PUBLIC AG-DR-01-048

REQUEST:

Reference the Schneider testimony at p. 25. If DEK's petition is approved, and after the completion of the upgrade program, in the event that DEK's cost-benefit analysis performed in regard to the instant filing does not establish that benefits are greater than costs, would DEK be willing to make a partial rate refund to restore its ratepayers to at least the point at which they suffer no financial detriment? If not, why not?

a. Does DEK's cost-benefit analysis include all costs and all benefits? If not, why not?
b. Does DEK's cost-benefit analysis provide a monetary value for all quantifiable benefits? If so, explain how that monetary value was derived.
c. As part of DEK's commitment that its proposed meter upgrade will provide greater quantifiable benefits than the cost of the program, is DEK willing to provide annual reporting for each of five (5) years following the completion of the program that would update both costs and benefits? If not, why not?
d. Provide a per-meter breakdown of costs and quantifiable benefits (in monetary terms) which DEK believes ratepayers in each class will receive.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET</u>

Objection. This Data Request is overly broad, unduly burdensome, misstates facts and seeks to elicit information that is neither relevant nor likely to lead to the discovery of admissible evidence. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, the Company's cost related to the AMI deployment will be subject to a review in its next base rate cases for both gas and electric base rates. Since customers will not pay for this metering upgrade until after the Company receives an order in the next rate case(s) there should be no need for any rate refunds. The Company's position is that its analysis shows that the metering upgrade is a prudent investment for the Company to make on the behalf of its customers. If the Commission agrees and approves the investment as part of this CPCN Application, then the Company should be permitted to recover all of its costs.

a. Duke Energy Kentucky's cost-benefit analysis quantified all foreseen costs associated with the deployment as well as benefits that could be reasonably quantified.

b. Yes. Monetary values for all quantifiable benefits can be found on Confidential Attachment DLS-3 and Confidential Attachment DLS-4. For the main quantifiable benefits referenced, Duke Energy Kentucky used a combination of experience in other jurisdictions and industry studies as listed below. These benefits were identified by the Department of Energy (DOE) and the Electric Power Research Institute (EPRI) in their *2014 Smart Grid System Report* (Pages 4 to 6). See AG-DR-01-048(1) Attachment. From there, Duke Energy Kentucky estimated values for those benefits based on internal experience or expertise.

   Reduced Meter Reading and Operations Costs: The DOE and EPRI study identifies reduced meter reading and operations costs from remote meter reading and the ability to perform remote connects/disconnects as a benefit of AMI. Duke

Energy experts in Meter Reading and Metering Services, who are familiar with Duke Energy Ohio's experience, were consulted in how these cost savings could be achieved for Duke Energy Kentucky.

Reduced Restoration Costs: Direct experience from Duke Energy Ohio's AMI deployment was used in calculating the reduced costs for this benefit category. Experts in Distribution Operations at Duke Energy Kentucky and Duke Energy Ohio were consulted in these cost savings could be achieved for Duke Energy Kentucky.

TWACS Costs: With the retirement of the metering infrastructure from the 2007 pilot, reduced costs are based on future upgrade costs necessary to continue support of the back office systems necessary to operate the infrastructure as well as continued maintenance and operating costs. These reduced costs would be removed from future years' operating budgets.

Non-Technical Losses: This benefit estimate is based upon: [redacted] (EPRI, 2008, "Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In The Future", Page 1-17). See STAFF-DR-01-32(a)(1) Confidential Attachment, being provided under a petition for confidential treatment. Duke Energy Kentucky applied the [redacted] figures to historic revenue in the jurisdiction to arrive at the estimated benefit value.

STAFF-DR-01-32(a)(2) Confidential Attachment, being provided under a petition for confidential treatment, is the work paper used by Duke Energy Kentucky to estimate this benefit.

Customer Feedback (Prius Effect): This benefit estimate is based upon: "The reported annual household kWh reductions range from zero to 28%. The average for indirect feedback is 8.4% and that attributed to direct feedback is 35% higher (11.5%)" (EPRI, 2008, "Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments", Page 5-2, publicly available at:

http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001017006). Based on data from Google Analytics, approximately 6% of Duke Energy Ohio's customers directly accessed the interval usage data from their AMI meter over a 12 month period (roughly 44,000 customers). Duke Energy Kentucky therefore assumed that 6% of its customers could reduce their electric usage by 11.5% by virtue of having direct feedback of their interval usage data. STAFF-DR-01-32(a)(2) Confidential Attachment, being provided under a petition for confidential treatment, is the work paper used by Duke Energy Kentucky to estimate this benefit.

c. Objection. The question misstates the Company's testimony and analysis insofar as alleging that the Company has committed to achieving a specific level of costs versus benefits. The Company's analysis is based upon the best information that is available. While the Company believes its analysis is sound, the Company cannot guarantee that the actual costs versus actual benefits will be identical to what has been presented in the Company's analysis. Without waiving said objection, and to the extent discoverable, if the Commission approves the Company's application as requested, the Company would be willing to discuss the frequency of reporting and reasonable level of content for reporting this information, but realizes while benefits identified in the cost-benefit analysis are easy to quantify, they are not necessarily easy to track.

d. Duke Energy Kentucky has not conducted such a per-meter analysis.

PERSON RESPONSIBLE: Peggy Laub (initial question and part d)
Donald L. Schneider, Jr. (a)-(c)
Legal- As to objections

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

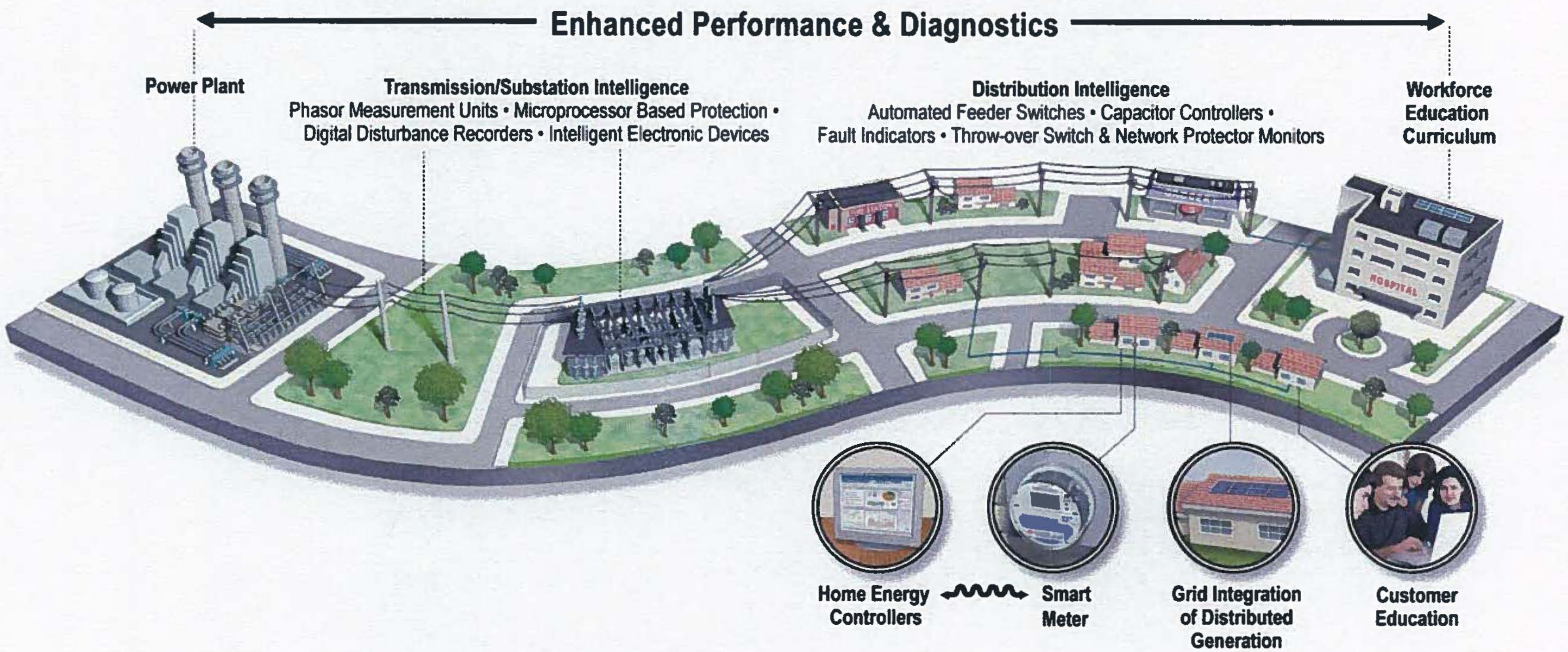
- **The Honorable Lisa Murkowski**
  Ranking Member, Senate Committee on Energy and Natural Resources

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.

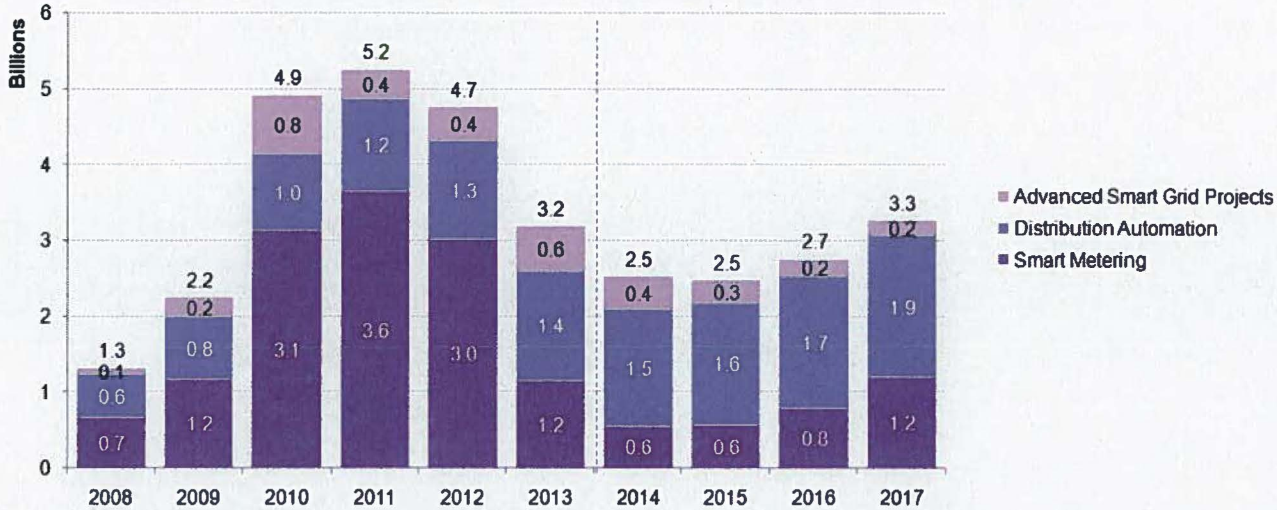
III. Smart Grid Deployment Status

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.

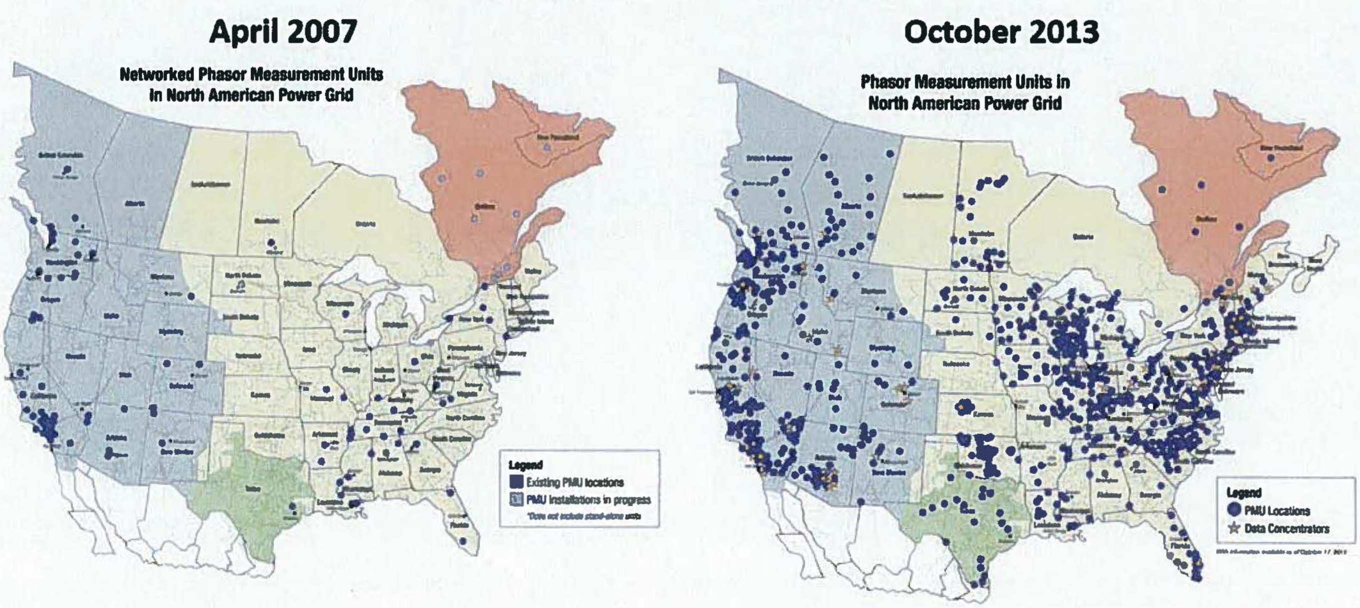
Since the 2003 Northeast blackout investigation revealed inadequate situational awareness for grid operators, utilities have increasingly deployed synchrophasors to provide real-time, wide-area grid visibility. Synchrophasors can provide time-stamped data 30 times per second or faster, which is 100 times 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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AG-DR-01-049

REQUEST:

Reference the Schneider testimony at pp. 27-28, wherein he discusses potential energy savings due to next-day interval usage data customer feedback, which he refers to as the "Prius Effect."

a. Provide the amount of estimated savings for this benefit.

RESPONSE:

a. Estimated savings associated with the Prius Effect are shown as the "Customer Savings" on Confidential Attachment DLS-3 and detailed by electric/gas and by year in Confidential Attachment DLS-4 as "Customer Savings".

PERSON RESPONSIBLE: Donald L. Schneider, Jr.

REQUEST:

Since DEK asserts that the meter upgrade program will lead to enhanced revenue collection and operational savings to the company, does it agree that if the program is approved, it will face less financial risk? If it does not so agree, why not?

RESPONSE:

Objection. The question is vague, overbroad, unduly burdensome, speculative and confusing insofar as what is intended by the phrase less financial risk. Without waiving said objection, and to the extent discoverable, the meter upgrade program will lead to more accurate revenue billing but will not enhance the collection of revenue from customers. The Company will face the same financial risks as it does today.

PERSON RESPONSIBLE: Peggy Laub

AG-DR-01-051

REQUEST:

Reference the Schneider testimony at p. 28, lines 5-15 wherein he discusses operational savings, and in which he states that once the meter upgrade program is completed, DEK's annual operational costs will be lower than what they otherwise would be.

a. Has this proven true in other Duke Energy jurisdictions that have employed an AMI meter upgrade program? If so, provide the amount of the decrease in terms of a percentage.

RESPONSE:

Duke Energy Ohio is the only one of Duke Energy's jurisdictions that has fully deployed the metering solution. While some operational benefits are hard to quantify, there is a marked decrease in Duke Energy Ohio's annual meter reading expenses from 2008 to 2015 as evidenced by the balance in FERC Account 902 reported in Duke Energy Ohio's FERC Forms 1 and 2. In 2008, the total meter reading expenses for both gas and electric reported in this account was $8.84 million. Adjusting this figure for inflation, using the Consumer Price Index (CPI), produces an inflation-adjusted figure for 2008 of $9.78 million, in 2015 dollars. For calendar year 2015, Duke Energy Ohio recorded $2.37 million in FERC account 902, which is approximately a 75% decrease since 2008 - the year Duke Energy Ohio began deploying its AMI solution.

PERSON RESPONSIBLE: Peggy Laub

REQUEST:

Reference the Schneider testimony at p. 32, lines 10-14, wherein he discusses DEK's "robust planning and evaluation process for its grid investments." Elaborate on the nature and extent of this plan, including the type of investments and programs envisioned.

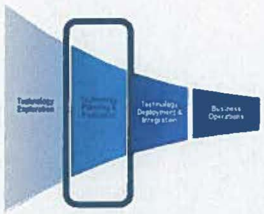
RESPONSE:

The referenced section of testimony refers to the project lifecycle process through which smart grid investments are considered and selected for deployment for Duke Energy Kentucky. The Duke Energy Kentucky Smart Grid Project Lifecycle is provided as Attachment AG-DR-01-052(1).

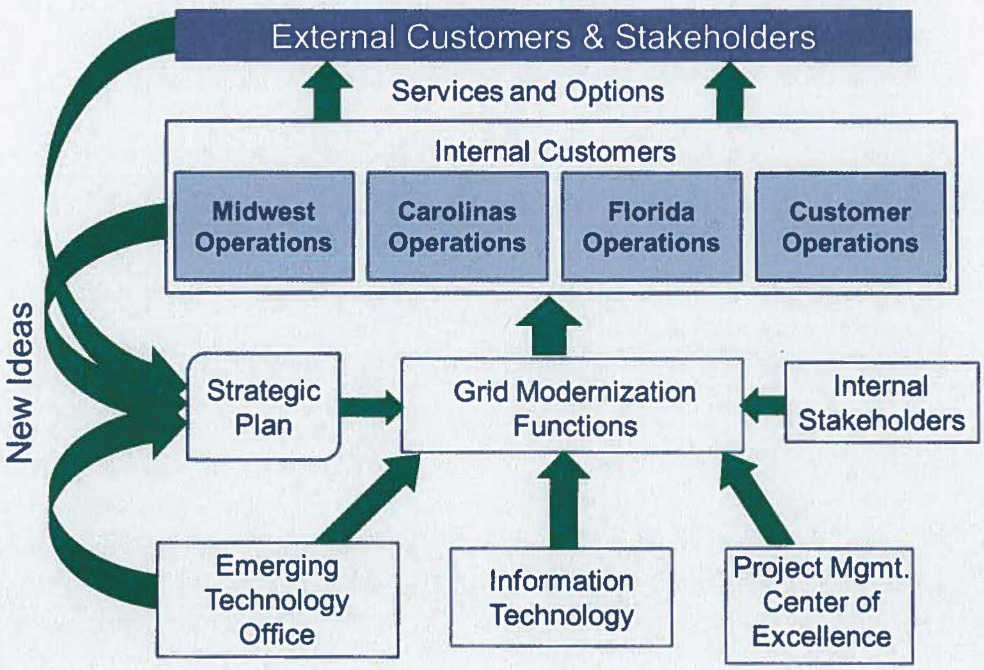
PERSON RESPONSIBLE: Donald L. Schneider, Jr.

Technology Planning & Evaluation

Planning and Executing on the Strategy



While the Company believes its strategic planning process will help it effectively allocate capital and resources to the right priorities, it also feels it maintains the organizational functions and development processes required to plan and execute against the 3-5 year Strategic Plan in an efficient, effective, low-risk manner. The figure below describes how front line business operations and corporate functions work together to accomplish the goals and manage the portfolio of initiatives established by the strategic planning process to create value. Duke Energy's grid modernization organizations play a central role in converting capital and resources into customer benefits.



The grid modernization functions at Duke Energy use a six step Stage-Gate process as pictured in the figure below to drive ideas and projects through the project lifecycle. Each Gate is governed by a cross-functional team (either the Grid Investment Development Team or the Project Management Team) to review ideas and make the decisions on whether or not they support the strategic plan and monitor projects to ensure they are implemented successfully.

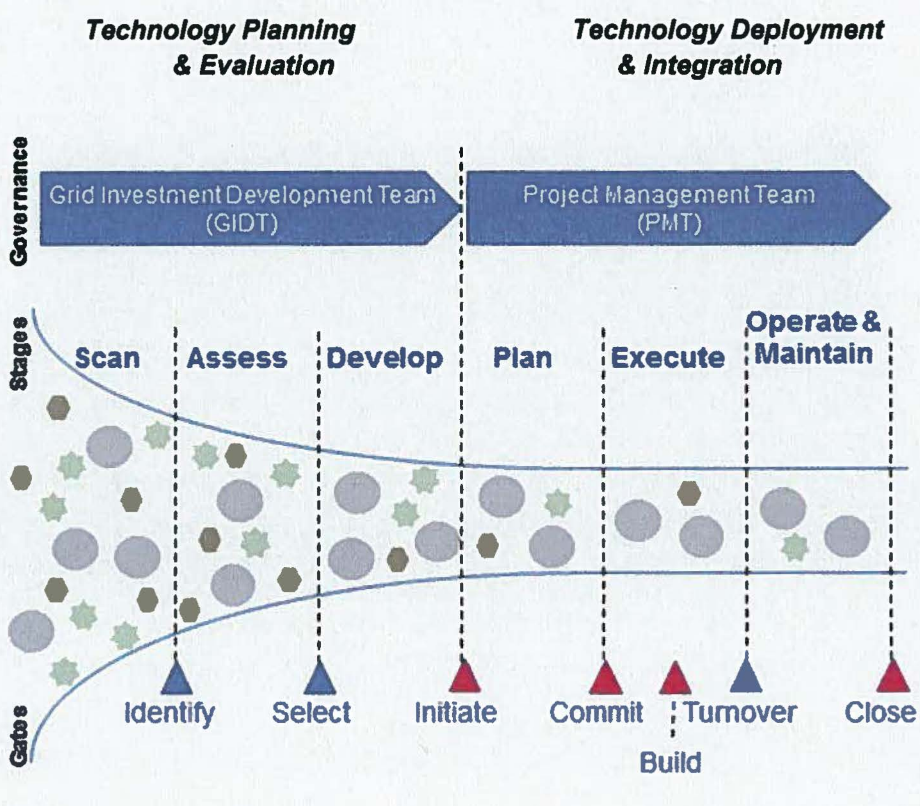
The project lifecycle is a recognized best practice for:

- Creating a portfolio of new ideas
- Assessing the ideas at a high level to identify those with the greatest promise
- Developing selected ideas into full business cases
- Planning and executing the projects selected for deployment
- Operating and maintaining the new assets and business processes

The Project Lifecycle: A Portfolio Management Tool

The Project Management Center of Excellence (PMCoE) project lifecycle methodology, built from the Project Management Institute (PMI) best practices, is a proven approach to idea evaluation and project management designed to reduce the cost and risk of developing a portfolio of initiatives and maximizing the value created per unit of resource input.

Grid Modernization Project Lifecycle



Scan Stage

The Scan Stage is designed to identify ideas available to help accomplish the Strategic Plan. It involves the clarification and synthesis of ideas presented to the grid modernization teams.

Identify Gate

The Grid Investment Development Team ("GIDT) regularly reviews potential projects to clarify ideas, approving some for more rigorous evaluation in the Assess Stage. Ideas are prioritized for the Assess Stage based on the degree to which each helps accomplish grid modernization strategy objectives relative to preliminary estimates of implementation effort. The Scan Stage is designed to generate and clarify many ideas and identify those worthy of additional evaluation.

Assess Stage

The Assess Stage can consist of different components for different project types. For example, not all technologies or concepts approved for the Assess Stage will require feasibility or market testing, though many, or perhaps even most, will.

Select Gate

The GIDT was formed to oversee the grid modernization project portfolio. The GIDT consists of a select group of key internal cross-functional stakeholders, each supported by subject matter experts, and has the following duties and responsibilities:

- Guide allocation of resources and funding within the project portfolio
- Develop, review, provide guidance on, and approve project, portfolio, or policy changes in support of the annual planning and budgeting process and as needed due to emergent issues and/or changing priorities
- Assure project portfolio alignment with corporate and grid modernization strategies
- Review information at the Select and Initiate Gates and choose to advance (to Develop and Plan/Execute Stages, respectively) or archive ideas

In prioritizing ideas for the Develop Stage, the GIDT takes into account value creation relative to costs. Value creation is defined by the Strategic Plan, which has identified four priorities for investment as identified below.

- Reduce costs
- Improve reliability
- Increase efficiency
- Enhance customer offerings

Assuming a proposed solution passes feasibility and technology and/or market tests, the information is summarized for the GIDT to review. The GIDT may move a concept design to the Develop Stage, archive it for future consideration, or recommend additional evaluation in the Assess Stage for subsequent reconsideration.

Develop Stage

The primary objective of the Develop Stage is to select assessed ideas for full development and implementation. The stage involves the transformation of ideas into projects and the development of a full business case and business plan (the Project Authorization Package).

Initiate Gate

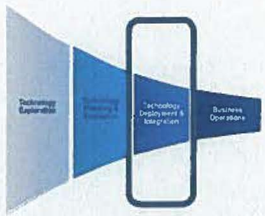
The GIDT described in the Assess Stage above must approve ideas refined in the Develop Stage for advancement into the Plan/Execute Stages. At the Initiate Gate, the GIDT must review the information below as it considers whether or not to approve an idea for the Plan/Execute Stages:

- Project charter (goals, performance measures, and approach)
- Project team (employees leading particular aspects of project planning and execution)
- Business case (including estimates of project cost, scope & schedule)
- Lessons learned (a review of other utilities' experiences implementing the idea)
- Risk register (major events, associated probabilities, impacts, preventative measures, and recovery controls)

Once a fully-developed idea is approved for the Plan and Execute Stages, it becomes a project. Responsibility for the management of approved projects from this point in the project lifecycle through completion falls to the Project Management Team ("PMT") described in the Plan & Execute section.

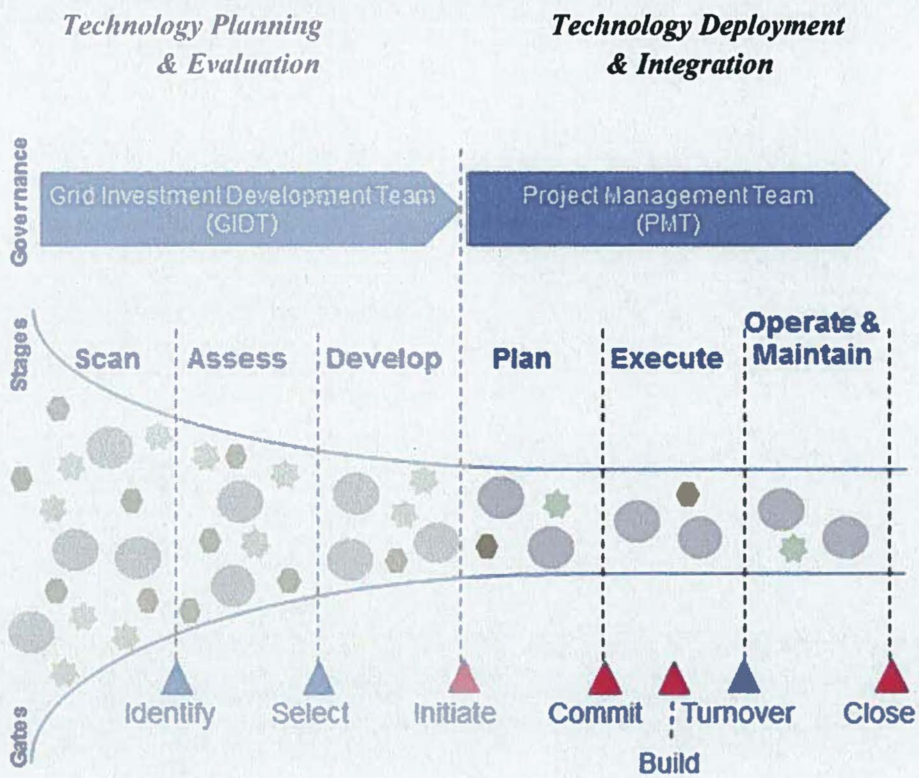
These materials are summarized into a Project Authorization Package for GIDT review. The objective is to include in the Package all the information the GIDT might need to make an informed decision. The GIDT can approve the project for the Plan/Execute Stage, archive it for future consideration, or recommend additional development efforts for subsequent reconsideration. Once a project is approved for the Plan/Execute Stage, responsibility transitions from the GIDT to the PMT.

Technology Deployment & Integration



Duke Energy's program management function is responsible for driving ideas and projects through the project lifecycle and for maintaining development process discipline. The technology deployment and integration functions – with review and input from the technology planning and evaluation functions – plan and execute projects approved for implementation and transition projects to operating organizations. As depicted in the graphic below, technology deployment and integration is aligned with the second half of the project lifecycle.

The Grid Modernization Project Lifecycle



The Plan and Execute Stages can best be summarized as, "Plan the work, work the plan, and monitor progress." Though the Plan and Execute Stages are technically two distinct stages separated by an approval gate (the Commit Gate) and incorporating an extra check step (the Build Gate), all are presented together here as they are so closely inter-related.

The Commit Gate is one of the most critical steps in the Lifecycle, as the costs of failing to proceed with a project past this point can become significant. Projects approved through the

Initiate Gate become the responsibility of the PMT, which is comprised of representatives from the cross-functional stakeholders across the enterprise.

Plan Stage

In the Plan Stage, the Project Team begins with the Project Authorization Package as a starting point and adds the additional detail the team will use to guide their work if the Project is approved for Execution. The package is sufficiently detailed regarding scope, schedule, and budget, such that it can be used as a control document to measure progress during the Execute Stage. Full Work Breakdown Structures for all primary Project components are developed and presented to the PMT at the Commit Gate as part of the package.

In addition, an Organizational Readiness Assessment is added in the Plan Stage. This is a prescribed process for ensuring that the organizations with roles to play in the Work Breakdown Structure are available and prepared to execute their respective components according to the schedule and work breakdown structure.

Commit Gate

At the Commit Gate, a Project Team presents an updated Project Authorization Package to the PMT. If the PMT approves a project through the Commit Gate to the Execute Stage, its Project Team is allowed to publicly announce a project and enter into contracts with suppliers. The Project Team artifacts reviewed by the PMT when considering approval for Execution include:

- Detailed Project Implementation Plan
- Updated Project Authorization Package
- Project Readiness Assessment
- Project Maturity (vendors, technology, organization, regulatory)
- Vendor contract legal review
- Independent Review trigger assessment

If the PMT is not satisfied with each document, it assigns re-works to the Project Team and asks them to return to PMT for reconsideration upon completion. It can also recommend the Project be archived for future consideration or approve the Project for execution.

Execute Stage

With Commit Gate approval of the Project Authorization Package, the Project Team begins to implement the extensive plans it had established for itself in the Plan Stage. The Project Team must submit monthly status reports in a prescribed format regarding project scope, schedule, costs, and operational readiness (for next steps), relative to the Project Authorization Package. Project Teams must request approvals for variances from the approved Project Authorization Package, as summarized below:

- Scope Change Requests
- Schedule Change Requests
- Cost Change Requests

When a Project proceeds to the point where fixed assets are ready to be installed, the Project Team must request authorization from the PMT to do so through an additional check step – the Build Gate.

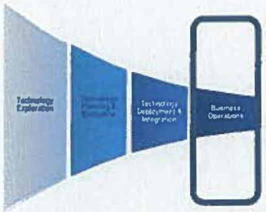
Build Gate

Build Gate is somewhat unique in that it is an interim approval within a stage (the Execute Stage). Duke Energy employs the Build Gate as a final check before assets are installed. At the Build Gate, a Project Team presents a final update to all components of the Project Authorization Package. As may be required anywhere within the Plan/Execute Stage, independent review of the Project Authorization Package and cost estimates may be triggered when variances in costs from the Plan Stage to the Build Gate update are observed.

Once the PMT is satisfied, asset installation may proceed according to the approved Package. Monthly project status reporting and change request requirements continue as described above. Operational readiness is then ensured through Business Process Management and Change Management services (see the next section on the Turnover Gate and the Operate and Maintain Stage for more information).

Business Operations

Operate/Maintain Stage



Parts of the Execute Stage, the Turnover Gate, and the Operate/Maintain Stage are presented together in this section as they are so closely related:

- Business Process Management and Change Management
- Turnover (also known as Commissioning) Gate requirements
- Performance measurement and review as part of the Operate/Maintain Stage

Business Process and Change Management

Though technically part of the Execute Stage, Business Process Management and Change Management are presented as part of the Operate and Maintain Stage as they are a critical part of ongoing capability operation and maintenance. The objective of both Business Process Management and Change Management is to maximize the use and value of new capabilities through operational readiness.

Business Process Management is a service offered by the grid modernization Technology Deployment & Integration functions to help operating units maximize the value of new capabilities. Business Process Management helps operating functions (like Carolinas Operations or Customer Care) design the optimum work flows associated with new capabilities. This is accomplished through a formal approach to plan, build and deploy new processes.

Change Management helps operating functions transition from old processes to new processes. Working in collaboration with the operating units, the Change Management team prepares, manages, and implements the changes necessary to incorporate the new technology and systems.

Turnover (also known as Commissioning) Gate Requirements

For a project to be approved for the Operate/Maintain Stage, the operating function responsible for delivering upon a new capability made available through grid modernization investment must sign off on its capability to operate and maintain the new capability.

Performance Measurement and Review as Part of the Operate/Maintain Stage

The grid modernization Program Management Office measures the performance of a new capability after the Turnover Gate. Actual benefits generated and performance are compared to the criteria established in the Assess Stage and the benefits expectations described in the approved Develop Stage Project Authorization Package. Project costs are compared to those approved in the Develop Stage Project Authorization Package. Post-project performance measurement and review frequently yields great new ideas for input into the Scan Stage.