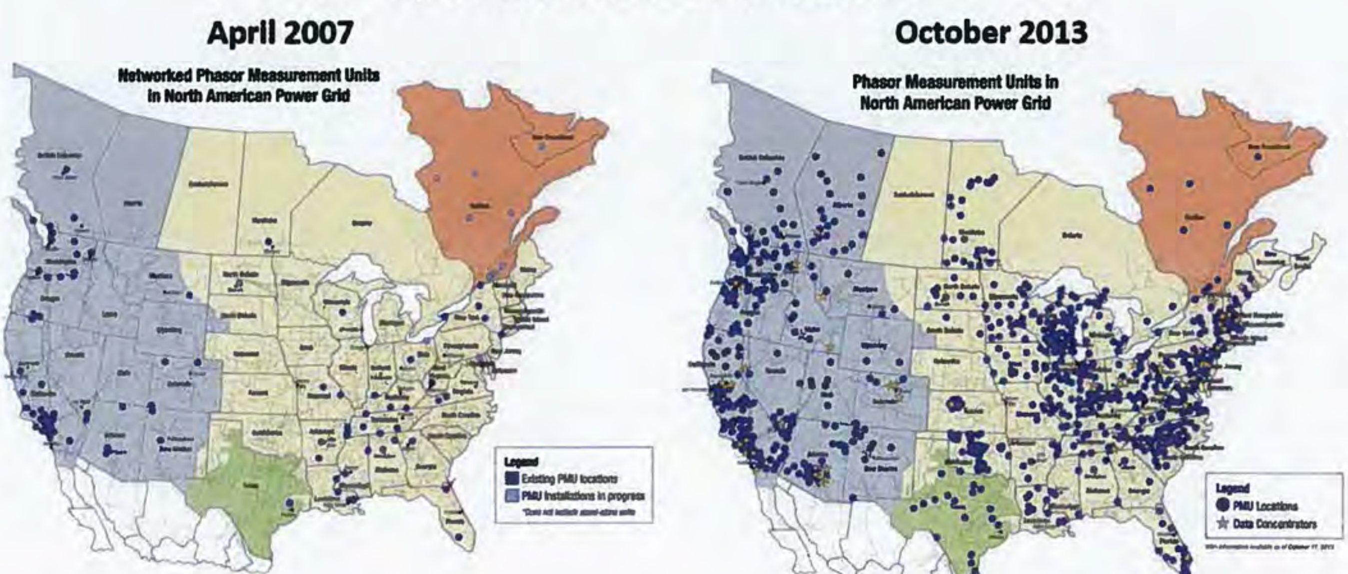
Since the 2003 Northeast blackout investigation revealed inadequate situational awareness for grid operators, utilities have increasingly deployed synchrophasors to provide real-time, wide-area grid visibility. Synchrophasors can provide time-stamped data 30 times per second or faster, which is 100 times faster than conventional supervisory control and data acquisition (SCADA) technology (DOE 2013c). Technology deployments includes phasor data concentrators that combine, time-align, and verify data from multiple PMUs; communication networks that deliver synchrophasor data; and information management, visualization, and other analytical tools to process synchrophasor data and support new data applications for grid operators.

The ARRA projects include a total public-private investment of about $330 million that will increase U.S. synchrophasor coverage from 166 networked PMUs in 2009 to more than 1,000 networked PMUs deployed by the 2014-2015 time frame (DOE 2013c). Progress in synchrophasor deployment is shown in Figure 3. As PMUs are deployed, transmission owners and reliability coordinators are working to develop suitable applications, build out high-speed data networks, improve data quality, and share synchrophasor data between transmission owners and operators across large regions.

Benefits

Utilities are already using synchrophasor data to improve the engineering models that simulate and explain how individual power plants and large system interconnections perform. Engineers design and operate the grid using mathematical models that predict how a power plant or other transmission assets will operate under various normal and abnormal conditions, and use these models to set grid operating limits and manage real-time operations and contingencies. These models are intended to prevent the high costs of potential power plant damage or large regional blackouts. Synchrophasors can provide historical data on actual grid performance under a variety of conditions to improve models, along with real-time data on current system operating conditions to allow operators to safely operate the grid closer to operational limits.

Figure 3. PMU Locations in 2007 and 2013



For example, the Bonneville Power Administration will use synchrophasor data as the basis of automated controls that will increase the operational capacity of the California-Oregon Intertie (COI). The 4,800-MW COI runs between the Pacific Northwest and northern California and frequently operates below capacity due to various system constraints. The COI energy flows can be increased by 100 MW or more using synchrophasors to take real-time control actions as needed—reducing energy costs by an estimated $35 million to $75 million over 40 years without any new high-voltage capital investments (WECC 2013).

In another example, the Bonneville Power Administration used historical synchrophasor data on the actual performance of the 1,100 MW Columbia Nuclear Generating Station to validate and calibrate the plant's dynamic model, negating the need to take the plant offline for manual tests every five years to meet reliability criteria standards requirements. Energy Northwest, the organization that owns and operates the power plant, saved up to $700,000 from not having to take the plant offline for model validation (WECC 2012). More importantly, the model for the plant's behavior has been significantly improved, resulting in more accurate predictions of power system performance and more precise operating limits that are neither too conservative nor too optimistic.

Cross-Cutting Technology Efforts

Communications Systems

Utilities are applying various types of communications systems to meet their needs with respect to bandwidth, latency, reliability, and security.

The application of smart grid technologies—such as AMI, distribution automation, customer systems, and synchrophasors—poses increased data communication challenges for legacy utility systems. To meet these challenges, utilities are investing in a range of technologies with varying bandwidth, latency, reliability, and security characteristics. Each smart grid application has unique bandwidth and latency requirements, often requiring utilities to use a combination of different communications technologies. These technologies can be deployed over either an existing public network (e.g., cellular and radio frequency [RF] mesh), which is often economical and readily available, or a licensed private network (e.g., communication over fiber, licensed RF mesh, or microwave links). Cost, reliability, performance, and technology longevity impact a utility's decision-making on communications technologies.

While some utilities implement private communications networks, lower costs and increased technical support are causing public networks to gain momentum for utilities. Recently, public cellular carriers have lowered the per-megabyte cost of AMI communications, making wireless broadband technology (e.g., 2G/3G and 4G LTE networks) more popular with utilities. However, certain applications, such as feeder switches and synchrophasors, require higher speeds than what cellular networks can offer. RF-based mesh networks have emerged as the leading technology for AMI and distribution automation deployments in North America, although fiber-optic cable is also used. Many U.S. municipal utilities also use microwave or Wi-Fi wide-area communications for AMI backhaul and distribution applications. To meet the high-speed, high-security communication needs of its utilities, the Western Electricity Coordinating Council is using a secure, fiber-optic, wide-area network—built to the same standard as the nation's air traffic control network—that sends PMU data in less than 30 milliseconds to grid control centers.

Cybersecurity Measures

Though cybersecurity remains a critical challenge, government and industry are actively developing the tools, guidance, and resources necessary to develop robust cybersecurity practices within utilities.

In response to Executive Order 13636, NIST released the *Framework for Improving Critical Infrastructure Cybersecurity* in February 2014 to offer a prioritized, flexible, repeatable, and cost-effective approach to manage cyber risk across sectors (NIST 2014). This effort built upon NIST's collaborative work with industry to develop the NISTIR 7628 *Guidelines for Smart Grid Cyber Security* (NIST 2010). In the same month, DOE released a second version (1.1) of the Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2), which uses a self-evaluation methodology to help grid operators assess their cybersecurity capabilities and prioritize actions and investments for improvement (DOE 2014b). The ES-C2M2 provides a complementary, scalable tool for NIST Framework implementation. To date, 104 utilities covering 69 million customers have downloaded the ES-C2M2 toolkit. Combined with the Risk Management Process that DOE released in 2012, and upcoming cybersecurity procurement language, utilities now have a holistic view of cybersecurity best practices across business processes (DOE 2012b).

In addition, DOE required each recipient of SGIG funding under ARRA to develop a Cybersecurity Plan that ensures reasonable protections against broad-based, systemic failures from cyber breaches. DOE followed up with extensive guidance on plan implementation, annual site visits to the 99 recipients, and two workshops to exchange best practices. As a result, recipient utilities are instituting organizational changes and leveraging new tools to strengthen organization-wide cybersecurity capabilities.

Advanced technologies with built-in cybersecurity functions are now being developed and deployed across the grid. For example, research funded by DOE has led to advancements in secure, interoperable network designs, which have been incorporated into several products, including a secure Ethernet data communications gateway for substations, a cybersecurity gateway (Padlock) that detects physical and cybersecurity tampering in field devices, and an information exchange protocol (SIEGate) that provides cybersecurity protections for information sent over synchrophasor networks on transmission systems. In addition, the

University of Illinois developed NetAPT, a software tool to help utilities map their control system communication paths, allowing utilities to perform vulnerability assessments and compliance audits in minutes rather than days.

Interoperability

Government and industry experts are actively advancing interoperability through standards development, testing, and supporting policies. Yet solutions often lag industry needs, and continued coordination for standards identification and independent testing is needed to define the rules of the road and streamline new technology integration.

Interoperability is the capability of two or more networks, systems, devices, applications, or components to connect effectively and share information securely with little or no disruption to the system or the operator. Interoperability is an essential enabler of grid modernization, allowing service providers and end users to integrate an expanding number of technology solutions and capabilities while maintaining reliable operations.

NIST formed the public-private Smart Grid Interoperability Panel (SGIP) in 2009 under a new effort to accelerate interoperability. SGIP engaged nearly 800 organizations and 1,900 individuals by 2013, when it became an independent, member-funded organization. Over this period, NIST leveraged the SGIP to develop and update the Framework and Roadmap for Smart Grid Interoperability Standards, which identifies agreed-upon standards and gaps for future development. SGIP actively works to address gaps and vet new standards, and has so far accelerated standards for exchanging energy usage data with consumers (Green Button); defined energy schedules, price, and demand response signals (used in OpenADR); and was instrumental in extending the SEP2 information model (a common vocabulary for messages) to support electric vehicle charging (CSEP).

The challenge is often not a lack of standards, but rather choosing common standards among diverse stakeholders, determining which products support them, and ensuring standards are consistently interpreted across a global marketplace of energy technologies. Even with strong coordination, standards alone do not achieve interoperability. SGIP and industry consortia support independent testing and certification programs that verify the ability of products from multiple technology suppliers to connect and work. Best practices and lessons learned from integration experiences are also being collected to educate the smart grid community and identify new gaps where progress on new standards, guides, and testing can simplify integration and maintenance.

IV. Trends and Challenges Shaping Future Deployment

Smart Grid Technology Valuation is Evolving and Varies Widely across Utilities and Jurisdictions

It will take time to validate the full costs and benefits of smart grid technologies, especially as many utilities begin to leverage new data and information technology (IT) applications that will generate additional value from deployed smart grid systems. Utilities and their state and local regulators have widely varying experience with smart grid technologies and differing views on costs and benefits. As a result, investment decisions and deployment rates are determined at the local level—shaped by individual state energy goals, regulator views on allowable investments, and the level of smart grid maturity and experience at individual utilities. DOE has teamed with EPRI to develop a consistent, step-by-step framework for utilities to estimate project costs and benefits based on past demonstrations (EPRI 2012). This methodology continues to evolve as new performance data emerges and additional benefits are generated by adding enabling technologies to existing smart grid systems. Improving interoperability and systems integration will enable utilities to realize new synergies among smart grid technologies.

The IT and communications infrastructure that support smart grid devices creates capabilities, costs, and integration challenges that are largely new to utilities, and difficult to value. The effort and time needed to integrate new networks and systems is difficult to predict; the lifecycle of digital devices and systems is largely undetermined; and the full range of new functions and operational capabilities will only be realized over time. Utilities do not yet know the extent to which IT and communications infrastructure may need to be upgraded and maintained as technologies evolve. Systems integration issues have challenged many demonstration projects, though several utilities have also realized large operational savings. Those utilities and regions with higher smart grid technology and IT adoption rates are facing the next level of smart grid technical and policy challenges more quickly.

Utilities and regulators are considering new benefit streams for valuing the technology and making investment decisions. For example, some utilities are now providing estimates of avoided *customer* costs of outages, rather than applying the traditional reliability indices (that merely provide the duration and frequency of outages) when submitting cost/benefit analyses of smart grid technology to their regulators. These value-of-service (VOS) estimates help utilities and regulators understand the customer-related and societal benefits of applying automated feeder switching and other system upgrades for improving reliability. This valuation approach will allow utilities and regulators to understand the true costs of power interruptions and help prioritize investments that lead to improved reliability and resilience.

In addition, smart grid technologies are now providing new information that the emerging field of data analytics will tap to achieve new operations and business efficiencies (e.g., in the areas of outage management, asset management, and system planning). Industry analysts predict that the U.S. market for utility data analytics will increase by 33% per year from $215 million in 2011 to $902 million in 2016 (UAI 2012). IT infrastructure and data analysis will enable more utilities to move beyond foundational sensing and communications technology deployments and leverage the smart grid data they produce to improve operations and decision-making.

The increasing severity of weather-related events has sparked a growing interest in modernizing the electric grid to improve both reliability and resilience. With 11 weather events each exceeding $1 billion in damages—including Hurricane Sandy at $65 billion—2012 was the second costliest year (as determined since 1980) for disasters, which included storms, droughts, floods, and wildfires (NOAA 2013). Political support from New York and New Jersey governors for infrastructure hardening and upgrades following Superstorm Sandy in 2012 have since triggered regional utilities to develop billion-dollar investment plans. For example, the Public Service Electric and Gas Company (PSE&G) in New Jersey has proposed the Energy Strong program, which would invest $3.9 billion over 10 years to raise and harden vulnerable substations ($1.7 billion), add smart grid technologies that improve problem detection and response ($454 million), and strengthen or bury distribution lines ($60 million), among other upgrades (PSE&G 2013).

Resilience and sustainability concerns have also increased interest in developing microgrids to provide dedicated power and islanding capabilities (i.e., rapidly connect/disconnect from the surrounding grid) during emergencies. Industry analysts predict North American microgrid capacity may reach almost 6 gigawatts (GW) by 2020, up from 992 MW in 2013 (Navigant 2013). However, optimal grid-to-microgrid interactions and microgrid functions will require more sophisticated, intelligent systems that apply advanced sensing, switching, and control technologies and effectively integrate distribution automation technologies and distributed generation. End-users such as military installations, hospitals, and university campuses with critical needs or favorable economics will likely be early adopters of microgrids.

Integration of Distributed Energy Resources is Transforming the Distribution System

Growing environmental concerns and decreasing technology prices are leading to greater adoption of distributed energy resources (DERs). These include distributed generation (e.g., rooftop solar and combined heat and power), electric vehicles, demand-response practices, and energy storage. DERs account for an extremely small percentage of U.S. generation capacity. However, installations will increase in scale and pace over the next decade (EPRI 2014), particularly in regions where policies and renewable portfolio standards are encouraging and rewarding adoption:

- 29 states, D.C., and two territories have renewable portfolio standards (RPS) that set percentage targets for renewable generation, and 17 states have mandates for solar and other DER (DSIRE 2014).
- 45 states have net metering policies, which credit the energy that consumers produce on site against the utility-provided energy they use (IREC and VSI 2014).
- 7 states, as well as utilities in other states, have established feed-in tariffs, which offer long-term contracts for energy producers with pre-established rates to encourage investment in distributed generation (EIA 2013a).

Subsidies, rebates, tax incentives, and financing incentives also promote DER adoption. Decreasing costs and local incentives for photovoltaic (PV) solar arrays spurred a 41% growth in U.S. adoption in 2013, and installations provided 12.1 GW system-wide by the end of 2013 (SEIA 2014). Non-utility (customer-based) solar arrays added 1,904 MW in 2013 (SEIA 2014) as system costs became competitive with retail power for some consumers (EPRI 2014).

DER adoption will require more fast-acting, finer control of distribution grid operations to integrate variable, intermittent generation resources while maintaining high reliability. The future grid presents a complex set of relationships among new market entrants and third-party power producers with highly distributed energy resources that will need to be optimally managed in real time.

DER technologies are being adopted at different rates across regions. High-adoption states like California, Arizona, New Jersey, and Hawaii (EPRI 2014) are on the frontline to address new challenges from effectively integrating intermittent, variable resources. In Arizona, for example, net metering laws spurred rooftop solar development by providing needed support for solar owners, but resulted in lost revenues for its utilities. As the number of rooftop solar customers increased, the Arizona Public Service Company (a distribution utility) asserted that non-solar customers now had to bear a higher amount of the costs for maintaining the grid—by as much as $1,000 per installed solar system—because such costs are built into the kilowatt-hour (kWh) rate. To ease this cross-subsidization issue, the Arizona Corporation Commission ruled in November 2013 to institute a fixed charge of $0.70 per kW per month (solar systems are rated in kW or MW) for new customers that sign a contract with a solar installer, in addition to their usage rate (ACC Docket 2013).

Also, growing adoption of renewable resources that provide variable power into the grid, like rooftop solar, may require energy storage systems to effectively balance quickly changing patterns of generation and demand. For example, in October 2013 the California Public Utilities Commission (CPUC) established an energy storage target of 1,325 MW for three investor-owned utilities with installations required no later than 2014. The purpose of the CPUC mandate is to optimize the grid (including peak reduction and deferment of upgrades), integrate renewable energy, and reduce greenhouse gases to meet California's goals (CPUC 2013).

The integration of DERs is expected to transform operations at the distribution-system level as customers and new third-party providers become involved in the production and management of electricity. As electricity customers and third-party businesses become more involved in the generation and the intelligent management of electricity, evolution of the grid technology, business models, and regulations will need to occur in a coordinated way (GTM Research 2013). Along with enabling policies, regulations, and interconnection rules, effectively integrating DERs and achieving the full value of a smart grid will require:

- New wholesale and retail business models that consider changing utility/consumer roles and properly value new sources and capacity.
- A more sophisticated grid that deploys advanced communication, control, and automation technologies to enable seamless and reliable integration of variable and distributed resources.
- Long-term system planning to determine technology investments that optimize DER and microgrid deployment with grid configurations.

Disruptive Changes Will Require New Business Models, Advanced System Designs, and Long-Term Planning

Going forward, business models must consider new market entrants from consumers-as-producers and the evolving role of the distribution utility from supplier to coordinator of highly distributed generation and energy resources. With greater levels of customer generation and energy efficiency, the traditional utility business model may be threatened by reduced revenues, increased costs, and lower profitability potential for utilities (EEI 2013). Regulators may need to consider new rate structures (e.g., applying a combination of fixed rates for all customers and traditional volumetric rates based on energy use) that determine how to best recover the costs of smart grid implementation and fairly allocate costs for grid management and maintenance among customers and third-party businesses.

To effectively integrate thousands of new devices and market participants, utilities across the grid will need advanced controls combined with sophisticated communications and IT to enable stable, reliable, and optimal balance of supply and demand. Effectively integrating these resources requires a more sophisticated, intelligent grid that can dynamically manage power flows between highly distributed energy sources and loads—while maintaining a high standard of reliability and resilience. A transactive energy framework may be needed—one in which utilities, consumers, and other market participants can identify the best technologies, configurations, and system designs that will optimize power flow and financial transactions within regional markets while maintaining wider system stability and efficiency (GWAC 2013).

Long-term investment strategies could be considered to optimize technology and asset deployment while coordinating the competing interests of reliability, efficiency, affordability, and environmental targets. Long-term investment strategies may better align the expectations of utilities, regulators, consumers, suppliers, and state/local governments to reduce uncertainty. New state-mandated strategies may emerge for long-range planning that considers performance-based expectations for integrated smart grid deployments and grid modernization. For example, the Department of Public Utilities (DPU) in Massachusetts has proposed that each electric distribution company develop and submit to the DPU a 10-year strategic grid modernization plan that will: (1) reduce the effects of outages; (2) optimize demand; (3) integrate distributed resources; and (4) improve workforce and asset management (Massachusetts, 2013). Reaching these goals simultaneously requires a coordinated strategy that balances competing demands for an optimal grid design. Plans would include pre-authorization for investments that consider timely cost-recovery based on new measures of expected smart grid benefits.

V. Conclusion

This report was designed to characterize the electricity system as it enters a period of potentially transformative change. Smart grid technologies are being deployed across the nation at varying rates depending largely on decision-making at utility, state, and local levels. The ARRA funding provided a strong incentive for deployment, and noticeable impacts are now being observed with respect to gains in reliability, efficiency, and consumer involvement. Industry has worked with researchers and standards organizations to advance cybersecurity practices and address interoperability challenges. Newly deployed smart grid technologies are now providing information streams that are beginning to advance utility operations and business processes, while engaging residential, commercial, and industrial consumers in electricity management and even production.

Disruptive challenges are on the horizon as the amount of grid-connected renewable and distributed energy increases, requiring an increasingly intelligent, sophisticated grid. However, interoperability and system integration challenges will persist as utilities regularly deploy new information management and control systems. Technology costs and benefits are still being determined and will continue to constrain decisions for deployment. By outlining these challenges, this report may help inform stakeholder decision-making. Many of these are ongoing challenges that we will address again in the next *Smart Grid System Report*, which will be submitted in 2016. In the near term, accelerating future grid modernization will require policymakers to consider technological options, cost recovery mechanisms, and investment planning horizons to ensure utilities meet goals for clean, affordable, reliable, and secure electricity delivery.

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Duke Energy Kentucky - Metering Upgrade Project
Cost and Benefit Details

Year	Program Costs					Program Benefits													
						Operational Savings											Increased Revenue	Customer Savings	
	Total Capital Project Costs	Total O&M Project Costs	Total Capital Recurring Costs	Total O&M Recurring Costs	Enterprise Systems Allocations (1)	Reduced meter reading costs	Reduced meter operations costs - service orders	Reduced meter operations costs - field metering labor	Reduced restoration costs - OK on arrival	Reduced restoration costs - major storms	Associated with Upgrading & Integrating TWACS	Associated with Maintenance of TWACS	Associated with Operating TWACS	Misc O&M savings	Reduced equipment failures	Misc capital savings	Non-technical loss reduction - power theft, equipment failures and installation errors	Customer Feedback Savings - Electric (Prius Effect)	Customer Feedback Savings - Gas (Prius Effect)
2016	[redacted]																		
2017																			
2018																			
2019																			
2020																			
2021																			
2022																			
2023																			
2024																			
2025																			
2026																			
2027																			
2028																			
2029																			
2030																			
2031																			
2032																			
	(46,291,595)	(1,217,844)	(10,361,615)	(10,016,759)	(1,299,000)	27,378,047	11,703,434	638,790	640,716	673,285	3,378,220	708,740	2,943,981	1,212,164	2,843,845	311,699	42,082,116	13,983,216	6,276,881

NOTES:
(1) - Systems include Meter Data Management (MDM) and Openway Meter Head-End (OW)

DEK Cost-Benefit Summary (2016 - 2032)

		Nominal Values	Net Present Values
Costs	Total Project Costs (Capital)	(46,291,595)	(40,141,099)
	Total Project Costs (O&M)	(1,217,844)	(1,084,627)
	Total Project Costs	**(47,509,439)**	**(41,225,726)**
	Total Recurring Costs (Capital)	(10,361,615)	(5,315,054)
	Total Recurring Costs (O&M)	(10,016,759)	(5,260,650)
	Total On-going Costs	**(20,378,374)**	**(10,575,704)**
	Non-Project Systems Allocations (1)	**(1,299,000)**	**(1,096,212)**
	Total Lifecycle Costs	**(69,186,812)**	**(52,897,641)**
Benefits	Operational Savings	52,432,921	27,593,245
	Increased Revenue	42,082,116	22,088,647
	Customer Savings	20,260,097	10,634,402
	Total Lifecycle Benefits	**114,775,135**	**60,316,294**
	Net Benefits vs. Costs	**45,588,322**	**7,418,653**

NOTES:
(1) - Systems include Meter Data Management (MDM) and Openway Meter Head-End (OW)

Discount Rate	**7.05%**

CONFIDENTIAL PROPRIETARY TRADE SECRET

Duke Energy Kentucky - Estimated Costs [Capital and O&M; Program Costs (Project Deployment Initial Capital), Non-recurring (O&M) and Recurring (Capital and O&M)] - 17 Year View

Capital - Program Costs Initial Capital						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	**Initiative**	**Cost Type**	**Cost Subtype**	**Description**	**Total Cost**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
1	AMI/ Smart Meter	Communications	Equipment	Communication device material	$ 1,236,038	[redacted]							
2	AMI/ Smart Meter	Communications	Labor	Communication device labor	$ 415,330								
3	AMI/ Smart Meter	Communications	Labor	Telecom labor	$ 89,316								
4	AMI/ Smart Meter	Communications	Contingency	Telecom contingency	$ 17,430								
5	AMI/ Smart Meter	Field Technology	Equipment	Electric meters material	$ 17,228,947								
6	AMI/ Smart Meter	Field Technology	Labor	Electric meters labor	$ 5,138,020								
7	AMI/ Smart Meter	Field Technology	Other	Electric meters - PM/Support	$ 6,207,407								
8	AMI/ Smart Meter	Field Technology	Contingency	Meter contingency	$ 2,996,339								
9	AMI/ Smart Meter	Eng. & Other Ser	Other	Overhead allocations	$ 2,299,260								
10	AMI/ Smart Meter	Eng. & Other Ser	Other	AFUDC	$ 24,484								

O&M - Program Costs Non-Recurring O&M						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	**Initiative**	**Cost Type**	**Cost Subtype**	**Description**	**Total Cost**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
11	AMI/ Smart Meter	Communications	Equipment	Communication device material	$ 25,000	[redacted]							
12	AMI/ Smart Meter	Eng. & Other Ser	Other O&M	MDM costs	$ 578,425								
13	AMI/ Smart Meter	Eng. & Other Ser	Other O&M	TWACS decommissioning costs (field work)	$ 413,280								
14	AMI/ Smart Meter	Field Technology	Equipment	Electric meters material	$ 25,939								
15	AMI/ Smart Meter	Eng. & Other Ser	Other O&M	TWACS decommissioning costs (IT work)	$ 175,200								

Capital - Recurring Costs						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	**Initiative**	**Cost Type**	**Cost Subtype**	**Description**	**Total Cost**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
16	AMI/ Smart Meter	IT	IT - Hardware	Communication device end of life replacement costs	$ 703,800	[redacted]							
17	AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with communication device failures	$ 442,087								
18	AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with Electric meter failures	$ 2,343,852								
19	AMI/ Smart Meter	Field Technology	Equipment	Material burdens - Electric	$ 360,374								

O&M - Recurring Costs						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	**Initiative**	**Cost Type**	**Cost Subtype**	**Description**	**Total Cost**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
20	AMI/ Smart Meter	Field Technology	Internal Labor	Duke operational labor (head-end system)	$ 1,539,470	[redacted]							
21	AMI/ Smart Meter	Communications	Other O&M	WAN costs	$ 2,054,462								
22	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	Billing team labor to manage interval reads	$ 3,856,627								
23	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	Analytics labor to support revenue protection	$ 2,566,200								

Non-Project Allocations						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	**Initiative**	**Cost Type**	**Cost Subtype**	**Description**	**Total Cost**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
24	AMI/ Smart Meter	Back Office Syste	Other	MDM & OW Enterprise allocation to DEK (1)	$ 1,299,000	[redacted]							

NOTES:
(1) Systems include Meter Data Management (MDM) and Openway Meter Head-End (OW)

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 1,236,038
									$ 415,330
									$ 89,316
									$ 17,430
									$ 17,228,947
									$ 5,138,020
									$ 6,207,407
									$ 2,996,339
									$ 2,299,260
									$ 24,484
									$ 35,652,571

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 25,000
									$ 578,425
									$ 413,280
									$ 25,939
									$ 175,200
									$ 1,217,844

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 703,800
									$ 442,087
									$ 2,343,852
									$ 360,374
									$ 3,850,114

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 1,539,470
									$ 2,054,462
									$ 3,856,627
									$ 2,566,200
									$ 10,016,759

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 1,299,000

CONFIDENTIAL PROPRIETARY TRADE SECRET

Energy Kentucky - Estimated Costs [Capital and O&M; Program Costs (Project Deployment Initial Capital), Non-recurring (O&M) and Recurring (Capital and O&M)] - 17 Year View

- Program Costs Initial Capital					Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
AMI/ Smart Meter	Field Technology	Equipment	Gas modules material	$ 6,439,290	[redacted]							
AMI/ Smart Meter	Field Technology	Labor	Gas modules labor	$ 2,348,038								
AMI/ Smart Meter	Field Technology	Other O&M	Gas modules - PM/Support	$ 1,851,695								

Program Costs Non-Recurring O&M					Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
AMI/ Smart Meter	Field Technology	Equipment	Gas modules material	$ -	[redacted]							
AMI/ Smart Meter	Field Technology	Labor	Gas modules labor	$ -								
AMI/ Smart Meter	Field Technology	Other O&M	Gas modules - PM/Support	$ -								

- Recurring Costs					Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with Gas modules	$ 5,388,531	[redacted]							
AMI/ Smart Meter	Field Technology	Equipment	Material burden costs - Gas modules	$ 1,122,970								

Recurring Costs					Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
AMI/ Smart Meter				$ -	[redacted]							
AMI/ Smart Meter				$ -								

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 6,439,290
									$ 2,348,038
									$ 1,851,695
									$ 10,639,023

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ -
									$ -
									$ -
									$ -

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ 5,388,531
									$ 1,122,970
									$ 6,511,501

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032	All Years
[redacted]									$ -
									$ -

Duke Energy Kentucky - Estimated Costs [Capital and O&M; Program Costs (Project Deployment Initial Capital), Non-recurring (O&M) and Recurring (Capital and O&M)] - 17 Year View

Capital - Project Costs Initial Capital						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
1	AMI/ Smart Meter	Communications	Equipment	Communication device material	$ 1,236,038	[redacted]							
2	AMI/ Smart Meter	Communications	Labor	Communication device labor	$ 415,330								
3	AMI/ Smart Meter	Communications	Labor	Telecom labor	$ 89,316								
4	AMI/ Smart Meter	Communications	Contingency	Telecom contingency	$ 17,430								
5	AMI/ Smart Meter	Field Technology	Equipment	Electric meters material	$ 17,228,947								
6	AMI/ Smart Meter	Field Technology	Labor	Electric meters labor	$ 5,138,020								
7	AMI/ Smart Meter	Field Technology	Other	Electric meters - PM/Support	$ 6,207,407								
8	AMI/ Smart Meter	Field Technology	Contingency	Meter contingency	$ 2,996,339								
9	AMI/ Smart Meter	Eng. & Other Servic	Other	Overhead allocations	$ 2,299,260								
10	AMI/ Smart Meter	Eng. & Other Servic	Other	AFUDC	$ 24,484								
11	AMI/ Smart Meter	Field Technology	Equipment	Gas modules material	$ 6,439,290								
12	AMI/ Smart Meter	Field Technology	Labor	Gas modules labor	$ 2,348,038								
13	AMI/ Smart Meter	Field Technology	Other O&M	Gas modules - PM/Support	$ 1,851,695								

O&M - Project Costs Non-Recurring O&M						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
14	AMI/ Smart Meter	Communications	Equipment	Communication device material	$ 25,000	[redacted]							
15	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	MDM costs	$ 578,425								
16	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	TWACS decommissioning costs (field work)	$ 413,280								
17	AMI/ Smart Meter	Field Technology	Equipment	Electric meters material	$ 25,939								
18	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	TWACS decommissioning costs (IT work)	$ 175,200								

Capital - Recurring Costs						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
19	AMI/ Smart Meter	IT	IT - Hardware	Communication device end of life replacement costs	$ 703,800	[redacted]							
20	AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with communication device failures	$ 442,087								
21	AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with Electric meter failures	$ 2,343,852								
22	AMI/ Smart Meter	Field Technology	Equipment	Material burdens - Electric	$ 360,374								
23	AMI/ Smart Meter	Field Technology	Equipment	Annual costs assoc. with Gas modules	$ 5,388,531								
24	AMI/ Smart Meter	Field Technology	Equipment	Material burden costs - Gas modules	$ 1,122,970								

O&M - Recurring Costs						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
25	AMI/ Smart Meter	Field Technology	Internal Labor	Duke operational labor (head-end system)	$ 1,539,470	[redacted]							
26	AMI/ Smart Meter	Communications	Other O&M	WAN costs	$ 2,054,462								
27	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	Billing team labor to manage interval reads	$ 3,856,627								
28	AMI/ Smart Meter	Eng. & Other Servic	Other O&M	Analytics labor to support revenue protection	$ 2,566,200								

Non-Project Allocations						Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Row #	Initiative	Cost Type	Cost Subtype	Description	Total Cost	2016	2017	2018	2019	2020	2021	2022	2023
29	AMI/ Smart Meter	Back Office Systems	Other	MDM & OW Enterprise allocation to DEK (1)	$ 1,299,000	[redacted]							

NOTES:
(1) Systems include Meter Data Management (MDM) and Openway Meter Head-End (OW)

Capital - Project Costs Initial Capital	[redacted]
O&M - Project Costs Non-Recurring O&M	
Total Project Costs	
Capital - Recurring Costs	
O&M - Recurring Costs	
Total Recurring Costs	
Total Capital	
Total O&M	
Total Project and Recurring Costs	
Non-Project MDM & OW Allocations	

CONFIDENTIAL PROPRIETARY TRADE SECRET

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Years 4-17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032		All Years
[redacted]										$ 1,236,038
										$ 415,330
										$ 89,316
										$ 17,430
										$ 17,228,947
										$ 5,138,020
										$ 6,207,407
										$ 2,996,339
										$ 2,299,260
										$ 24,484
										$ 6,439,290
										$ 2,348,038
										$ 1,851,695
										$ 46,291,595

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Years 4-17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032		All Years
[redacted]										$ 25,000
										$ 578,425
										$ 413,280
										$ 25,939
										$ 175,200
										$ 1,217,844

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Years 4-17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032		All Years
[redacted]										$ 703,800
										$ 442,087
										$ 2,343,852
										$ 360,374
										$ 5,388,531
										$ 1,122,970
										$ 10,361,615

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Years 4-17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032		All Years
[redacted]										$ 1,539,470
										$ 2,054,462
										$ 3,856,627
										$ 2,566,200
										$ 10,016,759

Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Years 4-17	Total
2024	2025	2026	2027	2028	2029	2030	2031	2032		All Years
[redacted]										$ 1,299,000

[redacted]	$ 46,291,595
	$ 1,217,844
	$ 47,509,439
	$ 10,361,615
	$ 10,016,759
	$ 20,378,374
	$ 56,653,209
	$ 11,234,603
	$ 67,887,812
	$ 1,299,000

Annual Electric Benefits		Electric & Gas Allocation		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Benefit Type	**Duke Benefit Description**	**Electric Percentage**	**Gas Percentage**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Expense Reduction	**Reduced meter reading costs**	**67%**	**33%**	[redacted]					
	Reduced meter operations costs - consumer order workers for meter orders	**100%**	**0%**	[redacted]					
	Reduced meter operations costs - field metering labor	**100%**	**0%**	[redacted]					
Avoided Costs - O&M	**Avoided restoration costs - OK on arrival**	**100%**	**0%**	[redacted]					
	Avoided restoration costs - major storms	**100%**	**0%**	[redacted]					
	Associated with Upgrading & Integrating TWACS	**75%**	**25%**	[redacted]					
	Associated with Maintenance of TWACS	**75%**	**25%**	[redacted]					
	Associated with Operating TWACS	**75%**	**25%**	[redacted]					
	Miscellaneous O&M savings	**100%**	**0%**	[redacted]					
Avoided Costs - Capital	**Avoided equipment failures**	**100%**	**0%**	[redacted]					
	Miscellaneous capital savings	**100%**	**0%**	[redacted]					
Increased Revenue	**Non-technical loss reduction - power theft, equipment failures and installation errors**	**100%**	**0%**	[redacted]					
Customer Savings	**Customer Feedback (Prius Effect - Electric)**	**100%**	**0%**	[redacted]					
	Customer Feedback (Prius Effect - Gas)	**0%**	**100%**	[redacted]					
	Total			[redacted]					

CONFIDENTIAL PROPRIETARY TRADE SECRET

Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**All Years**
[redacted]											$ 18,343,292
											$ 11,703,434
											$ 638,790
											$ 640,716
											$ 673,285
											$ 2,533,665
											$ 531,555
											$ 2,207,986
											$ 1,212,164
											$ 2,843,845
											$ 311,699
											$ 42,082,116
											$ 13,983,216
											$ -
											$ 97,705,763

CONFIDENTIAL PROPRIETARY TRADE SECRET

DUKE ENERGY

Annual Gas Benefits		Electric & Gas Allocation		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Benefit Type	Duke Benefit Description	Electric Percentage	Gas Percentage	2016	2017	2018	2019	2020	2021
Expense Reduction	Reduced meter reading costs	67%	33%	[redacted]					
	Reduced meter operations costs - consumer order workers for meter orders	100%	0%						
	Reduced meter operations costs - field metering labor	100%	0%						
Avoided Costs - O&M	Avoided restoration costs - OK on arrival	100%	0%						
	Avoided restoration costs - major storms	100%	0%						
	Associated with Upgrading & Integrating TWACS	75%	25%						
	Associated with Maintenance of TWACS	75%	25%						
	Associated with Operating TWACS	75%	25%						
	Miscellaneous O&M savings	100%	0%						
Avoided Costs - Capital	Avoided equipment failures	100%	0%						
	Miscellaneous capital savings	100%	0%						
Increased Revenue	Non-technical loss reduction - power theft, equipment failures and installation errors	100%	0%						
Customer Savings	Customer Feedback (Prius Effect - Electric)	100%	0%						
	Customer Feedback (Prius Effect - Gas)	0%	100%						
	Total								

CONFIDENTIAL PROPRIETARY TRADE SECRET

Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**All Years**
[redacted]											$ 9,034,756
											$ -
											$ -
											$ -
											$ -
											$ 844,555
											$ 177,185
											$ 735,995
											$ -
											$ -
											$ -
											$ -
											$ -
											$ 6,276,881
											$ 17,069,372

CONFIDENTIAL PROPRIETARY TRADE SECRET

DUKE ENERGY.

Annual Electric and Gas Benefits		Electric & Gas Allocation		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Benefit Type	Duke Benefit Description	Electric Percentage	Gas Percentage	2016	2017	2018	2019	2020	2021
Expense Reduction	Reduced meter reading costs	67%	33%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Reduced meter operations costs - consumer order workers for meter orders	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Reduced meter operations costs - field metering labor	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avoided Costs - O&M	Avoided restoration costs - OK on arrival	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Avoided restoration costs - major storms	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Associated with Upgrading & Integrating TWACS	75%	25%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Associated with Maintenance of TWACS	75%	25%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Associated with Operating TWACS	75%	25%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Miscellaneous O&M savings	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avoided Costs - Capital	Avoided equipment failures	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Miscellaneous capital savings	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Increased Revenue	Non-technical loss reduction - power theft, equipment failures and installation errors	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Savings	Customer Feedback (Prius Effect - Electric)	100%	0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Customer Feedback (Prius Effect - Gas)	0%	100%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Operational Savings				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Increased Revenue				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Customer Savings				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Total
2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	
[redacted]											$ 27,378,047
											$ 11,703,434
											$ 638,790
											$ 640,716
											$ 673,285
											$ 3,378,220
											$ 708,740
											$ 2,943,981
											$ 1,212,164
											$ 2,843,845
											$ 311,699
											$ 42,082,116
											$ 13,983,216
											$ 6,276,881
											$ 114,775,135
											$ 52,432,921
											$ 42,082,116
											$ 20,260,097